Which way is forward? Analysis of key choices for New Zealand's energy sector

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In a nutshell – key messages in one page

The 100% renewables question

- New Zealand's robust carbon price is unleashing a wave of renewable generation investment.
- This will power the decarbonisation-through-electrification of transport and fossil heating, and should displace almost all our fossil generation, reaching 98.5% renewables by 2030.
- In a highly renewable system, the amount of additional flexibility resources required to address dry-year and seasonal issues significantly reduces.
- However, meeting infrequent periods of North Island capacity scarcity grows as a major new flexibility challenge.
- The fundamental physics of renewable variability, coupled with renewables' inherent capital intensity, makes the cost of progressively displacing the last 1-1.5% of fossil generation exponentially more expensive.
- Forcing 100% renewables by as early as 2030, will lead to higher costs of electricity supply resulting in higher consumer electricity prices. In turn, the rate of electrification will be reduced resulting in higher rest-of-economy costs and emissions.
- Forcing 100% renewables with single mega-scale flexibility assets, such as a very large pumped hydro scheme, appears particularly costly and risky.
  - Mega-scale solutions located in the South Island are not well-suited to meeting North Island capacity scarcity requirements. (Plus, will reduce resilience against natural disaster.)
  - Mega-scale solutions which may not arrive until 2035 or later will be too late to provide the flexibility resources to manage a highly renewable system required by 2030, or earlier.
  - Mega-scale solutions will tend to crowd-out other flexibility providers such as demand-response from large industrial consumers or a flexible hydrogen production facility.
  - Commissioning a very large pumped hydro scheme will likely lead to significantly elevated prices (and higher fossil generation) in the 2-3 years of its reservoir being filled.

The green hydrogen question

- Green hydrogen is not an economic pathway to decarbonise pipeline fossil gas used for heating. This conclusion is robust against a wide range of possible futures for technology costs.
- Additionally, the amount of additional renewable generation required for a green hydrogen future will make an already challenging build requirement, even more challenging.
- Similarly, building large scale green hydrogen production for export will increase renewable build requirements and, despite likely flexible hydrogen production, electricity prices.
- New Zealand's higher costs and emissions from this outcome may be worthwhile if a sufficient premium can be earned from hydrogen sales. Any risk that New Zealand hydrogen may not be competitive in the long-term against international alternatives will need to be managed with a dependable offtake contract with a well-designed termination clause.

Network challenges

- To minimise electrification-driven network investment will require 'smart' demand solutions.
- Smart management of electric vehicles and hot water should be the highest priority, as they dominate (by orders of magnitude) the technical and economic potential.

Executive Summary

This report analyses a number of key 'pathway' choices for New Zealand's energy transition:

- Whether to intervene to force 100% renewable electricity generation by a fixed date?
- Whether green hydrogen should be pursued as an option for decarbonising pipeline gas?
- Whether New Zealand should develop large-scale green hydrogen export facilities to sell hydrogen to 'renewables poor' countries such as Japan and South Korea?
- How network challenges of the energy transition should be best addressed?

The modelling for this work was to support a Boston Consulting Group study – *The Future is Electric* – but this report presents Concept's key insights from our analysis, plus more detail on the key drivers of outcomes.

New Zealand is already heading for close to 99% renewable electricity generation

In response to a robust carbon price, New Zealand has started to rapidly accelerate development of renewable electricity generation. Not only will this power the decarbonisation-through-electrification of road transport and fossil heating, but it should also result in the displacement of almost all our fossil generation (including all coal-fired generation) by 2030.

Our modelling shows that, unless external factors (such as consenting constraints) hinder renewable development, this carbon-price-driven development should see New Zealand achieving 98.5% renewable generation by 2030. As a consequence, emissions from the remaining fossil generation should fall by 92% compared to 2021. By 2030, emissions from geothermal stations should be almost two-and-a-half times greater than from the remaining (entirely gas-fired) peaking stations.

Flexibility to manage South Island dry years will reduce in importance as North Island peak capacity scarcity grows in importance

The type of duty required for fossil stations will also significantly change.

Historically, managing dry years (particularly in the South Island, and particularly in wintertime) has been one of the most important drivers of the need for 'flexible' resources that can increase output for extended lengths of time during periods of scarcity. But in a system with 98.5% renewables, 'renewable overbuild' will replace 'fossil overbuild' (ie, building capacity that is only required for some of the time) for a significant proportion of this duty.

While procuring flexibility resources to manage dry year issues will reduce in importance in a highly-renewable system, managing North Island peak capacity scarcity will grow in importance. Intermittent renewables such as wind and solar are much less able to contribute to meeting periods of peak demand. Managing periods when the wind is not blowing, and the sun is not shining – particularly at times of peak demand, and particularly in the North Island (where the majority of the renewables will be built) – will become increasingly challenging.

The much shorter duration of these periods of peak capacity scarcity (compared to the longer duration of seasonal and dry year events) means there should be many more types of flexibility resources that could meet these flexibility requirements: Batteries (both in electric vehicles (EVs) and as stand-alone grid batteries) can meet much of this duty. For the very infrequent periods of extreme scarcity, demand response will be more cost-effective than building grid batteries to be called upon for a few hours a year, on average. In particular, industrial demand that has some flexibility could become much more useful. Although such industrial users would be called upon to reduce demand at times, they could achieve significant electricity price reductions as a result.

Although all these new flexibility sources will significantly reduce the need for fossil-fuelled generation, we expect a residual need for gas-fired peaking stations. These would operate infrequently, but should be the most cost-effective option for providing firm capacity that is seldom needed – even at high carbon prices.

100% renewables by 2030 is technically feasible but high cost, leading to higher electricity prices and poorer whole-of-economy economic and emissions outcomes

In addition to modelling pathways with a continuation of some limited fossil generation, we modelled the cost and emission impacts of two different 100% renewable by 2030 'pathways':

- A multi-resource scenario (called 'Renewable Pioneer') which called upon a greater amount of renewable and battery development, but also called upon 'green peakers': running the OCGTs on biofuels (such as biodiesel) rather than fossil gas. The price of the biofuel was estimated to be \$45/GJ compared to \$12/GJ for fossil gas for peaking.
- A 'Mega Infrastructure Build' scenario which included the building of an 800 MW Pumped Hydro Storage scheme (along the lines of the proposed Onslow project). Our system modelling found that this scenario would also require the development of a similar amount of North Island green peakers to achieve 100% renewables (albeit operating less often), as the limitations of the HVDC cable linking the North and South Islands would constrain a South Island-located mega-scale project's ability to help meet peaking capacity in the North Island.

Both pathways were compared with pathways which retained some fossil generation. All pathways faced the same carbon price projected by the CCC in its Demonstration Path. (Rising to \$250/tCO_2 by 2050).

Our modelling showed that cutting the last 1-1.5% of fossil generation by 2030 would be expensive. Furthermore, this higher cost would likely flow through to electricity prices. We used our whole-of-economy 'ENZ' model (the same model that was used by the Climate Change Commission to set the initial carbon budgets) to see how much impact higher electricity prices would have on the rate of electrification in the rest of the economy. The analysis found that slower electrification due to higher prices substantially counteracted the emissions benefit from reducing fossil generation. When considering the change in costs and emissions for both the electricity system *and* the rest of the economy, the abatement cost ranges from approximately \$2,000/tCO_2 through to approximately \$13,500/tCO_2 (with the range depending on: whether the fossil system is a 'smart system' with more demand response; and, whether the 100% renewables is the Renewable Pioneer scenario (lower cost) or the Mega Infrastructure scenario (higher cost)). In one sensitivity scenario (Onslow turning out to be materially higher cost to construct than expected) net emissions *increased,* as the higher rest-of-economy emissions from the higher electricity prices outweighed the reduction in fossil generation.

The abatement costs for those 100% renewable scenarios are orders of magnitude higher than most national and international estimates of the cost of measures required to limit global warming to 1.5°C. As such, they indicate that intervening to achieve 100% renewables by 2030 is expected to be a very poor way of taking action to tackle global warming.

Putting most of our flexibility 'eggs' in one very large South Island located 'basket' appears more costly and risky than procuring flexibility from a wide variety of resources and locations

Our modelling indicates that the Mega Infrastructure Build 100% renewables scenario is substantially more costly than the Renewable Pioneer scenario. The reasons behind this are instructive for considering flexibility issues more broadly:

- The Renewable Pioneer scenario allows for incremental development of flexibility resources to meet demand, whereas a mega project such as Lake Onslow would be a single large addition of flexibility resource. This means that the full costs are incurred from the outset, and yet the benefits of additional flexibility rise progressively over time. The mismatch between the timing of costs and benefits is particularly strong if a facility is developed as early as 2030.

- The capacity limitations of the HVDC interconnector constrain the contribution from South Island-located mega projects (such as Lake Onslow) to North Island peak capacity. As a result, green peakers are still needed to achieve 100% renewables in the Mega Infrastructure scenario.
- The 25% pumping-to-generating round trip losses from large-scale pumped storage means that broadly the same amount of renewables will need to be built as in the Renewable Pioneer scenario.
- A mega-scale flexibility project will 'crowd out' other forms of flexibility provision. For example, it will substantially reduce the returns for investing in demand flexibility at the Tiwai aluminium smelter, or in a potential hydrogen production facility. This will reduce the international competitiveness of electricity-intensive commodity industries for whom flexibility is a practicable option. It will also likely crowd-out potential investment in additional fast-start peakers or other equivalent sources of flexibility which our modelling indicates could be required even before 2030.[1]
- Commissioning a very large-scale pumped storage facility could be particularly challenging because it will initially increase demand (to initially fill the storage lake). This could result in materially higher prices and fossil generation in the two to three years leading up to its commissioning.
- It is not clear that Lake Onslow can be commissioned as early as 2030, with the Infrastructure Commission suggesting 2037 as a more realistic estimate. However, given that we should reach very high levels of renewables by 2030 with the associated need for flexibility resources, this will be too late. Coupled with the crowding out issue, this mismatch in timing between when substantial new flexibility resources are needed with when Onslow is likely to be available will likely increase electricity prices, which would reduce the extent of decarbonisation in the rest of our economy.
- Having so much of New Zealand's flexibility requirement in one asset, particularly one located in the South Island, will substantially reduce New Zealand's resilience to natural disaster such as a rupture of the Alpine fault.

The fundamental physics and economics of electricity flexibility, mean our conclusions are robust against a wide range of uncertainties on future costs for key factors

Understanding the physics driving the need for different types of flexible resources is critical to understand why it is very expensive to squeeze out the last ≈1% of fossil generation.

The nature of the variability of demand and intermittent renewables means there is a need for some flexible capacity which will be required to generate most of the time, except at periods of relative surplus: 'mostly-on' capacity. However, there is a very long (and growing) tail of flexibility needed from capacity whose output is only required at rare times of significant scarcity: 'mostly-off' capacity.

Our analysis of the operation of the thermal plant that has provided almost all this flexibility duty to-date shows that the one-third of capacity that has provided mostly-on flexibility is responsible for

[1] Our modelling for our BAU pathway indicates a need for approximately 1,000 MW of thermal capacity by 2030, and for such capacity to operate in a predominantly short-duration pattern – ie, operating for hours at a time. This is a substantially different mode of operation than the existing CCGTs and Huntly Rankine units have undertaken to-date. We have not undertaken analysis of whether the Rankine units or (much less likely) CCGTs would be practicable options for such modes of operation. If not, and we conservatively assumed for our system modelling that they would not be suitable, investment in new peakers would be required.

75% of the GWh from fossil generation over the past five years. It is this mostly-on flexibility duty for which renewables have overtaken fossil as being the most cost-effective solutions.

However, as the proportion of time for which the flexible capacity is required declines – ie, progressively moving towards mostly-off operation – it becomes exponentially more expensive for renewables to replace fossil stations. This is a function of:

- The high-capex-low-opex cost structure of renewables compared to the low-capex-high-opex structure of fossil plant
- The intermittent nature of wind and solar, making them poorly suited to providing firm MW at times of capacity scarcity

Thus, even if wind and solar halved in cost, and the price of gas and carbon doubled, it would still be more cost-effective to have gas-fired OCGTs providing infrequently required peaking MW – although the amount of duty required would be very small, resulting in ≈99.5% renewables.

Furthermore, even if gas and carbon prices doubled, gas-fired OCGTs would still be cheaper than biofuel-fired OCGTs if biofuel were at $45/GJ.

Physics is also a key driver of why the Mega Infrastructure scenario is significantly more expensive than the other 100% renewables scenario.

The South Island location of Lake Onslow means it is limited in its ability to provide capacity to meet NI peak capacity scarcity requirements. Furthermore, its round-trip losses mean that there is relatively little difference in the amount of renewable plant needing to be built compared to a 100% renewables pathway comprised of multiples sources of flexibility.

It is also important to note that, based on experience with overseas pumped hydro projects, the range of uncertainty over a very large scale pumped hydro scheme's cost and timing appears larger than the uncertainty over many other flexibility resources. Coupled with its very large scale, this will tend to make the Mega Infrastructure pathway a higher risk option than other pathways. (Although, even if it could be built at the low-end of cost estimates and be commissioned by 2030, our modelling indicates it would be higher cost than the other 100% renewables option – which itself would be more costly than the limited-fossil options.)

All the above indicates that pushing for 100% renewables by as early as 2030 is likely to be higher cost, leading to higher electricity prices and adverse rest-of-economy economic and emissions outcomes. 100% renewables options which are dominated by very large single asset 'solutions' over which there is considerable uncertainty over cost and timing will be even riskier.

That is not to say 100% renewable electricity generation might never be achieved. As flexibility resources develop – particularly medium duration storage technologies, various types of demand response technologies, and biofuels – the costs of achieving 100% renewable electricity will decline. However, intervening to force a 100% renewable electricity outcome before the time when it would be cost-effective will lead to poor economic and environmental outcomes.

Green hydrogen is almost certainly not cost-effective for decarbonising pipeline natural gas

We modelled another energy scenario which had current users of pipeline gas for space heating, water heating, and industrial process heat, progressively transitioning to a 'green gas' comprised of green hydrogen – ie, hydrogen produced by the electrolysis of water powered by renewable generation. This modelling combined our detailed electricity system model, with our whole-of-supply-chain model of the economics of pipeline gas for energy relative to electric alternatives.

This modelling showed that, even with the most optimistic (and yet to be proven as practicable) assumptions regarding how flexibly a hydrogen production facility can be operated, green hydrogen is substantially more expensive than switching to electric for all three heating needs.

Furthermore, the green hydrogen scenario will require substantially more renewable generation by 2050 than if New Zealand chose to decarbonise these current fossil technologies via direct electric options. This will make an already challenging target (sixteen times more wind and solar capacity than 2021 levels by 2050) even harder: twenty-three times the capacity of 2021 levels. Additionally, it is likely this significant increase in renewable generation will lead to higher electricity prices and consequent negative rest-of-economy impacts.

Development of large-scale hydrogen export facilities would incur significant cost and lead to higher electricity prices. Long-term guaranteed offtake arrangements may make such costs worthwhile

We modelled the development of an international-scale hydrogen export facility – increasing 2030 NZ demand by 60%, but which is only equivalent to 0.4% of Japan's current fossil fuel consumption. This substantially increased the amount of renewables needing to be developed: a sixteen-fold increase (relative to 2021) in wind and solar by 2030 rising to twenty-eight fold by 2050 (compared to seven-fold rising to sixteen-fold in our BAU scenario).

Despite modelling the hydrogen facility as having significant flexibility, this resulted in an approximately $11/MWh increase in consumer electricity prices relative to the BAU scenario and a consequent increase in rest-of-economy costs and emissions.

This increase in New Zealand costs and prices may be worthwhile if the sale of hydrogen can be at a sufficiently high price with a sufficiently dependable offtake contract with a well-designed termination clause.[2] This contractual structure is necessary to manage the risk associated with New Zealand hydrogen turning out to be uncompetitive in the long-term with alternatives for renewables poor countries, noting that the international hydrogen market is in its infancy, and it is not clear whether:

- NZ hydrogen will remain competitive with the likes of solar hydrogen produced in Australia or the Middle East
- shipping green hydrogen will be competitive relative to other means being progressed for decarbonising renewable-poor regions of the world, including HVDC transmission, nuclear power, and offshore wind.

Smart load control, particularly of EVs and hot water, is required to minimise the scale of network cost increases

New Zealand is facing some significant network cost increases over the coming decades. Based on information provided by the five largest network companies plus Transpower's recent Integrated Transmission Plan, network expenditure this decade under a 'BAU' demand management world is projected to increase by 37% relative to last decade, rising to 91% of last decade's value for the decade ending 2050.

A large proportion of this will happen anyway, as a significant amount of network investment that occurred in the 60's, 70's, and 80's will come due for renewal. However, there is a significant amount of expenditure which is driven by the electrification of our economy, and the consequent increase in peak demand.

This creates an opportunity to avoid much of this demand-driven cost increase by developing arrangements to enable 'smart' management of loads on the networks. Two technologies stand-out in this respect: EVs and hot water. Our analysis demonstrates they represent by far the greatest

[2] Key elements of such a termination clause would be a sufficiently long notice period (ideally with associated ramp down), to enable NZ demand growth to progressively absorb the renewable generation that would have been built to power the hydrogen export facility.

technical and practicable potential for smart management. If all of this potential is captured, growth in peak demand, particularly for low voltage (LV) networks, could largely be eliminated.

However, to capture this potential requires the development of market arrangements for 'managed appliance' tariffs. Ie, where a third party (eg, network company, retailer, or load aggregator) manages the electrical operation of these appliances (ie, avoiding charging the appliance (or injecting power for vehicle-to-grid) at times of peak scarcity).

Such arrangements already exist for managed hot water, using so-called 'ripple' control. However, there has been considerable decline in this key technology over the past couple of decades. Unless it can be demonstrated that the smarter control technology which will inevitably supersede Ripple control will be widely available in the very near future, this decline in the promotion and use of Ripple control needs to be reversed.

Developing smarter control technology is a key requirement for developing managed EV offerings. However, this will require the development of market systems and rules to allow the full value of this appliance specific control to be realised. For example, we believe a key requirement is to allow the on-board meters within EVs to be used within the reconciliation arrangements for the trading of electricity.

In conjunction with development of these managed appliance tariffs, additional tariff reform to more cost-reflective pricing will be required. The two key components of this are:

- Introducing peak-signalling tariffs – with simple time-of-use being more than sufficient in the majority of cases for at least the next decade or two; and
- Increasing the proportion of network and retail/metering costs recovered via fixed charges. At the moment, the over-variablisation of network and retail/metering cost recovery is making switching from a fossil to electric appliance appear more costly to consumers than the underlying supply cost implications of such a switch.

Enabling a smart future will save billions in network expenditure – we estimate at least $6bn in present value terms. Furthermore, minimising cost increases will minimise consumer network price increases. Our analysis is that the increased rate of electrification due to lower network prices from smart networks will deliver a similar amount in rest-of-economy cost savings plus significant emissions reductions. As such, the abatement cost of smart network outcomes is *negative* hundreds of dollars per tonne of carbon abatement.

This coming decade will be the most challenging in our transition

The amount of renewable build required to enable decarbonisation-through-electrification of transport and fossil heating is significant: a pace of development that is approximately seven times the pace of renewable development in the past couple of decades.

However, for this current decade, this pace of development will need to be over 1.5 times greater because of the additional need to displace existing fossil generation. Although the rate of development of wind, solar, and geothermal is accelerating, it could take until the latter part of this decade until we will have 'caught up' and have a balanced mix of renewable and fossil generation. Until that time, New Zealand will face higher prices and emissions due to having to call upon a greater amount of fossil generation than would be cost-effective given the underlying costs of the two technologies.

A key determinant of whether we achieve a more balanced mix by earlier or later in the decade is whether renewable projects face material delays in gaining consents to proceed. At the moment, problems with gaining resource consents and (for overseas developers wanting to invest in New Zealand) Overseas Investment Office approval, appear to be creating a real risk that New Zealand will face higher prices and greater fossil generation for more years than is necessary.

This decade will also face the challenge of increasingly requiring short-duration flexibility but while having a thermal fleet which still has a lot of slow-start plant (ie, the two CCGTs and the Huntly Rankine units) – a dynamic that is already starting to be felt with Transpower having to issue an increasing number of capacity shortfall warnings if slow-start thermals are not committed.

Two elements are critical to address this:

- Developing market arrangements to best enable slow-start thermals to operate in a way which minimises the risk of capacity shortfalls
- Ensuring that policy settings don't frustrate the investment in additional fast-start peaking capacity that our analysis indicates may be required

New Zealand is in a lucky position. We shouldn't squander this good fortune by making poor energy choices

Despite the scale of investment required to decarbonise our electricity sector and the broader energy economy, it is worth remembering that, in energy terms, we are a lucky country. This is due to our unique combination of: our starting position of having 82% renewable generation (including with large-scale hydro – a key flexibility advantage), relatively low levels of gas use for heating, lack of direct linkage to international gas markets, unusually good wind and geothermal resources, plus significant land-area for renewable development.

Taken together this means that most other countries face current gas and electricity price increases that are many times greater than we are experiencing, plus a renewable investment challenge that, in proportional terms, is also many times greater than New Zealand faces.

We should not squander our relative good fortune by making poor energy pathway choices.

1 Introduction

We have called this report '*Which way is forward?*' because New Zealand is facing some key energy choices around which pathways to choose for decarbonising its energy economy. As the analysis in this report sets out, choosing the wrong path could result in materially higher costs and emissions.

The key pathway choices explored in this report are:

- Whether to intervene to force 100% renewable electricity generation by a fixed date?
- Whether green hydrogen should be pursued as an option for decarbonising pipeline gas?
- Whether New Zealand should develop large-scale green hydrogen export facilities to sell hydrogen to 'renewables poor' countries such as Japan and South Korea?
- How network challenges of the energy transition should be best addressed?

To analyse these issues, we used Concept's proprietary models of the electricity system and the broader energy economy to model six different energy 'pathways' that New Zealand could follow.

These pathways were principally developed to support a Boston Consulting Group (BCG) report *"The Future is Electric: A Decarbonisation Roadmap for New Zealand's Electricity Sector"*. That report, and BCG's take on our modelling results, can be found on BCG's website.[3]

This summary Concept report presents the key insights we have drawn from our analysis, plus more detail on the key dynamics driving outcomes for the different pathways. Additionally, this report details some additional modelling we have done on the development of domestic hydrogen production (pathway six), which, due to time constraints, didn't feature in detail in the BCG report.

The six different energy pathways we have modelled are:

> ***P1: Business-as-usual*** (The system evolves to a least-cost mix based on the Climate Change Commission's 'Demonstration Path' carbon price projection)
>
> ***P2: Smart system evolution*** (as P1, but with increased demand response, including from the Tiwai aluminium smelter)
>
> ***P3: Renewable energy pioneer*** (as P2, but with 100% renewables, using bio-fuelled 'green peakers')
>
> ***P4: Mega infrastructure build*** (as P1, but with 100% renewables, including Onslow pumped-hydro scheme plus green peakers)
>
> ***P5: Green export powerhouse*** (as P1, but with a significant hydrogen export facility developed)
>
> ***P6: Domestic green hydrogen*** (as P1, but with current natural gas use for energy, and heavy truck transport, transitioning to green hydrogen. Three sub-pathways for differences in the flexibility of hydrogen production are modelled.)

This report is structured as follows:

- Section 2 details our analysis of where the New Zealand electricity system is likely to get to in a BAU world – ie, under current electricity market and carbon policy settings.
- Section 3 then explores whether moving to 100% renewables by 2030 will result in better or worse economic and environmental outcomes.

[3] http://www.bcg.com/publications/2022/climate-change-in-new-zealand

- Section 4 considers whether heading down either of the large-scale hydrogen pathways (for export or domestic use) will deliver good environmental and economic outcomes.
- Section 5 considers how robust are our conclusions against future uncertainties.
- Section 6 highlights some of the other key policy insights from this analysis including:
  - The increased importance of the demand-side in a highly renewable world
  - The fact that this decade is going to be the most challenging from this transition
  - The challenges facing networks from our energy transition, and the importance of EVs and hot water in addressing these challenges
- Appendix A describes the key models that have been used for this analysis.

2 Where are we currently heading?

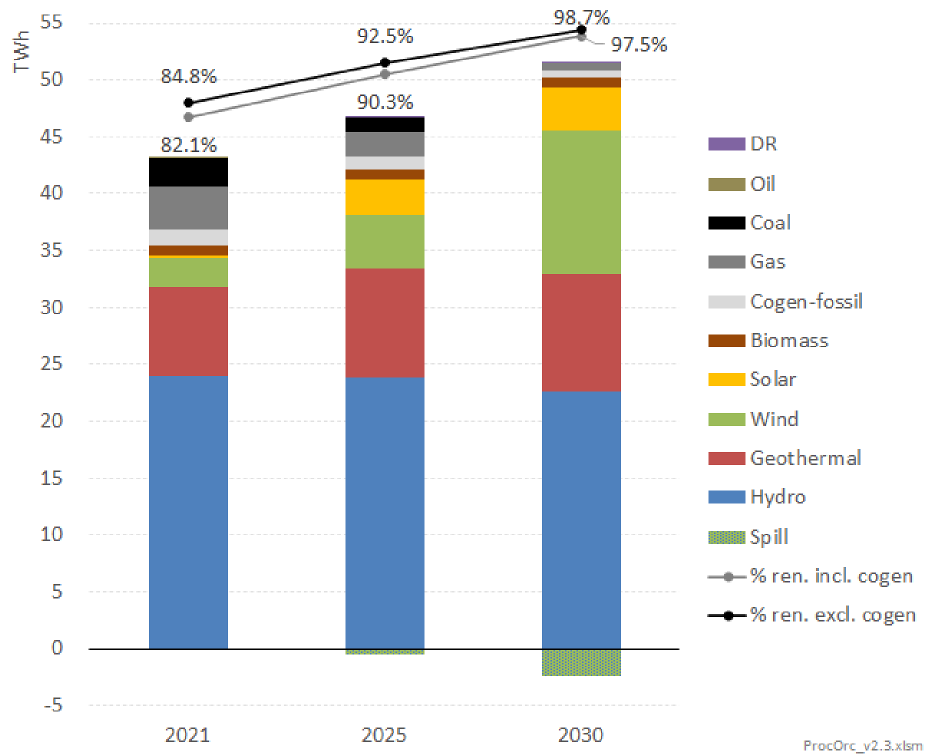
2.1 Under current policy settings, NZ should reach almost 99% renewable electricity by 2030

In considering the potential merits of a 100% renewables electricity policy, we must first understand where New Zealand will get to under current policy settings.

The significant increase in the carbon price under the ETS has unleashed a wave of renewable project developments as it is becoming economic to displace much of the existing fossil generation with new renewables. In the near term, projects that have been committed for development will add around 3,250 GWh of new renewable supply by 2025, relative to 2021. In addition, our analysis of forward contract prices indicates a further approximately 3,400 GWh of new renewable supply is expected by 2025.[4] This renewable development should increase New Zealand's renewable electricity share to approximately 92%[5] in 2025.

Our detailed market modelling of the economics of options under the 'Business-as-usual' scenario (Pathway 1) indicates that, provided there are no consenting or other constraints on their development, the share of renewables should rise further to 98.7% by 2030. Among OECD members, this could put us second only to Iceland for share of renewables.[6]

Figure 1: Projected generation supply mix based on current policy settings



[4] Our analysis looked at the extent to which contract prices in 2025 were above prices that would emerge from a market in equilibrium – ie, with prices driven by the long-run marginal cost of new-entrant renewables – and inferred the increased extent to which high-cost fossil generation was expected to be operating relative to such equilibrium conditions. In conjunction with analysis on the demand for flexible generation, this enabled estimation of the amount of renewable generation that market prices indicated would be developed by then.

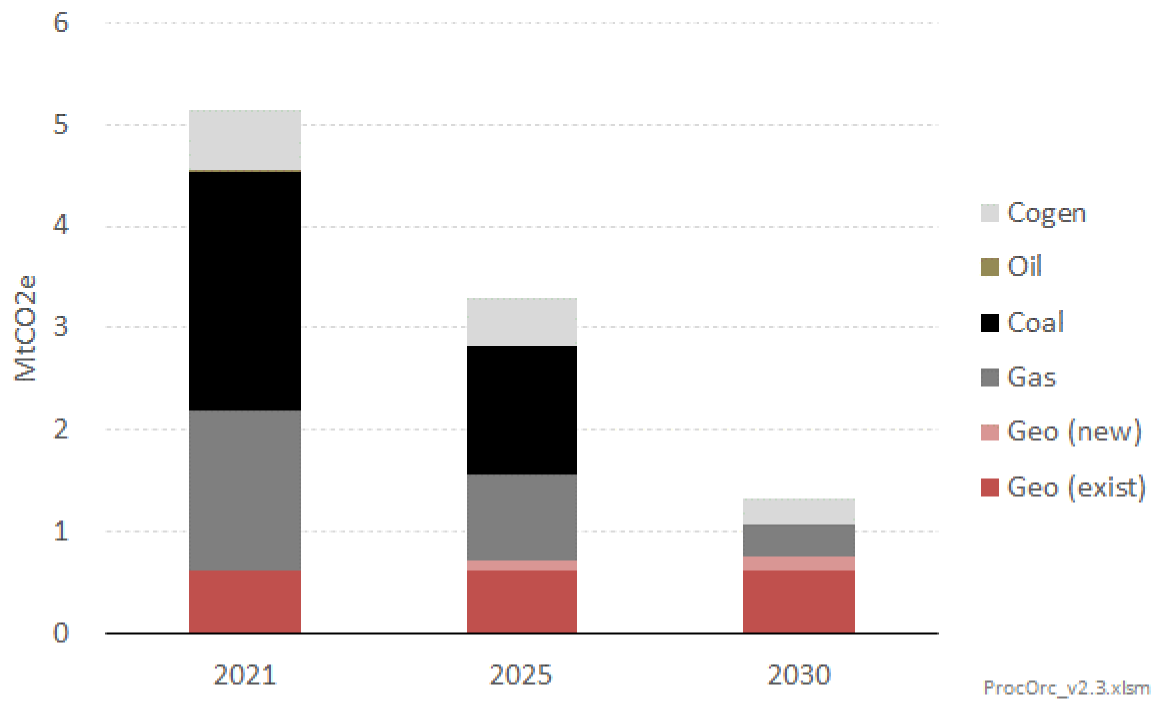
[5] Excluding cogeneration, and assuming mean hydrology conditions.

[6] Some OECD countries will have a similar share of their own renewable generation (eg, Norway), but they rely on interconnections with other countries with much higher shares of fossil generation to balance their renewable variation.

This evaluation of a carbon price resulting in high levels of renewable development to largely displace thermals is consistent with that from other parties, including the Climate Change Commission and electricity market participants.[7]

Figure 2 below shows the change in power generation emissions from this shift to renewables. By 2030, emissions from the remaining fossil generation should fall by 92% compared to 2021, and emissions from geothermal stations should be 2.4 times the amount from the remaining (entirely gas-fired) peaking stations.

Figure 2: Projected electricity generation emissions for BAU pathway



The key drivers for the rising renewable share are the Government's robust carbon pricing regime, excellent renewable resources in NZ, and the downward trend in wind, solar and battery costs (albeit tempered in the short term by global market disruptions). The above factors have made it economic to replace all 'baseload'[8] thermal generation with renewable alternatives.

Fossil-fuelled generation is becoming confined to the role of providing 'flexible' supply – turning on only at times when low renewable supply combines with high demand – rather than any baseload production. However, renewables are now competitive for the majority (in generation volume terms) of this flexible duty too. Two key factors have driven this outcome.

- First, New Zealand's large existing hydro fleet provides a 'buffer' to help integrate large volumes of intermittent renewables on to the system: Using the hydro storage lakes (among the world's largest 'batteries') to enable hydro plant to reduce generation at times of high wind and solar generation, and vice versa. This buffer reduces the amount of intermittent renewable generation that would otherwise be 'spilled' at times of low demand, and is a key advantage for New Zealand relative to most other nations.

[7] For example, analysis from Genesis Energy in a May 2022 presentation, "Biofuel Insights", indicates New Zealand reaching similar levels of renewables to our BAU scenario by 2030, and even higher levels of renewables in 2025.

[8] Baseload thermal stations have steady output which does not vary to offset changes in demand or varying wind or hydro generation etc.

- Second, fossil-fuelled generation costs have risen very strongly relative to renewable costs. As a result, it is becoming cheaper to build some renewables that will spill at times rather than rely on fossil-fuelled stations for flexibility. In effect, 'overbuilding' renewables is becoming cheaper than 'overbuilding' of fossil generation to provide much of the system's flexibility requirement.[9]

  Although it will still be cost-effective to keep some fossil generation to operate relatively infrequently, the amount of fossil generation required is only 10% of the amount of the approximately 5,900 GWh/yr of fossil generation currently required for flexibility duties.

To help understand how such a radical reduction in fossil generation will come about, it is necessary to understand:

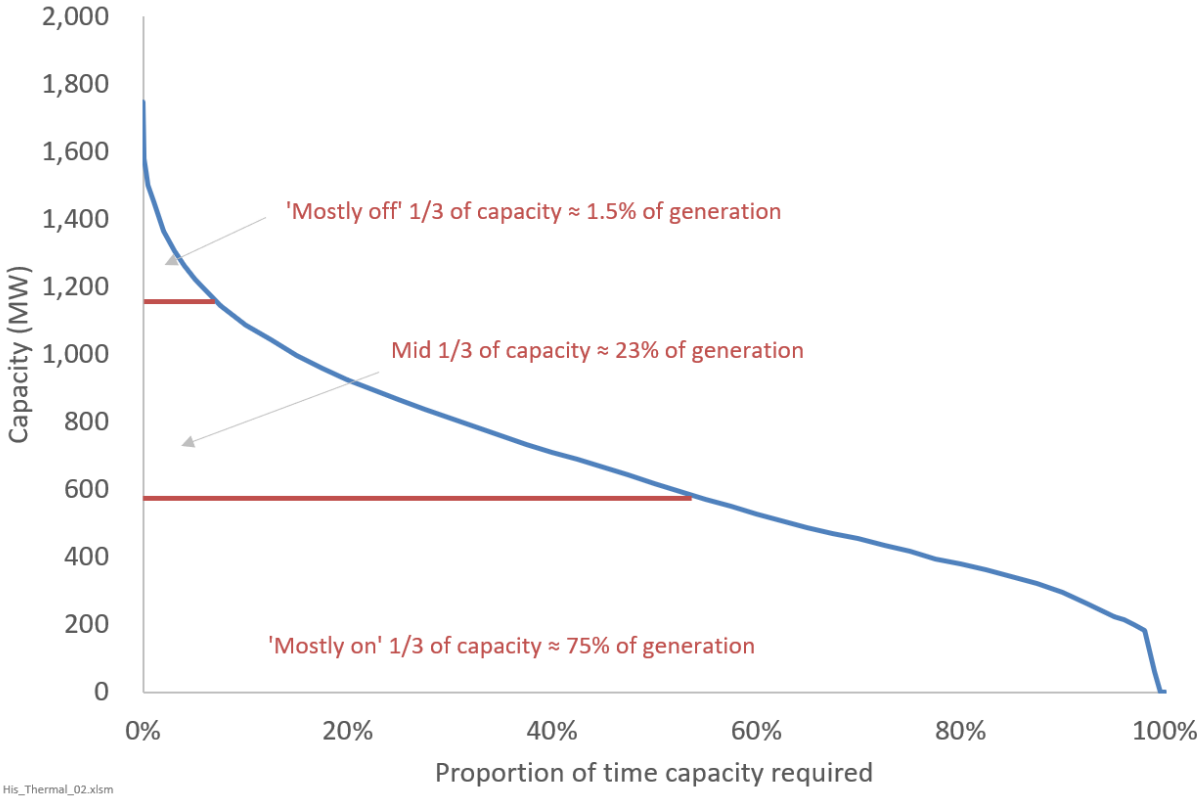
- How much generation is required from different types of flexibility capacity, ie, as between
  - that which is 'mostly-on' except at times of significant surplus; versus
  - that which is 'mostly-off' except at times of significant scarcity
- How the economics of thermal and renewable plant compare for these different types of flexibility duty.

To illustrate the first point, Figure 3 below shows a 'duration curve' of how thermal plant has operated over the past ten years, with a simple overlay dividing the MW capacity requirements into one-third blocks:

- The mostly-on third of capacity that will operate most of the time, and only turn off for a small amount of time during periods of significant renewable surplus.
- The mostly-off third of capacity that will be off for most of the time, and only turn on for a small amount of time during periods of significant renewable scarcity
- The 'middle' third of capacity whose operation will be somewhere in the middle

[9] In this context 'overbuilding' means building some generation capacity whose output will not be required for some of the time.

Figure 3: Historical pattern of flexible thermal operation



The total amount of generation (the area under the curve) is approximately 5,900 GWh, being the average annual amount of thermal generation – whilst noting that the amount of generation will be greater / lesser than this average amount in dry / wet years.

However, there is a significant difference in how much each MW of capacity will be called to run:

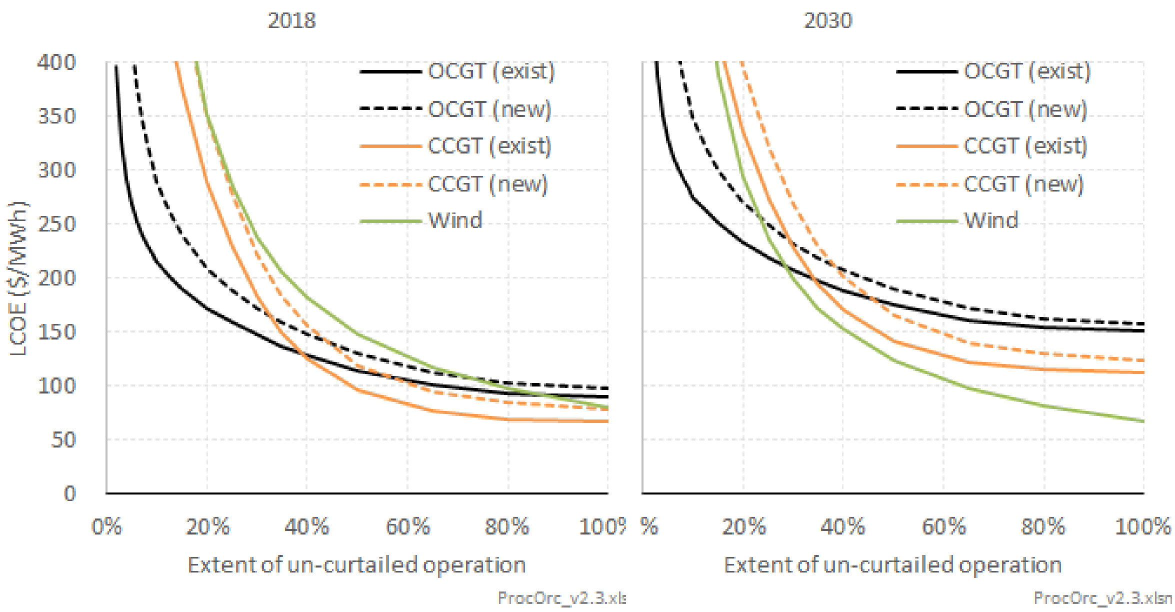
- In MW *capacity* terms, the mostly-on third of capacity accounts for approximately 75% of the flexible GWh *generation* requirement.
- In contrast, the mostly-off third of capacity, accounts for only 1.5% of the flexible generation requirement.

To illustrate how renewable and thermal plant compare in cost-effectiveness for performing mostly-on versus mostly-off flexibility duty, Figure 4 shows how the price of power from different types of power generation increases as the amount of time the output from the generator is required reduces ('moving left' along the graph). This increase has an exponential shape as the fixed costs of the station (including recovering the capital costs for new stations) are recovered over progressively fewer GWh of generation. For capital-intensive technologies such as wind, this rate of increase is faster than less capital-intensive technologies such as existing thermal stations (whose capital costs are sunk).[10]

This pattern of the relative cost of the fossil and renewable technologies is shown for two years – 2018 and 2030.

[10] Both wind and thermal generation also have other factors which increase the cost at lower capacity factors:
- For thermal generation, the $/GJ costs of the fuel also progressively increase at lower levels of operation, plus the plant incur increasing costs associated with starting up and operating at levels below full output.
- For wind, the intermittency starts to affect the effective LCOE at lower utilisation levels.

Figure 4: Comparison of gas-fired versus wind generation economics over time



In 2018, with carbon prices of only $20/t$CO_2$, it was not cost-effective to build wind generation to displace existing combined cycle gas-turbine (CCGT) generation – although it had just reached the point where it would be cheaper to build a wind farm than build a new CCGT to meet baseload demand growth.

However, with projected reductions in wind costs and increases in carbon prices (to almost $140/t$CO_2$ by 2030), it will be economic to build renewables to displace existing thermal plant up to the point where the output from the marginal wind farm built would only be required for approximately 30% of the time. For plant that is required less frequently than this, it is most economic to retain the use of existing open-cycle gas turbines (OCGTs). However, as illustrated in Figure 3 above, this operation of the remaining fossil generation would only account for approximately 10% of flexible generation requirements – approximately 1.5% of total generation requirements.

In our BAU projection, we have a significant amount of peaking thermal capacity required (1,000 MW), but operating in this mostly-off mode. Due to the predominant pattern of short-duration operation required in 2030 (ie, typically only being required for a few hours at a time, as set out in more detail later in section 6.2.2) we have conservatively assumed that this will be met exclusively by gas-fired OCGTs, rather than some of the existing 'slow-start' thermals – namely the two remaining CCGTs or the three remaining Rankine units at the Huntly power station. This means that we have assumed 500 MW of additional OCGT units will need to be built by 2030, with the build cost being taken into account for the determination of the least-cost mix of resources. We haven't evaluated whether it may be cost-effective to retain some slow-start units (probably Rankine units) rather than build new OCGTs. To the extent it is practicable to retain some Rankine units instead of build new OCGTs, this would only marginally change the overall results of our analysis in terms of the extent of fossil vs renewable operation and relative overall system costs.

Looking beyond 2030, our modelling indicates that in a BAU world with no new flexibility technologies emerging, the system will continue with similar renewable % levels – 98-99%.

2.2 Rising renewables will reduce the electricity system's 'residual' flexibility needs for dry-year duties, and increase the need for NI-peak capacity flexibility – beware the 'dunkelflaute'

To understand the implications of implementing policy to get rid of the remaining ≈1.5% of fossil generation, it is necessary to understand

- the general requirement for flexibility resources; and
- what specific role fossil generation will be required to undertake in a highly-renewable future.

In general terms, flexible energy sources are needed to maintain an even balance between electricity demand and supply. Historically, New Zealand's hydro reservoirs have provided the vast majority of 'short-duration' flexibility to meet within-day and within-week variations in demand, with thermal generation also providing some additional short-duration flexibility – particularly at times of peak demand, where it has provided much-needed capacity. In generation volume terms, the biggest flexibility role for thermal generation has been providing 'long-duration' flexibility: seasonal balancing (generating more in winter than in summer) and hydro firming (generating more in 'dry' years than 'wet' years). When required, these thermal generation needs typically extend over weeks or months.

As the level of wind and solar generation increases, there will be increasing need for short-duration flexibility sources that can operate for hours through to multiple days to manage periods when low wind and solar output coincide with high demand and the hydro system has reached its flexibility limits. In Germany these periods are called 'dunkelflaute' (literally, dark doldrums). The need for short-duration flexibility resources will be especially strong in the North Island because:

- that is where the majority of wind and solar is likely to be built to meet demand growth and replace the (entirely North Island) fossil-fuelled generation that will progressively retire; and
- South Island flexibility resources will be constrained in their ability to provide short-duration flexibility at times of extreme scarcity due to the capacity limitation of the HVDC interconnector between the North and South islands.

As set out in section 2, it will be cost-effective for overbuild of renewables to meet the majority (in GWh generation volume terms) of the need for flexibility. However, because of the intermittent nature of wind and solar (which will likely be the dominant renewable technologies to meet demand) it won't just be the quantity of residual (post-renewables) flexibility to be provided by other sources that will change, but also the mix of duty required:

- Renewable overbuild will significantly reduce the requirement for other flexibility sources to provide long-duration flexibility for seasonal and 'dry year' duties.
- However, renewable overbuild is much less able to meet short-duration peak flexibility requirements.

Figure 5 below shows how both the absolute demand for flexibility duties, and the relative mix between short-duration (regular within-day flexibility) through to long-duration (year-to-year) has been met historically, and will be met in our BAU scenario.

The flexibility requirements from demand represent the amount of generation which will need to vary output to meet variations in demand.

- The 'within-day' quantity represents how much this overall flexibility requirement would reduce if each day had completely flat demand (but still had day-to-day variations in demand).
- The 'within-month' requirement represents the additional reduction in flexibility requirement if each month had completely flat demand (but still had month-to-month variations in demand).

- The 'within-year' requirement represents the additional reduction in flexibility requirement if each year had completely flat demand (but there was still year-to-year variations in demand).
- The 'year-to-year' requirement represents the residual amount of flexible generation required in this situation of completely flat within-year demand, but some year-to-year variation

The bar showing the 'Residual' demand for flexibility represents the remaining requirement for flexibility after the operation of renewable generation, including hydro, wind, solar, and geothermal.

Historically, it can be seen that hydro generation has met the majority of the need for within-day and within-month flexibility, but has contributed relatively little to seasonal flexibility, and *increased* the need for year-to-year flexibility – due to the variation between 'dry' and 'wet' years.

By 2030 in our business-as-usual pathway, hydro will continue to meet this requirement, but will additionally be significantly supplemented by overbuild of wind and solar, with spill becoming a flexibility resource. Thus, in a dry year, the first resource to meet the increased post-hydro demand will be that the system spills less energy.

The final 'Thermal' bar shows the residual requirement for flexibility from thermal plant after other resources have contributed to the need for flexibility. In the 2030 BAU projection, this is significantly different from Residual because there is additional flexibility delivered by EVs, grid connected batteries and demand response. Historically there is negligible difference between Residual and Thermal, because such resources did not exist, or were called upon much less frequently.

Figure 5: Historical and projected demand for electricity flexibility[11]

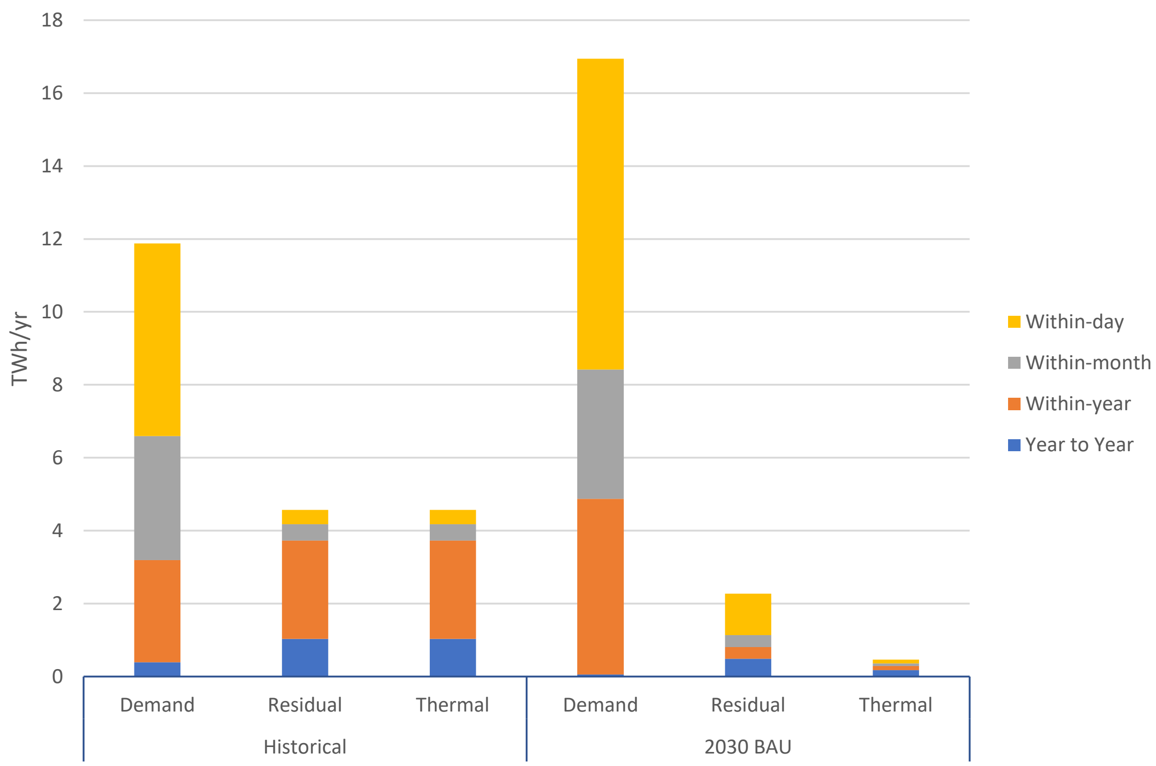


Figure 5 shows that the total quantity of flexible generation from thermal stations will reduce significantly, and the relative mix of duty will also change, with a proportionately greater amount from within-day duties.

[11] The historical thermal flexibility total here is 4,600 GWh, which is lower than the 5,900 GWh stated above for total thermal generation. The difference is the portion of thermal that operates in a "baseload" function.

Additionally, as set out in more detail in section 6.2.2, our modelling indicates that this will be comprised of much shorter spells of operation.

3 Is pushing for 100% renewable electricity by 2030 likely to be a positive or retrograde step?

3.1 Decarbonising the last 1.5% of fossil-fuelled generation by 2030 is technically feasible, but expensive and may increase economy-wide emissions

As set out in section 2, the modelling for our BAU pathway ('P1') indicates we are on-track (subject to consenting or other non-market constraints) to achieve almost 99% renewables by 2030.

To determine whether implementing measures to achieve 100% renewables is likely to be beneficial, we modelled three additional pathways:

P2: Smart system evolution (as P1, but with increased demand response, including from the Tiwai aluminium smelter)

P3: Renewable energy pioneer (as P2, but with 100% renewables, using bio-fuelled 'green peakers')

P4: Mega infrastructure build (as P1, but with 100% renewables, including the Onslow pumped-hydro scheme[12] plus green peakers)

All four scenarios had a core set of common assumptions around demand, geothermal build, rooftop solar ('rSolar') build, technology costs, gas prices, biofuel prices, and carbon prices, with the only differences between the scenarios being:

- In the 100% renewable pathways (P3 & P4), peaking thermal plant are fuelled from biofuel priced at $45/GJ. In contrast, the peakers in the non-renewable pathways (P1 & P2) faced gas prices of $12/GJ plus the carbon charge[13], giving an equivalent gas + carbon fuel cost of $19/GJ in 2030 rising to $25/GJ in 2050.
- In the 100% renewable Mega Infrastructure Build pathway (P4), the Onslow pumped storage scheme was developed. This was assumed to have a generation capacity of 800 MW,[14] a reservoir of 5 TWh, and with a central cost estimate of $5.9bn to build plus a further $350m to fill. Capital costs were assumed to be recovered over 100 years using a 5% real pre-tax discount rate. Sub-scenarios with higher and lower capital costs were also run.
- Pathways P2 and P3, had a greater amount of demand response to call upon:
  - The size of the general demand response tranches were 5% of load, rather than 2.5% of load in the other scenarios. The prices of the three tranches were the same in all scenarios: $700/MWh, $3,000/MWh, and $10,000/MWh.

[12] The Lake Onslow pumped hydro scheme would consist of a large storage reservoir (approximately 5 TWh, which is huge by international standards) at Lake Onslow, with a tunnel down to an approximately 800MW generating station located next to the Clutha river. The station would release water out of the reservoir to generate electricity at times of renewable scarcity, and pump water back up to the reservoir (by running the generator in reverse) at times of renewable scarcity. The station is estimated to have a round-trip efficiency of 75% - ie, it would generate 75% less electricity than the amount of electricity consumed pumping.
[13] We used the carbon values produced by the Climate Change Commission for its Demonstration Path, being $138/tCO$_2$ in 2030 rising at 3% per annum to $250/tCO$_2$ in 2050.
[14] While the potential capacity could be 1,000 MW (or higher), our modelling indicates that the benefit of additional capacity over 800 MW is limited due to HVDC constraints.

- The Tiwai aluminium smelter was assumed to have invested in the EnPot technology or equivalent to enable it to operate flexibly – reducing demand at times of high prices. It reduced demand in five tranches, depending on market prices. The first 16.7% tranche was reduced when prices went above $100/MWh, with the three subsequent 16.7% tranches increasing at $100/MWh intervals. The final 33% tranche only reduced demand for prices beyond $4,000/MWh.
- This increased demand response was assumed not to be available for the Renewable Mega Infrastructure pathway (P4) because, as detailed in section 3.2.2 later, the Onslow pumped storage scheme has a considerable effect on 'crowding out' other providers of flexibility.

As set out in Appendix A, for a given set of scenario assumptions, our ORC model determined the least-cost mix of resources to build (wind, utility solar ('uSolar'), batteries, and additional peakers).

Figure 6 and Figure 7 below show the projected GW supply mix and subsequent TWh generation, respectively, for the four different pathways.

Figure 6: Projected supply capacity

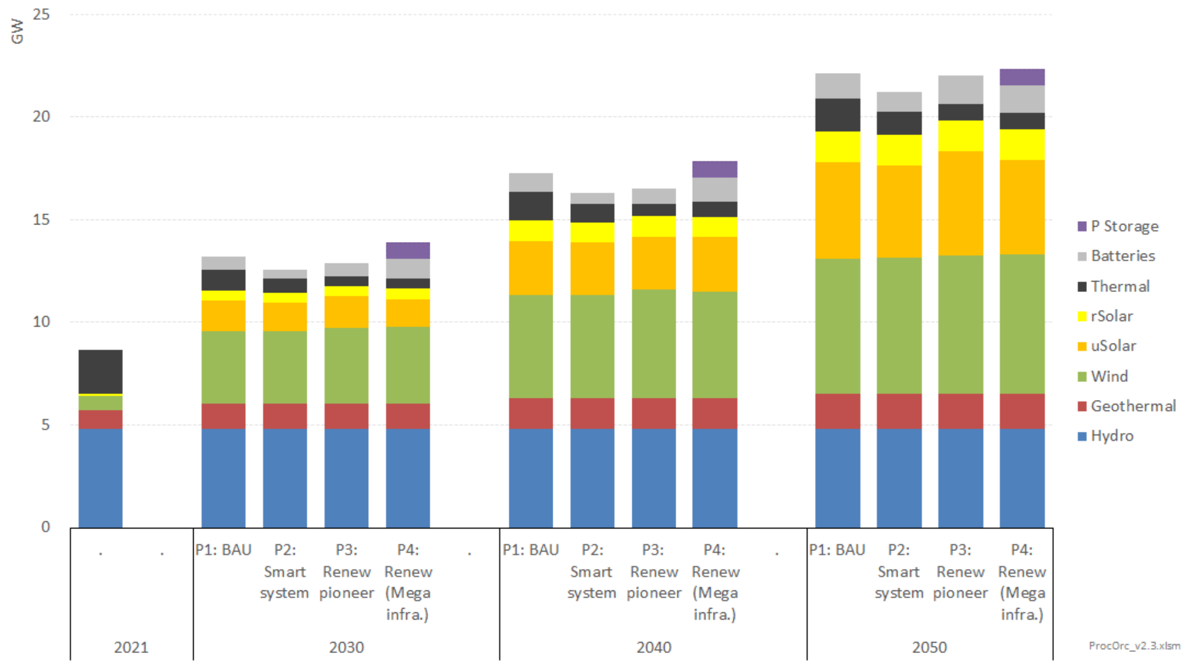
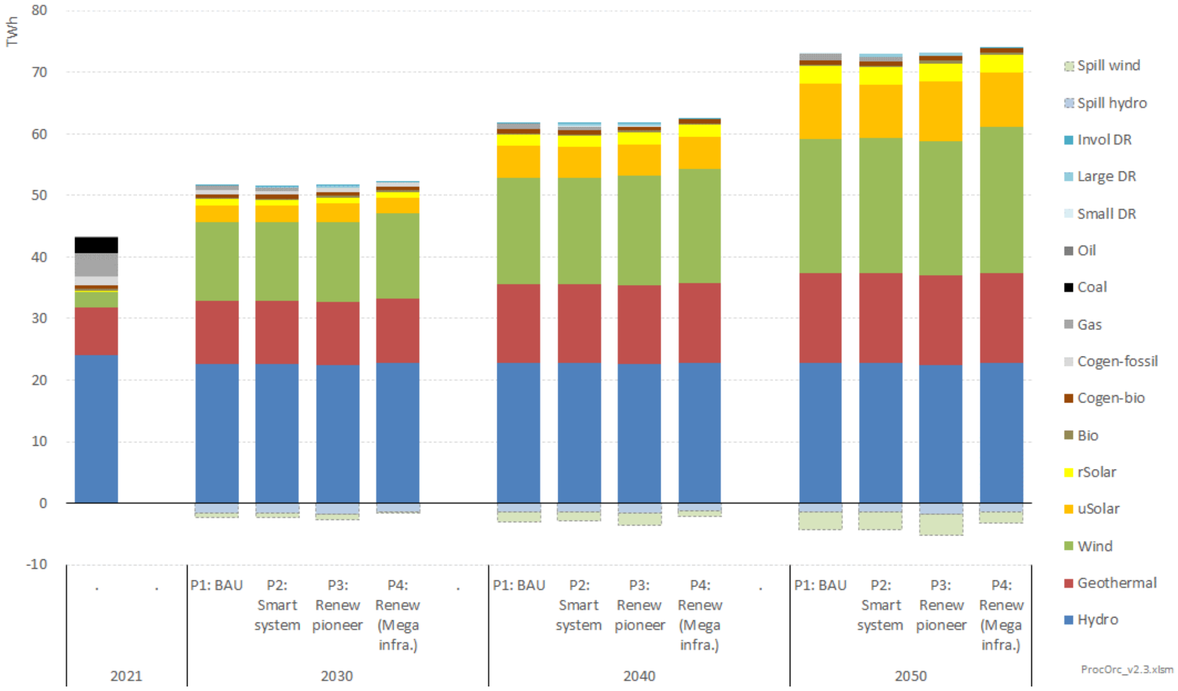


Figure 7: Projected generation and demand response



In addition to determining the total system costs arising from each of the scenarios, the ORC model also produced electricity prices. The difference between consumer electricity prices in the different scenarios was used to model the extent to which rest-of-economy (ROE) emissions and non-electricity costs would be different due to altered electricity prices affecting the rates of electrification of process heat, space & water heating, and road transport.

In terms of prices, the wholesale market component of consumer electricity prices under pathways 1 and 2 are broadly the same. This is because the level of renewable development is largely identical (very minor reductions in solar development), resulting in broadly the same level of new-entrant-cost-recovery-driven pricing. The main benefit of calling upon greater amounts of demand response in pathway 2, is reducing the amount of peakers and batteries that need to be built.

However, it indicates that wholesale-driven consumer prices under the two 100% renewables pathways will be higher than pathways 1 and 2: on average over the period from 2030 to 2050 by about $6/MWh under P3, and $2.50/MWh under P4. Additionally, as set out in section 3.2.3, the Onslow scheme is likely to result in significantly elevated prices in the years leading up to its commissioning.

Box 1: Why does the mega infrastructure pathway cost significantly more than the other 100% renewable pathway, but its consumer price impact is not as great?

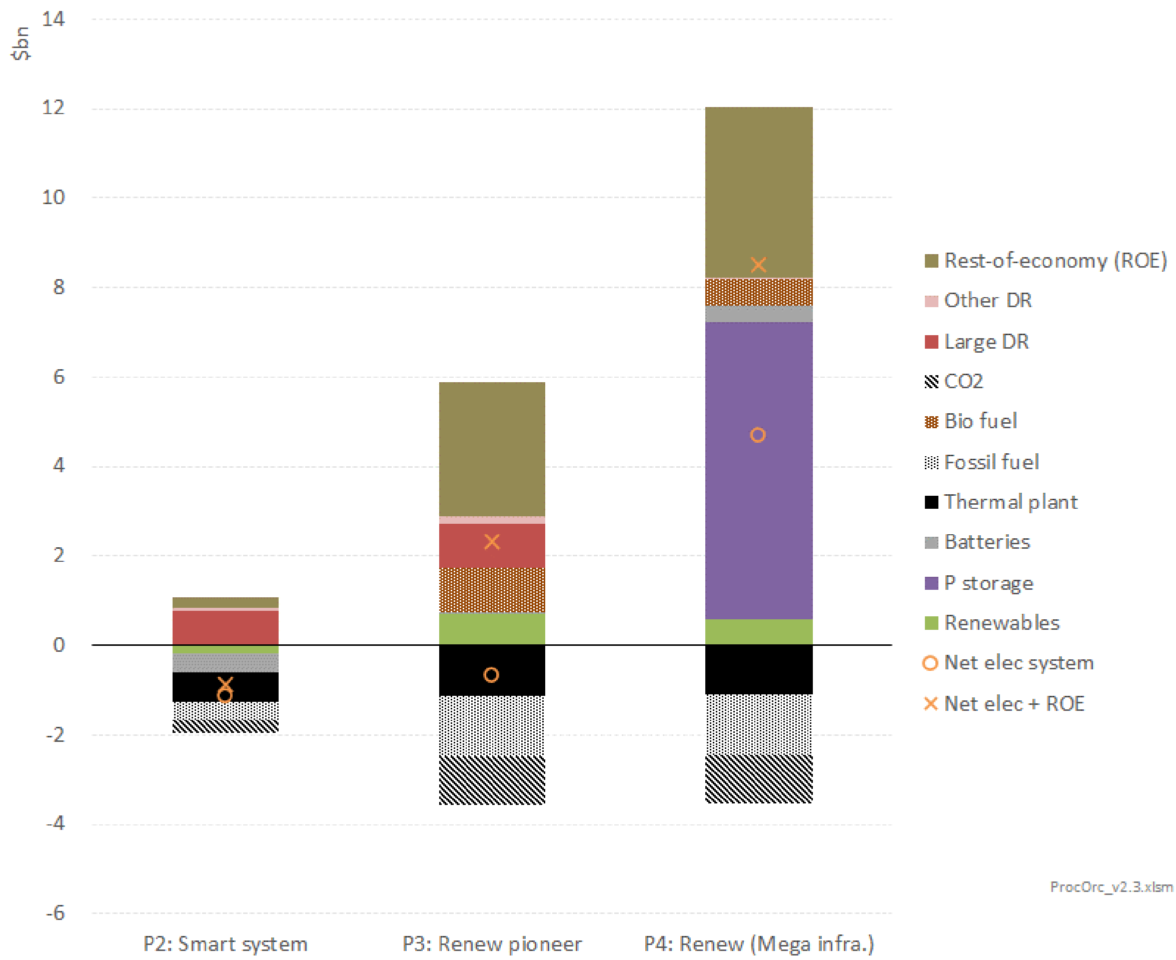
As illustrated in Figure 8 below, the electricity system costs of pathway 4 are projected to be approximately $5bn more than the other renewable pathway, pathway 3. However, the consumer electricity price impact of pathway 4 is not projected to be as great. This is because of the ‘out-of-market’ way in which Onslow is assumed to be funded.

Thus, the cost of calling upon all other electricity supply resources (renewable or thermal generation, batteries, demand response) is reflected in electricity prices, with the short-run marginal cost (a.k.a. ‘variable’ cost) of the most expensive resource called upon in any hour setting the market price. Resources are only developed in the model if the market prices they earn from operation in the market over time are sufficient to cover their variable costs plus recovery of their fixed and capital costs. This is how the electricity market works, and ensures that, over time, the least-cost mix of resources are developed to meet demand.

However, in pathway 4, Onslow is assumed to be built irrespective of whether it will earn sufficient revenues from its operation in the market. The significant under-recovery of Onslow's costs from its modelled operation in the wholesale electricity market is assumed to be recovered via a flat $/MWh levy on electricity consumers. This average pricing approach, rather than marginal pricing, for recovery of a major supply cost, explains why the price impact is much less than the cost impact.

Figure 8 shows the breakdown of the difference in costs (in present value terms out to 2050) for the three additional pathways compared to the BAU pathway.

Figure 8: Difference in pathway costs compared to P1: BAU pathway ($bn, NPV)



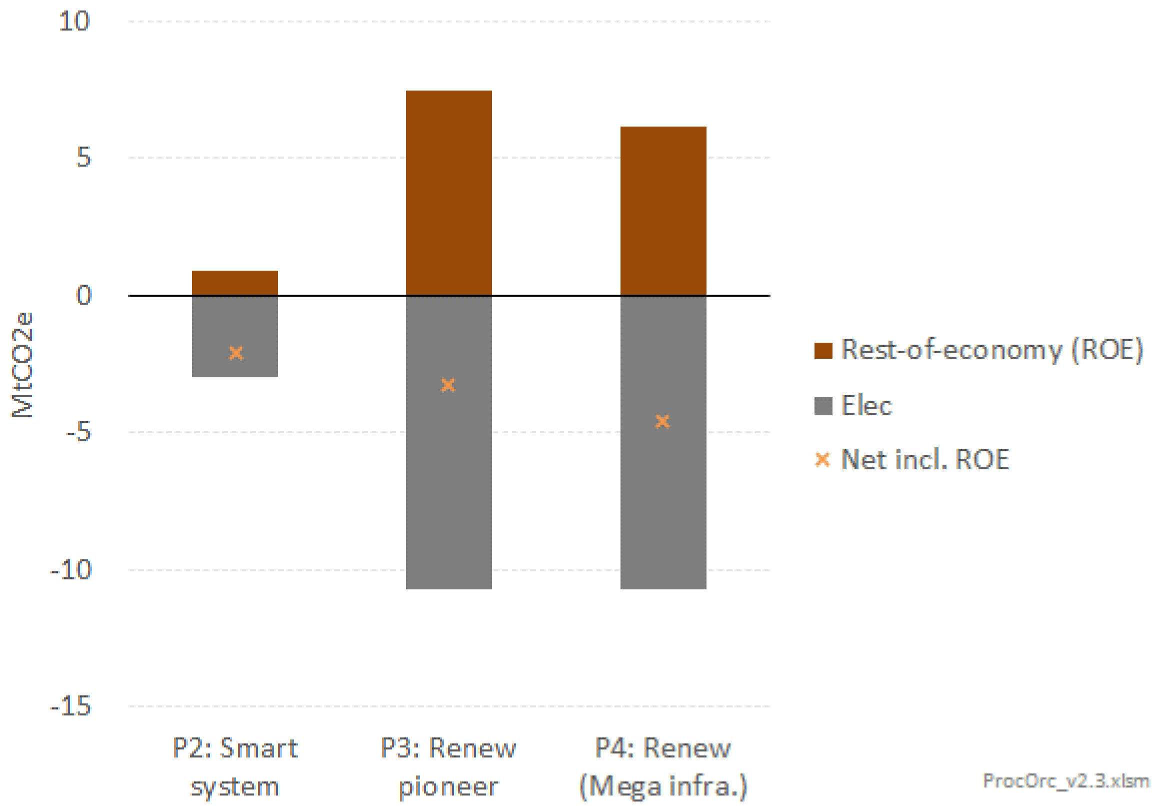
The key take-aways are:

- The 100% renewables pathways result in significantly higher costs compared to the two pathways that allow the continuation of a small amount of gas-fired peaking generation to perform renewable balancing
  - A significant proportion of this is due to the higher electricity prices in the 100% renewable pathways reducing the rate of electrification, leading to higher rest-of-economy costs
  - The high capital costs of the very large-scale pumped storage scheme further increase the costs of pathway 4
- The Mega Infrastructure pathway will still require a similar amount of bio-fuelled peakers to the other renewable pathway (500 MW in 2030, rising to 800 MW in 2050). This is because the

South Island location of the pumped storage scheme means it is behind the HVDC link which limits its ability to meet North Island peak scarcity issues. As section 2 has already set out, these North Island peak scarcity issues will increasingly become the key driver of flexibility requirements in a highly renewable system.

Figure 9 shows the difference in emissions to 2050 between the BAU pathway, and the other three pathways.

Figure 9: Difference in pathway emissions out to 2050 compared with the BAU pathway



Although the 100% renewable pathways do reduce emissions from electricity generation, this is significantly counter-balanced by the increased rest-of-economy emissions from the higher electricity prices reducing the rate of electrification.

Figure 10 shows the implied abatement costs of choosing one pathway instead of another. Eg, 'P1 to P3' shows the increase in costs from P3 compared to P1 divided by the decrease in emissions from P3 compared to P1.

Figure 10: Abatement costs from going from one pathway to another ($/tCO$_2$)

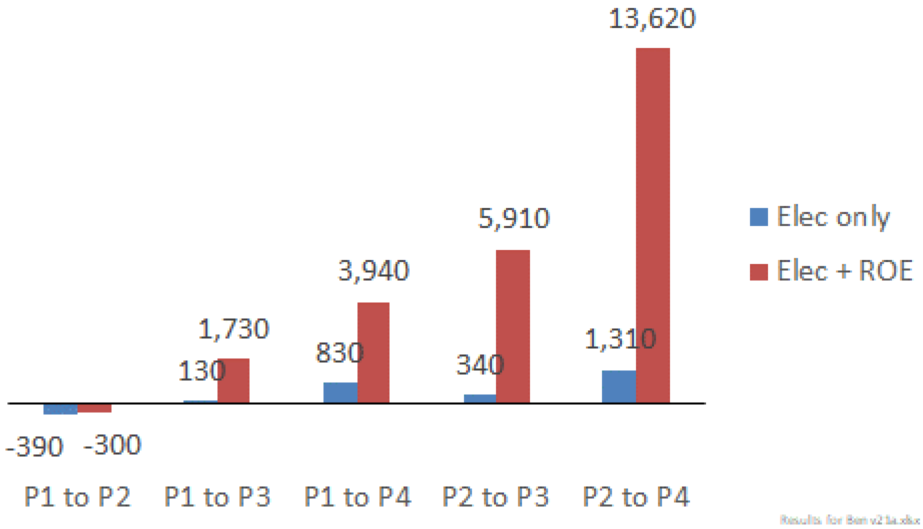


Figure 10 shows that, when rest-of-economy costs and emissions are included, aiming for 100% renewables (pathways 3 and 4) will result in abatement costs relative to a business-as-usual scenario which are several thousand dollars per tonne of CO_2 abated. This compares with:

- Current carbon prices of approximately $85/tCO$_2$
- The Climate Change Commission's central projection of marginal carbon abatement values consistent with New Zealand achieving net-zero non-agricultural emission of $250/tCO$_2$ by 2050; and
- International projections of 1.5°C-consistent carbon abatement prices of approximately $500/tCO$_2$ by 2050.[15]

In contrast, pathway 2 – allowing some continuation of fossil generation, but calling upon greater demand response to reduce the amount of fossil generation required – achieves *negative* abatement costs relative to our BAU projection. Ie, not only are emissions reduced, but costs are reduced as well.

Based on international experience, there is likely to be significant uncertainty over the costs of a major pumped storage scheme such as Lake Onslow.[16] Given this uncertainty, we tested the sensitivity of outcomes for costs to be higher or lower than our central $5.9bn build + $350m fill projection. Our Low and High build + fill cost scenarios were $4.5bn + $300m, and $10bn + $425m, respectively.

For the Low Onslow cost scenario, the whole-of-economy abatement cost fell to $1,700/tCO$_2$. However, in the High Onslow cost scenario the higher electricity prices that emerge result in the increase in rest-of-economy emissions *outweighing* the reduction in electricity generation emissions. Ie, pushing for 100% renewables via a mega project such as the Onslow scheme which turns out to be significantly more expensive than expected can result in *increased* whole-of-economy emissions.

[15] Source: Concept analysis of various international projections of shadow carbon prices consistent with limiting global warming to 1.5°C.

[16] Boston Consulting Group research published in "*The Future Is Electric*" on the experience of analogous overseas pumped hydro projects. This states that "*the average project cost roughly over double as much as originally thought and taking 2–3 years longer to build. The Snowy Hydro 2.0 scheme in Australia, which is still under development, is now scheduled to cost 2.5 times as much as originally planned and take 7 years longer to build.*"

These results strongly indicate that pushing for 100% renewables electricity generation as early as 2030 is very unlikely to deliver good environmental or economic outcomes for New Zealand.

That is not to say that 100% renewable electricity will never be desirable: As technologies develop – particularly medium-duration storage (days-to-weeks), biofuels, and more flexible industrial demand response – the costs of achieving 100% renewable generation are likely to fall to the point where it will deliver good environmental and economic outcomes. Such an outcome could occur under the existing market arrangements (ie, with the ETS providing the price signal for investment in technologies that reduce emissions), without a 100% renewable electricity mandate.

Lastly, as illustrated in Figure 2 previously, it is worth noting that in a system with close to 99% renewables, 75% of power generation emissions will come from *renewable* generation in the form of geothermal power stations. These emissions would not disappear in a move to 100% renewables. Indeed, it is possible that moving to 100% renewables could increase the amount of geothermal generation and associated emissions – it certainly wouldn't decrease the amount of geothermal generation. Given the highly situation-specific nature of available geothermal resource and lack of public data, we have not attempted to model the extent to which geothermal generation could increase in a 100% renewable future.

It is possible geothermal emissions could be abated by carbon capture and storage (CCS) – noting that geothermal power station operators are actively exploring this technology. However, it is also possible that the Taranaki-based thermal peakers could also have some of their emissions abated through CCS in depleted gas reservoirs – which is also being explored as an option by some parties. We do not consider the relative likelihood of either CCS option being cost-effectively deployed.

3.2 Mega-scale options come with particular challenges

Our analysis set out in section 3.1 indicates that not only will pushing for 100% renewables too early likely lead to poor whole-of-economy economic and environmental outcomes, but the Mega Infrastructure option with the Lake Onslow scheme will likely be worse than other 100% renewable pathways.

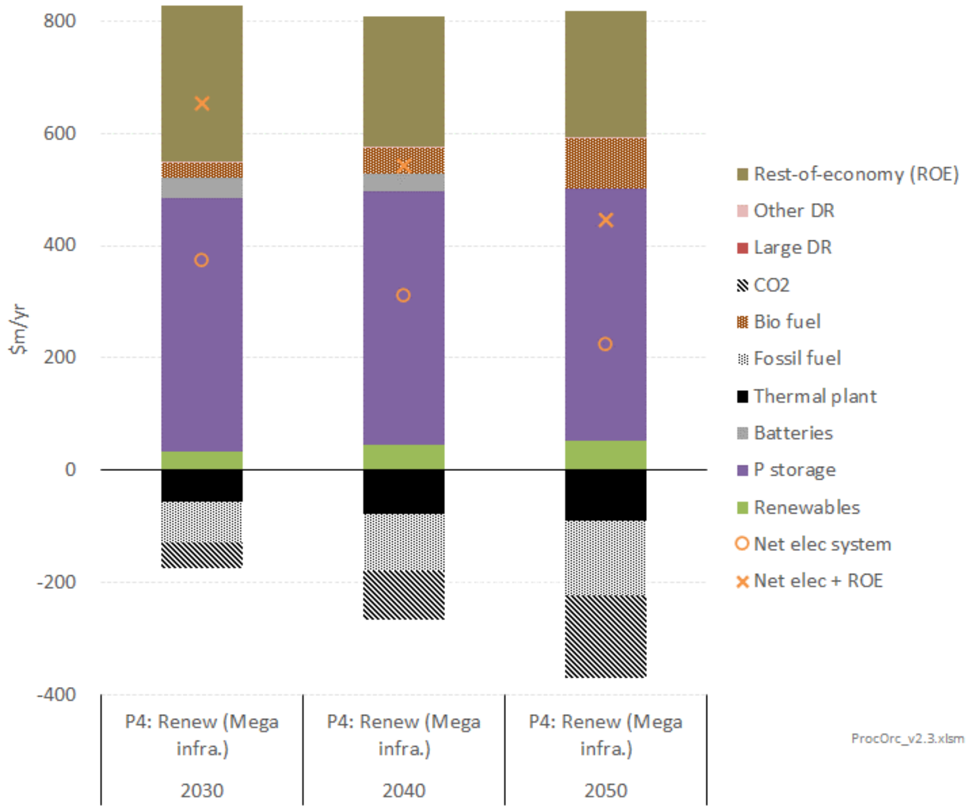
This section details the drivers behind this outcome. We think the insights are also instructive for New Zealand's flexibility challenge more generally.

3.2.1 A mega-scale flexibility option located in the South Island will most-likely have costs outweighing benefits

New Zealand's need for flexibility will grow incrementally. All the other flexibility options we have considered allow for incremental development.

In contrast, the Mega Infrastructure scenario has a massive addition of flexibility resource, the benefits of which (in terms of reduced thermal and CO_2 costs) don't justify the very large cost that is associated with its scale, as illustrated in Figure 11.

Figure 11: Difference in annualised costs/(benefits) for Pathway 4 relative to Pathway 1 (BAU) – Mid-case Onslow costs



Over time, the benefits of Onslow increase as the demand for flexibility increases, but by 2050 the benefits are still not large enough to justify the cost.

Figure 12 shows that even for our low scenario of Onslow costs, its benefits do not outweigh its costs.

Figure 12: Difference in annualised costs/(benefits) for Pathway 4 relative to Pathway 1 (BAU) – Low case Onslow costs

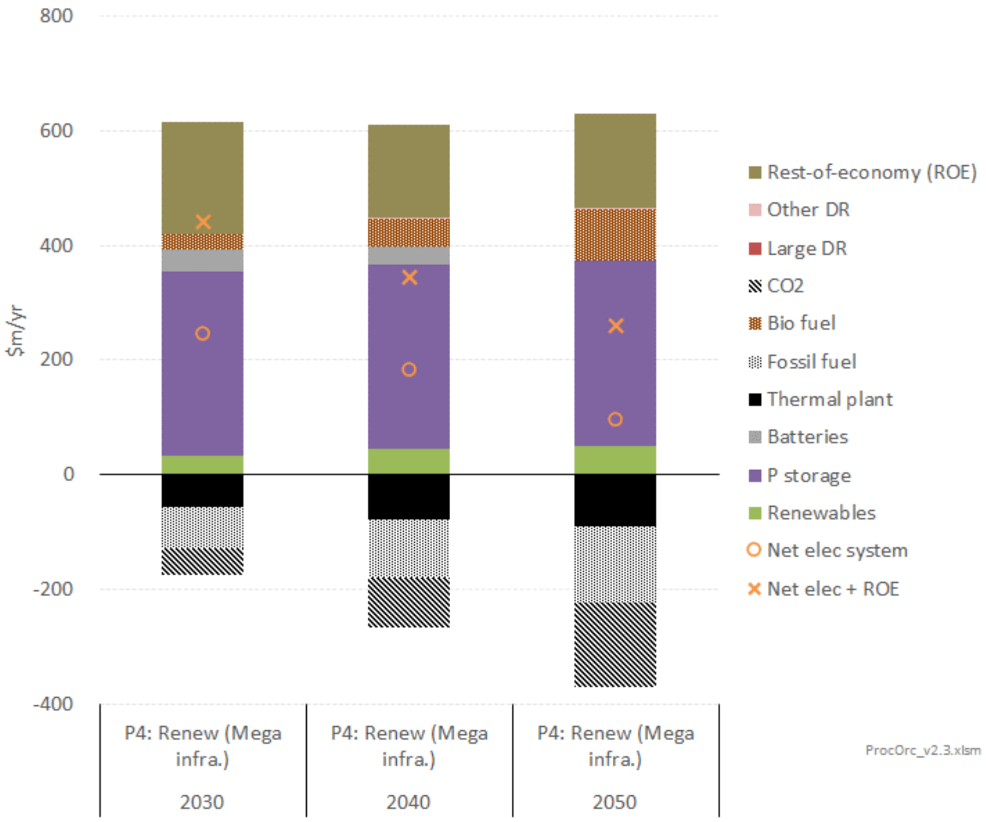
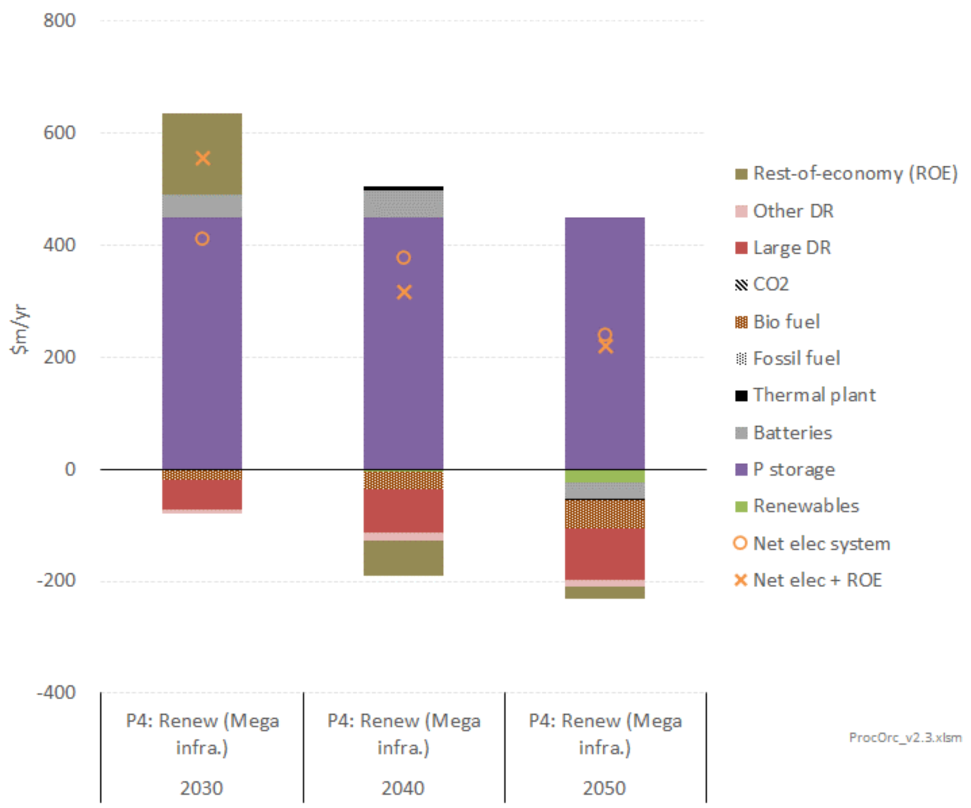


Figure 13 shows the costs / (benefits) of pathway 4 relative to the other 100% renewable pathway – Pathway 3, Renewable Pioneer.

Figure 13: Difference in annualised costs/(benefits) for Pathway 4 relative to Pathway 3 (Renewable Pioneer) – Mid case Onslow costs



The main reasons why the Mega Infrastructure option is significantly higher cost than this other 100% renewables option are:

- The Renewable Pioneer option (P3) allows for incremental development of flexibility resource to meet demand, whereas the Mega Infrastructure Build option (P4) represents a massive increase in flexibility resource (and associated cost) all at once.
- The mega-scale pumped storage scheme's South Island location limits its ability to contribute to meet the growing need for North Island peaking capacity. Accordingly, even with such a scheme, there will be a need for some biofueled peakers. Our analysis suggests the same MW capacity of biofueled peakers will be required in both scenarios – in part due to our assessment that the mega-scale option will have 'crowded out' the development of flexibility at Tiwai (as set out below) – but the green peakers will operate less often in the Mega Infrastructure scenario.
- The pumped storage scheme's 25% round trip losses (the difference between the amount of electricity it can generate, compared to the amount of electricity it requires to pump water back up into the reservoir) means that it doesn't actually reduce the quantity of renewables that will need to be built.

3.2.2 A mega-scale flexibility option will crowd out other forms of flexibility

The size of the pumped storage scheme modelled means that, as well as displacing flexibility from thermal stations, it will likely 'crowd out' other forms of flexibility resource. This is because flexibility resources are most valuable and profitable when there is a large spread between periods with high electricity prices and periods with low electricity prices. Flexibility resources operate by arbitraging energy – that is, they use or store electricity when the price is low, and generate (or reduce demand) when the price is high. A side effect of any flexibility resource that operates in this manner is it will tend to 'smooth out' the electricity price, reducing its variability.

An Onslow-scale pumped storage scheme would be a very large flexibility resource and would greatly reduce the opportunity for other forms of flexibility to arbitrage electricity. In our 2040 'business as usual' scenario, prices during the top 10% of periods are 36 times prices during the bottom 10% of periods.[17] Introducing Onslow to this scenario reduces this ratio to 23. Accordingly, this would reduce the opportunity for other forms of flexibility.

To illustrate the scale of this effect, we considered the economics of investing in technology to allow Tiwai to operate in a flexible manner ('Flexible Tiwai', as detailed previously on page 19), in two future systems: with and without Onslow. Without Onslow, Flexible Tiwai would pay a price about 30% lower than if it operated as baseload demand. However, if Onslow were to be built, this benefit of operating flexibly reduces by two-thirds.

This scale of reduction in benefit from resources operating flexibly would likely result in reduced provision from these other sources – many of which could be lower cost sources of flexibility. This will also harm the economics of hydrogen production facilities (whether they be for export, or for domestic consumption), as the benefits from operating the electrolysers flexibly are a key source of potential value for such facilities.

3.2.3 Very large-scale pumped hydro will make commissioning a challenge, with potential delays exacerbating this dynamic

There are two potential issues with the commissioning of a pumped storage scheme of the scale of Onslow:

- Its large size means that, once fully operational, it will cause a major step change in the quantity of flexibility resources made available to the market. This will tend to stifle investment in other flexibility resources in the years running up to its commissioning, causing a period of under-supply of flexibility resources. This will tend to increase electricity prices and cause greater operation of fossil generation than would otherwise be the case.
- Filling the reservoir to a useful level will require significant amounts of electricity. This will likely further increase electricity prices in the years during such filling and materially increase the operation of fossil generation.

Our modelling indicates that electricity prices in the two to three years' leading up to its commissioning could be elevated by approximately $25 to $50/MWh. Furthermore, a significant proportion of the electricity used to fill it will need to come from fossil generation, depending on hydrology during the first years following commissioning. New Zealand might "get lucky" and have 2-3 consecutive wet years that allow Onslow to store a working supply of water with minimal price increases, but we might not. A dry year while Onslow was still filling would lead to extremely high fossil fuel generation and associated emissions.

If the scheme is delayed beyond its expected commissioning time, the period of these elevated prices will be extended further, and likely reaching even higher price levels. In this it is notable that a significant number of large-scale pumped storage and hydro schemes around the world have had material delays in their construction. For example, BCG analysis of similar pumped storage schemes found that the projects, on average, took three years longer than initially expected, as did seventeen hydro projects reviewed in the same analysis.

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[17] This is much higher than has occurred historically, and reflects expectations about much higher levels of spill in the future.

3.2.4 If a mega-scale flexibility resource takes a long time to build, its benefit will be reduced

We have assumed for our modelling that the Lake Onslow scheme could be commissioned by 2030 – consistent with the proposed target of achieving 100% renewables by that date. However, there is considerable uncertainty over whether the scheme could be completed by that time.

For example, the Infrastructure Commission recently suggested that the earliest feasible date for building and commissioning Lake Onslow would be 2037, assuming the Government commits to it in 2025, the build takes seven years, and it takes a further three years to fill.[18]

If the scheme does take that long to develop it would reduce its benefit. This is because, as already set out, it will be cost effective to move to very high levels of renewables by as early as 2030 with an associated need for flexibility resources to perform renewable balancing. Accordingly, many of the flexibility resources that Onslow could avoid the need for development may anyway need to be built.

3.2.5 Having most of our flexibility 'eggs' in one South Island 'basket' would materially increase our exposure to natural disaster risk

As previously set out, increased overbuild in renewables will progressively reduce the requirement for thermal or other flexibility resources to manage South Island dry years, but will make far less contribution to managing the increasing need to manage the growing North Island peak flexibility requirement due to the electrification of transport and heating.

Locating a large proportion of the resource to meet this North Island capacity requirement in a single asset in the South Island materially reduces the electricity system's resilience to natural disasters. Thus, a major earthquake following the rupture of the Alpine Fault could affect the Onslow scheme itself or, more likely given that it spans most of the South Island, the HVDC interconnector which would transport Onslow's capacity to meeting North Island peaks.

Having many smaller-scale flexibility resources located in the North Island would be far more resilient against this risk.

4 Is large-scale hydrogen development likely to be a good pathway?

4.1 Large-scale hydrogen export will increase electricity sector costs, prices, and whole-of-economy emissions. NZ hydrogen would need to be very competitive with international hydrogen for this to be worthwhile

Some countries are relatively 'renewables-poor' (Japan and South Korea are two of the most significant examples) and may need to import renewable energy to decarbonise their economies.

One of the two most significant potential routes for importing such renewable energy is as hydrogen (either in liquid form, or converted into another chemical such as ammonia). This route may be the best for those countries that are not closely located to renewables-rich regions and thus face higher costs for the other main potential route for renewable electricity transport: along HVDC electricity cables.

The export hydrogen pathway modelled for the BCG study simulated the development of hydrogen production at a scale that would increase New Zealand's 2030 electricity demand by approximately

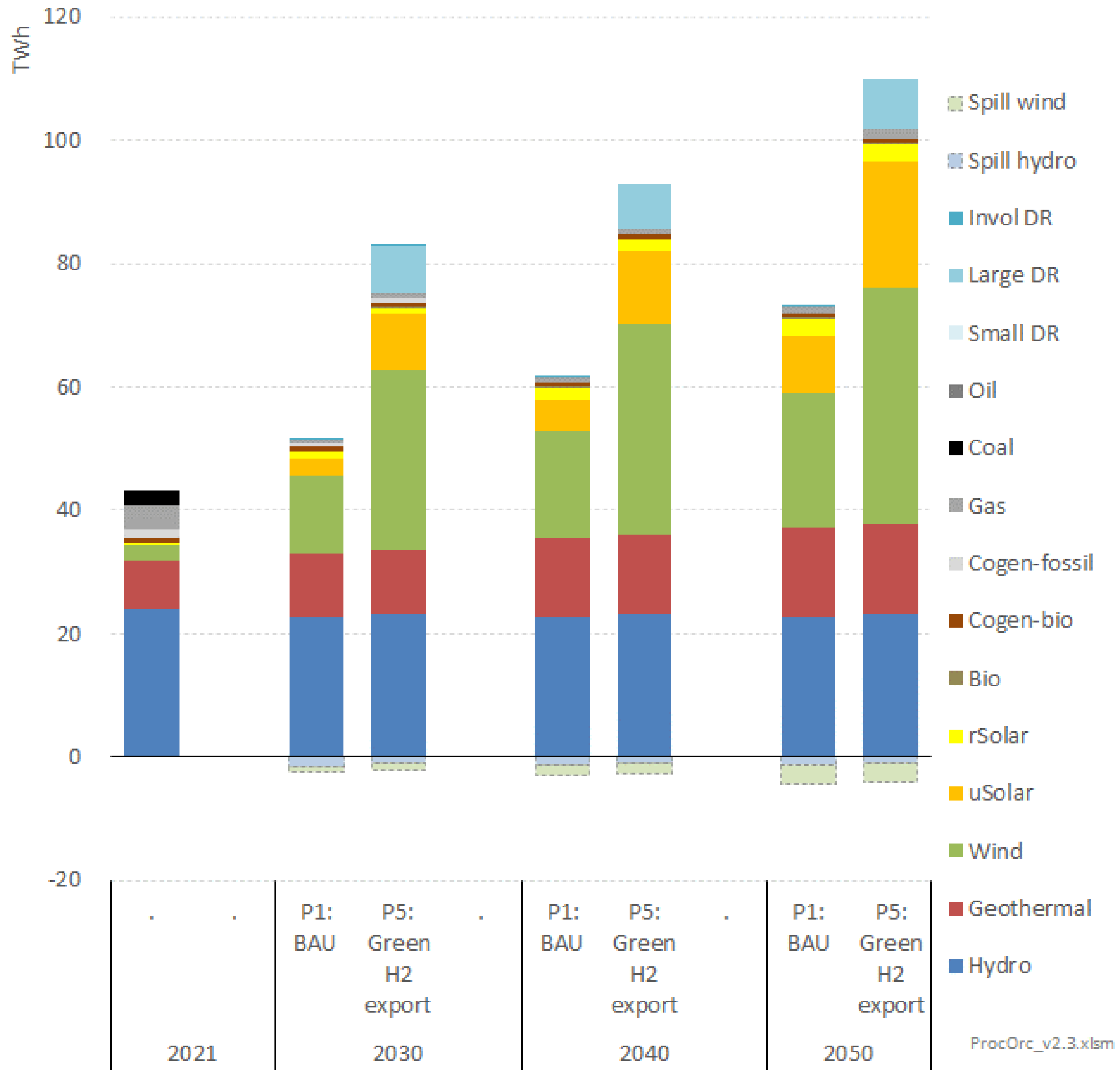
[18] *"Leveraging our energy resources to reduce global emissions and increase our living standards"*, May 2022, New Zealand Infrastructure Commission

60%. (For comparison, we estimate that the delivered hydrogen would equal 0.4%, in gross energy terms, of Japan's current fossil fuel consumption).[19]

This production was modelled as being highly flexible – ie, scaling back at times of higher electricity prices in a similar mode of operation to Flexible Tiwai detailed on page 19 previously, but with different price tranches: The first three 16.7% tranches are priced at $30, $50, and $80/MWh, respectively. The next 16.7% tranche is priced at $200/MWh, with the final 33.3% tranche priced at $500/MWh.

Figure 14 shows the resultant projection of generation and demand response to meet demand for this hydrogen export pathway. In comparison, the projection for the BAU pathway is shown, as well as the actual values for 2021.

Figure 14: Generation and demand response to meet demand



[19] This reflects not just the relative size of the two economies, but also the energy losses associated with producing the hydrogen. Our calculation assumes 50% energy conversion losses associated with producing the hydrogen in a form that can be shipped overseas.

As can be seen by the size of the 'Large DR' contribution to meeting demand, the flexibility provided by the hydrogen export facility results in it reducing demand significantly at times of relative renewable scarcity. On average, the facility only operates at approximately 75% of its capacity.

Nonetheless, despite this flexibility, the hydrogen export facility results in a significant increase in the amount of wind and solar needing to be developed.

The scale of increased renewables required will already be challenging in a BAU world – by 2030, wind and solar capacity will need to have increased to seven times the amount of capacity in place in 2021 – but will be doubly so to develop a world-scale green hydrogen export facility: wind and solar capacity in 2030 will need to be sixteen times the 2021 level.

We estimate this will require an additional $22bn in electricity supply side investment (renewable generation, plus transmission).

The increased development in renewable generation is estimated to increase wholesale electricity prices by approximately 25% relative to the BAU pathway. This is due to two factors:

- Increasing the proportion of variable renewables on the system, and thereby increasing the costs of procuring renewable firming services. This is reflected in the variable renewable plant facing an increasing discount between the average market price they receive when generating (their generation-weighted average price, 'GWAP') and the market time-weighted average price ('TWAP')
- New Zealand having to develop renewable options further up the cost-supply curve of available sites. (Noting that there is variation around the country in factors such as: the quality of the renewable resource, the cost of connecting to the grid, the civil engineering costs for construction).

This increase in wholesale electricity prices, is offset for consumers somewhat by the fact that we estimate the hydrogen export facility will pick up a significant share of transmission cost allocation and lower average transmission prices to consumers. However, the net effect is estimated to be approximately an $11/MWh increase in consumer electricity prices over the period modelled.

This increase in consumer electricity prices reduces the extent of electrification, increasing non-electricity costs and emissions. Overall, we estimate New Zealand emissions will be 0.6 MtCO2e per year higher because of this. This is equivalent to 15% of the emissions from fossil-fuelled power stations for the year ended March 2022.

From a net national economy perspective, these higher costs and emissions may be justified if they are exceeded by the hydrogen export earnings. For this to happen the international market price of hydrogen would need to materially exceed the cost of the additional required generation, transmission, and the hydrogen production plant. However, we expect one of the most competitive supplies of green hydrogen in the international market will be produced by solar generation in Australia or the Middle East, which may be able to undercut hydrogen production costs in New Zealand. Complicating this is whether the flexibility premium (ie, the achieved discount to the average electricity price through operating the plant flexibly) is better or worse in (hydro-and-wind-dominated) New Zealand compared to (solar-dominated) Australia and the Middle East.

Consideration of these issues was out of scope for this study. Nor have we considered the extent to which the shipped hydrogen market to renewables poor countries may be out-competed by other alternatives such as: large-scale HVDC transmission, nuclear power, offshore-wind, or re-location of energy intensive industries away from renewables-poor regions of the world.

If New Zealand were to proceed with a major hydrogen export facility, it should aim to protect itself from uncertainty over its long-term competitiveness by a well-designed contract. Specifically, having a termination clause with a sufficiently long notice period (ideally with associated ramp down), to enable NZ demand growth to progressively absorb the renewable generation that would have been built to power the hydrogen export facility.

Another challenge for large-scale hydrogen export is the "inter-island" problem – whether a facility be built in one island, or one in each, but neither are attractive options.

- If a facility were built in only one island, it would likely be the North Island, since that is where there is the most need for flexibility. However, unless there was significant investment in transmission, the HVDC constraint would limit the possible generation build in the South Island, which would exclude many attractive sites, and increase the overall cost of building enough generation.
- If we were to build a facility in each island, this may lose economies of scale for the hydrogen production and export facilities

If the Tiwai aluminium smelter were to close, that would create an opportunity for development of a hydrogen production facility in the South Island. However, based on current and forward aluminium prices, we think it unlikely it would be more cost-effective to build a new hydrogen production facility than continue with an existing aluminium smelter.

Lastly, as set out previously in section 3.2.2, it is worth noting that if New Zealand were to invest in mega-scale flexibility facility such as pumped storage at Lake Onslow, this would further harm the economics of a hydrogen export facility. This is because the mega-scale facility would satisfy much of New Zealand's requirement for flexibility, thereby reducing the value of additional flexibility from the hydrogen facility.

4.2 Green hydrogen for decarbonising New Zealand's pipeline gas used for heating will be higher cost than transitioning to electric heating

The sixth pathway we explored looked at developing green hydrogen for domestic use. This domestic hydrogen pathway assumed current gas consumption for space, water, and process heating would steadily transition over the period to 2050 to green hydrogen, and additionally that the heaviest category of trucks (over 20 tonne tarre) would transition away from diesel to fuel-cell hydrogen vehicles rather than battery electric.[20]

We also looked at different scenarios as to how flexible the electrolysers could be operated to meet the demand for hydrogen:

- Low flex: Using linepack[21] in the gas pipeline equivalent to having one day's worth of storage
- Mid flex: Linepack equivalent to five days' worth of storage
- High flex: Five-day linepack storage, plus 20 PJ of storage in gas reservoirs.

Both the Mid and High flex scenarios would require significant investment to enable such outcomes. This is because the volumetric energy density of hydrogen is only one-third of methane. Accordingly, to achieve five-day's linepack with hydrogen would require upgrading the transmission

[20] This assumption about heavy trucks was based on an assessment that it would be implausible to have hydrogen for space heating to be a pathway, without also having hydrogen for heavy trucks – noting that the consensus of international assessments seem more optimistic about hydrogen for heavy trucks than for heating. (Although, as set out in our June '22 report on zero emission heavy trucks (available here: https://www.concept.co.nz/updates.html) , there appears to be a growing international view that even hydrogen for heavy trucks appears less cost-effective than battery electric trucks for most use cases relevant to New Zealand).

[21] Linepack can be considered to be the amount of effective storage in a pipeline available through allowing pipeline pressures to move between upper and lower bands. Increasing the pressure in a pipeline is equivalent to injecting gas into a storage facility, and lowering the pressure is equivalent to extracting it again.

pipelines to operate under significantly greater pressure. Likewise, 20 PJ of hydrogen storage is equivalent to more than three times the capacity of New Zealand's only gas storage reservoir – the depleted Ahuroa gas field in Taranaki. It is not known how much it would cost to develop such capabilities or whether, in the case of gas reservoir storage, it is practicably feasible. However, the purpose of the exercise was to determine whether, if such flexibility capabilities did exist, hydrogen could be competitive with direct electric heating.

Figure 15 below shows the projected generation volumes to meet demand in the green hydrogen scenarios, with Figure 16 showing the projected generation capacities. In both cases, actual 2021 values and the projections for the BAU scenario are shown for comparison.

Figure 15: Projected generation in the domestic green hydrogen scenarios

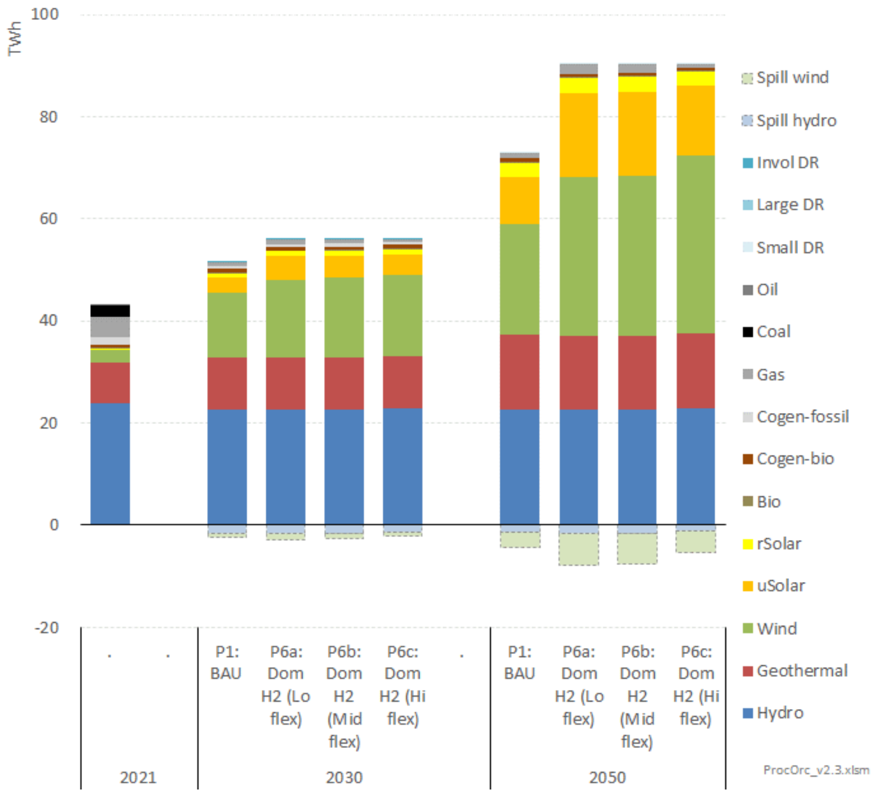
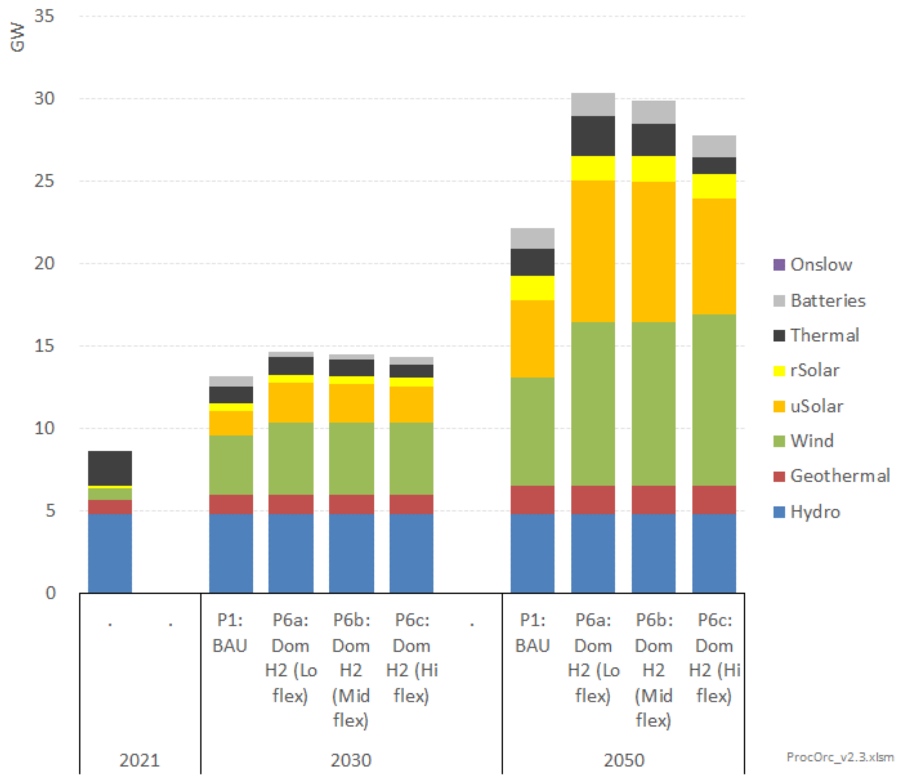


Figure 16: Projected supply capacity in the domestic green hydrogen scenarios



They show that developing domestic green hydrogen will require significantly more renewable generation by 2050 than if New Zealand chose to decarbonise gas consumption and heavy truck transport via electric heating and electric vehicles.

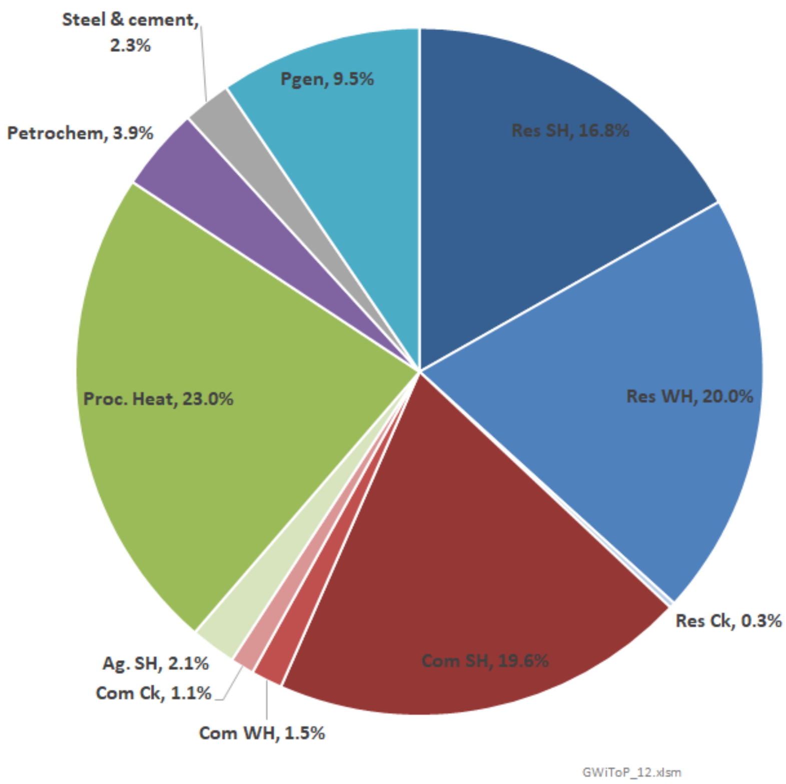
They also show that if the electrolysers can be operated with a high degree of flexibility, the amount of renewable generation and peaking thermal capacity required by 2050 will be materially less than if flexibility is limited.

Nonetheless, even in the highly flexible scenario, the amount of wind and solar capacity required by 2050 is twenty-three times the 2021 level, compared to 'only' sixteen times for the BAU scenario.

The most important output from our modelling was the effect on wholesale electricity prices, in particular the demand-weighted average price (DWAP) for direct electric energy uses (space, water, and process heating) in the BAU scenario, and the DWAP for electrolysers in the green hydrogen scenarios. This, in conjunction with other information about the rest of the supply chain costs of supplying heating energy services from direct electric or green hydrogen, allows evaluation as to which is likely to be most economic.

We undertook this detailed cost-of-supply analysis for the gas end-uses which, as illustrated in Figure 17 below, account for the majority of current gas pipeline revenue: space heating (SH) and water heating (WH) for residential ('Res') and commercial ('Com') consumers plus industrial process heat. Further given the significant expected reduction in gas-fired generation ('Pgen') and petrochemical production, they are likely to account for an even greater share of 2050 pipeline revenue in a hydrogen future – if such a future is plausible.

Figure 17: Estimated breakdown of current gas pipeline revenue



Source: Concept analysis of public data from Commerce Commission and published gas network tariffs

Figure 18 to Figure 20 below show the results of this direct electric vs hydrogen cost-of-supply comparison for the best-case flexible hydrogen scenario, P6c, for three different end-uses:

- Residential water heating
- Commercial space heating
- Industrial process heat

For each option (electric and hydrogen) the left-hand-most dark blue bar represents the demand-weighted average wholesale electricity price (DWAP) as modelled in our analysis. The DWAP is based on the demand shape of the use in question (eg, space heating, or water heating).

The direct electric option uses the values derived in our BAU pathway, whereas the hydrogen option uses the values derived in the highly flexible hydrogen pathway, P6c. In this pathway, our modelling indicates that the benefit of the significant flexibility of the electrolysers' operation just outweighs the costs associated with having to build more renewables. As such, the starting DWAP is slightly lower than in the BAU DWAP.

The subsequent bars to the right of this starting DWAP show, in waterfall chart format, the various additional costs (shown as red bars) and cost reductions (shown as green bars) to deliver the full cost of supplying useful heat energy.

The first green bar to the right of the starting DWAP for the hydrogen option represents the benefit associated with the electrolysers achieving an even lower DWAP compared to that of the end-use, due to the electrolysers' flexibility.

The next set of bars to the right of both the hydrogen and electric options represent the costs associated with energy losses incurred along the supply chain: network losses, electrolyser losses (in the case of hydrogen), and appliance efficiency losses (or gains in the case of electric heat pumps).

The hydrogen option also has capital and non-fuel operating costs associated with producing the hydrogen – the cost of the electrolysers, the electricity transmission costs associated with getting the renewable electricity to the electrolysers, and the costs of the hydrogen storage facility.

The intermediate blue bar 'useful energy: wholesale' in both hydrogen and direct electric represent the cumulative effect of all the above costs. The subsequent bars to the right represent:

- the costs associated with transporting the fuel along the electricity or gas networks from the point of production to the end consumer
- the incremental retail and metering costs for taking the fuel. This is assumed to be zero for electricity consumers; and
- the non-fuel appliance capital and maintenance costs. For the electric option, this also includes an amount for the 'make-good' costs associated with switching-out an existing gas appliance.

Figure 18: Electric versus hydrogen comparison for residential water heating in 2050 – optimistic high H2 flex scenario

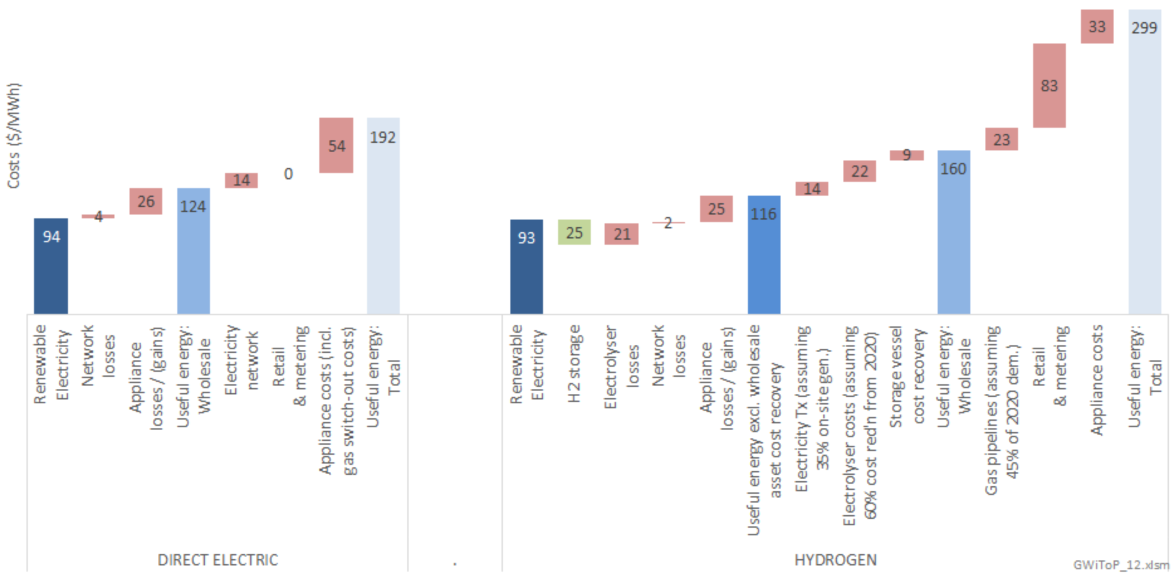


Figure 19: Electric versus hydrogen comparison for commercial space heating in 2050 – optimistic high H2 flex scenario

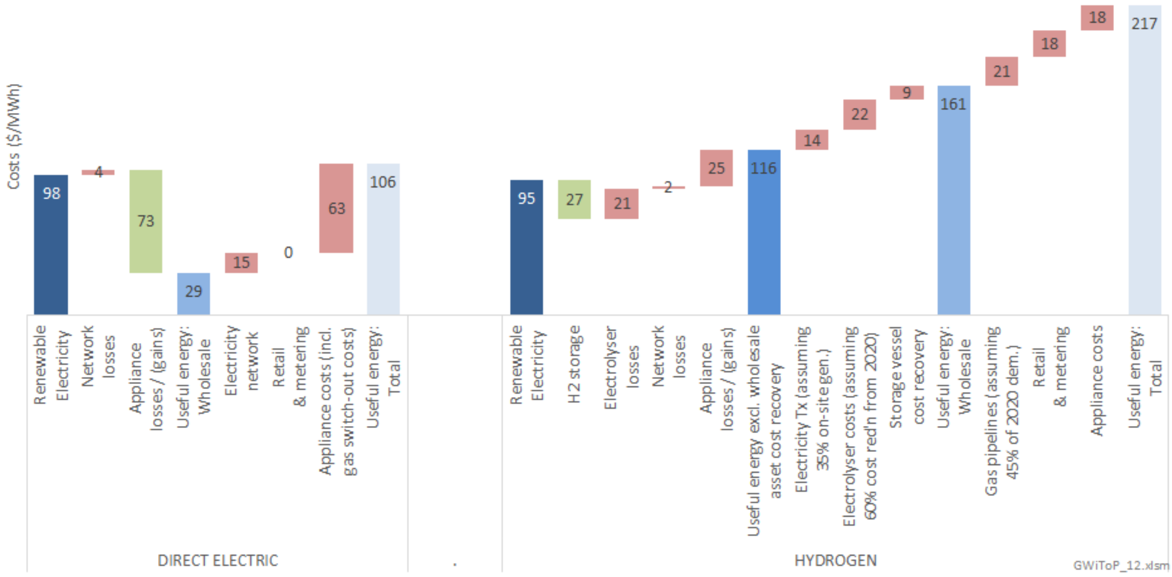
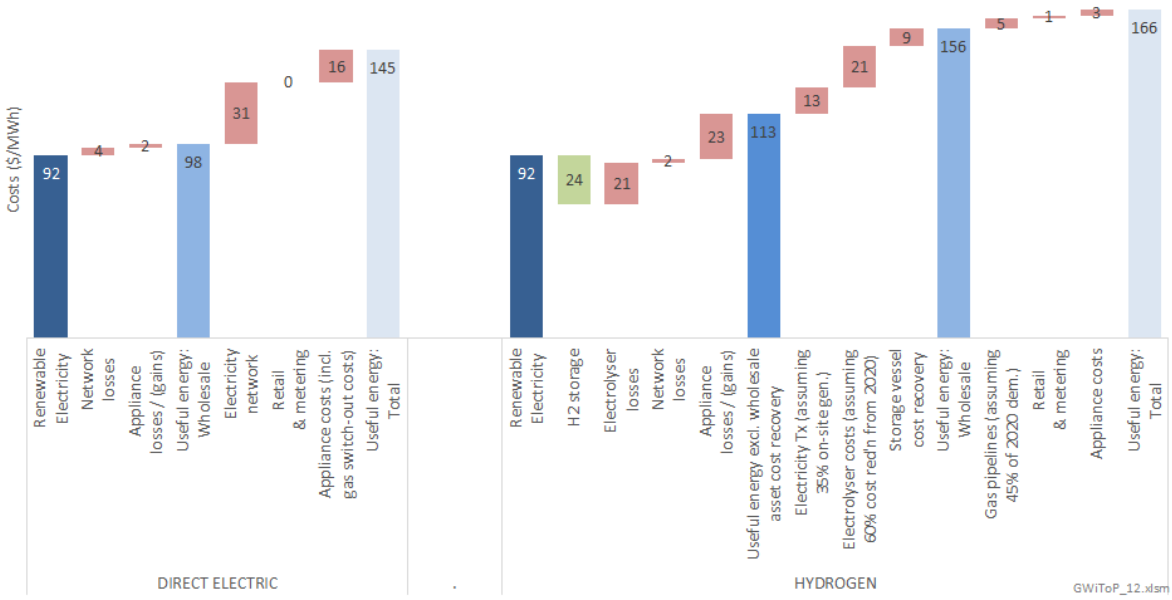


Figure 20: Electric versus hydrogen comparison for industrial process heat in 2050 – optimistic high H2 flex scenario



In all three use cases, the hydrogen option is materially more expensive than the direct electric option:

- 55% more expensive for residential water heating
- Twice as expensive for commercial space heating
- 15% more expensive for industrial process heat. However, it should be noted that neither option is as cheap as converting to biomass boilers in most cases.

As set out earlier, this is for the highly flexible scenario for hydrogen production. If hydrogen production can only achieve the level of flexibility associated with the low flexibility scenario, the extent to which hydrogen is more expensive than direct electric rises even further:

- 80% more expensive for residential water heating
- Two-and-a-half times more expensive for commercial space heating
- 45% more expensive for industrial process heat

Further, by 2050, the capex penalty for switching out an existing gas appliance is likely to be less than we have assumed as, by that time, a signfiicant number of existing gas appliances will have reached the end of their useful life.

Taken together, this analysis indicates that, even with highly optimistic assumptions about how cheaply hydrogen can be produced, hydrogen will be a substantially more expensive means of meeting consumers' heating needs than direct electric options.

5 How resilient are our conclusions on pathways?

The future is inherently uncertain. With major and rapid shifts in technology of the kind required to decarbonise our economy, the uncertainties are even greater. In choosing an energy pathway, it is therefore critical to understand how robust it is to key drivers turning out to be substantially different to expectations.

5.1 The physics of electricity flexibility will make pushing for 100% renewables more costly across a wide range of futures

Understanding the physics driving the need for different types of flexible resources is critical to understand why it is very expensive to squeeze out the last ≈1% of fossil generation.

As set out in section 2, the nature of the variability of demand and intermittent renewables means there is a need for

- some flexible capacity which will be required to generate most of the time, except at periods of relative surplus: 'mostly-on' capacity.
- some flexible capacity whose output is only required at rare times of significant scarcity: 'mostly-off' capacity.

It is the mostly-on flexibility duty for which renewables have overtaken fossil as being the most cost-effective solutions. As detailed in section 2.1, the one-third of total flexibility capacity that has provided mostly-on flexibility is responsible for 75% of the flexible GWh over the past five years

However, as the proportion of time for which the flexible capacity is required declines – ie, progressively moving towards mostly-off operation – it becomes exponentially more expensive for renewables to replace fossil stations. This is a function of:

- The high-capex-low-opex cost structure of renewables compared to the low-capex-high-opex structure of fossil plant
- The intermittent nature of wind and solar, making them poorly suited to providing firm MW at times of capacity scarcity

Thus, even if wind and solar halved in cost, and the price of gas and carbon doubled, it would still be more cost-effective to have gas-fired OCGTs providing infrequently required peaking MW – although the amount of duty required would be very small, resulting in ≈99.5% renewables.

Furthermore, even if gas and carbon prices doubled, gas-fired OCGTs would still be cheaper than biofuel-fired OCGTs if biofuel were at $45/GJ.

Physics is also a key driver of why the Mega Infrastructure scenario is significantly more expensive than the other 100% renewables scenario.

The South Island location of Lake Onslow means it is limited in its ability to provide capacity to meet NI peak capacity scarcity requirements. Furthermore, its round-trip losses mean that there is relatively little difference in the amount of renewable plant needing to be built compared to a 100% renewables pathway comprised of multiples sources of flexibility.

It is also important to note that, based on experience with overseas pumped hydro projects[22], the range of uncertainty over a very large scale pumped hydro scheme's cost and timing appears larger than the uncertainty over many other flexibility resources. Coupled with its very large scale, this will tend to make the Mega Infrastructure pathway a higher risk option than other pathways. (Although, even if it could be built at the low-end of cost estimates and be commissioned by 2030, our modelling indicates it would be higher cost than the other 100% renewables option – which itself would be more costly than the limited-fossil options.)

All the above indicates that pushing for 100% renewables by as early as 2030 is likely to be higher cost across a wide range of possible future values for renewable technology costs and gas and carbon prices. Furthermore, 100% renewables options which are dominated by very large single asset 'solutions' over which there is considerable uncertainty over cost and timing will be even riskier.

That is not to say 100% renewable electricity generation might never be achieved. As flexibility resources develop – particularly medium duration storage technologies, various types of demand response technologies, and biofuels – the costs of achieving 100% renewable electricity will decline. However, intervening to force a 100% renewable electricity outcome before the time when it would be cost-effective will lead to poor economic and environmental outcomes.

5.2 The physics of hydrogen production, will make it a higher cost option for decarbonising pipeline gas use across a very wide range of plausible futures

The hydrogen versus direct electric cost comparisons shown in Figure 18 to Figure 20 previously indicate that transitioning pipeline gas users who use gas for heating to direct electric will be much cheaper than transitioning to green gas in the form of green hydrogen. We believe this conclusion is robust against a very wide range of futures because:

- A significant driver of the cost difference is that the direct electric options take advantage of an existing supply chain that will be required anyway. Therefore, only the incremental wires (relatively low) and retail & metering costs (zero) will be incurred from this pathway. In contrast, the green hydrogen option incurs the full cost of the alternative supply chain, including the costs of pipelines, retail & metering costs, electrolysers, and storage facilities.
- The assumptions around the degree to which electrolysers could be operated flexibly were at the extreme end of plausibility, and would require significant investment in the gas pipelines and additional very large underground gas storage facilities. It is not known whether this investment could be undertaken for the relatively low cost assumed in the analysis or, in the case of the gas

[22] Boston Consulting Group research published in "*The Future Is Electric*" on the experience of analogous overseas pumped hydro projects states that "*the average project cost roughly over double as much as originally thought and taking 2–3 years longer to build. The Snowy Hydro 2.0 scheme in Australia, which is still under development, is now scheduled to cost 2.5 times as much as originally planned and take 7 years longer to build.*"

storage facilities, is even practicable. The most likely outcome is for hydrogen to cost even more than these values.

- By 2050, the capex penalty for switching out an existing gas appliance is likely to be less than we have assumed as, by that time, a signfiicant number of existing gas appliances will have reached the end of their useful life.
- The analysis doesn't take account of the significant transition costs associated with moving to green hydrogen including:
  - Progressively having to have engineers check every single gas appliance in every pipeline connected property in New Zealand to check/retrofit burners to ensure they are hydrogen safe. Given the scale of effort, this will likely need to be done progressively, pipeline section by pipeline section, over a couple of decades.
  - The fact that this slow transition, inevitably culminating in the final Taranaki section of the network (the source of all pipeline fossil gas), means that the potential to use gas storage facilities to reduce hydrogen production costs can only be called upon at the end of this transition. In the meantime, hydrogen will need to be produced at remote electrolysers with little access to storage for flexibility. This will significantly increase the cost of hydrogen gas during this period.

Lastly, it is worth noting that in a large proportion of industrial process heat situations, *neither* electricity or green hydrogen will be the cheapest option, but biomass will be cheaper.

6 Other insights

Our analysis has revealed some other key insights into how we can undertake a transition to a low-carbon energy system.

6.1 Demand-side flexibility will become increasingly important, but this may create some political as well as technical challenges

As the share of intermittent renewable supply rises, there will be increasing need for resources that can provide short-duration flexibility (from hours to days) to supplement flexibility provided by the hydro system. This additional need can be met by thermal generation (whether bio- or fossil-fuelled), batteries (static, and within electric vehicles (EVs)), and demand response.

The two most important categories of demand-side resources are:

- Electricity demand that can be 'shifted' within a day without curtailing the energy service for consumers, particularly EV battery charging and hot water cylinders; and
- Electricity demand that can be voluntarily curtailed during system scarcity periods.
  - In this category, our evaluation is that electricity-intensive industrial demand ('Large DR') is likely to be the biggest potential source. This is because such users are typically quite sensitive to electricity costs, and they could make material cost savings by reducing usage at times of higher wholesale prices. Some electricity users may find it attractive to do this, for example by meeting production orders from inventory or drawing on other overseas supply sources.
  - However, for very infrequent flexibility requirements, it would be more economic for some mass-market users to reduce their demand than to invest in batteries or peaking generation.

While the benefits of demand flexibility are expected to grow, there may be some technical and political challenges.

On the technical side, it will be important to ensure that the arrangements facilitate demand flexibility for those consumers who have the ability and willingness to shift or curtail their demand. As set out in section 6.3 below, we believe developing arrangements for managing EV demand and hot water will be the most important, particularly because of their additional network benefits.

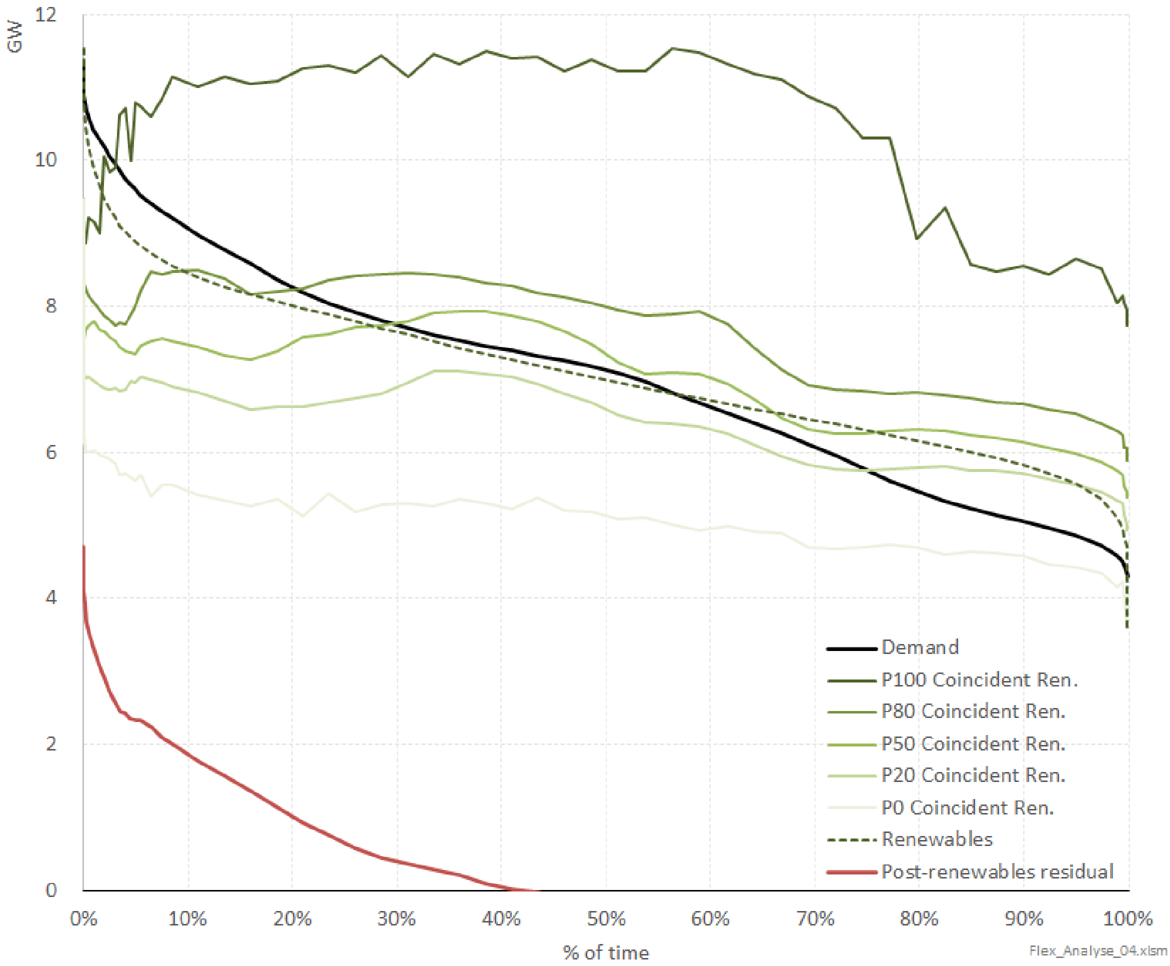
On the political front, it will be important explain the wider benefits of demand flexibility, and why reducing discretionary demand in very rare periods of tight supply should not be viewed as a failure of the system.

Figure 21 and Figure 22 below help illustrate how different flexibility resources will be called upon in a highly renewable system, and the importance of demand response.

Figure 21 shows a representation of our modelling of the 2040 system under Pathway 2 for:

- Hourly demand, represented as a duration curve
- The level of renewable generation (the total of wind, solar, hydro, and geothermal), represented as a duration curve, but *non-coincident* to the demand duration curve
- The level of renewable generation *coincident* to the demand duration curve at different percentile levels. A way of understanding these lines is to consider that, for each point along the demand duration curve, the corresponding points for the coincident renewable lines plot out a probability distribution. For example, the 20th percentile of hourly demand in 2040 is shown to be approximately 8.3 GW. When demand is at that level, the median level (fiftieth percentile) of renewable generation is shown to be approximately 7.5 GW. However, there is considerable variation as to how much renewable generation there may be at such times, with the 80th percentile being 8.2 GW, the 20th percentile being 6.6 GW, and the 100th and 0th percentiles being 9.3 GW and 6.0 GW, respectively.
- The post-renewable residual demand (ie, demand minus renewable generation), represented as a duration curve (but non-coincident to the demand duration curve)

Figure 21: Projected 2040 demand and renewable generation for Pathway 2

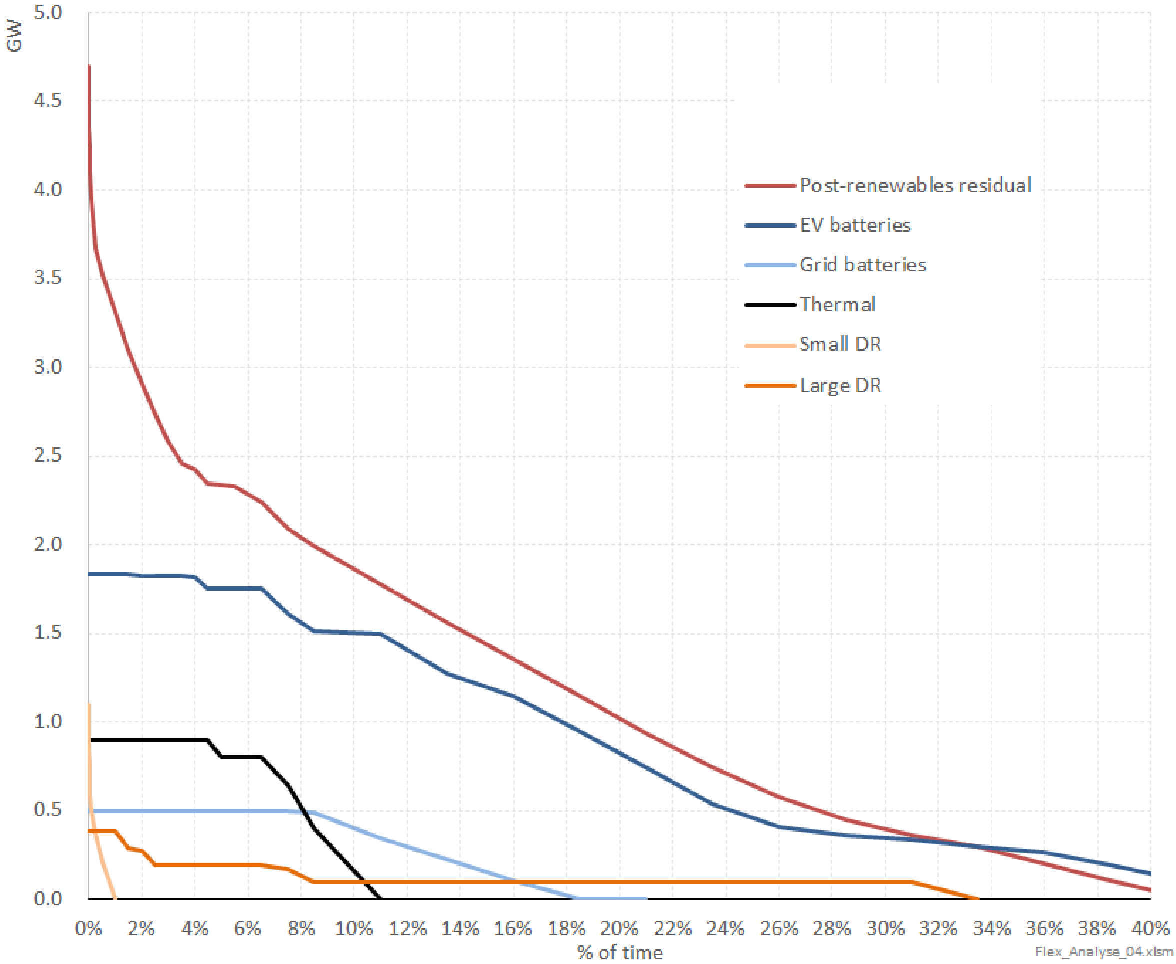


The key take-aways from this graph are:

- Renewables, prior to the operation of batteries and demand response, will meet the vast majority of demand on an average annual GWh basis – as illustrated by the area under the post-renewables residual demand curve being a small fraction (approximately 7%) of the area under the demand curve. In the absence of batteries and demand response, this would result in a 93% renewable system on an average annual GWh basis.
- However, the non-coincidence of periods of high demand and low-renewables, and vice versa, results in a post-renewables residual demand requirement where renewables only meet 59% of the peak GW capacity requirement.

Figure 22 shows how the post-renewables residual demand shown in Figure 21 is met by different flexibility resources. (Note, the x-axis only shows the 40% of time where additional flexibility resources other than renewables are required).

Figure 22: Projected flexibility resources to meet the post-renewable residual demand in 2040 for Pathway 2



The key take-aways from this graph are:

- The ability for batteries to materially increase the proportion of generation from renewables. Thus, grid batteries charge up periods of surplus in order to release the energy at times of renewable scarcity. For EV batteries, the effect is similar, but achieved through EVs avoiding charging at times of renewable scarcity (with the reduction in demand being shown as a positive contribution to meeting uncontrolled demand in Figure 22 above). Together, they effectively enable another 5.5% of renewable generation, bringing the renewable % (prior to DR) up to 98.5%.
- The importance of EV batteries at managing peak demand. (We assume that by 2040, 69% of EV demand can be reduced at times of peak scarcity. This compares with National Grid UK who's mean scenario for EV control is 83% reduction, but with scenarios ranging from 23% to 125% (ie, in the 125% scenario, widespread vehicle-to-grid would see EVs delivering a net *reduction* in peak demand)).
- The large MW capacity required from small-scale DR (over 1 GW), but the very small amount of time it is required (0.03% reduction in average annual demand):
  - No small-scale DR will be required for more than 70 hours a year, on average

- The top 500 MW of small-scale DR wouldn't be required for more than four hours a year, on average
- The top 250 MW of small-scale DR wouldn't be required for more than one hour a year, on average

It would be very expensive to build supply-side assets such as batteries or generation that are only required for four hours a year, or less.

6.2 This decade will be the most challenging for the electricity sector transition

6.2.1 This decade will have the fastest rate of renewable build requirements

Not only is there a need to build renewable generation this decade to meet the demand growth from electrification, there is also the need to build sufficient renewable generation to almost completely displace existing fossil generation. These twin challenges mean that the renewable investment requirement is front-loaded this decade. Targeting a 100% renewable supply by 2030 and/or choosing a green hydrogen pathway would add further pressure to this transition.

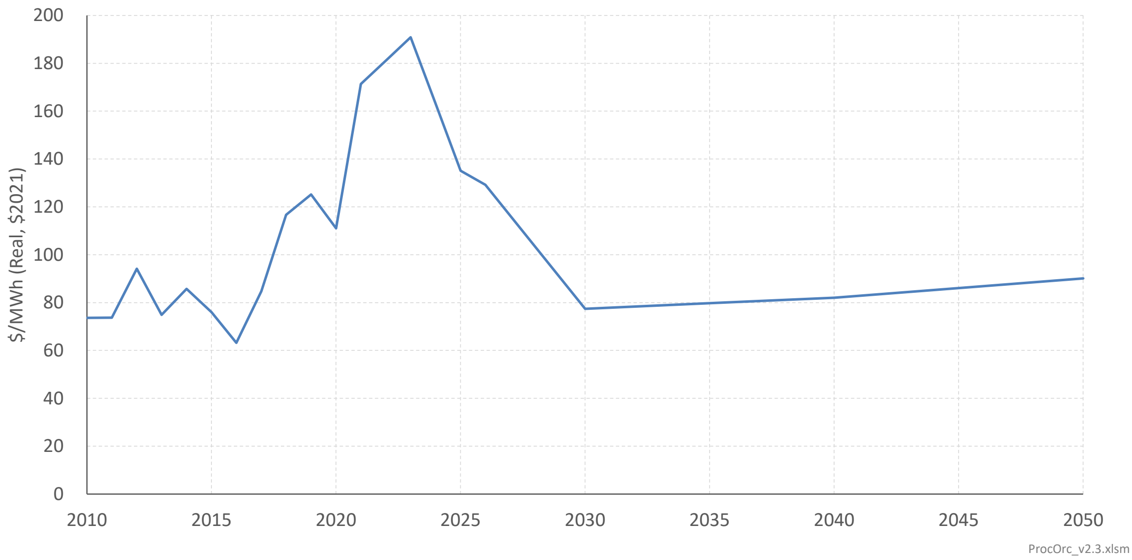
While the pace of renewable generation development has lifted to around 2.5 times the rate achieved in the last decade, it needs to accelerate further. If this does not occur, there will be an extended period of over reliance on high-cost fossil fuel plant to maintain reliable supply. That will result in higher wholesale prices and sector emissions than would be the case if renewable development was at a level consistent with the relative costs of fossil and renewable generation.

Forward contract prices indicate new renewable investment is accelerating, but that investment is not expected to catch up to requirements until beyond 2026. This underlines the critical importance of identifying and addressing factors that impede the development of new resources such as the consenting framework.

Having said that, once the electricity system is through the immediate transition, the outlook appears less challenging, with the rate of development for subsequent decades being approximately two-thirds of the rate of this current decade. This is because new generation investment requirements no longer need to address the twin requirements of thermal retirements and demand growth, and the system is more likely to be in balance.

The effect on prices of this decade being short of renewable generation as renewable development is progressively accelerated is illustrated in Figure 23.

Figure 23: Historical and projected (for the BAU scenario) average New Zealand wholesale prices ($/MWh, Real $2021)[23]



The falling forward curve (which was used for the 2022 to 2026 prices in Figure 23) indicates the accelerating build of renewables starting to bring the system into balance, but not achieving it by 2026. Our modelling for 2030 and beyond indicates likely average wholesale prices if sufficient renewables have been built to displace fossil generation to an efficient level.

6.2.2 We will increasingly be needing fast-start thermals, but continue to operate with a significant slow-start thermal fleet

This decade will also face additional challenges associated with moving towards a system with high proportions of intermittent renewables but still having some large slow-start thermals – the Huntly Rankine units and the two remaining combined cycle gas turbines (CCGTs). These types of units are not well suited to providing the short-duration, short-notice flexibility that will increasingly be required.

To illustrate this challenge Figure 24 and Figure 25 below show: the observed historical pattern of operation for the different types of existing thermal units, and the projected future pattern of operation required by thermal units in a highly renewable system.

[23] The 'New Zealand' price represents the demand-weighted average of Otahuhu (North Island) and Benmore (South Island) prices. Pre-2022 prices are historical spot prices escalated by CPI to show in real $2022. 2022 to 2026 prices are from the ASX forward curve of electricity market futures. 2030+ prices are Concept modelled prices.

Figure 24 - Observed operating duration for existing thermal for 10-year period ending June-22[24]

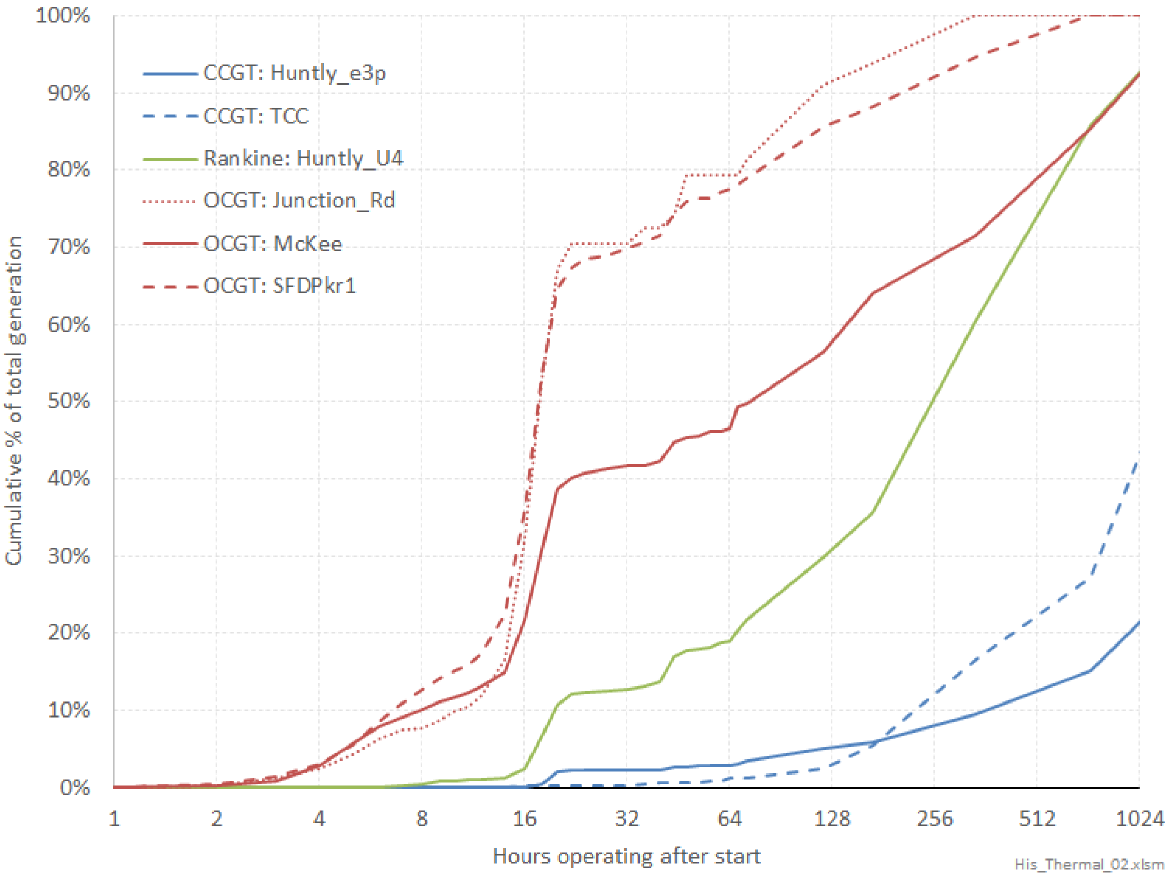


Figure 24 illustrates the different historical modes of operation for six different representative types of thermal plant by representing the cumulative amount of GWh generated for different durations of operation following a start.

- CCGTs operate for long periods of time without interruption. ≈80% of the MWh generated by e3p was generated when the plant operated without interruption for more than a month (730 hours) after starting up – ie, in a 'baseload' fashion. By contrast, the equivalent metric for OCGTs and Rankines is less than 10%.
- OCGTs are the plant for whom the greatest proportion of operation is from short-duration operation (less than one day). A much smaller proportion of operation (≈ 10%) for Rankines is sub one-day, and CCGTs almost never operate in such a fashion.
- OCGTs are the only plant who have historically operated for very short durations (8 hours or less)

This observed difference is consistent with Concept's understanding of the physical capability and economics of the different technology types.

Our modelling of the future required mode of operation of thermals, as illustrated in Figure 25 below, indicates a substantially different mode of operation.

[24] SFDPkr1 = Stratford Peaker # 1

Figure 25 – Modelled operating duration for thermal in 2030

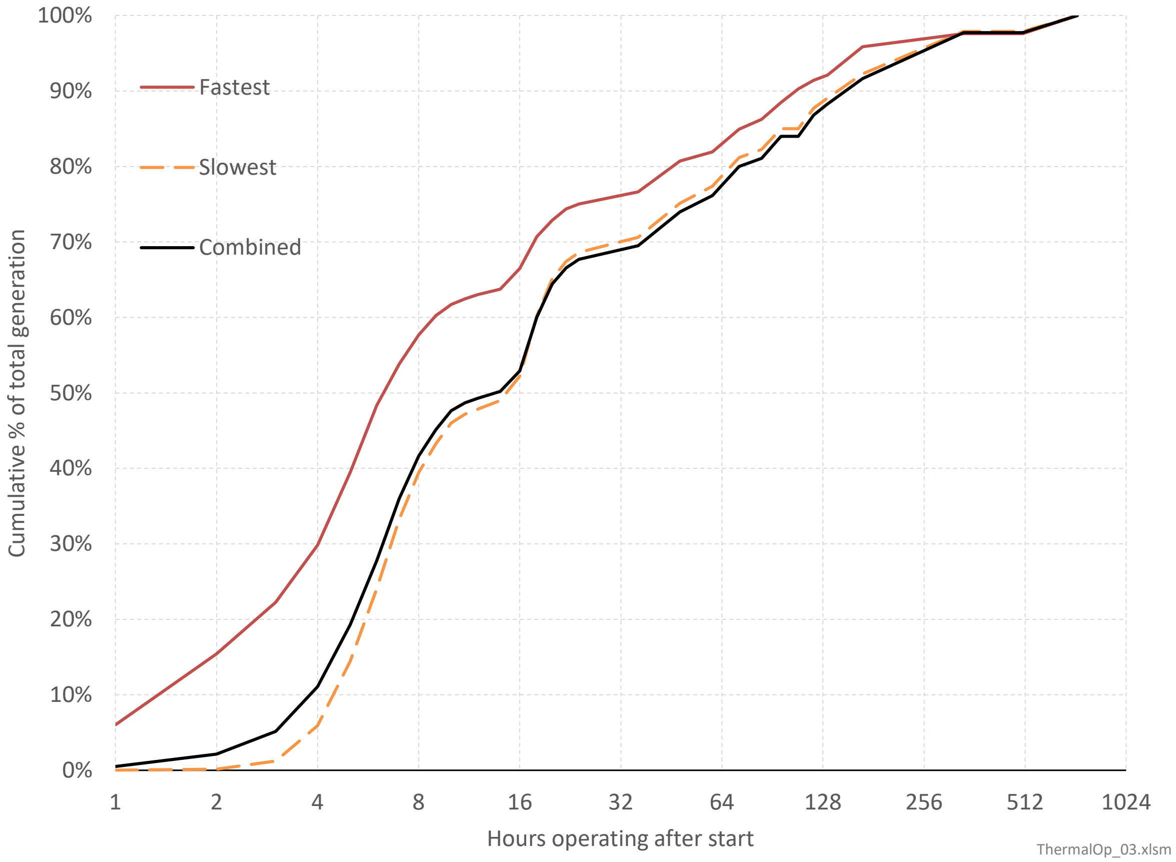


Figure 25 shows how all thermal plant operates in our 2030 pathway 2 (labelled as "combined"). We also show a 250 MW unit that starts and stops last would operate (labelled as "slowest"). This shows the type of operation that a slow start 250 MW unit might be called upon in our 2030 scenario. Even this "slowest" unit operates for less than a day about two-thirds of the time.

Our analysis clearly indicates that the requirement for thermal in the future is more akin to how OCGTs have operated in the past. The long uninterrupted periods of generation experienced by slower start thermal in the past do not appear in the future.

We have not investigated in detail whether existing slow start generation would be able to operate economically in this new mode of operation, or whether instead it would be more cost-effective to build new OCGTs to meet this requirement.

6.3 Avoiding significant network cost increases from electrification is achievable, but will require 'smarts' – particularly for EVs and hot water

Some of the biggest opportunities for cost-effectively decarbonising our economy come through electrification of a few fossil-using end-uses that dominate our emissions profile – road transport, space and water heating, and some industrial process heat.[25]

[25] For many industrial process heat situations, biofuels are a more economic solution.

This electrification will significantly increase energy demand on electricity networks and has the potential to significantly increase peak demand, which would prompt a need for costly investment in network capacity.

Based on information provided by the five largest network companies plus Transpower's recent Integrated Transmission Plan, network expenditure this decade under a 'BAU' demand management world is projected to be 137% of last decade's value, rising to 191% of last decade's value for the decade ending 2050.

It should be noted that a large proportion of this will happen anyway, as a significant amount of the wave of network investment that occurred in the 60's, 70's, and 80's will come due for renewal.

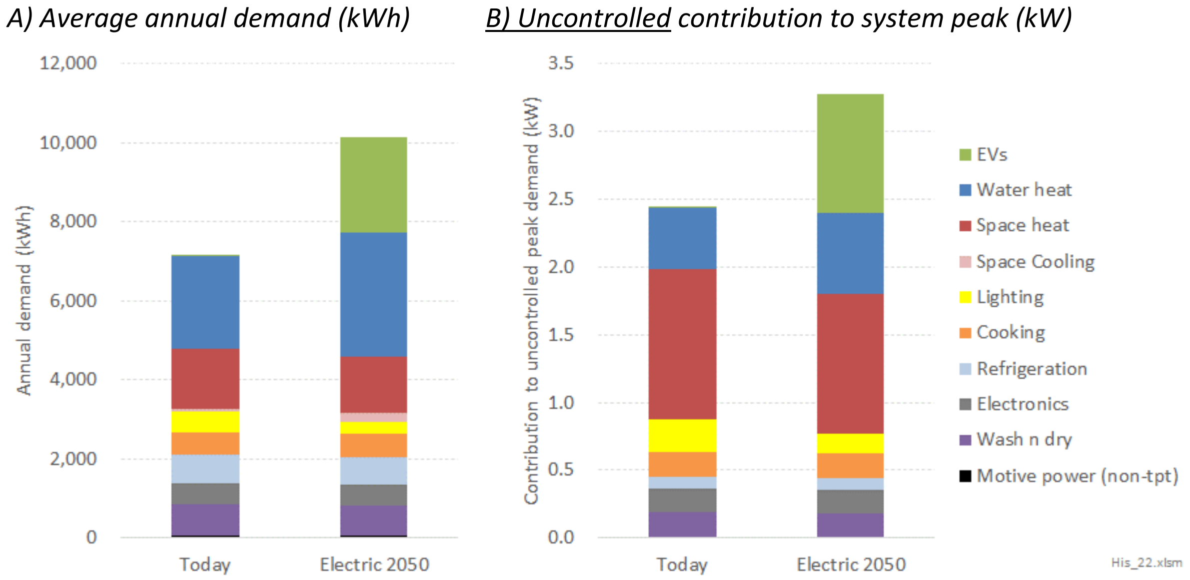
However, there is a significant amount of expenditure which is driven by the electrification of our economy, and the consequent increase in demand. This gives rise to an opportunity for much of this demand-driven expenditure to be avoided if we can take advantage of distributed energy resources (DER) such as batteries and 'smart' demand management to enable GWh demand growth to occur with minimal peak MW demand growth.

As we set out below, two technologies stand out for their potential to alleviate distribution network capacity investment pressures – hot water load control, and EV management (smart charging to avoid peaks, and vehicle-to-grid (V2G) to moderate extreme peaks[26]).

To start to illustrate this, Figure 26 shows the breakdown of average per-household residential demand today and what it will be like in 2050 following the electrification of transport and gas & LPG-fired space and water heating. This is shown for:

- A) average annual kWh; and
- B) average household contribution to uncontrolled system peak.

Figure 26: Impact of electrification on average household annual demand and contribution to system peak demand



Source: Concept analysis based on EECA Energy-End-Used Database data, MBIE energy statistics, BRANZ data, and EA system demand data

[26] Note that, while smart charging will be used all the time, V2G will only be required very infrequently.

Figure 26 shows that electrification (particularly of transport but also of space and water heating) will, if it is uncontrolled, significantly increase average household peak demand, despite improvements in energy efficiency.[27]

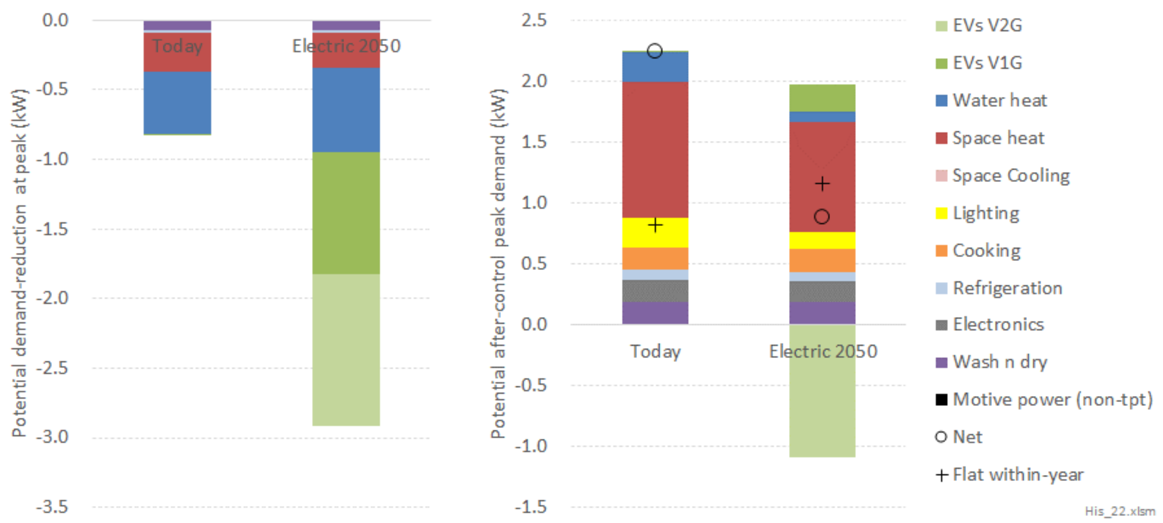
The increase in peak demand due to electrification will likely exceed the design capacity of many New Zealand networks, including at the low voltage (LV) level. This will be very costly to address, giving rise to the significant network cost increases from a 'BAU' peak demand growth world.

However, there is the potential for annual demand to grow, without significant increases in peak demand. This is illustrated in Figure 27below which shows:

- A) Our estimate of the practicable potential of peak demand management from the different appliances at times of system peak; and
- B) The consequent effect on system peak (Subtracting the values in Figure 27A below from Figure 26B above)

Figure 27: Potential contribution to peak demand from smart management of different appliances

A) Peak demand mgm't potential *B) After management system peak*



The key take-away from Figure 27 is the sheer scale of potential response from EVs and hot water. Thus, fully utilizing these technologies would mean that demand during peak would be *lower* than average – as illustrated by the 'Net' value being lower than the 'Flat within-year' value. Whilst this is a clearly implausible outcome, it illustrates the scale of potential response from these two technologies.

For EVs we distinguish between smart charging (ie, avoiding peaks), called 'V1G', and vehicle-to-grid (ie, injecting power back into the grid at times of peak), called 'V2G'.

The reason for these two technologies dominating is because of:

- They are very large contributors to peak demand; and
- They are *storage* technologies. This means that their electricity consumption can be managed in a way which has significant peak demand effects, but minimal impact on delivery of the underlying energy service (ie, transportation and hot water).

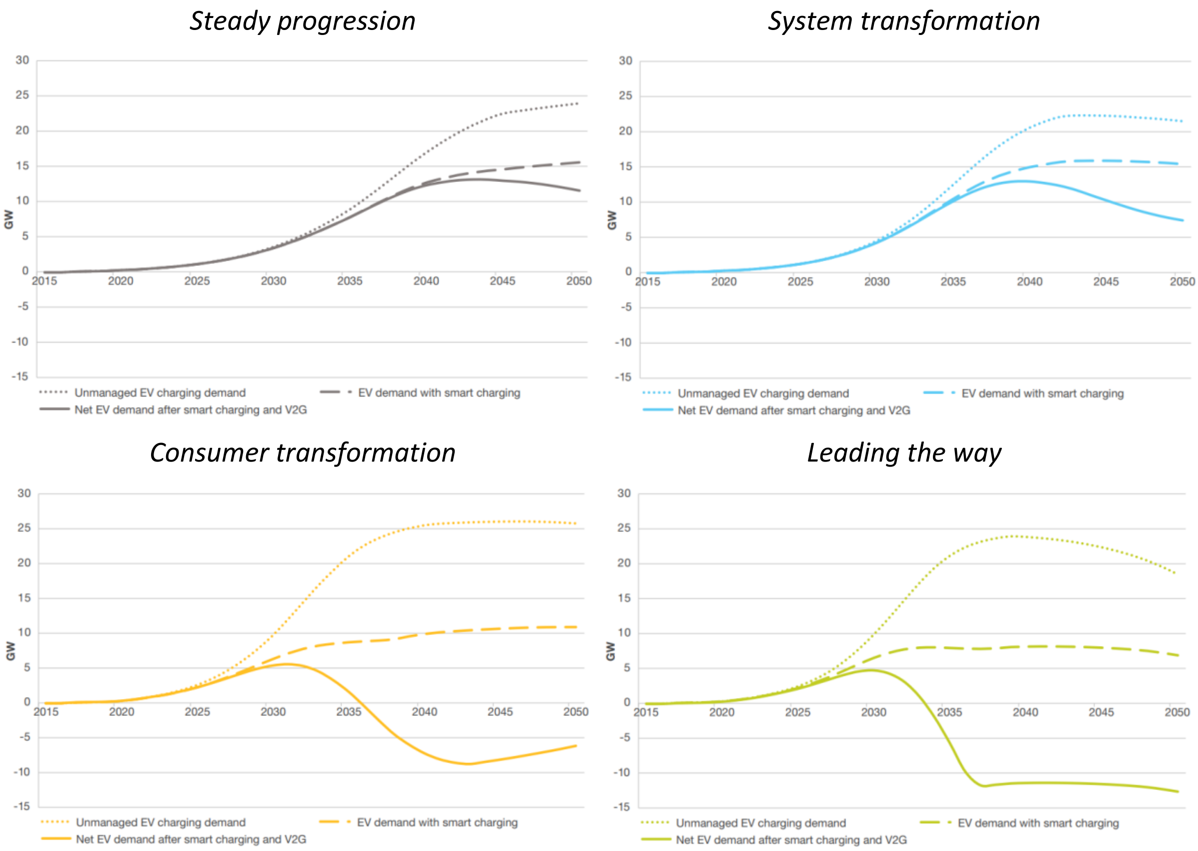
In contrast, although space heating is the largest contributor to system peak demand, it is much less able to be controlled at peak without affecting the quality of the energy service (ie, keeping homes

[27] We assume average per household efficiency improvements by 2050, relative to today of: 15% for space heating, 5% for water heating, 40% for lighting, and 2.5% for electronics, wash 'n dry, and refrigeration.

warm). Our assumption for Figure 27 is that space heating demand in 2050 is reduced via control by 12.5% at peak times.

Internationally there is increased focus on management of EVs in particular, as overseas networks face similar challenges associated with mass electrification of transport. For example, Figure 28 shows a recent National Grid UK assessment (under 4 different scenarios) of the impact on peak winter demand from EV uptake if such uptake were unmanaged (top line), with smart charging (V1G – the middle line), and if V2G were also used (bottom line).

Figure 28: National grid scenarios for EV flexibility at Average Cold Spell winter peak system demand



Source: "*Future Energy Scenarios*", July 2021, National Grid UK

Figure 29 compares the assumptions from National Grid's modelling shown in Figure 28 with those used for our modelling.

Figure 29: Comparison of modelled scenarios for EV Flex with National Grid UK scenarios

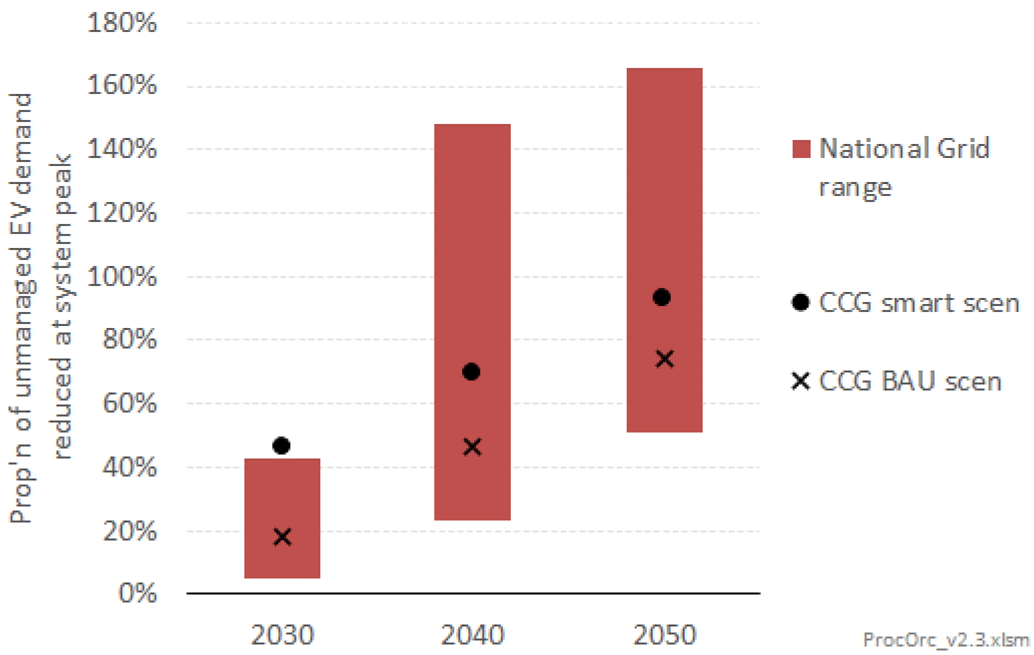


Figure 27B shows that, were all this demand management to be used, peak demands could be *reduced*. Clearly such an extreme outcome is unlikely, but it illustrates the significant benefit that could be achieved if management of EVs and hot water were captured.

However, to capture this potential requires the development of market arrangements and consumer tariffs for 'managed appliance' tariffs. Ie, where a third party (eg, network company, retailer, or load aggregator) manages the electrical operation of these appliances (ie, avoiding charging the appliance (or injecting power for vehicle-to-grid) at times of peak scarcity).

Such arrangements already exist for managed hot water, using so-called 'ripple' control. However, there has been considerable decline in this key technology over the past couple of decades. Unless it can be demonstrated that the smarter control technology which will inevitably supersede ripple control will be widely available in the very near future, this decline in the promotion and use of ripple control needs to be reversed.

Developing smarter control technology is a key requirement for developing managed EV offerings. However, this will require the development of market systems and rules to allow the full value of this appliance specific control to be realised. For example, we believe a key requirement is to allow the on-board meters within EVs to be used within the reconciliation arrangements for the trading of electricity.

In conjunction with development of these managed appliance tariffs, additional tariff reform to more cost-reflective pricing will be required. The two key components of this are:

- Introducing peak-signalling tariffs – with simple time-of-use being more than sufficient in the majority of cases for at least the next decade or two; and
- Increasing the proportion of network and retail/metering costs recovered via fixed charges. At the moment, the over-variablisation of network and retail/metering cost recovery is making switching from a fossil to electric appliance appear more costly to consumers than the underlying supply cost implications of such a switch.

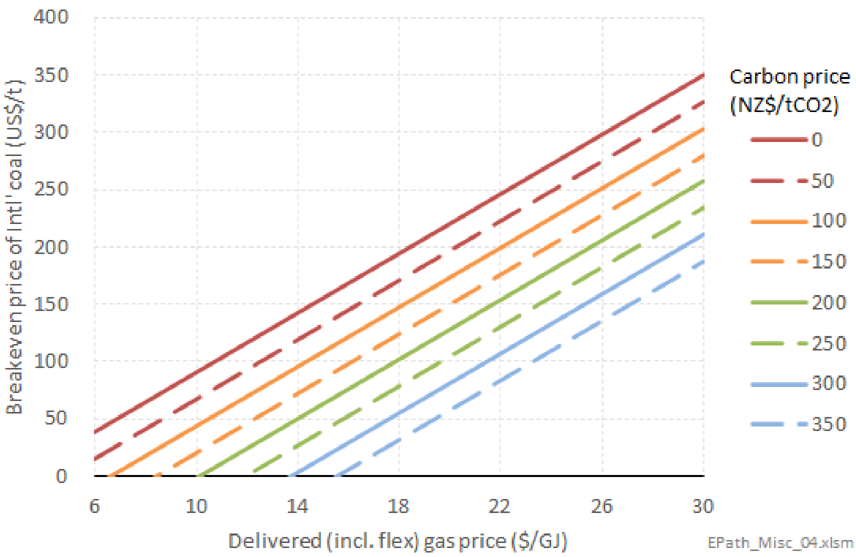
Enabling a smart future will save billions in network expenditure – we estimate at least $6bn in present value terms. Furthermore, minimising cost increases will minimise consumer network price increases. Our analysis is that the increased rate of electrification due to lower network prices from smart networks will deliver a similar amount in rest-of-economy cost savings plus significant emissions reductions. As such, the abatement cost of smart network outcomes is *negative* hundreds of dollars per tonne of carbon abatement.

6.4 Coal is toast – the remaining 1 to 1.5% of fossil-fuelled generation will be gas-fired

While coal-fired generation provided almost 40% of the flexibility generation provided by fossil stations in 2021, the rising carbon price means that coal's days as an electricity generation fuel are numbered.

Figure 30 shows our assessment of the break-even international coal price for it to be cost-effective to run a Huntly Rankine unit on coal rather than gas at different gas and carbon prices.

Figure 30: Break-even international coal price to be competitive with gas



Our assessment of the price of gas to meet low capacity factor operation (5 to 10%) is that it will be between $12 to 18/GJ (two to three-times the historical long-run average price for baseload gas). The Climate Change Commission's projection of the carbon price consistent with New Zealand's decarbonisation goals is approximately $140/tCO$_2$ by 2030. At these prices, international coal would need to cost between US$50 to $140/tonne. However, current and future international coal prices are substantially higher than this: about US$400/tonne today, falling to about US$240/tonne by 2027 (in real $2022).

Further, if Huntly Rankine coal is competing against a gas-fired OCGT, the breakeven coal price will be even higher. This is due to a combination of the higher fuel efficiencies of new OCGTs compared to Rankine units, plus the higher costs facing Rankine units operating in the predominantly short-duration mode required in a highly-renewable electricity system.

7 New Zealand is in a very fortunate position. We should not take decisions which squander this good fortune

Despite the scale of investment required to decarbonise our electricity sector and the broader energy economy, it is worth remembering that, in energy terms, we are a lucky country. This is due to our unique combination of:

- our starting position of having 82% renewable generation (including with large-scale hydro – a key flexibility advantage),
- relatively low levels of gas use for heating, thereby reducing the extent of future demand growth from electrification compared to many other countries
- lack of direct linkage to international gas markets, thereby insulating ourselves from international gas market price shocks
- unusually good wind, geothermal resources; and
- significant land-area for renewable development and development of biomass resources.

Taken together this means that most other countries face current gas and electricity price increases that are many times greater than we are experiencing, plus a renewable investment challenge that, in proportional terms, is also many times greater than New Zealand faces.

We should not squander our relative good fortune by making poor energy pathway choices.

Appendix A. Description of Concept's models

Concept has used two of its models to perform the electricity system and rest-of-economy analysis of the different pathways:

- ORC, its detailed electricity market model
- ENZ, its whole-of-economy model

ORC

The principal purpose of ORC is to simulate the detailed interaction of generation and demand across many different market situations. For a given future market situation scenario (ie, a combination of what generation has been built, the level and composition of demand, and fuel and CO_2 prices), it models how generation and other resources (eg, batteries) will be dispatched to meet demand.

It models each year using a chronological approach with a one-hour timestep. It repeats the modelling of each year using 40 historical 'weather years'. These have historical values for the key drivers of variable renewable generation: hydro inflows, wind, and sunshine. This allows for examination for how a given combination of supply resources (generation, batteries, etc.) will perform across a realistic range of weather situations. This historical weather data is used to simulate solar and wind generation, and is combined with a demand forecast to optimise the dispatch of its controllable resources. ORC dispatches hydro generation, thermal generation (where available), storage resources (eg, batteries), and demand response, to find the least cost way of meeting this demand profile. Long term storage is tracked for hydro schemes, taking into consideration the effect of inflows, maximum and minimum storage levels, and minimum flow constraints. Long term storage can also be tracked for gas storage facilities and some other types of longer-term storage.

It is a two-node model: North Island and South Island, linked by the HVDC. The model accounts for the need for Instantaneous Reserves to cover the potential loss of a major supply asset (eg, one of the HVDC poles, or a large generator).

The output for a given market situation run will include prices and total system costs (fuel, CO_2, capital and non-fuel operating costs, and demand curtailment). The model is run in an iterative fashion, varying the build of generation and batteries, until an optimal planting solution is found where costs are minimised. This planting iteration also ensures that each type of resource that is developed recovers sufficient revenue to cover its capital and operation costs.

ENZ

ENZ is a model of the whole of New Zealand's emissions-producing economy. It was used by the Climate Change Commission for setting New Zealand's carbon budgets. It has separate modules for agriculture, forestry, waste, transport, energy supply (electricity generation and networks, gas production and networks), and non-transport energy-use (including space & water heating, industrial process heat, steel, cement, petrochemicals, etc.).

It models the drivers of the demands for emissions-producing activities, and the extent to which activities are met by different technology options (or land-use change in the case of agriculture and forestry) in response to external scenarios regarding CO_2 price, oil prices, commodity prices, population growth, etc.

The integrated nature of ENZ's modules ensures that outcomes in one part of the economy flow through to all other parts in a consistent fashion. For example:

- increased electricity demand due to electrification of space heating will increase electricity prices that will affect all other parts of the economy that use electricity – and will also affect the future rate of electrification of space heating in subsequent years.
- switching away from pipeline gas for one use (eg, process heat) will affect gas network prices for remaining users of pipeline gas which will accelerate any switching-away from pipeline gas.

Combining ORC and ENZ

ORC and ENZ are separate models with no formal integration.

ORC was run for different pathways and scenario situations to produce electricity system costs and prices.

ENZ was run independently with different scenarios of key external drivers such as carbon price and biomass price (which is the key decarbonisation alternative to electrification for industrial process heat) plus, for each of these external driver scenarios, a range of scenarios for exogenously specified wholesale electricity price increases / decreases – both on a sustained basis, and for short durations of one to two years.

These electricity price change scenarios were used to determine the likely extent to which higher or lower wholesale electricity prices would alter the extent of electrification for key parts of the economy (industrial process heat, space & water heating, and transport). In effect, a function was derived which simulated the extent to which rates of electrification for these different end uses would vary with electricity price.

A separate ORC + ENZ results integration model was developed which took the ORC outputs and ENZ's central projection of emissions reductions for the different parts of the economy. It then used the ENZ-derived electricity price electrification function to model the extent to which rest-of-economy electrification would be different between pathways due to differences in ORC-modelled electricity prices, and consequent variations in rest-of-economy emissions and non-electricity costs.[28]

All of Concept's analysis using ORC and ENZ is based entirely on information from public sources, or information developed independently by Concept.

[28] Rest-of-economy non-electricity costs include items such as oil for transport, vehicle purchase costs, space & water heating appliances, etc.