Prepared for the New Zealand Productivity Commission

Transitioning to zero net emissions by 2050: moving to a very low-emissions electricity system in New Zealand

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Executive summary

We have investigated the potential for the electricity sector to contribute to the goal of a low emissions future in New Zealand. This report considers how the sector could transition from today's baseline of 4-5Mt CO2-e and the implications of substantial reductions in emissions in the sector especially the cost of progressively lower emissions.

Our brief

We were asked to:

> *To identify the opportunities and risks for electricity supply in New Zealand that arise from moving to a very low emissions electricity system, and the regulatory and technical changes needed to manage them in a manner consistent with economic efficiency.*

In order to meet the brief the analytical path we have followed is to address three questions:

1. In 2050 what is the lowest level of emissions that could be achieved in the New Zealand electricity sector technically and practicably while sustaining acceptable reliability and security standards?
2. What is the cost of providing a flexible and resource adequate system with progressively lower emissions levels?
3. Alongside the Emissions Trading Scheme (ETS), what other steps should regulators and policy makers consider with a view to accommodating a very low emissions electricity sector by 2050?

Our response to the first question is that all of the roles played by thermal generation[1] now could be readily displaced with low carbon emitting generation by 2050 although that couldn't just be achieved overnight. The hardest role to displace would be thermal's role satisfying demand during a prolonged hydro inflow shortage. If thermal is the only technology able to provide this role the level of emissions reductions would be inhibited. While there are many possible low or zero emissions solutions – across the supply and demand side - that could replace thermal in this particular role (and thus eliminate emissions completely), many are not practically or commercially available today at scale.

A number of low emissions supply side solutions may come to the fore to address the shorter term flexibility role that thermal contributes to significantly today. More seasonal use of geothermal is one that is possible now at a cost, but even if the flexibility role is underpinned by geothermal in 2050, its fugitive emissions could continue to be a feature of the electricity sector (in the order of 1Mt CO_2-e per annum compared with total sector emissions of approximately 5Mt today)[2]. We expect what we currently refer to as the demand

1 In this paper we use the term "thermal" or "thermal generation" to include plant that generates power using fossil fuels (coal or natural gas) i.e. traditional coal/gas fired boilers, a combined gas-fired turbine and steam turbine (CCGT) or open cycle aero derivatives (OCGT).

2 We note geothermal's emissions profile could improve if investors moved substantially towards zero-emissions geothermal solutions but this is dependent on a range of site-related factors.

side is going to become more dynamic and have a greater impact on the level of investment required on grid scale supply than it has in the past but, again, that won't happen overnight.

The second question seeks the cost of progressively lower emissions. The cost of wholesale electricity will rise as carbon prices impact on the use of continuing thermal generation and investment in renewable alternatives to thermal generation is required to satisfy resource adequacy. We expect the electricity sector will make modest reductions in emissions by 2050 (down to 3 - 4Mt CO_2e per annum) if carbon prices are between \$60 /t CO_2e and \$100/t CO_2e (depending on the rate of demand growth). We find that a critical transition point in making deeper reductions in emissions would be where the industry transitions away from flexible, discretionary gas for hydro firming to renewable fuels. Sector emissions reductions of a further 2-3Mt or more would require carbon prices of over \$130/t CO_2e.

There are a lot of uncertainties in any analysis that contains predictions across such a long timeframe. Between 2018 and 2050 there will inevitably be many developments both on the supply and demand side where technological and cost changes could make the reductions we identify more achievable at lower cost. One exception to that is the possibility that additional transmission investments may be required to support a low emissions sector.

The answer to the third question lies in two elements. The first element is mainly about reducing barriers to innovations that lead to lower emissions outcomes given the objectives in the Electricity Act and the Commerce Act currently. We note that the Commerce Commission and the Electricity Authority are both taking steps to facilitate innovation and the trends that are emerging. We identify a small number of key issues the sector will need to address if it is to ensure the most economically efficient emission reductions are able to be achieved by 2050. The second element of the regulatory question is whether interventions should be considered if barriers to innovation were reduced but emissions stay stubbornly high compared with reductions we expect relative to the carbon price. We do not consider possible interventions for that circumstance in this paper.

Findings summary

Ultimately the policy instrument providing incentives to switch from providing resource adequacy with thermal to providing it with renewable solutions is the ETS. A cost of carbon enters the system via a carbon price determined under the rules of the ETS. We do not consider whether any level of the carbon price reflects the true cost of carbon to the economy. We confine ourselves to observing outcomes we can expect in the electricity industry at different levels of carbon and the accompanying cost of resource adequacy.

On the supply side of the electricity sector, the wholesale market pays all generators the cleared price and there is no accompanying payment for making capacity available where it isn't dispatched. Since the wholesale market was introduced dispatch has been based on the least cost secure solution and resulting wholesale prices have been a key driver for investment decisions. Decision making, including investment decisions, increasingly include decisions made by many small scale consumers rather than few decisions makers making decisions with a heavy emphasis on the supply side. As a result the basis for investment decisions increasingly include more factors than just return on investment and an assessment of risk (e.g. environmental sustainability and greater independence from traditional retailers).

The increasing penetration of intermittent sources, such as wind and solar, is likely to require an evolution of frequency keeping or fast response ramping products at the wholesale level. The periodicity of supply changes may not align with the current definition of instantaneous reserve, free governor response and frequency keeping, and we observe international examples where standby reserve and ramping products are being added to market designs. Further, at some point the sector is going to have to consider whether the energy-only reward mechanism for generation will continue to deliver efficient outcomes as renewables replace thermal generation and the demand side becomes more dynamic. The situation where the design of the market does not provide adequate reward for generation dedicated to supplying resource adequacy is sometimes referred to as the "missing money" problem. The risk of this occurring rises as the market is increasingly served by renewable generation.

Historically demand has been treated as an exogenous variable with supply being the dynamic variable continuously shaped to meet demand. If an efficient and low emissions sector is to emerge this approach has to change, as consumers' decisions will play a greater role in reducing emissions, for example, by providing resource adequacy. The trend is towards all consumers being better able to manage their consumption and having access to small scale generation and storage which also reduces their net load. This will also open the way to far greater coordination and optimisation across distribution networks than has been the case historically. Electricity sector outcomes in 2050 will be the combination of an intermittent supply side and a dynamic demand side. The way we model the market is going to have to change accordingly.

The distribution sector has historically delivered a bundled reliability product to consumers. Distributed Energy Resources (DER) is the term often used to describe the combination of distributed (small scale) generation, battery storage and demand response. The fact that these elements will be increasingly owned by consumers means that components of what are currently distribution services could be unbundled and supplied by competing suppliers including aggregators of DER or individual consumers. Distribution level pricing is currently moving to more transparently reflect the value of individual services distributors provide and that will, in turn, signal better to consumers the value of their DER.

Resource adequacy – the ability to reliably meet demand at every point in time – has historically been dealt with substantially by flexibility on the supply side. While load control has been a conspicuous exception, what we think of as load control today will have a far broader scope in future. As consumers become much more involved in the decision making about how and when their DER is utilised and the price at which they are prepared to respond they will contribute far more that n is currently the case to delivering resource adequacy. We believe some of these developments would occur more efficiently if they were properly coordinated from an economic perspective. It raises the question of whether an independent distribution system operator (DSO) model would lead to more efficient coordination and optimisation outcomes at the distribution (mass market) level of the market.

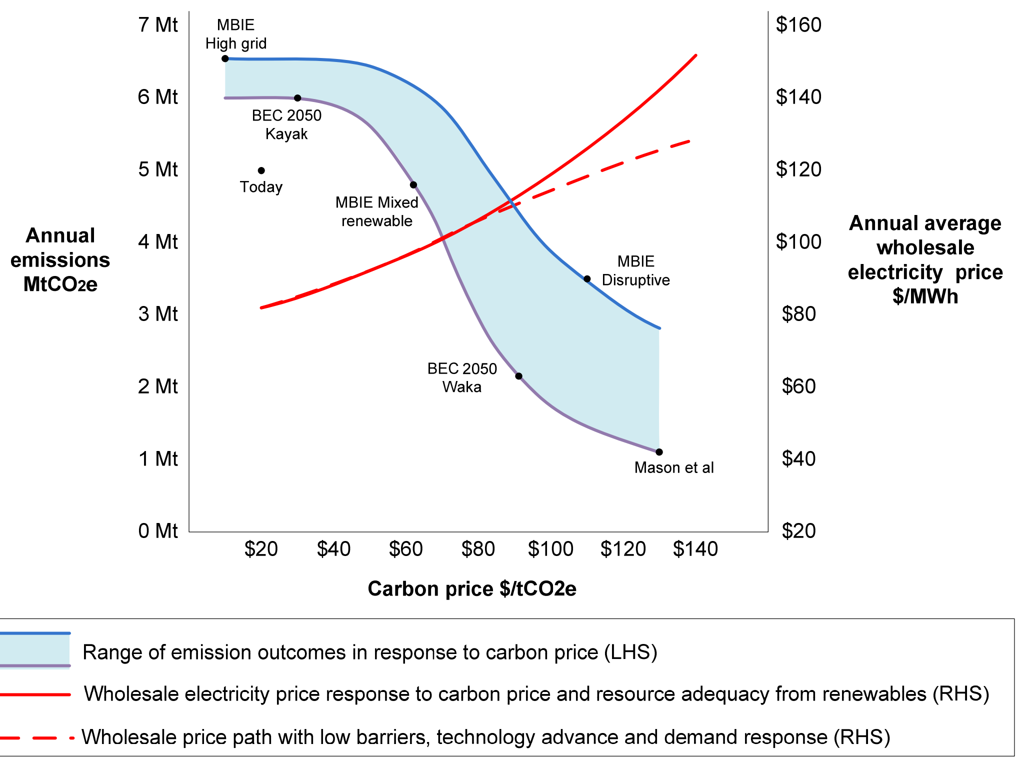
We commend the Electricity Authority for moving to ensure everyone can get equal access to the network, to buy and sell electricity easily and to access high-quality data to inform their decisions. We commend the Commerce Commission for exploring ways to accommodate innovation in the regulated businesses. However, neither of these regulators is targeting emission outcomes specifically. We conclude there is a case for an appropriate agency – perhaps the new Climate Change Commission - to conduct a holistic review of the regulatory system and test whether it will give consumers assurance that the sector can transition to low emissions while preserving resource adequacy, in the most efficient manner.

To determine the scope for very low emissions from the sector we tested how resource adequacy can be met with a heavily renewable supply side. We drew on three modelling approaches that have offered a view of how the sector might look in 2050:

- the Business NZ Energy Council's (BEC's) "Kayak" and "Waka" energy system scenarios to 2050[3]
- MBIE's[4] "Electricity Demand and Generation Scenarios" (EDGS)[5]
- Vivid's "Net Zero in New Zealand" scenarios to 2050[6].

We focussed on the scenarios established by these models that were resource adequate in 2050. In this way we were able to tease out the supply side pathway to low emissions, map it to carbon prices and determine the cost implications of this progression. Figure 1 is a summary view of what we found.

Figure 1 Emissions/carbon price relationship in 2050 and impact on wholesale electricity prices



[3] http://www.bec.org.nz/projects/bec2050

[4] The New Zealand Ministry for Business Innovation and Employment

[5] http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-demand-and-generation-scenarios/edgs-2016

[6] http://www.vivideconomics.com/publications/net-zero-in-new-zealand

Based on the carbon prices on the horizontal axis and emissions on the left hand vertical axis we don't see a marked fall in emissions until the carbon price gets above $60/t. As we move from a carbon price of $60/t to over $100/t we see the effect of the removal of Combined Cycle Gas Turbines (CCGTs). Further emission reduction are achieved as the use of thermal peakers for resource adequacy is replaced with renewable sources of energy on the supply side and, we presume, greater participation in outcomes by the demand side. The lowest level of emission reached is where emissions have declined to just fugitive emissions from geothermal[7]. In this situation, illustrated by the work of Mason et al, resource adequacy is almost exclusively provided by renewable energy sources or demand response, and thermal generation is reserved only for the direst inflow situations (e.g. 2008-style inflow scenarios). But this would substantially increase cost to consumers as it results in a much lower utilisation of geothermal resources compared to what is observed today.

A number of factors create the range for emission reductions for a given level of carbon price. Notably, the higher demand growth is the harder it will be for the system to wean itself off thermal generation providing the flexibility the system needs. The range of emissions outcomes also reflects the cumulative effect of different potential thermal decommissioning decisions that investors may make, which is in turn a function of uncertainty and risk management. Another aspect that contributes to a range of outcomes for any given carbon price is the degree to which policy makers and regulators accommodate innovation and investment in renewable solutions to the challenge of resource adequacy at all times.

Figure 1 also shows the progression of wholesale electricity prices relative to carbon prices. These prices include the cost of carbon in prices set by thermal and the long run marginal cost (LRMC) requirement of new renewable plant that will meet resource adequacy. The dashed line represents the likelihood that consumers will respond to the projected price path.

The wholesale market design doesn't guarantee LRMC. Large scale investments tend to be based on the ability to secure a return through long term contracts or retail load and those prices, in turn, reflect expectations of wholesale energy prices. For the purpose of illustrating potential wholesale prices over a 32 year time horizon we have used an LRMC-based approach as an estimate of future contract prices but these may not be reflected in future wholesale prices, even in the long-run.

MBIE calculate the LRMC in 2050 for each of their scenarios, which we use here. Our understanding of the MBIE LRMC estimates suggest that, due to the increase in the cost of generation alone, the average price rise for consumers, in real terms, between now and 2050 is between $25/MWh (2.5c/kWh) for a modest reduction in emissions, and $40/MWh (4c/kWh) for the deeper cuts in our amended version of the Disruptive scenario. Achieving deeper cuts (e.g., using flexible geothermal instead of gas peakers) will, based on what we know today, set the marginal technology at approximately $140/MWh, which would imply a 75% increase over today's prices. We reiterate that these price rises are based on an assumed technology cost trajectory, which may change substantially in the future.

7 As mentioned above it may be the case that future investment or reinvestment in geothermal generation may have a lower emissions profile.

Well before 2050, as we suggest above, DER and demand response will be competing directly with network companies to provide distribution level electricity services. To the extent that a higher carbon price encourages more DER, there will also be a net reduction in system operation and distribution costs by 2050. We assume no discernible effect on distribution costs on consumer prices for higher contributions of DER.

All of the scenarios we have relied on for our assessments have thousands of megawatts of wind located predominantly in the lower North Island and, if that is the case, all scenarios would lead to transmission upgrades to export the wind energy to load centres. If that was to be the case we would have to add transmission costs to our assessment.

Resource adequacy

Resource adequacy has two broad dimensions

- meeting the highest instantaneous demand from the system (capacity adequacy)
- the ability to meet demand over a period of time (energy adequacy) Energy adequacy is commonly thought of as dry year risk but very much includes flexibility to meet demand at all times and in all conditions.

Due to the intermittency of renewable fuels, both dimensions must consider scenarios not only of high demand but also low levels of hydro, wind and solar. It also must consider the sufficiency of underlying thermal fuel arrangements. This raises several points that we take into account in reaching our conclusions:

1. Energy adequacy requires flexibility from the system as from one time period to the next, generation from intermittent fuels and demand is changing. This manifests in the short term from wind and solar, but also in the medium term as a result of the pattern of inflows over the year being uncertain, variable, and, on average, anti-correlated with demand. Due to the dominance of hydro, New Zealand is particularly affected by significant variations in inflows caused by changes in the weather.

2. The flexibility is plant output has historically been underpinned by flexibility in underlying fuel contracts, as well as the ability to store fuel in the form of gas reservoirs, coal stockpiles and hydro reservoirs. Resource adequacy is the collective impact of the constraints on those contracts and storage facilities.

3. Looking out to 2050 we expect batteries and demand response will play a significant role in providing this flexibility. However both these are 'energy limited' in the sense that they are likely to only provide a short term response, rather than the medium term requirement arising from the confluence of seasonal demand and inflows.

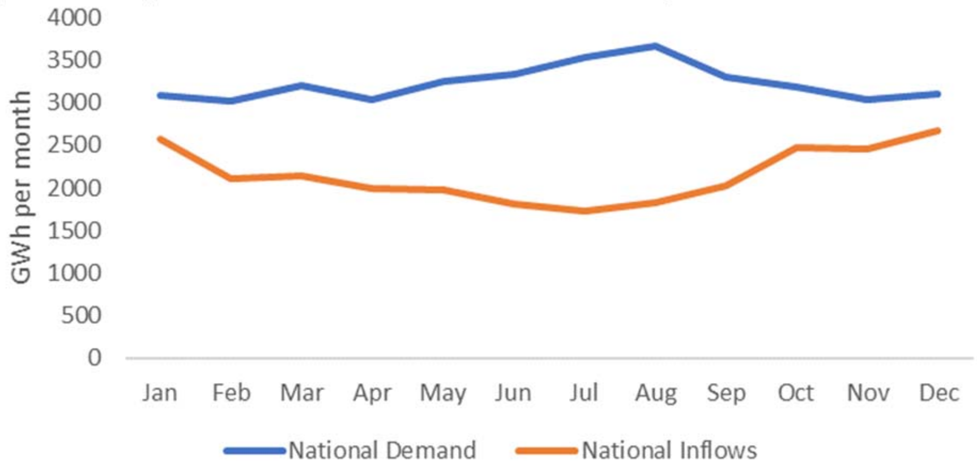
4. Irrespective of the degree to which emissions are reduced through investment in renewables, a minimum level of flexibility must be retained to manage energy adequacy. The periodicity and uncertainty in this flexibility service drives the economics of investment in flexibility providers. Plant retained purely to manage extreme hydro shortfalls may only operate very infrequently and require underlying fuel contracts or storage facilities that are commercially challenging.

The time dimension is an important aspect of resource adequacy. The energy supply a plant may be able to achieve in any given half hour is different to what it could provide over a prolonged period. For intermittent fuels, such as wind, their contribution to energy adequacy is much higher than for capacity adequacy. Over time, wind is relatively dependable and gas plants are assumed to be able to run at near capacity (should they be required), despite the fact that in "normal" hydrological years, this would not be the case.

We note that solar without accompanying battery storage does not provide any capacity adequacy (insofar as New Zealand remains a winter peaking system) due to peak demand in New Zealand occurring during winter nights. In fact, if the large installed capacity of solar on the system is not paired with battery storage that reinforces the need for flexible, responsive capacity in the system, as the hour-to-hour swings in solar output at this level of penetration would be significant.

Further, average national hydro inflows and solar production are highly correlated with each other and both are actually not well correlated with the pattern of demand over the year. The correlation between national inflows and demand is shown in Figure 2.

Figure 2 Average National Inflows vs National Electricity Demand.



Source: EMI, Sapere Analysis

Individual inflow years are unlikely to reflect the pattern of "average" inflows, and can be quite volatile from month to month and season to season. But hydro owners will make decisions with this general trend in mind. The way the supply side of the market collectively manage this is a combination of:

(a) Using hydro reservoirs to "shift" some of the summer inflows to winter.
(b) Relying on discretionary (thermal) plant, which may not be used much in summer, to supplement supply in winter (sometimes referred to as hydro firming).

Figure 2 suggests that a reservoir storage capacity of approximately 2,000GWh would be sufficient to manage this issue today in an average hydrological year, i.e. to provide a profile of hydro generation which matched the profile of demand. Since New Zealand has a national storage capacity of approximately 4,000GWh, this appears to be feasible within current storage constraints.

However, reservoir management is substantially more complex than indicated by this analysis. Firstly, as demand grows through to 2050, the absolute level of shifting required to be done by hydro storage – even in an average generation year, let alone a dry year – increases commensurately. As time progresses, the 4,000GWh of storage capacity may become less effective at managing the annual demand profile, unless the growth in generation comes from flexible sources (e.g., thermal).

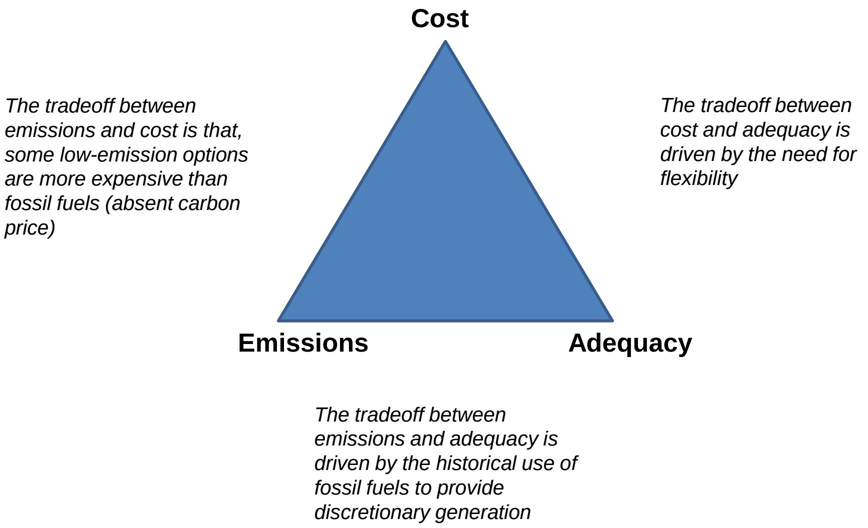
Secondly, inflow patterns invariably never match the average (orange) line in the figure above, and, thirdly, reservoir managers do not know the future; hence their storage behaviour prior to winter will be based on a risk-adjusted expectation of the future.

The balance between (a) and (b) - ultimately coordinated through the wholesale price[8] - is (partly) reflective of hydro owner's storage at any point in time, and their expectations about the near future,[9] particularly with respect to inflows.

Modelling 2050 emission outcomes based on changes to the supply side

Figure 1 describes the trade-off outcomes between cost, emissions and resource adequacy and these elements are described in Figure 3 as they informed our analysis. Our approach was to treat resource adequacy – which we define in Chapter 4 - as a constraint (i.e., a lower bound). We assume that the levels of resource adequacy that consumers enjoy today must continue, noting that in the future, technology may allow consumers to express their own preference for reliability. Within that constraint, we examine the trade-off between cost and emissions

Figure 3 - The cost-emissions-adequacy trade-off



The scenarios were developed with different objectives but all incorporated a carbon price. The diversity allowed us to form a robust view of the relationship between cost and emissions outcomes. We tested each scenario to see if, irrespective of emissions and cost, each investment path would satisfy current market objectives for energy adequacy and

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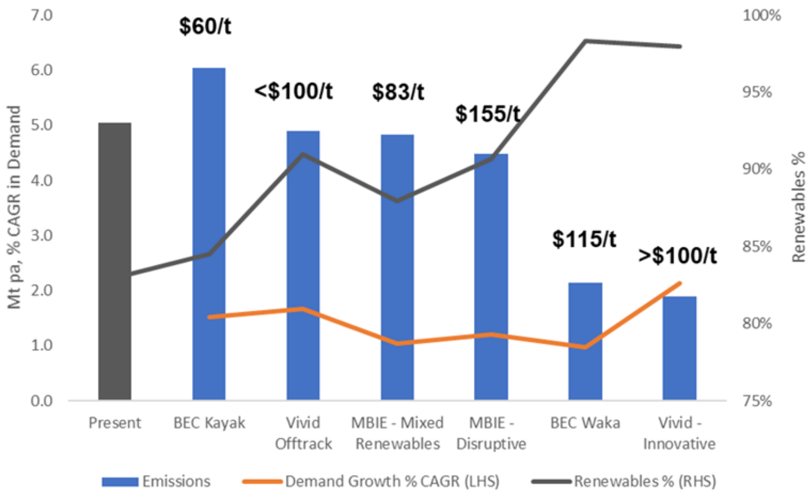
[8] We note that the market has done this coordination successfully, through some very dry sequences, since the market reforms introduced in 2009.

[9] These expectations are communicated to the market through the hydro owner's "water value", implicitly embedded in their market offer each half hour.

capacity adequacy[10], thus giving some level of assurance that resource adequacy is accounted for on a consistent basis.

Figure 4 shows emissions outcomes, the percent of generation from renewable sources, demand growth and carbon prices as at 2050 for each of the scenarios we used.

Figure 4 – Electricity sector emissions, renewables, carbon prices and growth in 2050



The relationship between renewables and emissions across the scenarios is not perfect because some scenarios had to meet higher demand making it more difficult to reduce emissions and some had higher proportion of geothermal than others. Figure 5 shows generation by fuel and emissions in 2050 for each of the scenarios.

The workings of each scenario showed that emissions reductions were a function of retiring existing thermal plant without replacement through the period. Electricity emissions come mainly from:

(a) Fossil fuel cogeneration (associated with an industrial process).
(b) Coal/gas generation from the Huntly Rankine station (HLYR).
(c) Generation from combined-cycle gas plant at Huntly (HLY5) and Taranaki (TCC).
(d) Gas generation from flexible peaking turbines in Taranaki and Huntly.

[10] The market currently operates to a Winter Energy Margin (WEM) and Winter Capacity Margin (WCM) which we used as a proxy for the complete resource adequacy requirement we expect to be met.

Figure 5 - Breakdown of total generation by fuel and emissions, 2050

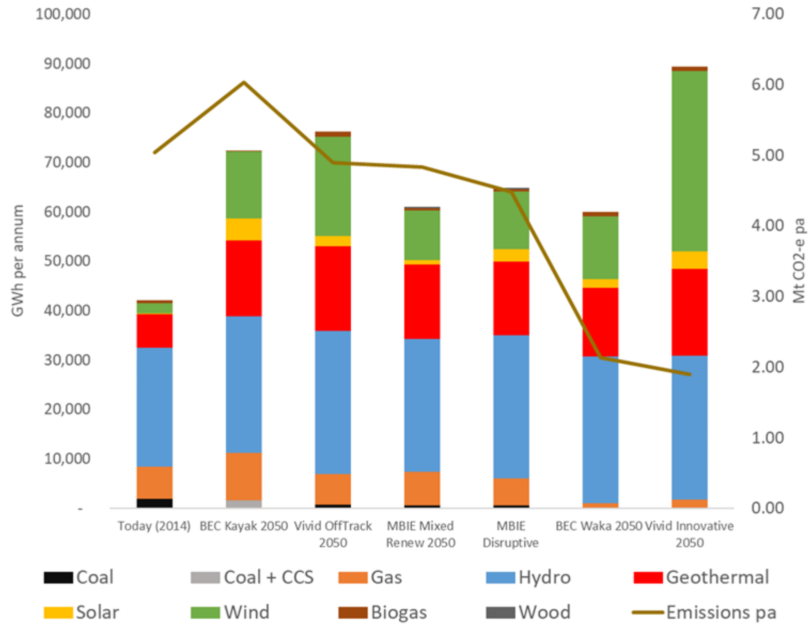


Figure 6 - Emissions trajectories in MBIE Disruptive and BEC Waka

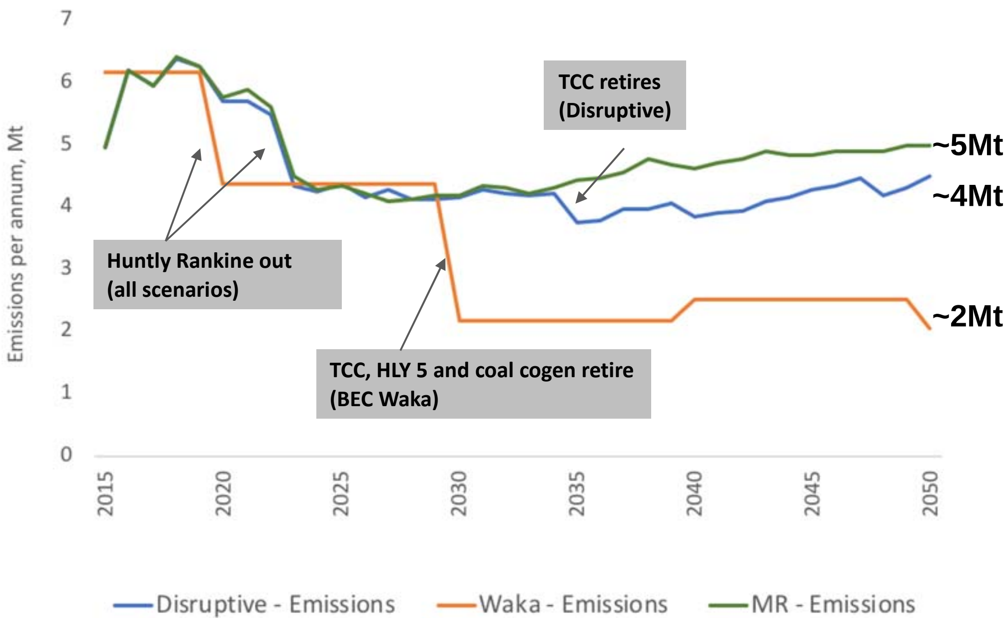
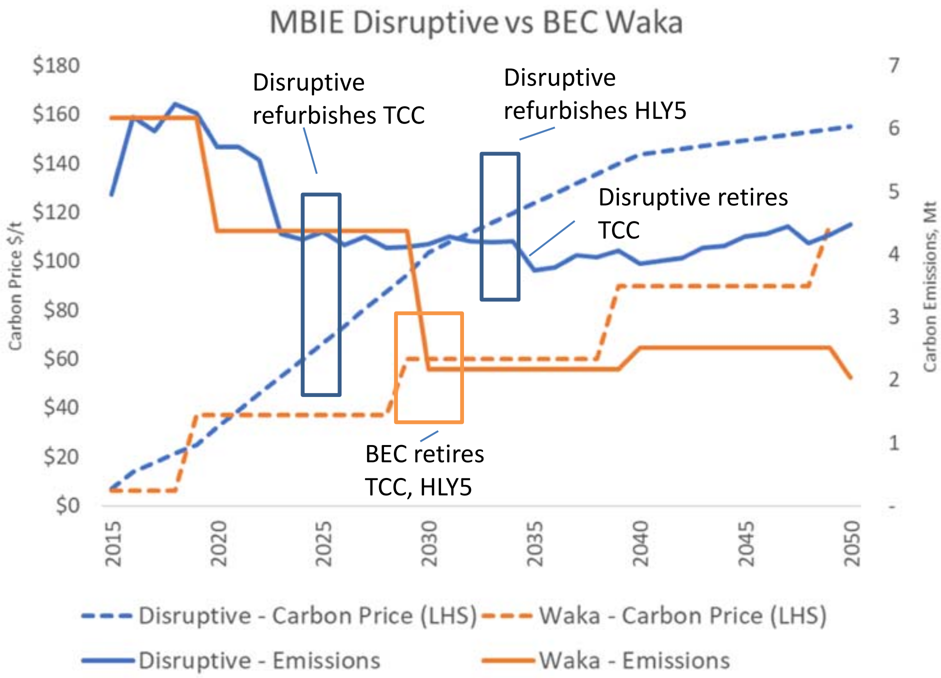


Figure 6 illustrates the different emissions profiles that would come about from finally retiring thermal units rather than refurbishing them or replacing them. The scenarios differ in terms of whether thermal owners decommission or refurbish thermal plant. We believe that scenarios that retain Huntly's Unit 5 CCGT until 2050, under high carbon prices, are optimistic.

Figure 7 - Comparison of carbon prices and emissions projections in MBIE's Disruptive and BEC Waka scenarios



From Figure 7 we can see:

- a decision to refurbish TCC is economic in 2025, at a time when the carbon price is $60/t, and is expected to rise to $120/t at the point the model retires it in 2035
- a decision to refurbish HLY5 is economic in 2033, at a time when the carbon price is $120/t, rising to $155/t by the end of the modelling horizon.

Should, instead, these two plants be forcibly retired in the 2030s[11], neither would be fully replaced with a new CCGT, at a carbon price trajectory of $60/t at the time, rising to $115/t by the end of the horizon.

Overall the scenarios tell us that national demand levels up to 60,000GWh (growth of around 1% CAGR, including the effect of electric vehicles), carbon prices below $100/t may be sufficient to constrain emissions in the energy sector at their current levels, and possibly even reduce them.

Towards a 100% renewable system

The most comprehensive technical assessment of reducing emissions further while maintaining resource adequacy in the NZ system was conducted by Mason, Page and Williamson's work on a 100% renewable electricity system in 2010.[12]

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11 Recall that the BEC modelling occurred in 10-year time steps, hence we do not have any guidance on when during the period 2030-2040 this occurs

Mason *et al*'s scenario was to replace thermal generation with a combination of wind, pumped hydro and over 600MW of geothermal which is switched on and off to manage the variation in inflows (and, implicitly, demand). The periodicity of this switching is unlikely to be technically challenging for geothermal, but does reduce its utilisation to around 60%. As this does not save any substantial capital costs, it drives the unit-based cost of geothermal up commensurately. Mason's analysis was, as far as we can tell, a perfect foresight approach, and even higher levels of flexible geothermal capacity may be required to manage the genuine uncertainty about inflows.

Increased wind and "switched" geothermal alone drives Mason's solution to 99.8% renewable. The residual 0.2% - largely reserved for the direst of years - is proposed to be provided by a large pumped storage facility, which we believe would be prohibitively expensive.

We calculate that, for a geothermal plant to fulfil the flexibility requirements, its LRMC would rise at least by $40/MWh (depending on the site). For a geothermal plant in this role to have a similar LRMC to a CCGT, the carbon price would have to reach at least $130/t as an expectation over the investment period. Further, if the geothermal used in this role were to have a similar emissions profile to the existing plant today, Mason *et al's* solution would result in total electricity emissions of ~1.2Mt. Emissions could be lower than this if investors moved substantially towards zero-emissions geothermal solutions (binary plant) rather than flash technology, but this is highly depending on a range of site-related factors.

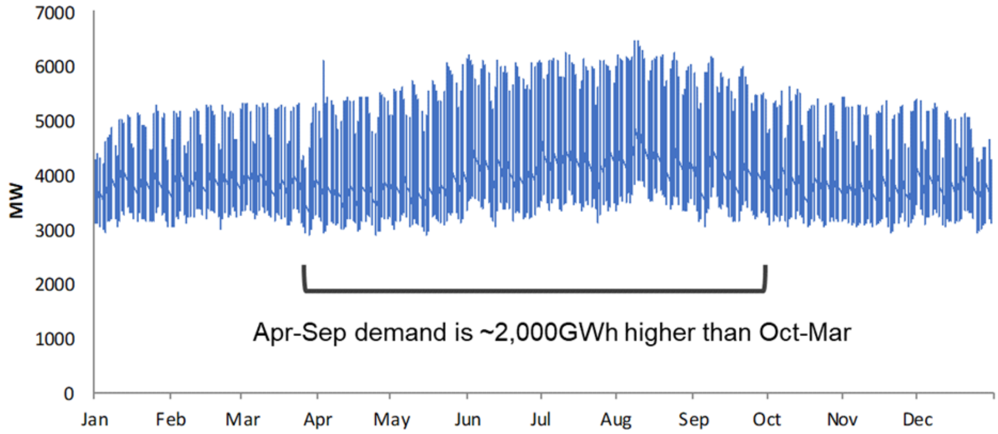
Driving emissions below this is likely to require technologies which are not in use at scale today. While batteries and demand response could adequately compete with peaking thermal for the capacity adequacy role, the technologies that might provide the medium-term flexible shifting between seasons are less obvious. Hydrogen, biomass, and carbon capture and storage are all potential candidates, but a significant amount of work is required to demonstrate the credibility of these sources to replicate the substantial work that thermal plant and associated fuel arrangements does today.

Transformation on the demand side

Figure 8 shows half hourly demand over the year of 2016. This shows how demand varies considerably over two dimensions: the period of a day, and over the year. This reinforces the need for the system to have sufficient flexibility to increase output during the periods of high demand, and decrease output during the low demand periods.

12 Mason, Page, Williamson (2013), "Security of supply, energy spillage control and peaking options within a 100% renewable electricity system for New Zealand", *Energy Policy*, Vol 60 (2013) pp324-333

Figure 8 – NZ Electricity Half Hourly Demand for calendar 2016



The models we used made limited assessments of the effects of the transformation of the demand side to more decision makers with access to small generation and storage thereby giving them the ability to change their intraday load shape and reduce overall consumption.

The New Zealand system has a long history of hot water heating being remotely switched on and off to manage demand peaks. The decisions to control load in that way were made by power boards originally and made for the purpose of network security. There was also the effect of deferring investment in new distribution capacity. Since the reforms of the 1990s hot water switching decisions have been made mostly by lines companies and for both reasons. Recent years have seen advances in demand response especially with smart meters enabling Time of Use (TOU) charges, aggregators rounding up parcels of interruptible load for on sale to retailers and the ability for consumers to incorporate generation and storage alongside their demand decisions. These changes are just the beginning of the transformation away from a passive demand side.

Demand response

The Federal Energy Regulatory Commission defines demand response as:[13]

> *Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*

The FERC definition is consistent with demand response's potential to perform the role of "flattening" demand over the whole year, if that is the efficient thing for consumers to do.

Distributed storage complements demand response by reducing net demand at peak times and, as a result reducing the need for peaking plant. Distributed storage can come both in the form of electrical storage (e.g., batteries) or thermal storage (e.g., hot water heaters). In

13 https://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp

both cases, the "charging" of the storage can occur when electricity price is low, but is then released to the consumer when price is high[14].

Demand response during system peaks can reduce the need for gas peakers. MBIE's modelled demand response has nearly 500MW of demand-side response (compared to around 160MW today) substituting for the peaking role of gas and diesel peakers.

Conservation

Conservation is when consumers decide not to consume for a range of price and non-price reasons. Hence conservation is, in some ways, a more general form of demand response. While much conservation behaviour is ad-hoc, New Zealand has a long experience with organised conservation campaigns. A framework for the use of (and charges to retailers for) official conservation campaigns have been embedded in the market Code since 2010.

Efficiency

Energy efficiency refers to the consumer's ability to deliver the same service (heating, lighting, entertainment) at a lower consumption of energy (in this case, electricity). Energy efficiency plays two important roles that relate to both resource adequacy and also a low-emissions future:

- reducing long term demand growth
- reducing demand growth at particular times of year e.g. LEDs for lighting, and heat pumps and insulation for heating which have their biggest impact during the winter months.

Demand Growth

On an annualised basis the scenarios we drew on foresee demand growth of between 0.9% CAGR (BEC Waka), and up to 2.1% in the case of Vivid's Innovative scenario - a range of demand outcomes in 2050 which vary by nearly 30TWh (75% of today's total demand)[15].

Figure 9 illustrates the different scenarios assumptions about growth drivers. The range in underlying drivers of demand growth (population and GDP) gives rise to a wide range of potential growth values (between 10TWh and 23TWh). The absolute values of assumed economic and population growth are only one factor. Assumptions about structural change within the economy, and energy efficiency uptake in each sector[16] can mean quite different energy outcomes, even for the same total growth. Similarly, at the household level, the same

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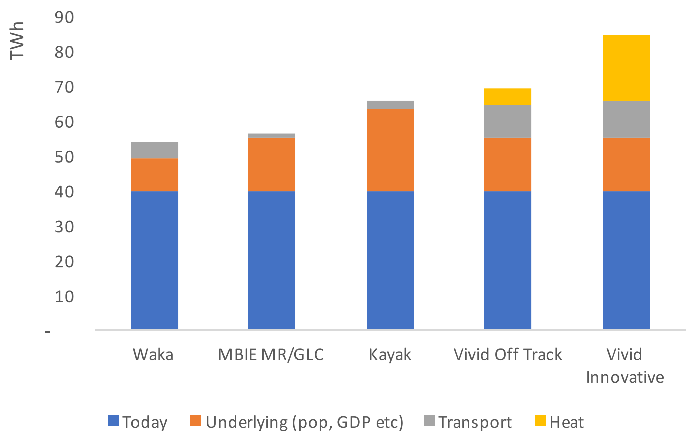
14 Technology is now widely available for solar customers to use excess solar power during the day to effectively "overheat" their hot water cylinder, thus reducing the cylinder's demand for electricity at night when the solar panels are not producing. This is the same optimal behaviour as using an electrochemical battery to charge and discharge.

15 We note that these projected growths are substantially above the growth rate observed over the past 10 years (0%), and, in Vivid's case, well above any compounding growth rate observed at any time in the last 50 years.

16 BEC's "Deep Dive into Energy Targets" reports a 47%-54% reduction in heating and air-conditioning demand between now and 2030 as a result of energy efficiency (relative to a no-efficiency improvement baseline). Similar figures were not available for the other scenarios

population growth can result in different consumption growth depending on assumptions made about efficiency at the household level (insulation, appliances etc.).

emand



Agriculture

Agriculture makes up 9% of total electricity demand, and is the fastest growing sector of demand that is reported by MBIE in its "Energy in New Zealand" publication. Future demand in this sector depends on the extent of continued growth in agriculture (including the growth in land to be irrigated), and the efficiency of pumps etc. Transpower takes the impacts of irrigation on its load forecasts and recently revised 2030 peak demand forecast for South Canterbury upwards by nearly 20%.

Industrial

Most scenarios assumed a general continuation of the decreasing energy intensity trend, at a rate reflective of that observed for the past 10-15 years. This underlying narrative is one of greater growth in low energy intensity sectors of the economy (e.g., financial services) than in energy intensive sectors. By 2050, this resulted in between 37% and 50% reductions in energy intensity compared to today.

Transport

Despite the wide range of uptake scenarios (400,000 vehicles in BEC's Kayak, through to 3.5m vehicles in Vivid's Innovative) the resulting range of impacts on growth – while not immaterial – were the smallest of the three underlying driver categories. Electric vehicles (light domestic through to large industrial vehicles) are substantially more efficient than fossil fuelled vehicles (in terms of energy use per km driven); and we expect that a trend of increasing efficiency will occur between now and 2050. The most aggressive scenario for electrification of the transport sector would add 11TWh of consumption to the electricity sector in 2050.

Heat

In the scenarios MBIE and BEC's assumptions about the electrification of heat are inherent in their underlying growth figures. Vivid present this sector separately, to highlight the significance of the heat sector. Vivid have cited the evolution of both air-source and ground-source heat pumps and their potential to deliver low-grade (<100deg) heat across residential and commercial settings, as well as for more industrial-scale heat pumps in medium grade heat (100-300deg) applications. In the medium grade setting, we note that low emissions heat from electricity may compete with biomass.

Distributed Energy Resources (DER)

We use the term DER to describe resources distributed throughout the power system, usually in the distribution network, which provide energy services to the power system. This term is sometimes used to describe the full range of energy supply including battery storage, services ancillary to energy supply and demand response where demand response is providing an ancillary energy service.

There is a great deal of focus on these issues as technology trends but the emphasis we want to draw out in this context is the emerging role of consumers as both suppliers and consumers of DER services and that aspect of the transformation of the demand side. We want to highlight that improving the access, utilisation and integration of DER will play an important role in helping reduce carbon emissions for two reasons:

1. Where DER is producing energy, it is increasingly likely to be from a low carbon source, especially solar and wind. These low emission energy sources can be encouraged by a carbon price but can also be encouraged by recognising, financially, other contributions they make to energy services.
2. DER, including demand response, enables a dynamic demand side that can respond to economic and control signals to match supply and demand. This two-way dynamic supply and demand matching enables more low carbon supply to meet demand, reducing supply side emissions.

There are good examples why the early consideration of how we integrate DER is worthwhile. In overseas markets that have had a large amount of DER, especially solar photovoltaics, significant problems have arisen that have required expensive retroactive action, e.g. in Germany solar penetration lead to difficulties in absorbing the extra generation, high voltage problems and the lack of inertia[17] is increasingly a concern.

Low emission DER installations can provide capacity and energy services, such as matching supply and demand, voltage support, power factor control, frequency and voltage stability, and power quality improvement (with high quality inverters and/or batteries). However, DER does not get access to the commercial opportunities grid connected generators do. There are a number of differences including:

- grid generators get paid the marginal cost of energy to maximise consumer benefit reflective of the time they generate and the location. DER gets the average cost of energy, which generally doesn't reflect the time of generation and is only generally reflective of location

[17] Inertia resists change in frequency in a power system, if power system frequency can change too quickly the system can become unstable.

- grid generators can earn revenue from ancillary service markets if they meet the market requirements for that ancillary service. DER cannot access these markets regardless of whether they meet the requirements or not.

The potential scale of DER might be much greater than is currently the case if DER had the same incentives as grid-scale generators.

Upstream from individual consumers, decisions can be made about the use of low emission DER at the distribution substation, and in the distribution network. Locating DER at this level would lead to more efficient if communal arrangements could:

- share the benefits of a common battery/inverter
- coordinate the contribution of DER injections with battery optimisation
- coordinate and optimise any demand management systems (demand response)
- allow for peer to peer trading of distributed generation (e.g. solar) surpluses and shortages within the community.

These are some of the purposes of emerging technologies such as smart grids and block chain transactions.

Currently, the organisations in the strongest position to provide these services (due to asset ownership and historical arrangements) are lines companies or embedded network owners, and some lines companies are pursuing the technology and infrastructure to offer these services; but this raises the issue of competition and open access to other providers.

A combination of DER and unbundled services could drive a more efficient system (and more emission friendly load profiles) with distribution level security coordination and some form of economic dispatch provided separately from the network owners by distribution system operators (DSOs). This is the model currently partially deployed at transmission grid level[18]. The primary purpose of a DSO would be to:

- ensure all power system resources (including DER) have competitive access to common infrastructure, optimised for all competing resources, and at a reasonable cost for monopoly assets

- coordinate DER (including smart, flexible demand) so that participant's preferences for security, quality and reliability are maintained, while recognising each load's and generating source's influence and preferences on marginal cost and marginal benefit.

An independent DSO with optimisation modelling, not only has the potential to maximise the benefit of smart technology but also enable the level playing field of competition between traditional (predominantly supply side) solutions and DER (storage, distributed generation and/or flexible demand). Such a levelling of the playing field would likely make a significant contribution to achieving a very low emissions electricity sector.

18 In New Zealand the System Operator is not separate from the Transmission Asset Owner (both are Transpower). However, this was only agreed to after assurances, rules, policies and procedures were put in place designed to ensure the System Operator had operational and governance separation from the rest of Transpower sufficient for it to perform the SO function as if an ISO. In addition, long run investment decisions are under the mandate of the Commerce Commission, and transmission pricing decisions are under the oversight of the EA, where they may be under the ISO in other jurisdictions.

1. Introduction

The Productivity Commission has commissioned us to identify the risks and opportunities associated with achieving very low emissions in the electricity sector. The work will be used as an input to the Productivity Commission's report on its enquiry into how New Zealand could transition to zero net emissions economy by 2050. This report will show how the electricity sector can contribute to the goal of a low emissions future, and how the sector could transition towards it.

Accordingly we have investigated the implications of *substantial* reductions in the GHG emissions from the sector (from today's baseline of 4-5Mt CO_2-e) and, in particular, the cost of progressively lower emissions. This would be achieved by reaching higher and higher shares of renewable fuel sources on the supply side (e.g., 95% and higher), noting that not all renewable fuel sources are emissions-free[19]. Grid scale storage is expected to become economic during the time horizon and is expected to play a role in achieving lower emissions. The path to lower emissions at a reasonable cost would also be shaped by a much more dynamic demand side incorporating small scale renewable generation combined with battery storage.

There may be a point at which further reductions from the electricity sector are less efficient than those that can be achieved in other sectors (e.g., industrial heat or transport). It is beyond the scope of this project to investigate the cost of abatement outside the electricity sector.

We also consider the key regulatory considerations of the sector progressing to an increased share of low-emission electricity sources at minimum cost while maintaining acceptable energy security and system reliability. Account has been taken of prospective changes in the way consumers produce store and consumer electricity while this progression on the supply side is underway.

[19] It is noted that renewable generation sources such as solar, wind, and geothermal vary in their GHG emissions per PJ of electricity produced. Some of this variation is from embedded carbon in the manufacture of needed plant, and some comes from the variation in emissions from geothermal according to the chemistry of individual fields.

2. Purpose and security of supply

2.1 Purpose

Our brief:

> *identify the opportunities and risks for electricity supply in New Zealand moving to a very low emissions electricity system with the additional demand that may result from increased direct use of electricity where consumers switch from fossil fuel to electric power e.g. industrial heat and electric vehicles.*
>
> *consider the regulatory and technical changes needed to manage a low emissions sector, taking account of future technical and pricing uncertainty.*

2.2 Security of supply

In Chapter 4 we distinguish between different roles required to maintain security of supply in all circumstances. Consumers have come to rely on an electricity supply that is reliable and secure but may not be aware of the details around how this is achieved. Consumers are aware when the lights go out but the component parts of security of supply and the cost implications of reliable supply are not well explained until there is a crisis or an outage. Even terms such as reliability are used in different ways depending on the context and jurisdiction that they are being used in. For our purposes reliability means that supply has to meet demand[20] at every point in time.

In order to do this, an electricity system must be designed to respond to uncertainty in supply and demand. To understand how this is done in an electricity system, especially a hydro based system, we have to consider how the system is designed to address two different time dimensions.

On the one hand there is short and medium term uncertainty about demand level and plant availability at each point in time. Shifts in demand and transmission constraints that occur from time to time mean that the market design has to have the capacity in place, and a system able, to respond quickly to meet demand as required. On the other hand, the design of a highly renewable system must also consider variations in the weather and the resulting impact on supply. The highly renewable system has to be able to respond to changes in generation as well as changes in demand.

These variations in renewable generation happen over multiple timeframes, for example:

- Wind, solar, run of river hydro ("intermittent generation") in the short term, and
- Hydro inflows to storage reservoirs in the medium term.

[20] Technically we should refer to "economic demand" as some customers may be willing to reduce demand at certain prices.

In New Zealand thermal generation is used to manage both sorts of variability, in order to reliably meet the demand from consumers at every point in time. This is because, generally, thermal generation is "discretionary", in the sense that its fuel source is not subject to the vagaries of the weather, and is flexible enough to allow generation output to be varied in response to both consumer demand, and the uncertain output from intermittent generators.

As a system increasingly substitutes renewables for thermal plant, its exposure to short and medium term uncertainty is likely to grow. Careful thought must be given to how the role of thermal is either preserved or substituted with other forms of plant able to respond to variations in demand and renewable generation.

In this paper we describe the overall task of providing reliable supply across all timeframes as **resource adequacy**. The sector currently addresses two distinct facets of the adequacy problem: short-term **capacity adequacy** and medium term **energy adequacy**. Capacity adequacy measures the ability of the system to reliably meet the highest half-hour demand period of the year, while energy adequacy measures its ability to reliably meet demand over a period of sustained low hydro inflows. Most international jurisdictions, including New Zealand, have broadly similar measures of capacity adequacy. These indicators measure the reliable redundancy in the system to allow for low wind and solar output, or plant outages. Only hydro systems tend to have measures of energy adequacy and the term security of supply is often used to mean the same[21]. Resource adequacy must also take account of the transmission and distribution infrastructure required to get power to the demand locations on the grid.

As indicated above, resource adequacy must occur across the full spectrum of timeframes, and must consider a range of sources of uncertainty and abilities of plant to respond. Simple metrics to measure adequacy across all these dimensions are only approximations, but are used in practice in the New Zealand system. The distinction between capacity adequacy and energy adequacy is reflected in the Electricity Industry Participation Code (EIPC) which has standards for both:

- The Winter Capacity Margin (WCM, peak adequacy)
- The Winter Energy Margin (WEM, energy adequacy, SI and National)

An essential part of our brief is to consider the transition path and cost implications as the sector shifts to lower emissions outcomes. We consider this in the context of maintaining security of supply to the levels currently expected or, in the language we use, while maintaining resource adequacy with all that entails.

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21 That said, we note that thermal plant can also have medium-term adequacy considerations, such as limited coal stockpiles and capped gas supply arrangements or limited gas storage

3. Framing the issues

3.1 Decision making in the New Zealand electricity sector

3.1.1 The regulatory environment

The electricity industry is subject to the Electricity Industry Act 2010, Commerce Act 1986, the Fair Trading Act 1986, the Consumer Guarantees Act 1993 and the Resource Management Act 1991, among others.

The Electricity Authority (Authority) is the primary regulatory body for the electricity market i.e. the market regulator. The Authority is an independent Crown entity responsible for the efficient operation of the New Zealand electricity market. It operates to the statutory objective of the Authority set out in section 15 of the Act:

> *The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.*

The Commerce Commission is responsible for regulating suppliers of electricity lines services under the Commerce Act, on the grounds that these services are provided "in a market where there is little or no competition and little prospect of future competition". Commerce Commission regulation (from 1 April 2011) also applies to Transpower, the operator of the New Zealand national electricity transmission grid.

Seventeen electricity distribution businesses and Transpower are subject to price-quality regulation by the Commerce Commission i.e. the economic regulator in this context. The Commission sets:

- the maximum prices/revenues that are allowed at the start of the regulatory period
- the annual rate at which maximum allowed prices can increase, and
- the minimum service quality standards that must be met.

Twelve EDBs are trust owned and subject to lighter regulatory requirements. These twelve trusts owned EDBs must disclose information to the Commerce Commission, as do the seventeen EDBs under price-quality control.

In addition, Transpower must seek Commerce Commission approval for investment proposals for upgrades to the electricity transmission grid that are above a certain size.

3.1.2 How the sector is currently organised

Since the inception of the New Zealand Electricity Market in 1996 decisions, and accompanying risks relating to investment in electricity generation and innovation, have lain with investors rather than the government or regulators. Investment decisions in distribution and transmission have had regulatory oversight and market rules have impacted on the opportunities available to investors. Since the 1990s investors and participants have made decisions based on:

- an energy only electricity market (i.e. no explicit payment from the market for capacity adequacy or energy adequacy);
- bilateral financial contracting for risk management (whether over the counter or through an organised exchange in financial instruments - exchanges in financial instruments are outside the Authority's jurisdiction);
- separation between lines and retail businesses (although this has been relaxed, the extent of retailing activity by lines company's remains minor);
- economic regulation of lines and transmission businesses;
- open or equal access arrangements to transmission and distribution networks;
- the methodology for distribution and transmission pricing are ultimately the responsibility of the market regulator(although the regulator currently only imposes pricing methodology for transmission);
- full retail contestability;
- retail tariffs are not regulated, although the distribution and transmission components are the subject of economic regulation and the Low Fixed Charge Tariff Option regulations (2004)[22] and these influence the structure of retail prices; and
- Retail tariffs for most domestic scale consumers come on a single invoice with all of the component parts bundled together e.g. distribution, transmission, energy, risk, retailer costs, metering, market administration and GST. Where a consumer also has domestic scale generation "behind the meter" the distribution charges may take this into account and the energy component may take this into account.

The approach to resource adequacy (more commonly referred to as "security of supply" in the industry vernacular) has varied during this period. From 1996 – 2003 security of supply outcomes were left substantially to participants. During dry years participants, the Market Operator and the System Operator[23] worked together to ensure the situation didn't get out of hand. From 2003 – 2010 responsibility for security of supply was assigned to the Electricity Commission but they only had limited powers to do anything during a dry period other than work with participants and the System Operator. The main tool at the Commission's discretion during this period was investment in reserve energy plant. Only one plant, Whirinaki, was built as a reserve energy provider and was commissioned in 2004. In 2010 the independent Electricity Authority was created with its statutory objective[24] to guide it; and, at the same time, the reserve energy scheme was disestablished. Whirinaki was sold

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22 The objective of these regulations is to (a) ensure that electricity retailers offer a low fixed charge tariff option or options for delivered electricity to domestic consumers at their principal place of residence that will assist low-use consumers and encourage energy conservation; and (b) regulate electricity distributors so as to assist electricity retailers to deliver low fixed charge tariff options.

23 The Market Operator has been a separate role in earlier stages of the market and under the current Code the Electricity Authority provides the services previously described by that role. The System Operator role has been provided by a division of Transpower since the inception of the market.

24 The Electricity Authority's statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

into private hands. It is now owned by Contact Energy and is offered in to the market on the same basis as any other peaking plant.

The most recent occasion at which the New Zealand government substantially revisited regulatory settings for the electricity sector was the Ministerial Review of Electricity Market Performance in 2009. The terms of reference stated:

> *the objective of the review is to improve the performance of the electricity market and its institutions and governance arrangements in order to better achieve the Government's objectives for the electricity sector*
>
> *…the Government is particularly concerned to ensure that the electricity sector contributes to economic growth by providing for security of supply and efficient prices.*

Within the context of investigating lower emissions from the electricity sector, contributing to economic growth by providing for security of supply and efficient prices forms the backdrop to our assessment.

3.1.3 Dispatchable generation is dispatched based on cost and paid only for running

The New Zealand electricity market is an "energy only market". That is, it solves the problem of establishing the wholesale price of the lowest cost supply of electricity in all conditions, but generators only receive payment if and when they run. No payment is made to plant capacity that is available to run but is not called.

As electricity demand rises and falls the System Operator calls additional generators on to the system or dispatches them off so supply meets demand. The selection of which stations are on and the level of generation they are asked to provide is primarily based on the prices they indicate they are prepared to operate for. For large generating units there is also the need to provide for an instantaneous response to cover for a unit tripping off the system. Generation that is not able to be dispatched up or down (or the owner doesn't wish to be dispatched up or down) tends to run regardless of conditions and prices, i.e. this generation is offered at prices low enough to be certain to clear. In most cases this generation is offered at $0/MWh and is referred to as "must run" generation. Where the must run dispatch exceeds demand the Code contains provision for a must run dispatch auction where generators pay for the rights to run even with prices at $0/MWh.

The System Operator is responsible for maintaining quality of supply on the transmission grid; and manages the continuous process of dispatching generation based on provisions in the Electricity Industry Participation Code 2010 (Code). The outcome of the process is secure electricity supply at lowest offered cost, and wholesale prices are published every 30 minutes for a number of locations around the grid. These prices represent the marginal cost of supplying electricity and accompanying services each separate half hour at every pricing node. All generation that runs receives the marginal price, which is generally the price of the highest priced dispatched generator's offer adjusted to each generator's (and load's) location.

The Code is administered by the Electricity Authority guided, in turn, by their statutory objective. The Code sets out the duties and responsibilities that apply to industry participants and the Authority.

As intermittent renewable energy has been added to the system, a great deal of consideration has been given to the implications of maintaining secure supply. Such intermittent renewable generation includes grid scale generation and small scale generation connected to the distribution networks. The System Operator makes provision for the intermittent nature of this generation.

3.1.4 Decision making by market participants

Investment decisions on generation, including location, fuel source, forward financial contracting arrangements and the level of market risk are matters for investors. The requirements of the market are that generators connected to the grid meet Code requirements for connection (administered by Transpower) and that they comply with the market rules including the prudential requirements. Generators earn revenue based on the volume of electricity generated in each half hour they operate and the price in those half hours, for energy and/or ancillary services. The half hourly "wholesale" price also determines any settlement payments arising from fixed-price financial arrangements (hedges, including any retail products sold to consumers). We note that discretionary plant (hydro, thermal) generally sets the wholesale price as they can operate 'at the margin', while other, less flexible plant, are "price takers". The net overall generation revenue, hedge settlements and (if relevant) retail margin is an income stream, which, once operational costs are deducted, provides a gross margin to the business through time. Depending on the operating regime of the plant, the hedges signed, wholesale prices, and variable costs, this may be quite a volatile revenue stream. Hence in constructing the ideal collection (or "portfolio") of these physical and financial instruments consideration must be given to both expected margin and expected risk.

Irrespective of whether it satisfies capacity or energy adequacy requirements, all investments in generation will, to a large extent, have their revenue determined by the uncertain factors outlined in Chapter 5. Outcomes potentially include operating in fewer periods than expected (i.e., having a lower "load factor" than expected), and/or the income stream being more volatile than expected (i.e. price and volume volatility). These outcomes are likely to impact both the expected return on fixed costs, and the risk of the investment.

Clearly, transparent market information about the need for capacity or energy adequacy is critical to investors' decisions. Investors and retailers are kept aware of the levels of adequacy through the Winter Capacity Margin (WCM) and Winter Energy Margin (WEM SI and National). Generators and retailers decide whether they respond and how they respond to that information.

The market includes two mechanisms designed to enhance the incentives on generators and retailers to take responsibility for their own actions, especially in the face of potentially low inflows.

Scarcity pricing

Scarcity pricing refers to arrangements to modify prices in the wholesale electricity market (spot market) when the system operator reduces demand through administrative action to manage security. The scarcity pricing provisions in the code provide for the introduction of a $10,000/MWh price floor and $20,000/MWh price cap to the spot market when an electricity supply emergency causes forced power cuts (called emergency load shedding) throughout one or both islands. If invoked this clause would expose retailers to high costs for covering their retail load. It provides an incentive to hedge wholesale purchases and take whatever other steps are available to them to avoid this exposure.

Customer Compensation Scheme

If customers are asked to conserve electricity during an official public conservation scheme, retailers must pay each qualifying customer $10.50 per week. In the past customers have not necessarily been compensated for their savings efforts during public conservation campaigns. This mechanism improves security of supply by removing the incentive retailers had to call for electricity conservation to reduce their exposure to high spot market prices. Instead they are incentivised to take whatever steps available to them to reduce the risks of a public conservation campaign being triggered.

Since introducing these two measures the calls for activating public policy campaigns has abated despite several years of low inflows having occurred. These measures were introduced following the passing of the Electricity Act 210 and the formation of the Electricity Authority. The Authority also worked with market participants to encourage providing liquidity in the trade of risk management products and that has further helped with the management of dry years.

Retailers are free to enter and leave the market as long they comply with the market rules. Risk management (hedge) strategies are a matter for each retailer's own risk appetite and the opportunities available to manage those risks.

The market regulator and the economic regulator are both taking active steps to support an environment where innovation is able to flourish. Otherwise there are no subsidies for providers of innovative products or investors in innovation; they take their own risks in the market place.

Decision making is being devolved increasingly to consumers. Consumers are able to install their own small scale generation and battery storage. Electric vehicles may offer the ability to discharge back into the distribution network as well as consume electricity to recharge batteries. Arrangements increasingly provide consumers incentives to consume at times of the day that reduces distributor's and retailer's costs. More and more consumers trade their excess generation output and their ability to shift their load.

3.2 The ETS and a carbon price

The NZ ETS has been New Zealand's main policy response for reducing domestic emissions and for meeting international emission reduction commitments since the scheme's introduction in 2008. At the time the scheme was launched the Climate Change Response Act 2002 (CCRA) was amended to provide for the implementation, operation, and administration of NZ's ETS and sets out its principal legal framework.

The purpose of the NZ ETS is to support and encourage global efforts to reduce the emission of greenhouse gases by

(a) assisting NZ to meet its international obligations, and

(b) reducing NZ's net emissions of greenhouse gases below business-as-usual levels.[25]

From its inception to mid-2015, the NZ ETS operated without a cap on domestic emissions; instead, it was nested within the international Kyoto Protocol cap, which enabled buy-and-sell linkages to the Kyoto market. In 2015, the NZ ETS delinked from the Kyoto market and it currently operates as a domestic-only system.

In October 2016, the NZ Government ratified the Paris Agreement. The agreement commits New Zealand to reducing GHG emissions by 30% below 2005 levels by 2030. This is equivalent to 11% below 1990 levels by 2030 (NZ INDC, 2015). The NZ ETS has been New Zealand's main policy response for reducing domestic emissions and to meet international emission reduction commitments.

To date, the NZ ETS has had little success in helping New Zealand meet its emission reduction objectives.

Although the NZ ETS may have had a small impact on the forestry sector, officials have found no evidence that it has contributed significantly to domestic mitigation of greenhouse gases.

Since de-linking from the Kyoto market, the scheme has not provided any certainty on the future supply of units into the domestic market. As a result, the market has not been able to set efficient emission prices relative to demand, and there is no dependable emission price signal that sectors can use to make long-term investments.

During 2015 and 2016, the Ministry for the Environment conducted a review of the NZ ETS to assess the operation and effectiveness of the scheme to 2020 and beyond. The review focused on three key areas (MfE, 2015):

(a) The transitional measures, except the surrender obligations, for biological emissions from agriculture;

(b) The evolution of the ETS design, taking into account the changing conditions under which it operates; and

(c) Operational and technical improvements.

The key findings of the review were that (MfE, 2017a):

- The Government is lacking the tools required to effectively manage the supply of units into the NZ ETS;
- Existing settings and management of the NZ ETS create significant regulatory uncertainty for participants; and that
- Operational and technical issues are causing administrative inefficiencies.

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25 CCRA Act 2002, section 3.

As a consequence of the review, the Government made in-principle decisions on a package of four proposals to improve the operation of the scheme beyond 2020 (MfE, 2017a; 2017c). These proposals include:

- An auctioning mechanism set to be established by 2020;
- Limiting participants' use of international units when the NZ ETS reopens to international carbon markets;
- Developing a different price ceiling to replace the current $25 fixed price option, with a possible adjustment upwards; and
- Coordinating decisions on the supply settings in the NZ ETS over a rolling five-year period.

As a result of the change in Government in 2017 it remains to be seen what path these proposals will now take. On the 18th of December 2017 the Prime Minister and Minister for Climate Change jointly announced government was taking the first steps towards a Zero Carbon Act which they expect to be passed by October 2018. They also announced that, in parallel, work would commence on working out the role of an independent Climate Change Commission. All of these developments and the uncertainty of how they will evolve have a bearing on the price of NZUs (the price of tradeable New Zealand carbon units).

3.2.1 Taking account of carbon emissions in the wholesale electricity market

The cost of carbon is factored into investment decisions making and offer price strategy by the generators who own plant that emits carbon when it runs. The NZU price and expectations of the NZU price is how the cost of carbon is reflected in electricity prices.

In 2011 the Authority published a detailed document explaining its interpretation of its statutory objective and, by implication, whether any other account should be taken of emissions targets other than the carbon price. This interpretation is widely accepted and remains in force today. It is clear on its role with respect to carbon emissions from electricity production and consumption:[26]

> *2.4 Efficient operation limb*
>
> *2.4.1 The Authority also notes that:*
>
> *2.4.1 (b) efficient operation of the electricity industry is interpreted within the context of other Government legislation and regulation affecting the electricity industry, and in particular does not allow consideration of pan-industry externalities such as carbon emissions; and*
>
> *A.60 It is important to note that the Authority does not consider the promotion of efficiency for the long-term benefit of consumers to cover all matters that may deliver long-term benefits to consumers. In particular, the Authority believes that policies to address*

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[26] Electricity Authority *Interpretation of the Authority's statutory objective* 14 February 2011

externalities arising generally from industry and consumer activity that is broader than electricity industry-related activity do not fall within the scope of the Authority's functions.

A.61 For example, carbon emissions arise from many sources of human activity, not just electricity-related activity, and are being addressed by the Government's environmental policies, including its emissions trading scheme.

For our purpose we understand this to mean that the current expectation is for investors in the electricity sector to account for the carbon impact of their investment, or operational decisions, based on the provisions of the ETS and the carbon price that results.

The Commerce Commission does not consider the implications on emissions when it considers whether to approve major transmission projects, nor does the Commission consider emissions when assessing allowed revenue and pricing approaches by transmission and distribution (e.g., the grid owner (Transpower) earns the same return on assets connecting a coal fired generator to the grid as it does providing access to the grid to a suburb investing in solar and battery packs).

Consideration of emissions is explicitly excluded from matters that should be "recognised and provided" for in decisions on whether to issue a resource consent under the Resource Management Act (RMA). Decision makers are only required to "have particular regard to" the "effects of climate change" and the "benefits to be derived from the use and development of renewable energy".

3.3 A public policy imperative to reduce emissions in the electricity sector

Having summarised the way the electricity sector is currently structured the question that remains is whether these arrangements are the best to accommodate, or provide no barriers to, the electricity systems transitioning to low emissions as the carbon price rises.

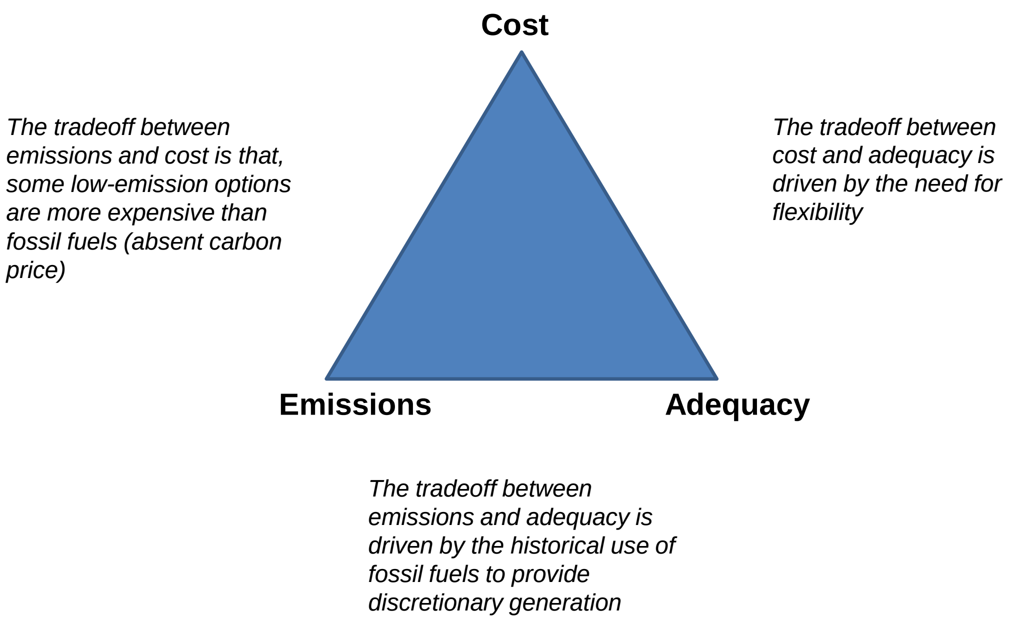
In the following section we investigate the implications if the system reduces its reliance on thermal generation for whatever reason between now and 2050. What we show is that if generation investment decisions (including generation decommissioning decisions) proceed down that track the cost of renewable generation required to fill the role that thermal generation currently fills become progressively higher. The combination of increased wholesale prices resulting from a higher carbon cost for any thermal generation still running with the higher cost of maintain resource adequacy will feed in to the energy component of retail tariffs. These combined costs equate to the marginal costs of abating GHGs. Also, as the combined cost rises and is reflected in the energy component of retail tariffs consumers will receive stronger incentives to change behaviour so wholesale prices won't necessarily rise as strongly.

In a later section we consider what has to happen so this process is able to run its course. That will help policy makers and market designers to focus on steps that could be taken to accommodate this process and so we may expect the best emissions outcome possible. These sorts of steps might include changes to the Code requirements, financial instruments, resource consent parameters, competition rules and regulations, regulations for use of new technologies and support for the penetration of distributed devices (including small scale generation, domestic scale batteries and electric vehicles). It is only after the carbon price has done its work and measures to reduce barriers to a low emissions sector have been taken that policy makers would need to think about intervention.

3.4 The trade-off between emissions, resource adequacy and cost in New Zealand

Sections 4-7 are a quantitative analysis of the trade-off between cost, emissions and resource adequacy, as illustrated in Figure 10. Our approach is to treat resource adequacy – which we define in Section 4 - as a constraint (i.e., a lower bound). We assume that the levels of resource adequacy that consumers enjoy today must continue, noting that in the future, technology may allow consumers to express their own preference for reliability. Within that constraint, we examine the trade-off between cost and emissions. The analysis shows that different types of generation plant, storage and demand-side mechanisms can provide resource adequacy; but low emissions options may be more expensive for meeting demand and resource adequacy.

Figure 10 - The cost-emissions-adequacy trade-off



4. Resource Adequacy

This chapter provides an overview of resource adequacy today, including the way in which different parts of the system coordinate to meet demand in all periods; and how we can use simple metrics to test whether an acceptable level of adequacy is being met

We define resource adequacy as the requirement for supply to meet demand at every point in time.

In the context of overall resource adequacy, "demand" refers to:

1. consumption from all types of electricity consumers

3. electrical losses on the national grid and distribution networks incurred in transporting power from generators to consumers

4. the need to maintain "headroom" in generation to allow for (a) responding to sudden outages of generation or the HVDC (known as instantaneous reserves[27]), and (b) an allowance for the management of very short-term variation in the supply-demand balance (known as "frequency keeping").

The discussion in this chapter primarily focuses on the need to match supply to demand category (1) above, but any quantification of the need for generation should take into account categories (2) and (3).

We illustrate demand in two ways below. Firstly, Figure 11 shows half hourly demand over the year of 2016. This shows that demand varies considerably over the period of a day, and over the year. This underpins the need for the system to have sufficient flexibility to increase output during the periods of high demand, and decrease output during the low demand periods.

27 We note that instantaneous reserve is not just provided by generation, but also interruptible load

Figure 11 – NZ Electricity Half Hourly Demand for calendar 2016

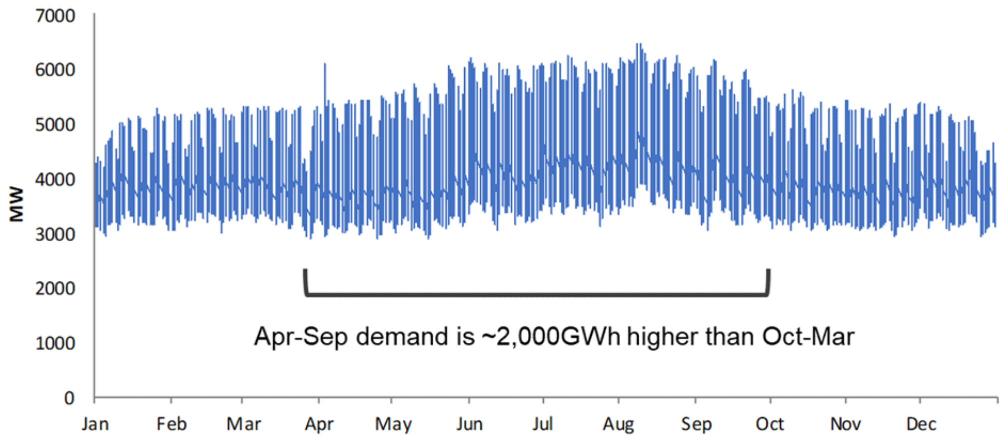
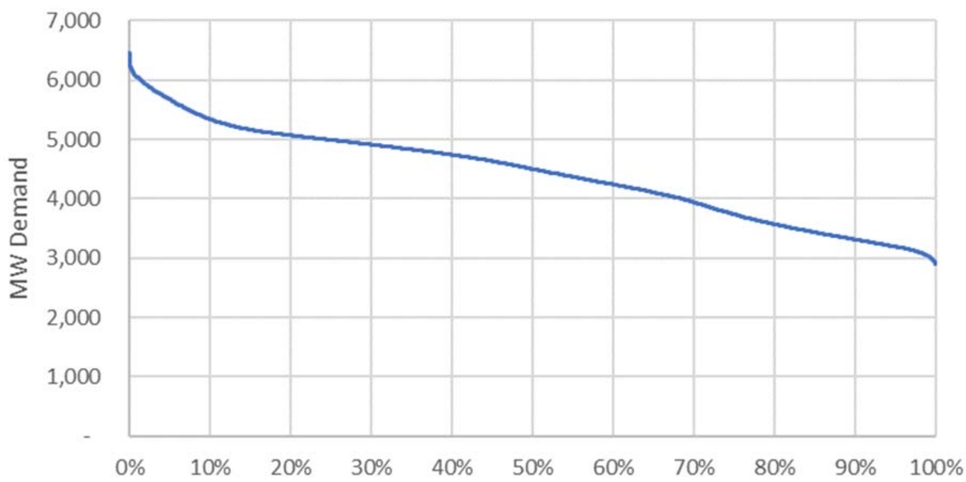


Figure 12 shows a "load duration curve" (LDC). This is a convenient way to visualise the collective requirements of a secure market. The LDC ranks all the half-hourly demands in Figure 11 from highest to lowest. We can tell from the LDC:

- at all times over the year, the system must have at least 3,000MW of generation output reliably available
- at its peak, the system must have sufficient capacity to reliably meet demand of ~6,500MW for a very short period of time
- in between, plant must be able to reliably turn on and off to meet a range of different demands.

Figure 12 - NZ Load Duration Curve for 2016.



Source: Sapere data

These two charts illustrate the range of different demands that must be matched with supply, and how those different demand levels vary over the year.

Invariably, electricity supply systems (generation and transmission, combined with demand response) are planned to ensure that there is sufficient available capacity to meet demand at its highest level (the left-most point in Figure 12). But these systems must also be flexible enough to reliably meet the different levels of demand at each point in time through the year. In a system which has intermittent renewables, the coordination of market resources is not only responding to the needs of consumers (as described by the LDC), but also the variability of intermittent generation.

Hence, collectively, our electricity system must contain sufficient resources to "shift" electricity through time, through the storage of electricity or fuel. It is the ability of plant to turn on and off at the appropriate times which enables system operators to maintain an exact supply-demand balance at every point in time. We will refer to this general capability as "flexibility"; and adopt the conceptualisation of Orvis and Aggarwal (2017)[28]:

"Flexible comes in many forms, but broadly, it means the ability to respond over various timeframes – from seconds to seasons – to changes in supply, demand and net load."

Having understood what we require from the supply-side, we now need to consider what fuel and plant is suited to performing these roles. Traditionally, the industry has characterised fuel/plant combinations as follows:

1. **Discretionary** plant with a <u>fuel</u> that can be stored either immediately upstream (e.g., coal stockpile, underground gas storage, or hydro reservoir) or more distantly (in the original gas or coal field, but where it has some degree of "on demand" availability). Discretionary plant is sometimes referred to as:

   (a) "peaking", which tends to operate for a relatively low proportion of the year (e.g., less than 20%)

   (b) "mid-merit", which may run between 20% and 80% of the year, operating at higher levels when demand (net of other plant) is sustainably higher, either because demand itself is higher, or because the available fuel for intermittent plant (or hydro) is low.

2. **"Must run"** plant, which either directly converts the fuel into electricity as it arrives onsite, or "spills" it (allows it to escape without using it for generation). Must run plant falls into two categories:

   (a) "*Intermittent*" or uncertain – such as wind, solar and run-of-river hydro

   (b) Baseload – such as geothermal[29] and co-generation plant, or thermal plant on take-or-pay gas arrangements

[28] Orwis, R and Aggarwal, S (2017), "A Roadmap for Finding Flexibility in Wholesale Markets

[29] But, as discussed later, the definition of geothermal as "baseload" is a commercial one, not really a technical one. It could technically be seen as a discretionary plant with a fuel reservoir.

3. An **electrical storage** mechanism (e.g., batteries) whereby electricity (rather than fuel) can be stored when a surplus is available, and re-injected back into the system at a later time.

4. **Electricity shortage:** Once a common occurrence, as societies have modernised, consumer and political tolerance of shortage has declined commensurately. All systems will, however, have some acknowledgement that a system cannot be 100% reliable; but in modern economies the expectation of shortage is very, very low.

Each electricity system around the world has evolved its own mix of discretionary, intermittent, baseload and storage to reliably meet its own version of the LDC shown in Figure 11[30]. Historically, due to the sheer expense of electrical storage, systems have relied on discretionary plant and fuel storage to respond to meet the shortfall between the must-run plant and demand, as it varies from one period to the next. This remains almost exclusively the case in New Zealand today – a hydro-dominated system with significant short-term flexibility and limited medium-term storage (subject to the vagaries of the weather), supplemented by gas and coal flexibility enabled by fuel storage and underlying fuel contracts.

It is the combination of fuel storage and fuel contract flexibility that determines the extent to which thermal generation provides flexibility and resource adequacy:

- Deliveries of fuel that are not well synchronised with the need to generate (for example gas take-or-pay contracts) may provide little flexibility unless they are paired with storage (e.g., the Ahuroa gas storage facility, or a coal stockpile)
- Deliveries of fuel that are highly flexible (e.g., gas purchases on the gas spot market)

In many ways, hydro is just another form of a fuel contract; weather conditions determine the delivery of the fuel (which may or may not be well timed with the need to generate), while the hydro reservoir allows these "deliveries" to be smoothed through time.

As will be discussed later, as decarbonisation occurs, and the quantity of thermal generation in the system reduces, we need to consider the impacts on the ability of thermal owners to secure sufficient flexibility (either in the contract, or via storage) to meet the system needs.

In the future, electrical battery costs are reducing significantly, and are likely to play a bigger role. But we reinforce that, while battery technology excels at short-term shifting (hours and perhaps days), it is not suitable for the degree of shifting required to supplement the medium-term volatility in hydro inflows.

The desire to reduce emissions tends to see more intermittent renewables introduced, which may in turn increase the requirements for discretionary plant, and/or any required fuel storage. We note that the traditional categorisation of supply-side assets above should not preclude intermittent generation from providing flexibility. Market operators are considering more ways in which intermittent generation plant can be "dispatched" in order to manage

[30] It is important, when comparing New Zealand with other jurisdictions, to consider the differences in the shape of the LDC, and how that might influence the implied need for flexibility through time.

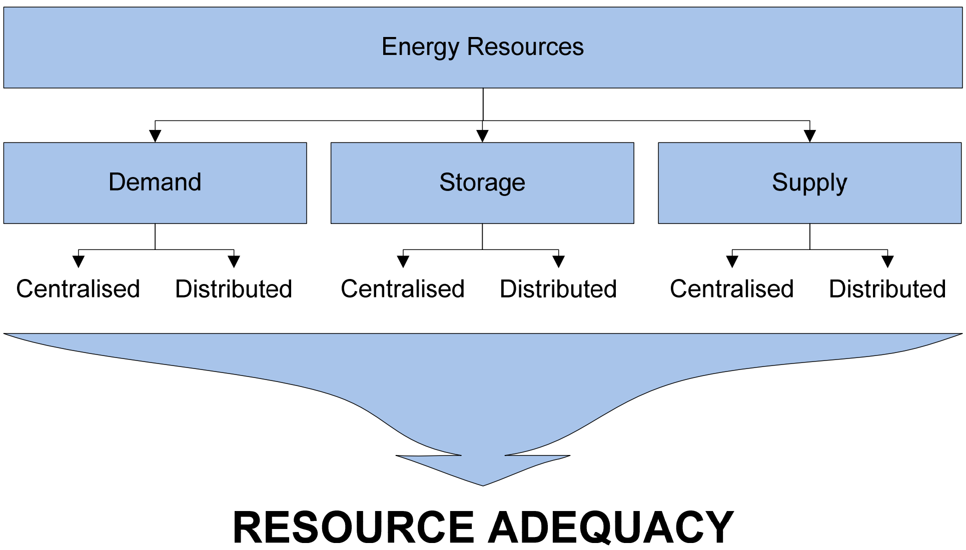
the system balance. This may mean that wind, solar or hydro may be deliberately spilled to provide some headroom in response. Also, as will be explained later, the presence of power electronics inside the control systems of these intermittent plants gives rise to the opportunity for them to provide a range of ancillary services, including voltage support, frequency keeping and inertia.

Traditionally, analysing and planning for resource adequacy was an exercise in considering demand as an exogenous forecast, and then determining whether the supply side of the industry had sufficient flexibility to meet demand at every point. Since demand varies over the year as a result of consumption behaviour (heating, lighting, commercial activity for example), meeting demand at every point in time means that the electricity system must have sufficiently flexible supply to respond to this variation. However, increasingly, the potential for flexible demand to play a role in resource adequacy has to be factored into planning for resource adequacy. Additionally, electricity storage (such as batteries) may avoid the need for changes in either demand or supply, by smoothing out the pattern of demand or supply. Overall system operators will come to consider flexible demand, supply and storage as a set of resources which interact to ensure that supply and demand is matched in real time.

As summarised in Figure 13, it is worthwhile considering that these resources may be centralised or distributed (decentralised). At this point in time, this is a very important distinction for how resources are coordinated. At a centralised level, there are a small number of large generation plants, fuel storage and some demand response (targeted at the instantaneous reserve markets). These centralised energy resources (CER) are coordinated via a highly organised wholesale market and resource adequacy is maintained, at least cost, through a range of codified actions by a central system operator based on offers of capability from the owners of the CER.

However, there is significant scope for distributed energy resources (DER) – i.e., energy resources beyond the "grid edge" – to provide flexibility for resource adequacy. These include distributed generation, flexible demand, energy efficiency, and storage at the distribution and consumer level.

Figure 13 - Framework for considering the contribution of energy resources to adequacy



If it is the actions of consumers that create the need for system flexibility, it is possible that this behaviour could be influenced or changed, which in turn could reduce the requirements on the supply side. Again, quoting Orvis and Aggarwal (2017)[31]:

"The new paradigm of grid management will be oriented around flexibility, renewable energy generation, and the participation of demand as a resource, marking a fundamental departure from how the grid has historically been managed…As the grid decarbonises, [Regional Transmission Operators] have an opportunity to ensure that the market continues to work with as little friction as possible, minimising overall system cost for customers."

We return to the theme of "friction" in the market in a later section but in this section we focus on the interplay of decarbonisation, flexibility and cost.

4.1 Measuring and Managing Resource Adequacy

As discussed above, the need for resource adequacy extends over multiple timeframes and reflects a range of needs: varying demand, intermittent renewables and variations in fuel. This makes it difficult to create a single "complete" measure of resource adequacy. Here we discuss two metrics (referred to as "standards"), that are contained with New Zealand's Electricity Industry Participation Code, which we will use to assess the viability of future scenarios.

The Electricity Authority contextualises the standards as follows:

> *The function of these standards is to serve as points of reference in determining how likely it is that there will be efficient levels of generation and inter-island transmission available to meet demand in the next 5-10 years.*[32]

Before discussing each standard, it is very important to understand what these "standards" represent. Often, in industry discourse, the standards are implied to be minimum levels of capacity or energy adequacy. However, the Authority is clear that:

> *Each security of supply standard is intended to represent an optimal level of investment, in the narrow sense that the combined cost of shortage and reserve generation is minimised. In other words, the marginal cost of adding new reserve generation is equal to the marginal benefit of reducing unserved energy.*[33]

We note that the use of the word "optimal" suggests that in reality industry levels of adequacy will inevitably vary around the standard's level, and that this is tolerable to the Authority (insofar as it is an expected loss of economic efficiency, rather than a violation of

[31] Ibid.

[32] Electricity Authority, 2012, "Winter Energy and Capacity Security of Supply Standards", Consultation paper.

[33] Ibid. That said, the very next sentence in this consultation states "*It may be that a higher level of investment is optimal when other considerations are taken into account*". Interestingly, the Authority does not comment on the corollary, that lower levels of investment may also be optimal. It is not clear whether this omission is deliberate or not, and could be taken as an implied commentary on the asymmetry of risk between erring on the side of too much capacity, versus too little.

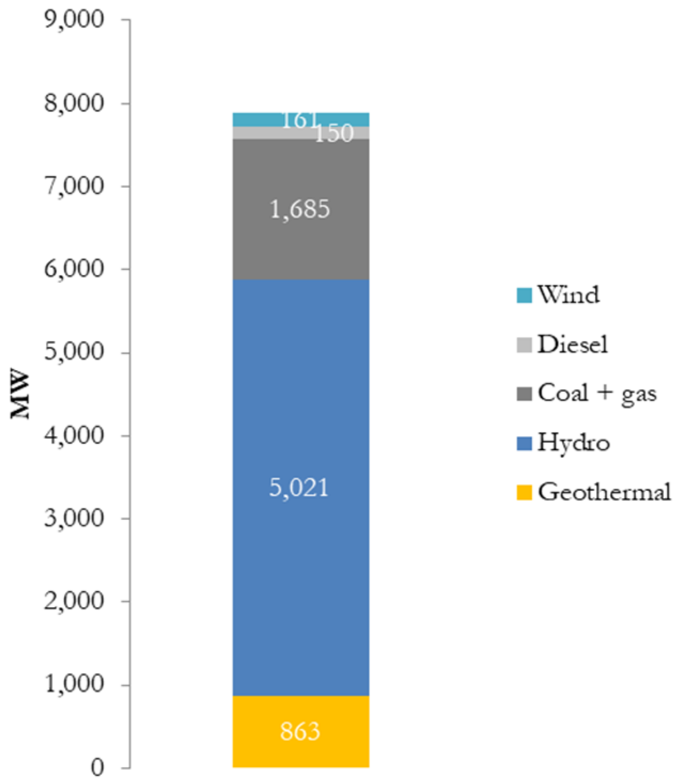
some underlying minimum level of reliability). To reinforce this, the standards, as discussed below, are expressed as ranges, rather than point estimates.

4.1.1 Capacity Adequacy and the Winter Capacity Margin

Most international jurisdictions (including New Zealand) assess some measure of what is variously termed “peak adequacy”, “capacity adequacy” or “capacity margin”. Whichever of these terms is used, they fundamentally aim to measure the dependable supply that can be expected to be available at the system peak (the most left-hand data point in Figure 12). Intermittent forms of generation are usually ascribed a low contribution to peak adequacy as wind is highly volatile, and the New Zealand system peak typically occurs on a winter’s evening, when no solar will be available. Reliable, discretionary plant (geothermal, stored hydro, thermal and, potentially, demand response) are assessed at close to their full capacity for contribution to peak demand.

Under the Security of Supply Forecasting and Information Policy (SOSFIP), the System Operator publishes annually a “Winter Capacity Margin” forecast for 10 years into the future, across a range of scenarios.

Figure 14 Contribution to capacity margins by fuel source

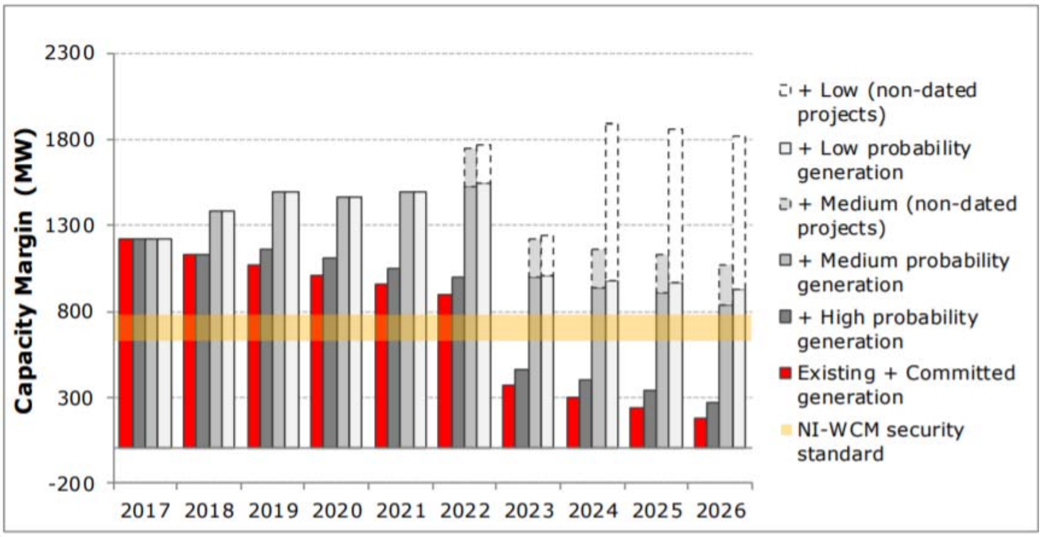


Source: Sapere based on Transpower (2017) data

The methodology forecasts peak demand in the North Island[34], and compares it against a measure of "reliable" supply (adjusted for any limitations on the inter-island HVDC link that may be present during these peak periods). Current reliable supply (from the System Operator's 2017 assessment) is illustrated in Figure 14. The dominance of hydro in the capacity margin calculation is obvious, although, while highly flexible, it is insufficient by itself to meet peak demand requirements and must be supplemented with thermal and geothermal generation. But the presence of significant hydro is one of the reasons why, in recent history, the capacity dimension of resource adequacy has been well served in New Zealand.

The winter capacity margin "standard" states that a buffer of 650-750MW[35] over and above peak demand is an efficient level of capacity. This standard is exceeded currently in New Zealand, and is likely to continue to be exceeded (in a base case scenario) until the decommissioning of Huntly (expected to be at the end of 2022 as shown in Figure 15).

Figure 15 North Island Winter Capacity Margin 2017 to 2026 – Base-case



Source: Transpower Security of Supply Annual Assessment 2017

4.1.2 Energy Adequacy and the Winter Energy Margin

The importance of maintaining sufficient flexible generation to reliably respond to different medium-term hydrological outcomes is embodied in the "Winter Energy Margin". The

[34] Technically a measure of peak demand known as "H100", i.e., the average of the 100 highest hours of peak demand.

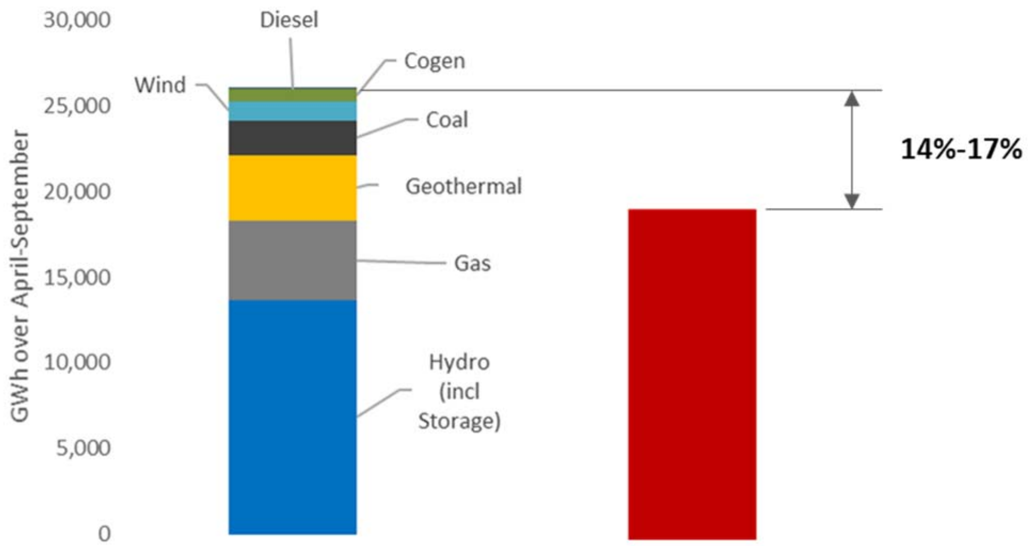
[35] We acknowledge that the current range includes an allowance for instantaneous reserves and forecasting error. As peak demand grows over the next 35 years, forecasting error may change (and could get either better or worse). Also, the need for instantaneous reserve supply from grid-based generation may also change. Hence the standard in 2050 may be different from the values we use here, which are taken directly from the Code.

WEM is a planning standard, as distinct from the hydro risk curves[36] (or its predecessor the "minzone") which are aimed at monitoring current storage levels and the near-term risk that this implies for the system.

The WEM is effectively the same as the WCM, except that it is defined by an energy requirement for a specific period (a 6 month period from 1st April through 30th September). Hydro contribution to WEM is determined by mean inflows and expected storage as at 1st April[37], while for other fuels, it is a measure of the dependable energy they can contribute over this 6 month period (Figure 16).

However, we note that the WEM standard presumes that owners of thermal plant have sufficient fuel available to allow them to generate at the "dependable" level presumed by the WEM calculation, as detailed below. In reality, the dependability of this generation level is highly dependent on the underlying fuel situation, whether it be a coal stockpile,

Figure 16 - WEM Calculations by fuel type, 2017

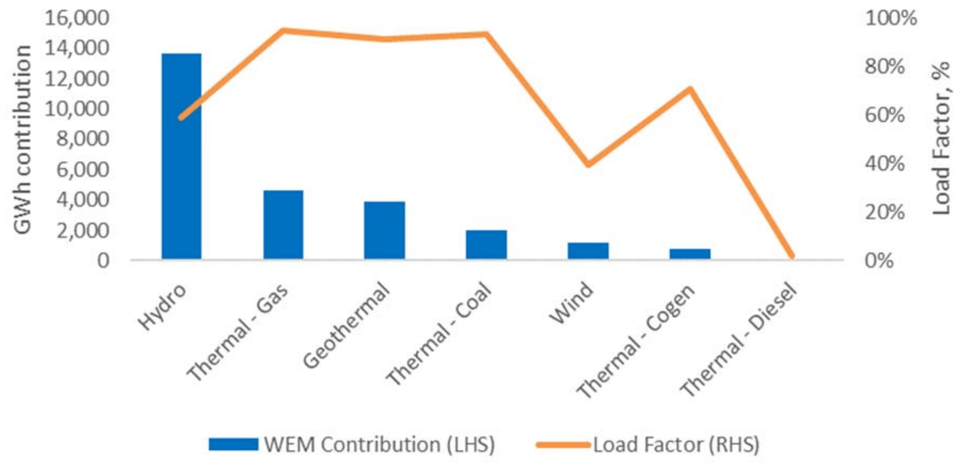


The time dimension is an important aspect of the WEM. The energy supply a plant may be able to achieve in any given half hour is different to what it could provide over a prolonged period. For intermittent fuels, such as wind, their contribution to WEM (on a load factor basis) is much higher than for the WCM. Over time, wind is relatively dependable (Figure 17) and gas plants are assumed to be able to run at near capacity (should they be required), despite the fact that in "normal" hydrological years, this would not be the case.

36 Hydro risk curves describe the probability of emptying hydro reservoirs for a given storage level at any point in time. See https://www.transpower.co.nz/system-operator/security-supply/hydro-risk-curves

37 Security of Supply Forecasting and Information Policy , 8.2, Downloaded from https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/Security%20of%20Supply%20Forecasting%20and%20Information%20Policy.pdf

Figure 17 - Contribution to National WEM by fuel type, 2017.



Source: System Operator

The WEM itself is expressed as a percentage of surplus dependable generation over forecast demand for the 6 month period (rather than an absolute GWh amount). It is defined separately for the South Island (reflecting the importance of South Island storage) as well as for New Zealand as a whole. The Electricity Authority's most recent amendments to the standard states that a national WEM of between 14%-17% is optimal and 26%-30% is optimal for the SI. [38] These margins, over and above expected demand, allow for the chance that hydro inflows (or starting storage) deviate significantly below their mean values. However, as raised earlier, the margin does not allow for insufficient thermal fuel.

Figure 18 shows that the small excess in the current WEM margin is eroded over the period 2017-2019, and by 2021 (even prior to the Huntly decommissioning decision) WEM falls beneath its optimal range even if high probable generation projects are built.

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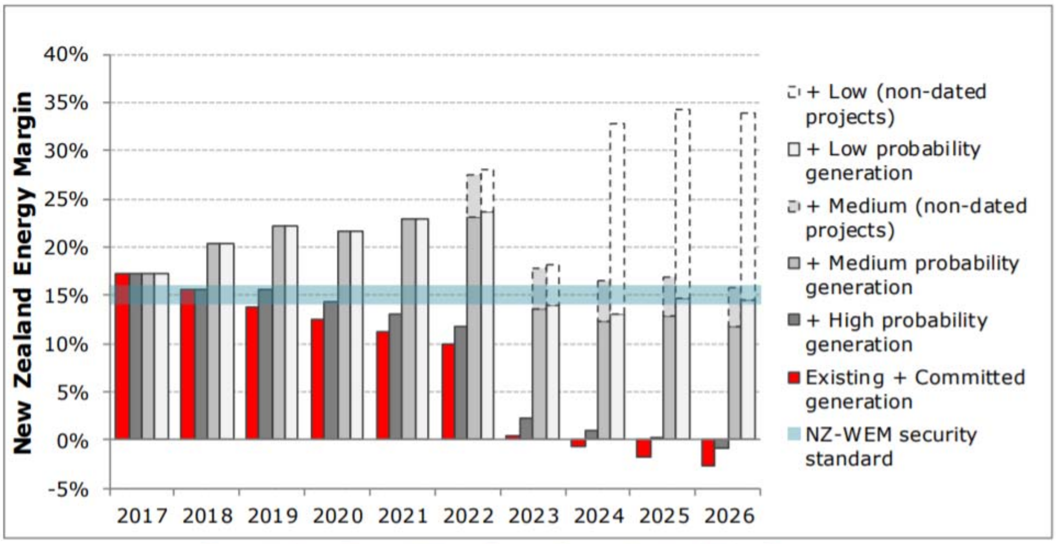
[38] The WCM and WEM standards were actually developed by the former Electricity Commission, and formed part of the Reserve Energy scheme, which was terminated in 2010. While the Authority made some minor amendments in 2013, they remain in the same form as developed by the Commission, with an amended role as part of security of supply monitoring, and "are intended to provide market participants and other stakeholders with information about future security of supply risks and investment opportunities." (Authority, 2012)

Figure 18 NZ winter energy margin 2017 to 2026 – Base-case



Source: Transpower Security of Supply Annual Assessment 2017

4.1.3 Using WEM and WCM to assess future resource adequacy

When assessing how a system will meet future demand, the simplest approach is to ensure that sufficient generation is built each year to meet annual energy demand. We have shown above that this would be a risky simplification, as the system's ability to reliably meet peak demand, as well as its ability to reliably manage a sustained period of low inflows, are critical features of the commitment to consumers that the New Zealand system is secure.

The two metrics introduced above are the standards used in the New Zealand Electricity Industry Participation Code 2010 (EIPC) that effectively give assurance that the system has sufficient reliable generation to cope with two "stress" scenarios: a scenario where demand is at a credible maximum, and a scenario where hydro inflows are very low for an extended period of time.

The standards do not tell us how generation will be utilised in any particular period or year. The high load factors for gas and coal in the WEM would only be realised in an extended dry period. Similarly, any system peak may turn out to be during very windy conditions, in which case peaking gas plants may not be used as much as the WCM calculation suggests.

However, our earlier discussion of resource adequacy highlighted the need for flexibility from plant to respond through time to varying demand and generation from intermittent sources. The standards only indirectly make an assessment of this. The WCM ensures that there is sufficient reliable capacity in the system to meet the highest demand period, allowing for a conservatively low estimate of intermittent generation. By definition, this means that there is sufficient capacity to deal with any lower demand. But the greater the extent to which the system must rely on this plant to be flexible *through* time the more the availability and flexibility of its underlying fuel source becomes relevant.

Hence the WCM confirms that the *capacity* is available, but the underlying fuel contracts and storage are the critical factors for flexibility through time. The Winter Energy Margin is one manifestation of this: it is concerned with a scenario of insufficient hydro fuel over a 6 month period, and attempts to assure us (although ignorant of fuel contracts) that the system has the ability to flex in response. More generally, we could imagine a range of "energy margins" each concerned with a different period of time (days, weeks, months) and fuel scenarios which would collectively define the overall flexibility required of the system

Below we simply apply the WCM and WEM metrics to our assessments of future scenarios in the next section, noting that they are not the complete picture, as outlined above. Hence they assure us of sufficient reliable *plant* to meet the highest demand period, and a hydro shortage, but make no assessment of other fuel and time scenarios. This would be the realm of more detailed modelling[39].

4.2 Impacts of Climate Change on Resource Adequacy

Below we consider how resource adequacy will be met over the next 35 years given scenarios of supply and demand. Here we briefly consider whether the resource adequacy dynamic may change as a result of a changing climate.

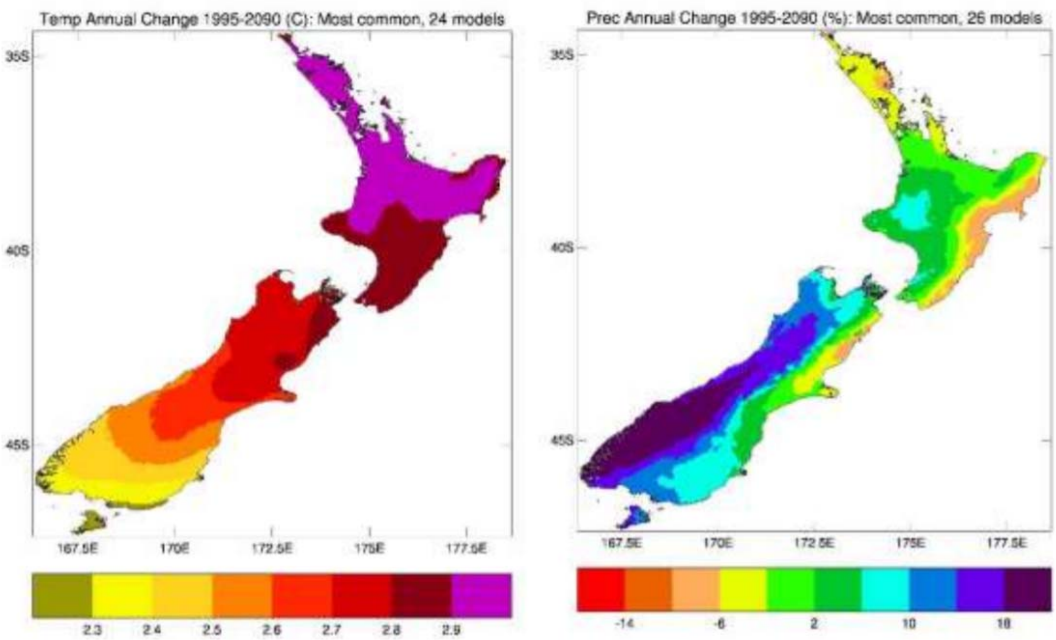
MfE[40] summarise the most likely impacts of climate change in New Zealand (depicted in Figure 19) as:

- The highest degree of warming being in the north of New Zealand,
- The largest increases in rainfall in the west of the South Island, and the largest decreases in the east of the North Island and in coastal Marlborough and Canterbury,

[39] As will be discussed later, MBIE's EDGS modelling does disaggregate the LDC into different "sections" and different seasons; hence it creates a more representative requirement of the flexibility required in reality.

[40] Ministry for the Environment 2016. Climate Change Projections for New Zealand: Atmosphere Projections based on Simulations from the IPCC Fifth Assessment. Wellington: Ministry for the Environment

Figure 19 - MfE summary of annual temperature and rainfall changes between 1995 and 2090. [41]



The most common patterns of annual temperature (left) and precipitation (right) change between 1995 (1986–2005) and 2090 (2081–2100), as assessed from the statistical downscaling results. The temperature pattern is the ensemble average of 24 models, and precipitation of 26 models (out of 41), for the 2090 projected changes under RCP8.5

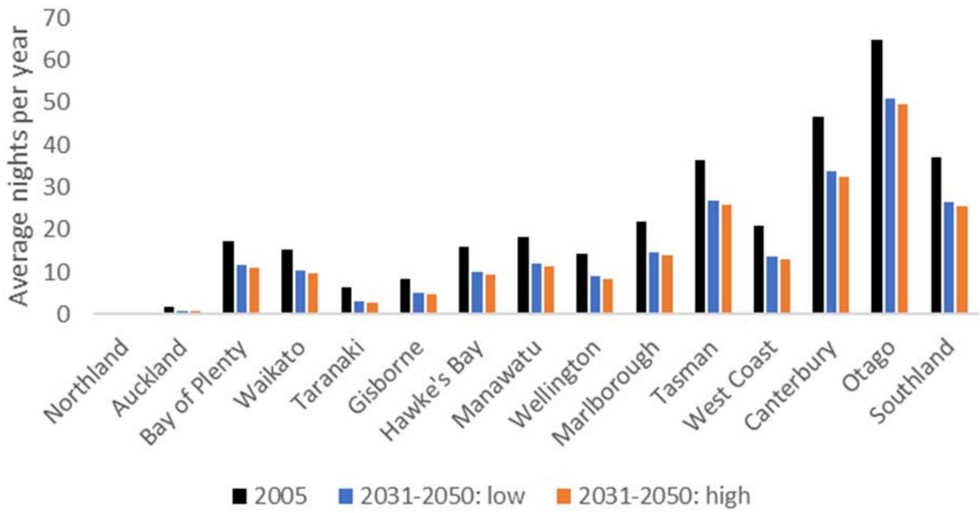
Source: MFE 2016

As discussed above, one of the adequacy challenges we currently face is the poor correlation between demand over the year, and (average) inflows over the year. However, a generally warming climate may affect this as follows (other things being equal):

- Warmer winters may decrease heating demand, especially since the greatest warming is predicted to be where NZ's largest population centre is (Auckland).

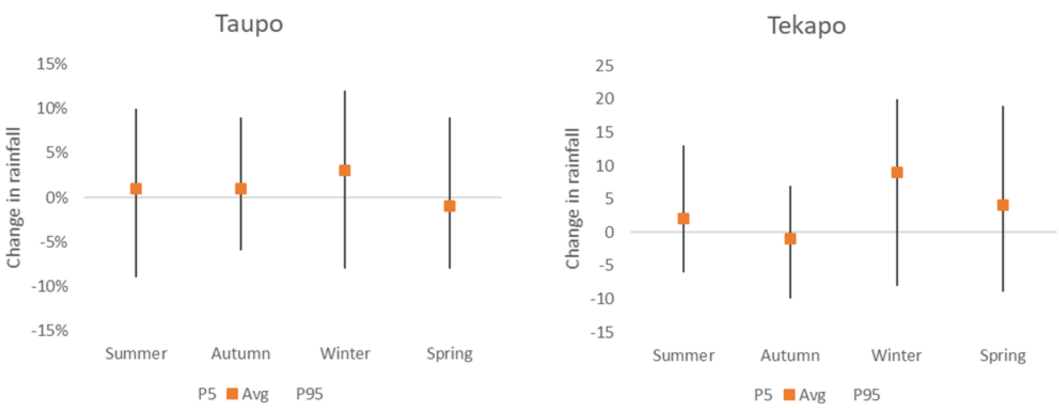
41 See Ministry for the Environment *Climate Change Projections for New Zealand* 2016

Figure 20 Average number of nights below 0 degree C



- Wetter winters may increase inflows into hydro catchments, and warmer winters may reduce the amount of precipitation falling as snow. We illustrate how this might affect the Taupo and Tekapo regions in Figure 21.

Figure 21 - Changes in rainfall (%) between 2005 and 2031-2050 in the 4.5 degree scenario for Tekapo and Taupo: expected, 5th percentile and 95th percentile (source: MfE)



- An increase in drought conditions on the east coast will drive up irrigation demand in spring/summer

Hence it is plausible that climate change may ameliorate the resource adequacy challenge presented above, by better aligning inflows with demand over the year[42]. However, we cannot necessarily rely on that conclusion for two principal reasons:

[42] Meridian contend that this is the case on slide 105 of their 2017 investor presentation. They also note that a warming climate will lead to increased wind in NZ.

1. As illustrated in Figure 21, MfE's predictions of changes in rainfall in the key hydro catchments have very wide confidence intervals around them. Within these confidence intervals are scenarios where rainfall could both increase and decrease.

2. Like today, any individual year will have its own pattern of weather, which may depart significantly from any long-term expected trend. Hydro reservoir operators will thus still face uncertainty about weather patterns over a 3-6 month window, and will behave accordingly.

An additional factor that has to be taken into account is that MfE's analysis of global climate models suggests an increase in storms. Severe weather events are often the cause of interruption to power supply (as a result of impacts on generation, transmission and distribution), and thus go to the resilience of the power system. We have not analysed this particular impact of climate change in the context of reducing emissions in the electricity sector, but note that a supply chain with a greater presence of weather-dependent renewables (hydro and wind) may be more susceptible to storm events. We recommend investigating this potential impact from climate change for future work.

5. Supply-side Options

In this section we consider:

- The relative costs of different generation options
- How each of the these generation options might contribute to resource adequacy
- On the assumption that the industry pursues the least-cost investment path, and is constrained by resource adequacy, what the different mixes of generation might be in 2050 under different future carbon prices

5.1 An investment merit order

Generation investment decisions are the result of myriad factors, some of them quantifiable, others not. Many of these underlying drivers are specific to each investor's unique circumstances and expectations, and, indeed, each generation investment decision is effectively a statement of the decision makers' belief about the future.

This dynamic is little different from the many decisions that go into determining future electricity demand levels and shape, as discussed later, except that:

- supply-side investment decisions (at the grid connected level, at least) are larger and less frequent than many of those on the demand side
- on the supply side each individual decision can be modelled in some detail, as opposed to the demand side, where modelling tends to be based on the aggregate effect of many decisions at the consumer level (refer our discussion about the changing composition of demand with the emergence of DER in our previous section.)

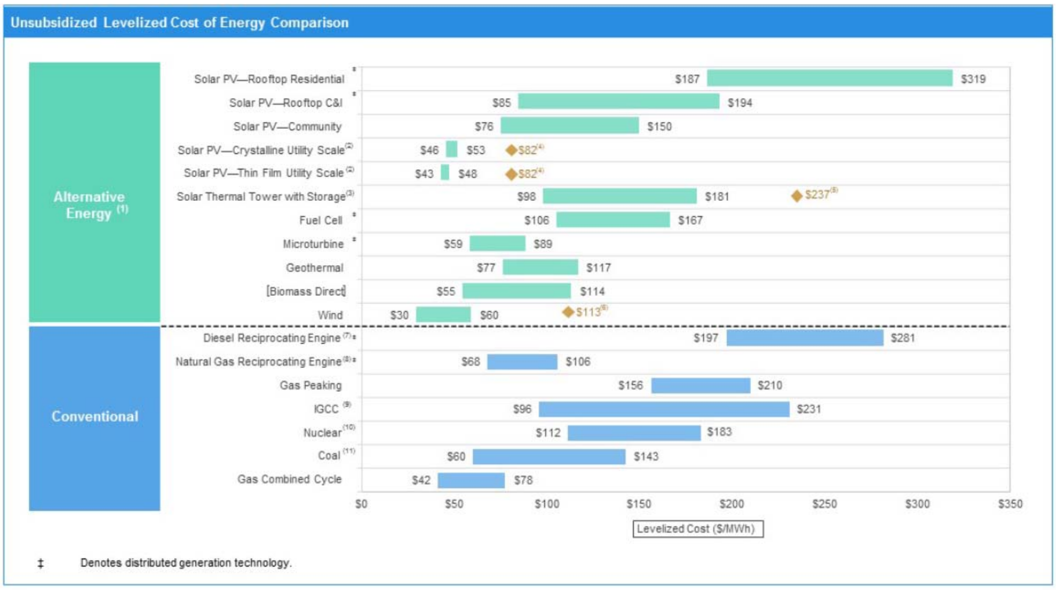
Typically supply side modelling assumes that, when faced with a need for a new power station (ultimately driven by a net increase in demand) market participants will choose to build the lowest overall cost power station. This assessment of cost must include capital, and fixed and variable operating costs (including fuel and the cost of carbon emissions). However, this is not a trivial exercise, due to the uncertainty inherent in estimating these:

- The underlying capital costs are uncertain as technology improves, and, since a large proportion of the capital costs of most power stations will be procured internationally, these costs are exposed to international commodity (e.g., steel) and currency markets.
- Particularly with renewable decisions, the amount of fuel available for a given wind, hydro or geothermal project is highly site-specific.
- For thermal projects, the cost of fuel is uncertain, as is the ability for the owner to achieve flexibility in the fuel supply contract. The two (price and contract flexibility) are not unrelated.
- Land acquisition, consenting and grid connection costs are also factors that are uncertain and highly site-specific.
- Of course, with specific relevance to this report, the cost of carbon emissions is uncertain.

As outlined later in this section, we will investigate the sensitivity of generation investment decisions to a range of carbon prices. For the remaining factors, MBIE's Generation Cost Assumptions, which are used for their Electricity Demand and Generation Scenarios (EDGS), are an excellent resource which is publicly available. We will later discuss the sensitivity of the predicted decisions to changes in these underlying costs.

With these costs, we can establish a "merit order" of investment decisions, which is effectively a ranking of potential investments by some measure of a unitised cost. The "Long-term Cost of Energy" (LCOE) is often used internationally to compare different potential investments that have different mixtures of fixed and variable costs, and annual production. A popular example, published by Lazard (2017)[43], is illustrated in Figure 22.

Figure 22 - Lazard Levelised Cost of Energy Analysis



More commonly in New Zealand we refer to the combined effect of capital, fuel, carbon and other operating costs (fixed and variable) as a "long run marginal cost" (LRMC). The LRMC, is very similar to the LCOE, expressed in $/MWh, and converts the various fixed and variable costs into an equivalent cost per unit of production over the life of the plant (allowing for the time value of money). An LRMC can be thought of as the volume-weighted average price[44] in today's dollars that an investor would have to receive, on average, for the *expected* output of the plant, in order to make an acceptable return on capital. An LRMC calculation should take into account the likely "load factor" of the plant, i.e., what proportion of the time it is expected to operate on average (noting that, in reality, it will vary from year to year). As the plant produces lower levels of output, its fixed costs are spread over a smaller volume, and thus the average price it earns must increase.

43 Lazard, 2017, *Lazard's Levelized Cost of Energy Analysis – Version 11.0.*

44 For this reason, LRMCs are often used as a way of forecasting electricity prices. However, in our experience, there are numerous assumptions and interpretations of the resulting prices, some of which can be very misleading. It is not our purpose here to predict prices.

Figure 23 illustrates the range of LRMCs from MBIE's cost data. The range, for each technology type, represent different projects (and thus generation yields, site-specific cost factors etc) and is presented here for an illustrative carbon price of $60/t.

Figure 23 - Indicative Long-run Marginal Costs for plants in MBIE and BEC scenarios (carbon price = $60/t)

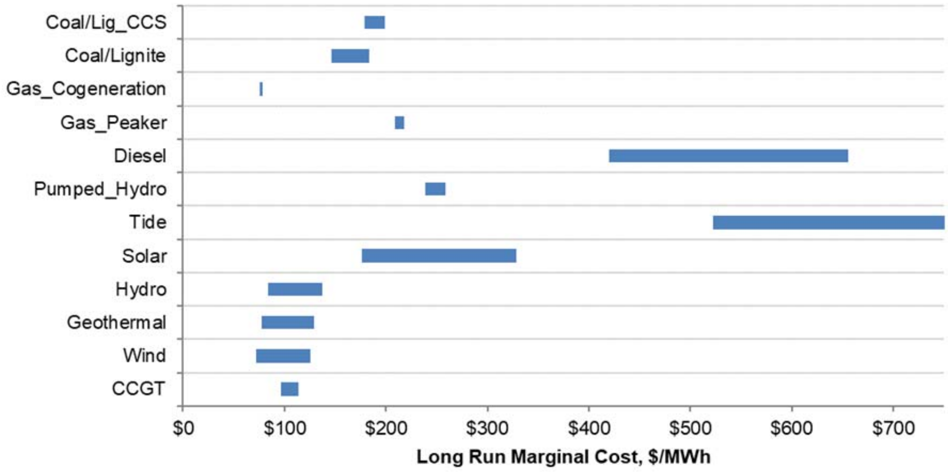
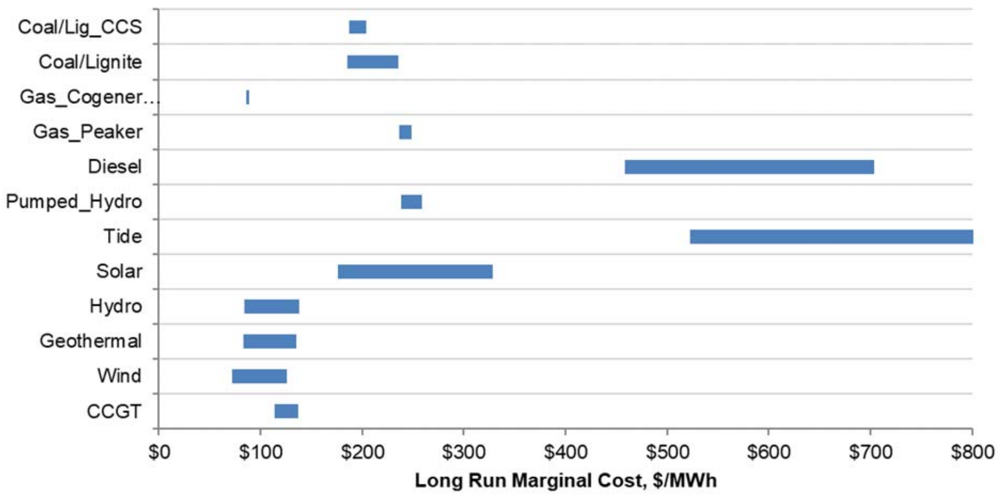


Figure 23 shows that, for a carbon price of $60/t, there are some wind, geothermal and possibly hydro projects that would be built in preference to additional gas plant; but, if these lower cost resources were to be exhausted, a CCGT may become the most economic decision for a participant. We would not expect to see investments in grid-scale solar, tidal or pumped hydro until after the lower cost resources had been exhausted.

To illustrate the sensitivity of the merit order to an increasing carbon price, we show below how the relativity of the lower-cost renewables and CCGTs change with a higher carbon price of $115/t, the 2050 price in BEC's Waka scenario.

Figure 24 – LRMCs at carbon price of $115/t



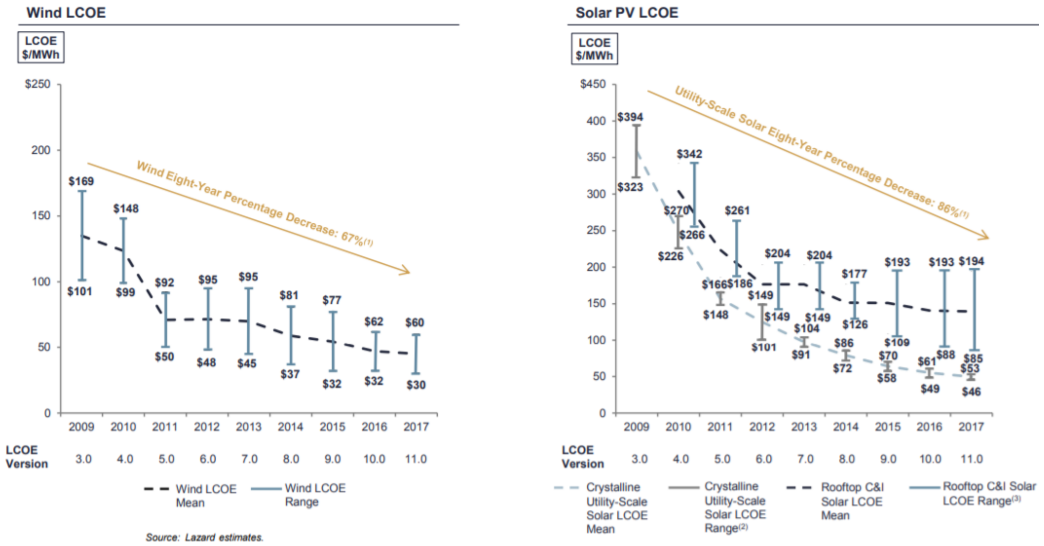
This clearly shows the sensitivity of the merit order to carbon price – the LRMC of a CCGT has increased, making it highly unlikely that it would be preferred – on an LRMC basis alone

– to most wind, hydro and geothermal options. Geothermal has increased as well, but not by nearly as much, due to its lower emissions intensity.

While a LRMC-based merit order is a useful way to compare different potential investments on a single measure, it is not without its flaws:

- In reality, these LRMC estimates do not capture all the factors that go into investor decision making, not least of all risk. While we expand on this in Section 0, investors will be mindful of a range of uncertainties not captured by the ranges above.
- While an individual power station may be the least cost, this does not imply that it should, or will, be the next station built, due to the constraints of resource adequacy. As discussed above, even if wind was consistently the lowest cost technology to be built, at some point a more reliable and flexible generation plant (e.g., a gas peaker) will need to be built in order to maintain resource adequacy even if – on a strict LRMC basis – it appears much more expensive. To some extent, an energy-only wholesale market will signal the need for this more expensive plant, through prices being very high during periods of resource scarcity. Even a station – such as a gas peaker – with a LRMC may be economic, since it will likely only operate during these higher priced periods. Hence it can meet the economic test of achieving a volume-weighted average revenue equal or greater than its LRMC. However, the extent to which investors can be confident of this, in the face of uncertainty about future prices, is debatable, as discussed later.
- On a similar theme, the assumed utilisation (or load factor) is a critical input into investment economics. As utilisation increases, fixed costs (capital and fixed operating and maintenance costs) can be spread across a larger volume, lowering the effective price that has to be earned during operation. The figures in the charts above assume certain utilisations for all plant. A changing mix of generation, towards low emissions sources, my affect the realised utilisation of some plant – moderate or high variable cost plant (CCGT or gas peakers) may get used less frequently, driving up the LRMC. Similarly, overbuilding low SRMC plant (e.g., wind, geothermal and hydro) may lead to periods when one or more of these fuels are "spilled". This leads to a lower load factor than assumed.
- Due to changing costs through time, the merit order is likely to change as underlying costs change. Lazard (2017) reports on the declining costs of wind and solar over the past eight years, suggesting that costs that are even only 3-4 years old may be out of date (Figure 25).

Figure 25 - Lazard's historical cost curves for wind and solar PV (Unsubsidized Levelised Cost of Energy—Wind & Solar PV)



Wind and solar PV have become increasingly cost-competitive with conventional generation technologies, on an unsubsidized basis, in light of material declines in the pricing of system components (e.g., panels, inverters, racking, turbines, etc.), and dramatic improvements in efficiency, among other factors

There are numerous global studies describing the potential future cost reductions in technologies. We illustrate two examples here from media organisation Greentech Media: Figure 26 shows a forecast of falling solar costs, while Figure 27 and Figure 28 are especially relevant to our later discussion – in both the US and Australian context, batteries are eventually forecast to be preferable to gas peakers. We urge caution with the relevance of these conclusions to New Zealand, especially with reference to "system security" in Figure 28. As discussed previously, the ability for batteries, or solar plus storage, to compete with gas for the hydro firming role is far more limited, if not non-existent.

Figure 26 – Greentech Media forecasts of utility-scale solar USD/Wdc

Figure 27 – Greentech Media forecast relativity between open cycle gas turbines and batteries for peaking (source: greentechmedia.com)

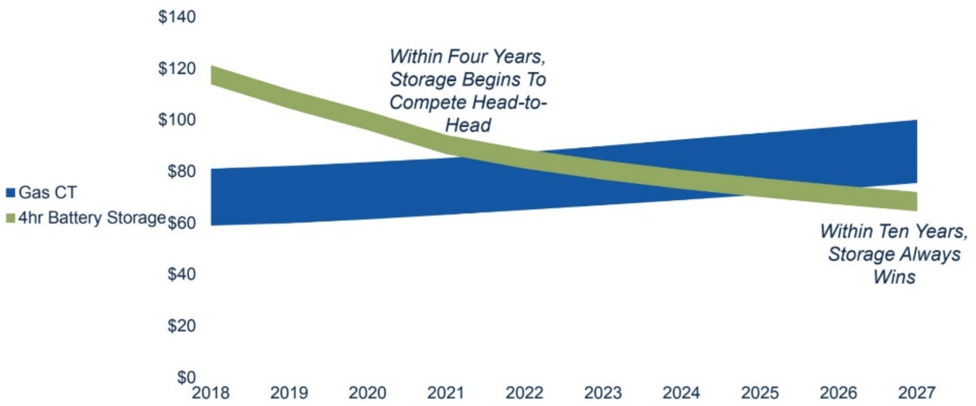
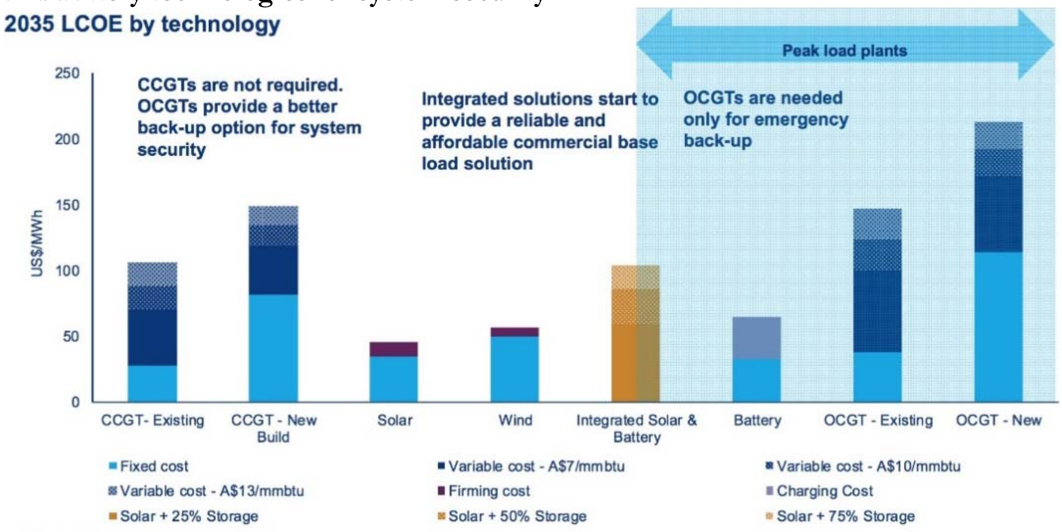


Figure 28 - Wood Mackenzie estimates of gas technologies versus integrated solar and battery technologies for system security

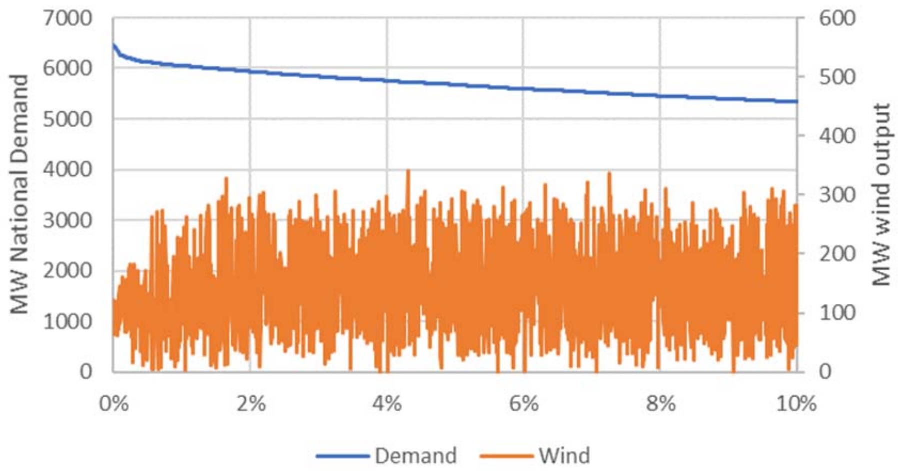


We have not validated these charts for the NZ context; however, they illustrate that the costs of technology are by no means static, and LRMC-based merit orders are a snapshot in time and struggle to represent the full picture, which is very dynamic. Ideally, models using LRMC concepts as a merit order should incorporate forecasts of declining costs, cognisant of the uncertainty inherent in them.

5.2 Low-emissions generation options, flexibility and resource adequacy

Systems with a substantial share of renewables, such as New Zealand, must give consideration to the impact that these types of fuels have on resource adequacy. Wind, run-of-river[45] hydro and solar are examples of generation plant whose fuel at any point in time is largely determined by weather conditions (referred to as "intermittent" generation in New Zealand). Hence, while they make a substantial contribution to meeting total demand over the year, their contribution at any point in time is somewhat uncertain[46]. Wind output in NZ during the top 10% of demand periods is illustrated in Figure 29 below.

Figure 29 - Wind output vs the top 10% of demand periods.



Source: Sapere

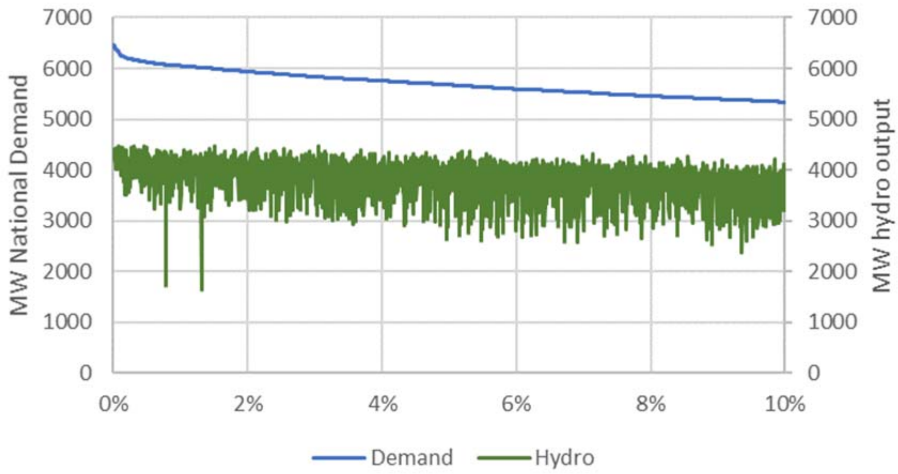
On average, the total quantum of wind generation is relatively reliable over long periods, but is highly volatile from period to period. In this particular example (2016), wind output actually reduces at the very highest demand periods. Given that the aim of system operation is to exactly match generation to demand (shown by the blue line in Figure 30), wind creates a need for another fuel type, or demand response, to offset this variation.

This is in contrast somewhat with hydro plants that are paired with storage reservoirs (referred to as stored hydro). These plants are flexible and responsive (to different degrees) and can reliably operate at different levels over the short-term (days-weeks). Figure 30 shows that the output of all hydro increases as demand increases; its volatility is a combination of the presence of run-of-river schemes, and it is acting (along with thermal) to offset the volatility of wind.

45 Ron-of-river hydro does not have any material storage, and thus its potential generation is largely a function of available flows in the river at every point in time.

46 We acknowledge that weather forecasting gives us some short-term ability to forecast these fuels in advance. But our focus here is on how investment is considered, which is a timeframe beyond weather forecasts.

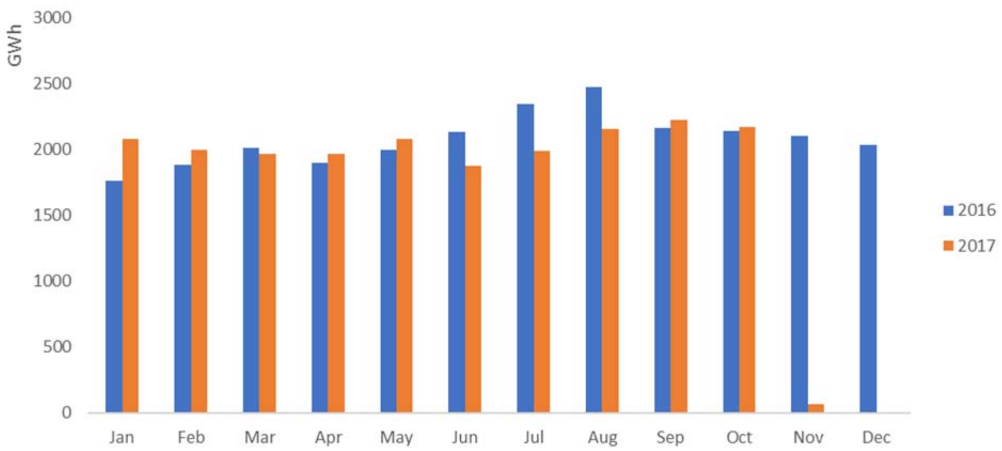
Figure 30 - hydro output during top 10% demand periods of 2016.



Source: Sapere

However, hydro fuel (precipitation and snow melt) is quite volatile over the medium term (months). Given the relatively small size of New Zealand's hydro reservoirs, their ability to "smooth" their production over the year is quite limited. This is shown in the different patterns of hydro production over the year in 2016 (where national inflows were close to average) and 2017 (where there was low inflows between June and August, when demand is high).

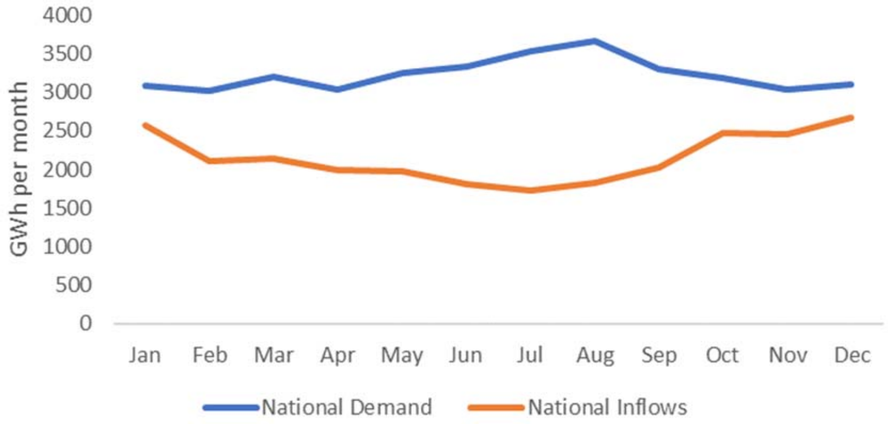
Figure 31 - Monthly national hydro output, 2016 v 2017.



Source: EMI data and Sapere analysis

Even putting aside the prospect of low inflow periods, average national hydro inflows are actually not well correlated with the pattern of demand over the year. The correlation between national inflows and demand is shown in **Figure 32**.

Figure 32 Average National Inflows vs National Electricity Demand.



Source: EMI, Sapere Analysis

Individual inflow years are unlikely to reflect the pattern of "average" inflows, and can be quite volatile from month to month. But hydro owners will make decisions with this general trend in mind. The way the supply side of the market collectively manage this is a combination of:

(a) using hydro reservoirs to "shift" some of the summer inflows to winter.

(b) relying on discretionary (thermal) plant, which may not be used much in summer, to supplement supply in winter (sometimes referred to as hydro firming).

This series suggests that a reservoir storage capacity of approximately 2,000GWh would be sufficient to manage this issue <u>today</u>, i.e. to provide a profile of hydro generation which matched the profile of demand. Since New Zealand has a national storage capacity of approximately 4,000GWh, this appears to be feasible within current storage constraints.

However, reservoir management is substantially more complex than indicated by this analysis.

Firstly, as demand grows through to 2050, insofar as growth replicates the profile in **Figure 32**, the absolute level of shifting required to be done by hydro storage – even in an average generation year, let alone a dry year – increases commensurately. As time progresses, the 4,000GWh of storage capacity may become less effective at managing the annual demand profile, unless the growth in generation comes from flexible sources (e.g., thermal). That is unlikely to be a significant part of a transition to a low-emissions system.

Secondly, inflow patterns invariably never match the average (orange) line in the figure above, and, secondly, reservoir managers do not know the future; hence their storage behaviour prior to winter will be based on a risk-adjusted expectation of the future.

The balance between (a) and (b) - ultimately coordinated through the wholesale price[47] - is (partly) reflective of hydro owner's storage at any point in time, and their expectations about

[47] We note that the market has done this coordination successfully, through some very dry sequences, since the market reforms introduced in 2009.

the near future,[48] particularly with respect to inflows. The degree to which this translates into a need for discretionary plant to increase output is partly determined by the consented limits on lake levels (noting that storage only allows the hydro owner to shift water through time; it does not create any additional energy).

Figure 33 and Figure 34 below illustrates two very different thermal profiles (2016 and 2017), highlighting that, during the dry 2017 year, having thermal "headroom" available to the market played a fundamental role in maintaining resource adequacy.

Figure 33 - 2016 Thermal[49] Production by month

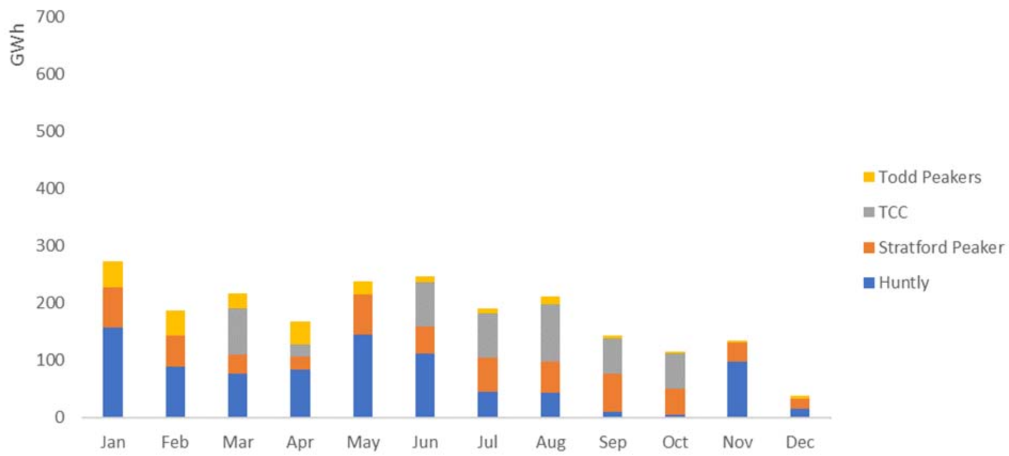
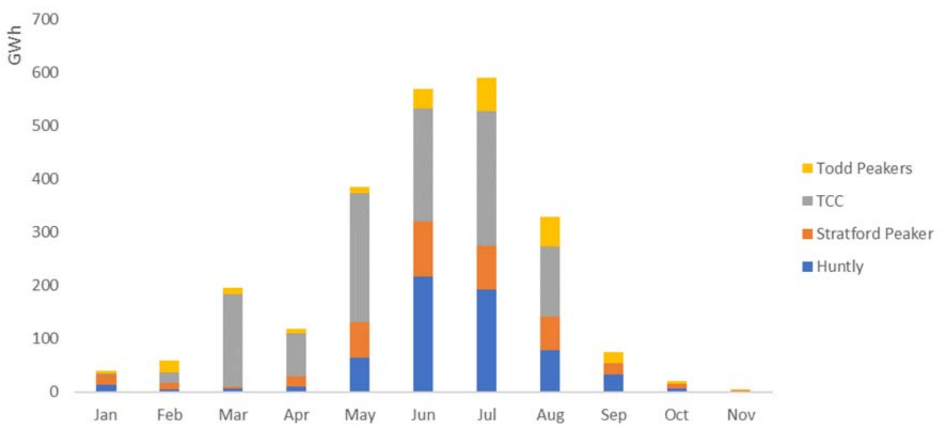


Figure 34 - 2017 Thermal Production by month



In 2016, thermal generation was concentrated earlier in the year, helping the hydro reservoirs store water for the (yet unknown) winter demand and inflows. As inflows turned out to be relatively normal, the conservative storage approach from the hydro operators meant more

48 These expectations are communicated to the market through the hydro owner's "water value", implicitly embedded in their market offer each half hour.

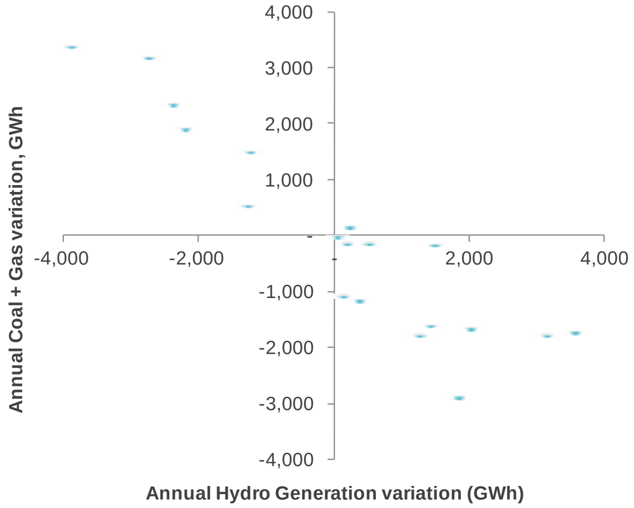
49 Note we have excluded Huntly Unit 5 from this graph, as it runs primarily in a baseload role.

water was available for late winter and spring, and thermal plant was able to back off. 2017 was quite a different story, with very little thermal required in summer (due to high inflows), but then a substantial amount required from May – August due to one of the worst hydro inflow sequences ever observed.

While 2017 is an example of the "dry year" challenge New Zealand faces, the 2016 profile is illustrative of the reservoir operators managing inflow *risk*. Even though a year does not turn out to be a "dry year", reservoir managers still need to take account of the risk that future inflows are low, especially during the high demand winter period. This causes them to operate conservatively until the state of the weather is more certain.

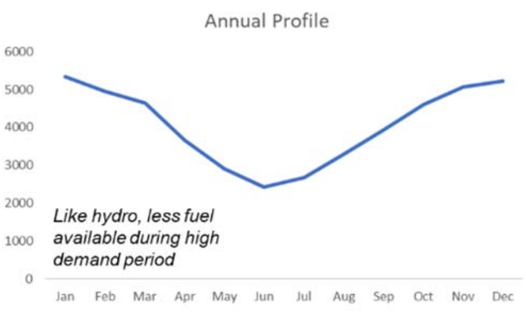
More generally, the relationship between hydro inflows and thermal plant over the last 20 years is shown in **Figure 35**. This illustrates the key role that thermal has played in managing hydro inflow variations over the inter-annual time dimension.

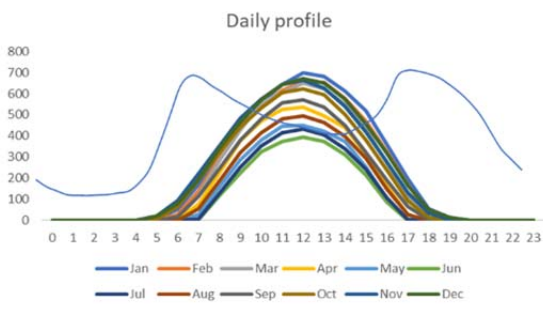
Figure 35 - year-on-year variations in national hydro and thermal generation



Finally, from an energy adequacy perspective, solar generation's energy profile over the year adds to the winter inadequacy issue created by hydro inflows i.e. solar's production is at its lowest during the high-demand winter period. Both the capacity and energy adequacy effects are illustrated in Figure 36.

Figure 36 Annual and daily solar profiles.





Source: NIWA data, Sapere analysis

Summarising this section, the job the overall system has to do is to meet the varying profile of demand over time, while some of the underlying generation fuel is also varying. The discussion above highlights that stored hydro is both a form of generation which can flexibly respond to short-term variations in intermittent generation (and demand), and a source of fuel uncertainty over the medium term.

It follows that the job of flexible plant is not only to meet the changing levels of demand over the year, but also to respond to the short-term variations of intermittent generation, and medium term variations in hydro inflows. Plants that fulfil this role effectively make use of fuel storage – whether it be a coal stockpile, a flexible gas contract, a gas storage facility, a battery, or a hydro reservoir – to shift their output reliably between hours, days, weeks, months and years. We draw attention to the substantial variation in year-to-year output from thermal plant, which is only made possible through having discretionary fuel supplies. Their ability to perform this critical "swing" system role is both enabled by, and constrained by, the storage "capacity" (which includes the flexibility inherent in gas contracts) and the plant characteristics, which determine how quickly it can reliably respond to the need. For example, open-cycle gas turbines will be able to respond much quicker to changing system conditions than combined-cycle gas plant. Some hydro plant will be quicker still. All of these factors need to be carefully and reliably coordinated in order to maintain minute-by-minute system reliability.

No system with varying demand and intermittent generation can escape the need for storage (either of fuel, or of electricity). Some storage is only needed within a day (e.g., from overnight to day-time peak periods), or, as shown above for hydro, some storage is needed to 'move' generation over many months (and years). As the system reduces emissions by reducing thermal plant, it needs to ensure that the new fuel mix has sufficient flexibility to perform the role that thermal currently performs, i.e. responding to changing demand and intermittent generation.

5.2.1 The "normal hydrological year"

The discussion of resource adequacy needs is highly relevant when considering setting emissions or renewable targets that are conditioned by "in a normal hydrological year". Our discussion of the resource adequacy roles (peaking, mid-merit, must run etc) highlighted that:

- Hydro occupies an unusual place in the supply stack: when it has sufficient fuel storage, it can provide a discretionary mid-merit or peaking service.
- Owners are constantly focused on the risk that hydro storage drops to low levels with a sequence of low inflows, and act conservatively.
- Even if inflows followed the "average" (or what might be termed "normal"[50]) path over the year, hydro owners do not know that in advance, and must manage the risk that the pre-winter period is dry by storing conservatively. This is likely to require some firming from thermal fuel, even if sufficient inflows eventuate.

[50] The term "normal", when used to reference the average hydrological year, suggests this inflow pattern or level is common. This is far from the case, and hence we find the term "normal" to be very unhelpful in understanding hydro risk.

- In reality, a year can receive average inflows in total over the year, but this can be characterised by a dry summer/autumn, and a wet spring. Such a pattern almost certainly will require hydro firming leading up to winter.

Hence it is difficult to delineate between thermal firming that is required to complement hydro because of a dry year, from that which is required to perform a mid-merit role – in an average hydrological year – because of the necessary conservatism in hydro.

If renewable targets were set to be measured "in an average hydrological year", we believe it would be very difficult to assess – in anything by a pure abstract or modelled sense – what the expected pattern of generation would be.

5.3 Using scenarios to explore cost-emissions-adequacy trade-offs

In the absence of a resource adequacy constraint, we might expect market participants to invest strictly according to the least-cost merit order – which, for modest levels of the carbon price, favours wind and geothermal. But, even if it is the lowest-cost investment on average, the intermittency of wind, and their combined inability to respond to varying demand, will lead to periods of high and low wholesale electricity prices, reflecting underlying scarcity (and possibly shortage) and surplus (spill) respectively. This will incentivise investors to develop flexible generation which, on a simple merit order basis, may seem "uneconomic", but will be able to specifically target high price periods and thus achieve an average production-based price which delivers a sufficient return. This is how we have generally observed investment occurring under the current market structure.

Hence determining the potential mixes of generation investment, under different carbon price levels, requires us to model this tension between the investment costs and resource adequacy.

5.3.1 Scenarios

Rather than create new scenarios, or complicate our assessment with an alternative modelling framework, we have drawn on the bountiful electricity system scenario work that New Zealand now enjoys. Specifically, we make use of:

- the Business NZ Energy Council's (BEC's) "Kayak" and "Waka" energy system scenarios to 2050[51]
- MBIE's "Electricity Demand and Generation Scenarios" (EDGS)[52]
- Vivid's "Net Zero in New Zealand" scenarios to 2050[53]

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51 http://www.bec.org.nz/projects/bec2050

52 http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-demand-and-generation-scenarios/edgs-2016

53 http://www.vivideconomics.com/publications/net-zero-in-new-zealand

We note that not all of the scenarios we scrutinised had an underlying motivation to reduce emissions, but all incorporated a carbon price, and hence are relevant to our study here. And these differing objectives give us a diversity of assumptions and views about the future, which, given the uncertainty we face, makes a collective assessment more robust. Below, as much as possible with the information to hand, we tie these diverse views back to the cost and emissions outcomes observed in each. We then ensure, irrespective of emissions and cost, any investment path must satisfy the WEM and WCM in their current form[54], thus giving some level of assurance that resource adequacy is accounted for on a consistent basis.

That being said the diversity of modelling approaches and assumptions creates some complications for our analysis. Specifically, we note at the outset:

- **Costs:** We carefully consider how the total cost of each scenario is determined, in order to make reasonable comparisons. MBIE and BEC share the same underlying capital and operating cost data for generation, which is publicly available. We do not have the cost basis for Vivid's scenarios.
- **Demand**: The scenarios differed significantly in their assumed demand growth, ranging from 0.8% Compounding Annual Growth Rate to over 2% CAGR (as discussed below). The issue of growth is a genuine uncertainty; and we do not want to normalise for growth, and thus obscure the fact that future costs and emissions are very much dependent on the underlying growth in demand.
- **Technological evolution**: Changes in technology (e.g., assumptions about changes in demand response, storage, solar PV, hydrogen, biofuels, and the future emissions intensity of technologies) were often determined exogenously to the models; and, again, a reasonable diversity of views is established which we believe is appropriate.
- **Emissions**: For most forms of generation, emissions calculations can be made directly using IPCC factors, based on fuel usage (or generation output, assuming an appropriate heat rate). Geothermal is an exception. The impact of geothermal investment on emissions is an open question. While the current fleet of geothermal plants emit, on average, 115t CO2-e/GWh, the individual plant rate varies between 32t CO2-e/GWh (Wairakei) and 597t CO2-e/GWh (Ngawha), as illustrated in Figure 37[55]. The emissions for any given plant are a result of both the technology, and the field chemistry[56]. Figure 37 highlights that it is possible to have a geothermal field (such as Ngawha) that has a

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54 We note that the levels inherent in the standards may change in the future, but find it hard to contemplate a future where some surplus capacity, and surplus energy (for hydro), won't be required in a similar form as at present.

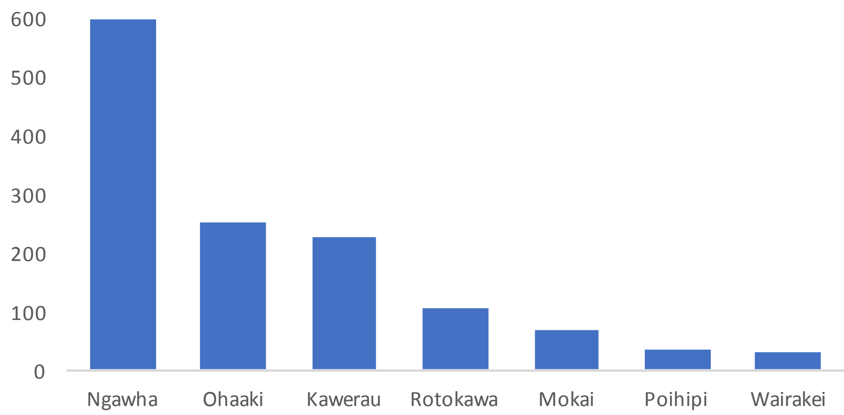
55 Retrieved from http://nzgeothermal.org.nz/emissions/

56 All geothermal fluids contain non-condensable Greenhouse Gases (GHGs), mainly CO_2. Any generation process that releases the dry steam from a geothermal fluid will also release these non-condensable gases. While all geothermal fields contain GHGs, the chemistry of each field, and the proportion of GHGs, varies significantly. Efficiency is currently the key criteria for the choice of technology for geothermal turbines. Binary units (which use a second fluid in a heat exchanger) are efficient at low enthalpy (energy per tonne of steam) and can reinject nearly all extracted fluids back into the field (including the GHGs). Double or triple flash plants are more efficient for high enthalpy fluids but the 'flashing' off of the dry stream from the 'wet' fluids also releases the GHGs. Hybrid plants are often used for moderate enthalpy fields, but again the 'flashing' stage releases GHGs. It is feasible to use heat exchangers at higher enthalpy but this comes with significant efficiency loss using current technology.

higher emissions intensity than a low-efficiency gas plant[57]. However, 6 out of the 7 current fields have emissions intensities substantially lower than even a high efficiency gas plant, and the volume-weighted average across all fields is approximately a quarter of that of gas.

The MBIE and BEC scenarios reported geothermal emissions, and assumed a continuation of the current average emissions intensity of 115t CO2-e/GWh. Vivid, however, did not publish fugitive geothermal emissions, but subsequently provided them to us on request. For Off Track, they reported 1.6Mt (an emissions intensity of 93t CO2-e/GWh). For Vivid's Innovative scenario they assumed that the intensity will reduce by ~40% over the next 35 years[58], reaching 70t CO2-e/GWh in 2050.

Figure 37 Emissions intensity (t CO2-e per GWh) of existing geothermal plant



Notwithstanding these differences, the purpose of using the different scenarios here is to understand the trade-off between cost and emissions (for a given level of adequacy), rather than to critique any individual set of assumptions. Hence, as long as costs and emissions calculations are made consistently throughout the scenarios, we can obtain some strong insights into the prospects for a low emissions electricity sector.

5.3.2 Scenario Summary

BEC Kayak and Waka scenarios

Kayak and Waka are energy sector scenarios, and hence explicitly consider the interactions between electricity, transport, and process heat. For example, the electric vehicle uptake

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57 For example, we estimate the emissions of gas generation from the Huntly Rankine units at around 530t per GWh

58 *"We have made a conservative assumption that no significant mitigation of fugitive emissions occurs in the Off Track New Zealand and Resourceful New Zealand scenarios. In the Innovative New Zealand scenario, we assume the emissions intensity of electricity generation from geothermal reduces by 1.4 per cent per annum, in line with international literature on the potential for fugitive reduction (ClimateWorks Australia 2014)."* Vivid (2017), "Net Zero in New Zealand – Technical report". We could not find any reference to declining geothermal emissions intensity in the ClimateWorks publications.

calculated in the transport sector interacts directly with the cost of building the generation capacity to meet that uptake.

The underlying BEC model is a perfect foresight, cost minimisation model. The Kayak scenario reflects a world of high population and economic growth, but relatively low carbon prices, while the Waka scenario reflects more binding international obligations around carbon and thus a higher carbon price trajectory. Waka assumed lower population and economic growth.

The BEC model was unique (amongst the scenarios we tested) in that it allowed hydrogen, biofuels, and carbon capture and storage to emerge as generation options in the future. On the upstream side, LNG importation also appeared in the Kayak scenario.

MBIE's Mixed Renewables and Disruptive scenarios

MBIE produces 5 EDGS scenarios. We only assessed two in detail[59]:

(a) Mixed Renewables (MR), as it is a reasonable reflection of a "business as usual" scenario.

(b) Disruptive, as it represents a higher carbon price trajectory[60], and a more aggressive assumption set regarding the uptake of solar, batteries and electric vehicles.

MBIE's model is also a perfect foresight, cost minimisation model. It also analyses adequacy in more detail than other scenarios: rather than simply matching to an annual demand figure, it disaggregates demand into a seasonal, 7-piece approximation of the LDC, which is a more detailed representation of the shape of demand over the year. MBIE's scenario also appears to be alone in explicitly considering demand response (presumably at peak) as a future choice for the model. Like BEC's model, MBIE's model considered carbon capture and storage (CCS) as a technology, although none of the scenarios chose this.

MBIE's underlying model for the EDGS scenarios also captures aspects of the dry-year resource adequacy requirements. When making generation investment decisions, it allows for a 20% probability that a dry year occurs (and a commensurate 80% weighting on normal hydro years). While this does not guarantee resource adequacy in a dry year (as the least cost solution may be to allow shortage to occur in these years), at a second stage the model is run separately and exclusively for a dry year and peakers are constructed for any shortfall[61]. MBIE only allow peakers to be constructed for this purpose.

59 That said, MBIE's other scenarios are worthy of consideration. "High Grid" gives an assessment of high demand growth but also a low carbon price, which is useful as a counterfactual. The Global Low Carbon scenario has a higher carbon price trajectory than Disruptive, but further emissions reductions were constrained due to very conservative assumptions about commissioning of new renewable plant. "Tiwai Off" tested the market outcomes following an exit of NZAS smelter at Tiwai Point.

60 Although we note that "Tiwai off" achieved lower emissions, principally as a result of having 20% lower demand.

61 Inherently this reflects a plausible trade-off and identifies the agency problem: market participants, when making investment decisions, will allow for some probability of a dry year, but won't scale or time their

Which generation options are executed in any scenario is limited by the number of projects allowed for in MBIE's modelling. While hydro may be an attractive option, MBIE's options list suggests that there are only 7,700 GWh of hydro options available, compared to 11,000 GWh of geothermal and over 16,000GWh of wind. Given our scenarios require sufficient generation to be built to meet a demand growth of between 20,000 GWh and 45,000 GWh, plus the decommissioning of up to 3,200 GWh of thermal plant, we acknowledge BEC's contention that in higher growth scenarios, the model will more quickly move up the "merit order" of investment options, and fossil fuels – even with a modest carbon price – may remain competitive.

Vivid's Off Track and Innovative scenarios

Vivid's scenarios are the broadest (in terms of their consideration of all emissions sources) considering land use, agriculture and the energy sector. We use two scenarios:

- **Off Track:** Energy sector emissions reductions driven by "current technology", and carbon prices less than $100/t, but with a much higher demand growth trajectory than MBIE or BEC's scenarios, including an additional 5TWh of electrification of low-grade and medium-grade heat.
- **Innovative:** It is not clear whether any underlying technology assumptions are different in this scenario. But the major difference to Off Track is a more aggressive electrification of the process heat sector (19TWh, now including an increase in high grade heat), which results in a more than doubling of electricity demand in 2050 compared to today. Despite the higher demand, greater emissions reductions are achieved through >$100/t carbon prices.

We understand that Vivid's projections weren't created through the use of their own coherent modelling approach, but by selecting from a range of credible sources (such as BEC and MBIE).

While they specifically excluded CCS, Vivid make reference to other aspects of their scenarios – energy efficiency, demand response, pumped storage and batteries – without quantifying the role that they play. Also, they only provide annual energy figures for each of the fuel types, and do not provide capacities. This makes a genuine costing of their scenarios very difficult, and prevents us from applying the WCM or WEM metrics. As a result, we are not able to extract the insights from the Vivid scenarios to the same extent as the BEC and MBIE work, but will use the Vivid assumptions and results as counterpoints to other scenario work.

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investment as though they were individually and fully responsible for dry year adequacy. The "re-optimise" run, assuming a 100% probability of a dry year, then takes the role of the WEM standard. If the market investment seems insufficient to cope with a dry year, some process (either regulatory or market based) would eventually be needed to contract flexible generation. The Huntly Rankine contracting between Meridian and Genesis could be seen as a loose example of the "re-opt" run occurring in the real world.

5.3.3 Modelling frameworks

While there is a rich literature around how best to model how these decisions might play out over multiple decades, it is important to understand the underlying modelling framework of the scenarios we are drawing on for this paper:[62]

- the basic premise of the scenarios is that industry participants, driven by profit motives, will choose the lowest cost generation investments to meet demand. In a modelling sense this is applied by effectively assuming that decisions are made centrally in a coordinated manner[63], as if by a cost-minimising social planner; thus future supply-side investment decisions are targeted at meeting demand in the future at least cost.
- only MBIE's modelling incorporated uncertainty, albeit limited to the prospect of a dry year (with a 20% probability assumed for investment timing). Putting hydro aside, all scenarios assume that the investment decision in each year is made with perfect foresight over future demand and costs (including carbon). Since uncertainty is a critical element in investment decisions, this assumption may bias the models away from how investors may think. Later, we assess the implications of this bias.
- investment decisions are made to meet at least forecast annual demand, and some measure of capacity adequacy. MBIE's model also ensures the system can meet an approximated load duration curve, and hence provides an insight into the role of flexible plant.

5.3.4 Comparison of Scenarios in 2050

As discussed above, it is not our purpose to critique any of the individual assumptions made by the scenarios' respective authors, but rather to leverage their diversity to obtain some insights about the cost-emissions trade-off (assuming resource adequacy is maintained).

Table 1 summarises the key scenario characteristics.

[62] In terms of modelling of the future, only MBIE and BEC (as far as we are aware) published the methodology by which they arrived at an "optimal" system (in both cases a linear cost minimisation model, including a carbon price). We believe that Vivid based their generation and demand figures on available research (in some cases, MBIE and BEC's scenarios), but the manner in which it was globally optimised is not clear.

[63] There is a significant literature on the introduction of strategic behaviour to these models, to avoid the assumption that decisions are made centrally.

Table 1 - Summary of key scenario characteristics in 2050

	Current	Projected outcome in 2050					
		BEC Kayak	Vivid Off Track	MBIE Mixed Renewable	MBIE Disruptive	BEC Waka	Vivid Innovative
Emissions (Mt)	5.0 (2015)	6.0	4.9	4.8	4.1	2.2	1.9
Emissions Intensity (t/MWh)	.09	.08	.07	.08	.07	.04	.02
Carbon Price (NZD/t)	$18	$60	<$100	$83	$155	$115	>$100
Renewable %	85%	85%	91%	88%	91%	98%	98%
Demand[64] (TWh)	42	72.3	76.2	61.1	64.9	59.9	89.4
EV Penetration of LDVs		5%	85%	N/A[65]	N/A	47%	95%
Consumption Transport (GWh)	~	2,500	9,258	1,347	4,566	4,700	10,630
Hydro (TWh)	25.7	27.7	29.1	26.9	28.9	29.7	29.1
Geothermal (TWh)	7.4	15.3	17.1	15.1	13.9	13.9	17.6
Wind (TWh)	2.3	13.6	20.2	10.0	12.8	12.8	36.5
Solar (TWh)	0.05	4.4	2.0	0.9	2.5	1.7	3.6
Thermal (TWh)	6.4	11.2	6.9	7.3	6.0	1.0	1.8

64 Some scenarios reported total generation figures, and others generation and consumption figures. The difference is transmission and distribution losses. We report total generation figures here, as they were the most consistently available amongst all the scenarios

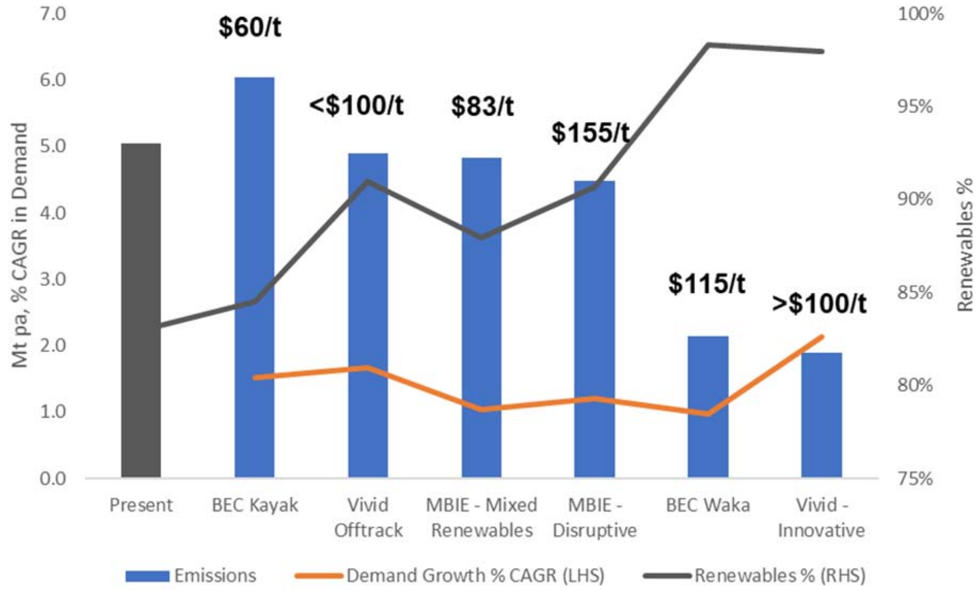
65 MBIE report that both the Mixed Renewables and Disruptive scenarios have "Transport" consumption in 2050 of around 1,300GWh but are not explicit about their assumptions regarding EV penetration. Based on BEC figures for the light fleet, this would be around 25% penetration. But MBIE's assumptions regarding the share between light-duty EVs and heavier transport (e.g., buses, rail and trucks) would be critical to the energy consumption figure. For example, BEC's Kayak scenario has transport consumption of 2,700GWh, of which 85% is rail and buses.

5.4 Carbon price and emissions

5.4.1 Scenario outputs

As discussed above, the scenarios provide a range of emissions outcomes in 2050. We would expect key drivers of this to include the carbon price and demand growth. Figure 38 illustrates these three variables across the scenarios – carbon price in 2050, emissions, and demand growth. Generally there is a decreasing relationship between the 2050 carbon price and emissions - the higher carbon prices (over $100/t) achieved greater emissions reductions than the lower carbon prices - but this is not strictly the case. We also note that the figure only presents the carbon price in 2050. Given the long life of the assets involved the profile of the carbon price between now and 2050 is relevant. We explore this issue further below.

Figure 38 – Electricity sector emissions, renewable %, carbon prices and growth in 2050

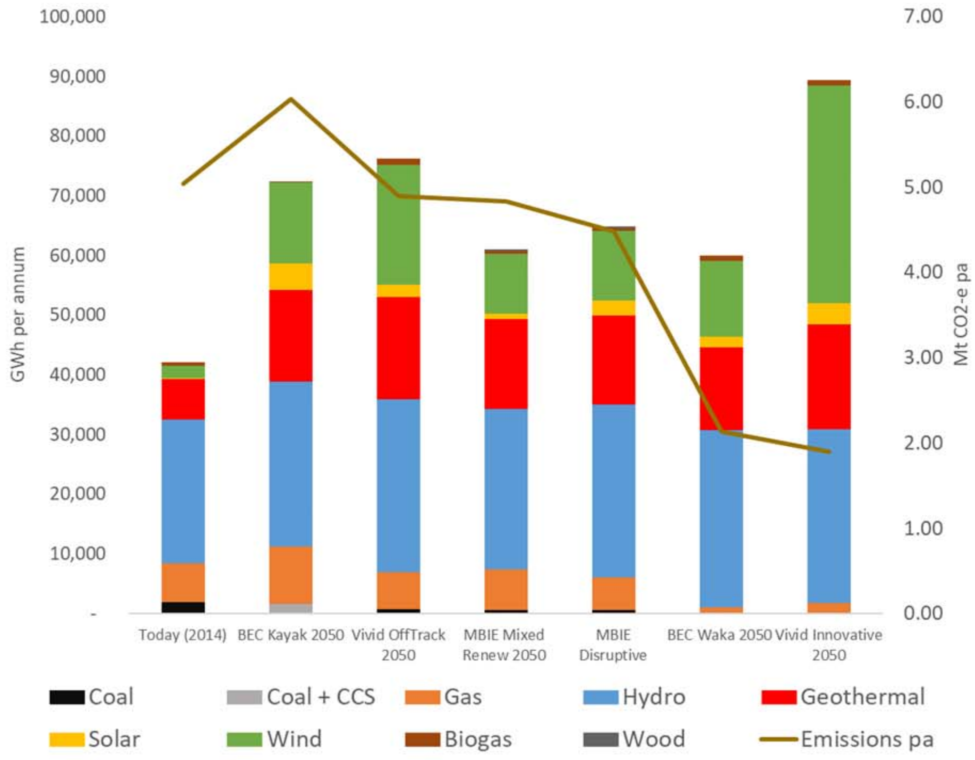


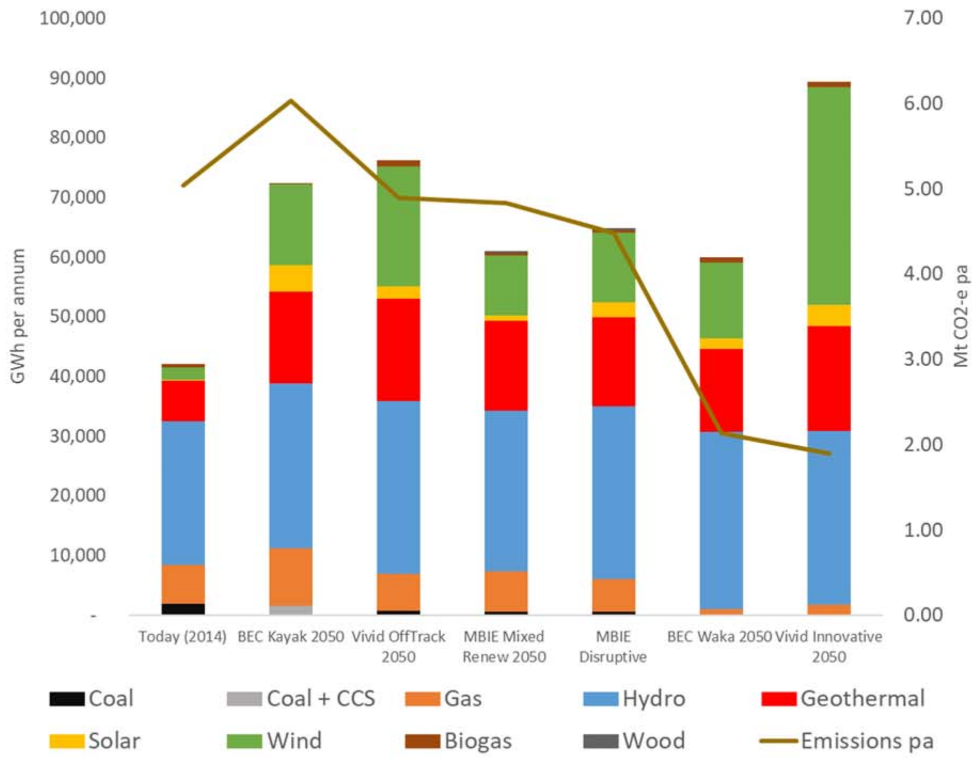
The relationship between renewables and emissions shown across the scenarios is not perfect, due to the fact that:

- some scenarios had to meet higher demand; even though the proportion of low-emissions generation was higher, total emissions were greater
- for a given proportion of renewables, scenarios that have a higher penetration of geothermal have higher emissions.

Against that backdrop, Figure 39 shows the generation mix for all scenarios, which gives an initial sense of how each scenario achieved its emissions outcomes.

Figure 39 - Breakdown of total generation by fuel and emissions, 2050





Before considering the scenarios in detail, we consider several general points about the scenarios.

Thermal Decommissioning

Ultimately, emissions reductions will come from retiring existing thermal plant. We observe that electricity sector emissions today come from the following primary sources:

(a) Fossil fuel cogeneration (associated with an industrial process)

(b) Coal/gas generation from the Huntly Rankine station (HLYR)

(c) Gas generation from combined-cycle gas plant at Huntly (HLY5) and Taranaki (TCC)

(d) Gas generation from flexible peaking turbines in Taranaki and Huntly

The scenarios effectively differ in their assumed retirement of the plants in (c) above – all six scenarios assume that the Huntly Rankines are retired sometime in the next 15 years. The Rankine decision is not a model decision, but a forced assumption.

Beyond this, decisions about retirement of thermal are a mixture of end of life assumptions and refurbishment decision points. Table 2 summarises the scenarios' different approaches to the future life of existing thermal plant.

Table 2 Assumptions about life of existing thermal plant

Scenario	Refurbishment decision point	Thermal Plant Retired	Existing plant still operating in 2050
MBIE MR	TCC (2025) HLY5 (2033)	HLY R (2025, forced)	TCC HLY5
MBIE Disruptive	TCC (2025) HLY5 (2033)	HLY R (2025, forced) TCC (2035, end of life)	HLY5
BEC Kayak and Waka		HLY R (in the 2020s, forced) TCC (early 2030s, end of life) HLY5[66] (early 2030s, end of life)	None of the existing plant, but Kayak builds replacement/new CCGTs

All of MBIE's refurbishment decisions are based on an assumed cost of $505/kW, or $200m for a 400MW CCGT[67]. This is a substantial investment, implying a very extensive

66 We note that BEC Waka also appears to decommission coal cogeneration plant

67 We presume this is a very extensive refurbishment, or a present value figure of a series of more modest refurbishment. By way of comparison, Contact's 2017 refurbishment of TCC was expected to cost ~$50m (~$135/kW), and the firm suggested that it would extend the life of the plant by around 5-6 years. See comments by Contact CEO Dennis Barnes at http://www.energynews.co.nz/news-story/electricity-generation/34267/close-call-tcc-refurbishment-contact

refurbishment, but is less than half the capital cost of a new plant. But the economics of refurbishment are a function of both the cost, and the degree of life extension achieved. While we consider the refurbishment versus retirement decision in more detail below, we observe that MBIE's assumption effectively implies that a $200m refurbishment of HLY5 in 2033 is sufficiently extensive to extend the life of the plant until (at least) 2050 (17 years). In Mixed Renewables, Contact's election to refurbish TCC in 2025 ($185m) extends plant life by 25 years. We suspect both assumptions about the life extension of refurbishment are ambitious; Disruptive's assumption that TCC elects to retire in 2035, 10 years after refurbishment, is possibly closer to the truth.

The impact of these assumptions on resulting emissions is discussed further below.

Resource Adequacy

All BEC and MBIE scenarios[68] meet the industry capacity and energy adequacy tests (WCM and WEM) in 2050. We note that the low-emissions BEC Waka scenario relies on a fleet of peaking plant which, in a normal hydrological year, would only be operating at ~15% load factor but operating at much higher output for an extended period in a dry year . As discussed later, this presumes that the available gas supply arrangements in New Zealand permits this regime[69].

Only MBIE's modelling assesses resource adequacy across the LDC (in a normal hydrological year), and thus MBIE's scenarios are the only ones which create a realistic requirement[70] for mid-merit plant. Hence we can only be sure that the MR and GLC plant mix reflect a minimum-cost delivery of overall resource adequacy. This does not necessarily mean that the other scenarios are not resource adequate. They will have sufficient spare *capacity* to perform the "energy shifting" role but doing so may result in higher output (and thus emissions) from these units than reported by those scenarios[71]. However, we are not greatly concerned by these errors in 2050; there is a strong likelihood that more of this peak shifting role will be performed by electricity storage devices (e.g., batteries) rather than gas peakers.

Hydro

There are some modest investments in hydro in all scenarios. These investments add 400MW-800MW of firm peaking capability to the system however none of the scenarios

68 Unfortunately, Vivid's scenarios only quoted annual energy production figures, and did not supplement this with capacity information. Only capacity information allows us to estimate the degree of compliance with the WEM and WCM standards

69 Contact's Ahuroa storage facility may have sufficient storage to support this, but Ahuroa may also be used to support mid-merit operation. And, if not Ahuroa, this presumes that the availability of spot gas allows a 4-5 fold increase in gas output in the occasional dry year, or that the gas can be purchased off an industrial gas consumer.

70 Acknowledging that MBIE only approximates the true LDC, as discussed earlier.

71 While MBIE's scenarios solve the supply-demand balance across different segments of the year, the BEC scenarios determine output from thermal stations by deducting expected annual renewable output from electricity demand. At higher renewable penetrations, there may be periods of the year where total renewable output exceeds demand, and thus wind or water is spilled. Thus the renewable energy available to the system is actually lower than assumed, and thus the required thermal is higher than assumed.

reveal the storage capability of these investments. Hence we cannot judge their contribution to energy adequacy (as measured by WEM).

Solar

All scenarios see a substantial increase in solar generation capacity (to at least 600MW, compared to the current capacity of 62MW[72]) although – except perhaps in the case of BEC's Kayak – it makes only a very minor contribution to energy production, due to its low load factor (15-20%). Further, solar would not provide any capacity adequacy (insofar as New Zealand remains a winter peaking system) due to peak demand in New Zealand occurring during winter nights. Finally, the large installed capacity of solar reinforces the need for flexible, responsive capacity in the system, as the hour-to-hour swings in solar output at this level of penetration would be significant. However, when paired with batteries, the capacity adequacy and intermittency issues could be improved (depending on the available solar energy from the daytime that could be stored until night)[73].
We now consider the three categories of emissions outcomes outlined above.

To understand the influence that the carbon price is having on investment decisions, and the resulting cost, we categorise the scenarios and explore the trade-offs as follows:

- maintaining current emissions levels or increasing them (BEC Kayak, Vivid OffTrack and MBIE MR)
- reductions in emissions (MBIE Disruptive, Vivid Innovative, BEC Waka)

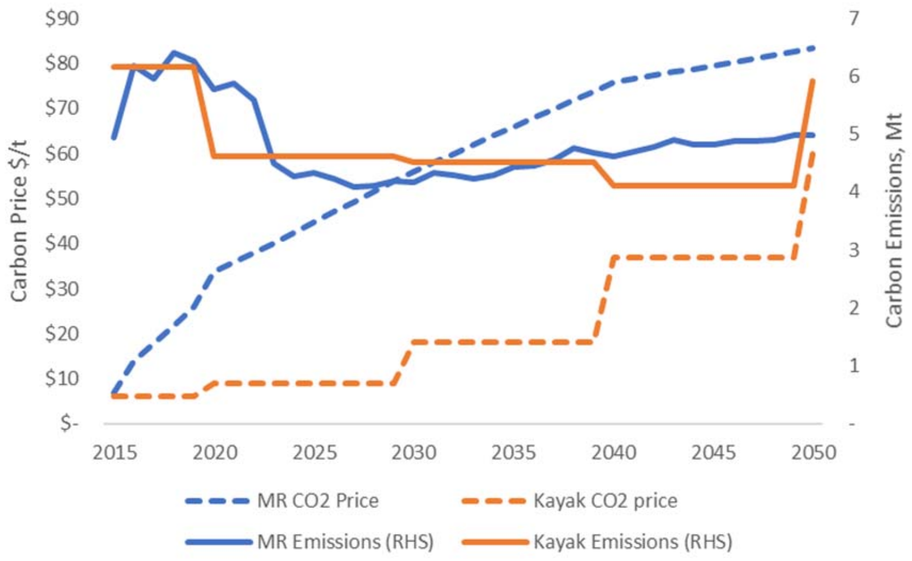
5.4.2 Scenarios that maintain similar or increased emissions compared to today

MBIE's MR scenario principally met its 18,000 GWh growth through a mixture of geothermal and wind, with low load-factor gas peakers meeting capacity and energy adequacy requirements. But both Vivid's Off Track and BEC's Kayak scenarios had much higher growth factors which were met in different ways.

72 Source: emi.govt.nz, Installed Distributed Generation Trends, as at 31 October 2017.

73 We note that MBIE modelled both residential solar *paired* with batteries and solar without batteries in its EDGS scenarios. We are unsure of the resulting penetration of battery-based systems, which would inform an analysis of the resulting demand profile. But the battery issue goes beyond just residential solar systems, and larger scale batteries may be installed at distribution and grid level by a range of market participants to manage peak loadings on the network as well as generation dispatch issues, as discussed above.

Figure 40 - Carbon prices and emissions in MBIE's Mixed Renewables and BEC's Kayak scenarios



BEC's Kayak scenario met its 30,000 GWh growth through a diverse mixture of geothermal, wind, baseload (or mid-merit) CCGT and solar. BEC's Kayak scenario was the only scenario to expand the current fleet of CCGTs, which we expect was a result of the lower carbon price trajectory (Figure 40). We also note that the Kayak scenario contains the greatest uptake of solar of all the scenarios[74] (see Table 1 above), adding 3,400MW of capacity to the system (17% of total capacity in 2050, making it the third largest contributor behind wind and hydro). But, for the reasons proffered above, this does not add much to the resource adequacy of the system.

We note that, in 2040, demand in Kayak had reached 61,000 GWh, almost exactly the same level of demand MR reached 10 years later. At this point, Kayak had reduced emissions to 4.1Mt, a deeper reduction than MR, and at a carbon price (at the time) of only $37/t. It seems remarkable that Kayak reaches an emissions level close to that of Disruptive – with its much higher carbon price trajectory. It is only after 2040, as Kayak's demand continues to grow higher than that of the MBIE scenarios that it reverts back to a substantial investment in gas (combined with 400MW of coal with carbon capture and storage, the only scenario to do this). Hence the takeaway of the BEC scenario is that higher demand growth may trigger investment in thermal plant if demand growth outstrips investors' ability to build relatively low-cost renewables, in a moderate carbon price environment.

However, Vivid's Off Track scenario offers a counterpoint: meeting its 35,000GWh growth through renewables alone (principally wind, but with hydro and geothermal as well). While

[74] BEC's Kayak scenario is, as discussed above, the "market-led" scenario and contains no subsidies for solar. BEC's scenario commentary suggests that it was the higher growth of its Kayak scenario which drove the solar. Hence it is somewhat surprising that it had substantially more solar uptake than Vivid's Off Track scenario which had both substantially higher carbon prices and growth than Kayak, and appear somewhat pessimistic on the potential for solar.

Vivid reports that this could be achieved with a carbon price of <$100/t. Unfortunately, we do not know where Vivid's trajectory lies relative to Kayak or MR; we believe, given Kayak's conclusion of high demand triggering thermal, and Vivid's even higher growth assumption, that it would lie above those displayed in Figure 40.

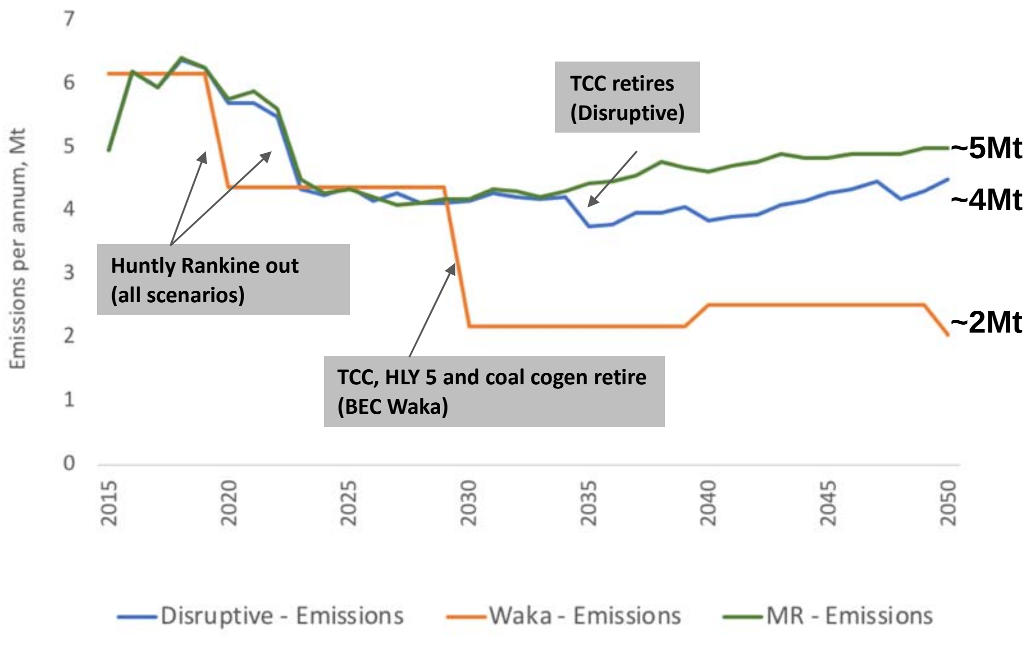
In summary, these three scenarios appear to show that, for national demand levels up to 60,000GWh (growth of around 1% CAGR, including the effect of electric vehicles), sub-$100/t carbon prices may be sufficient to constrain emissions in the energy sector at their current levels, and possibly even reduce them. At demand growths that exceed that, BEC's Kayak scenario suggests natural gas will continue to feature in the investment mix at its relatively low carbon price trajectory. These scenarios highlight the trade-off between assumptions about (i) low-emissions resource availability, (ii) demand growth and (iii) the carbon price trajectory, underscoring that – given the uncertainty about all three factors out to 2050 – more precise conclusions about the necessary carbon price could be misleading.

5.4.3 Scenarios that reduce emissions

The scenarios above present future generation mixes that are not significantly different from today's, and hence are unlikely to uncover substantially different ways to manage resource adequacy. MBIE's Disruptive, BEC Waka and Vivid's Innovative scenarios, however, all reduce emissions compared to today, and hence present us with a system in 2050 which reduces the role that thermal generation plays in the system.

The resulting emissions trajectories of the MBIE and BEC scenarios are illustrated in Figure 41.

Figure 41 - Emissions trajectories in MBIE Disruptive and BEC Waka



The different thermal retirement decisions highlight a key uncertainty – the triggers for retiring existing plant:

- In the BEC scenarios, existing CCGT plant is assumed to reach the end of their economic life after 30 years, at which time the only way to maintain this thermal capacity is through a replacement new build.
- In the MBIE scenarios, as discussed above, both TCC and HLY5 are given a $505/kW refurbishment option at 2025 and 2033 respectively. In MR, the model finds it economic to refurbish both these plants (rather than replace with low-emissions alternatives), and they are assumed to operate until the end of the modelling horizon. In the Disruptive scenario, both are also refurbished at those dates, but the model elects to retire TCC in 2035[75].

Refurbishment versus retirement is a decision investors face. Refurbishment is certainly lower capital cost than constructing a new plant from scratch, but is unlikely to provide anywhere near the future life of a new plant. We suspect MBIE's assumptions about refurbishment is optimistic, and therefore makes this option look more economically attractive than an investor would perceive in reality[76]. And, ultimately, the life of a plant cannot be extended indefinitely. The decision to refurbish or retire is thus a complex one, comprising:

(i) The cost of the refurbishment
(ii) The expected carbon price
(iii) The availability of appropriate gas contracts (flexibility and price)
(iv) The condition of the plant, and the life extension that refurbishment provides
(v) The availability of other investment options in the owner's portfolio

The combination of these factors can lead to quite different decision outcomes. To illustrate, in 2017, Contact Energy elected to undertake a refurbishment of TCC, costing $50m, which it stated extended the life of the 20 year old plant by 5-6 years[77]. Two years earlier, Mercury and Contact Energy elected to retire their respective CCGTs, which were of similar age to TCC.

In Figure 42 we illustrate the role the carbon price plays in the refurbishment/retirement decisions in MBIE's Disruptive and BEC Waka.

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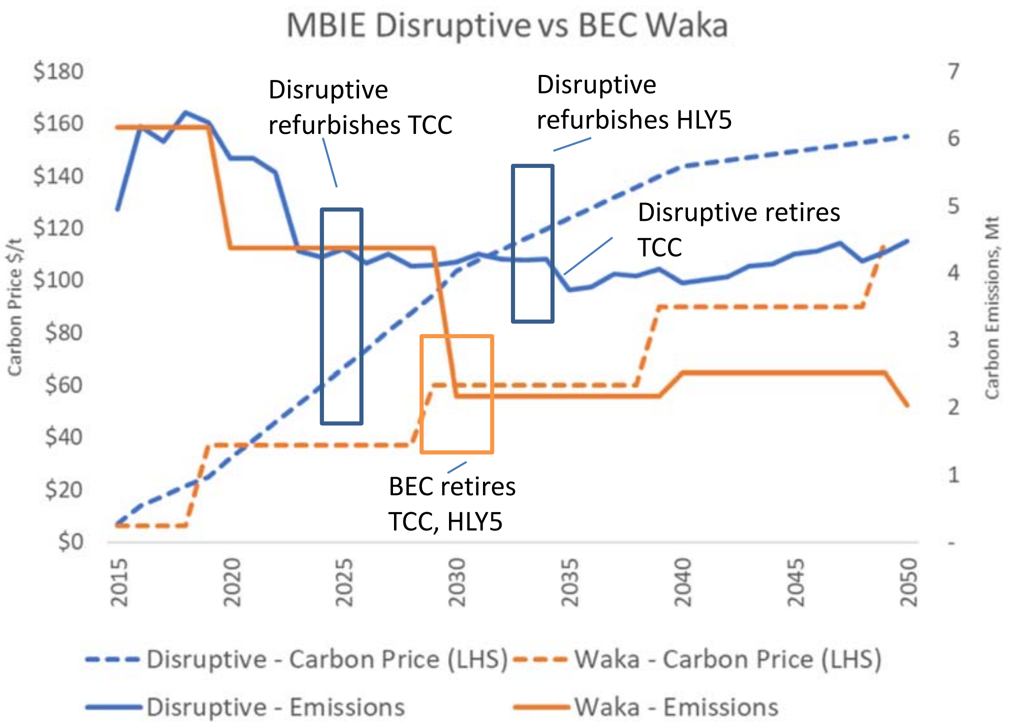
75 Our understanding is that the underlying model is given an option to retire in 2035 and assesses the economics of doing so. The implication of this is that the model does not contemplate retirement in other years.

76 Contact's stated refurbishment cost of TCC is an implied cost of $125/kW, well below MBIE's estimate of $505/kWh, which in turn is well below the cost of a new plant at ~$1,200/kW. That said, we expect the scope of MBIE's refurbishment may be more extensive than what Contact undertook in late 2017. Notwithstanding that, while we believe that MBIE's refurbishment cost may be high, its impact on plant life is optimistic.

77 See footnote 67

Figure 42 - Comparison of carbon prices and emissions projections in MBIE's Disruptive and BEC Waka scenarios



From Figure 42 we can observe:

- A decision to <u>refurbish</u> TCC is economic in 2025, at a time when the carbon price is $60/t, and is expected to rise to $120/t at the point the model <u>retires</u> it in 2035.
- A decision to <u>refurbish</u> HLY5 is economic in 2033, at a time when the carbon price is $120/t, rising to $155/t by the end of the modelling horizon.
- Should, instead, these two plants be forcibly retired in the 2030s[78], neither would not be fully replaced with a new CCGT, at a carbon price trajectory of $60/t at the time, rising to $115/t by the end of the horizon.

It is surprising that decisions to refurbish existing CCGTs would still be economic at relatively high carbon prices. That said, at the time the HLY5 decision is made in 2033, 755MW of an available 825MW of geothermal has already been commissioned; hence if HLY5 was decommissioned at this point there would be insufficient firm renewable

[78] Recall that the BEC modelling occurred in 10-year time steps, hence we do not have any guidance on when during the period 2030-2040 this occurs

generation to replace it. It is possible that the decision to refurbish HLY5 in 2033 is driven more by resource adequacy than the carbon price[79].

This leads us to conclude that, at the carbon price trajectory in Disruptive, by 2050 both CCGTs would most likely have been retired and replaced with renewable alternatives. This would lower the net emissions (assuming it was replaced by geothermal) by around 0.8Mt, bringing it to between 3.2Mt and 3.5Mt[80].

Notwithstanding this, BEC's Waka scenario achieves a greater overall reduction in emissions of 3Mt (compared to today's level), to 2.1Mt pa. It appears counterintuitive that a scenario with a lower carbon price trajectory than Disruptive would achieve higher reductions in emissions. This occurs for two key reasons: (i) Waka has 10% lower demand than Disruptive, which mostly results in lower geothermal and gas production (and thus lower emissions) and (ii) Waka has more pessimistic assumptions about gas and coal cogeneration than Disruptive, which is consistent with its underlying narrative of a difficult environment for industrial consumers under a high carbon price and a challenging global trade situation. This accounts for additional reductions of 1.5Mt. Waka and Disruptive have similar levels of gas/diesel peaking capacity (1,200-1,300MW), with similar peaking generation in an average hydrological year (~1,000GWh, or a load factor of 10%).

Again, we reinforce that these scenario differences represent genuine uncertainties about future decisions by plant owners.

Vivid's Innovative scenario achieves approximately the same level of emissions as BEC's Waka, but with twice the demand growth rate. The scenario does this by retaining a minimal level of gas generation (which appears to be in a peaking role) and fulfilling all growth (including that triggered by the retirement of all existing baseload thermal plant) through renewables (mostly wind) and a small amount of biogas generation. We were not able to validate the resource adequacy of Vivid's Innovative scenario due to level of information made available to us. The Innovative scenario has by far the most aggressive uptake of wind, which sees it eclipse hydro as the dominant fuel in the sector. While Vivid do not provide capacity figures (only generation), we note that, at an assumed 35% load factor, this would be 5,700MW of wind capacity, which exceeds the current total hydro capacity. While we have not been able to apply the WCM and WEM resource adequacy metrics to Vivid's scenarios, we expect the system would require a large fleet of gas peakers, demand response, batteries and/or flexible hydro to manage the hour-to-hour and day-to-day variability.

[79] MBIE's assessment of the available resources may be too conservative here, although perhaps appropriately so. However, since more geothermal becomes available later, the assumption that the 2035 refurbishment lasts (at least) until 2050 may be the operative limitation. If, as we believe is more realistic, that a refurbishment in 2035 may give HLY5 another 8-10 years of life, a further refurbishment would be contemplated in 2045, at which time more geothermal would be available to replace it. This further reinforces our conclusion that, at these carbon prices, HLY5 is unlikely to still be operating by 2050.

[80] The range arises because of the lumpiness of investment. Low-emissions plant is commissioned every 3-4 years by the end of the horizon, and demand growth in between is met by increasing output from the remaining gas capacity. It appears that an investment in a low-emissions plant is imminent in 2050, since emissions have reached a peak at that point (compared to a low of ~4.1Mt a few years earlier).

5.4.4 Options to make deeper cuts in emissions

Vivid's Innovative and BEC's Waka scenarios make the most aggressive cuts in emissions, resulting in 2.1Mt. While these scenarios assume carbon prices much higher than observed today, they beg the question of what level of carbon price would be required to make further reductions.

The Innovative and Waka scenarios have two residual sources of emissions: geothermal and gas. Below we discuss ways in which these emissions could be further reduced.

A 100% renewable system

In our view, the most comprehensive technical assessment of reducing emissions further while maintaining resource adequacy in the NZ system was conducted by Mason, Page and Williamson's work on a 100% renewable electricity system in 2010[81].

Mason *et al*'s work is not a forecast of how the industry may meet future demand. However, on the assumption that the 6-year sample period they used is reflective of system variability it is a comprehensive treatment of the resource adequacy problem, across the LDC. While their proposed approach was not costed, the authors offer an insight into how a power system may almost eliminate natural gas if a more flexible role for geothermal was contemplated. We note that Mason *et al*'s objective was to achieve a 100% renewable system (rather than zero emissions), and to do so in a challenging hydro year (2008 in their sample).

In their analysis of the NZ power system as it stood in 2010, the authors progressively removed thermal plant until it was eliminated and replaced by a combination of wind, geothermal (some baseload, and some partially dispatched) and pumped storage, and simulated this across a 6 year history (at half-hourly resolution) to ensure no unmet demand and minimal spill. 620MW of partially dispatched geothermal (load factor of 73% on average) is used to manage hydro and wind spill. We note that the dispatch of the geothermal appears reliant on being able to predict in advance when hydro will spill (so that the geothermal can back off). This is obviously a probabilistic decision, and the load factor in reality may vary somewhat from what the authors modelled.

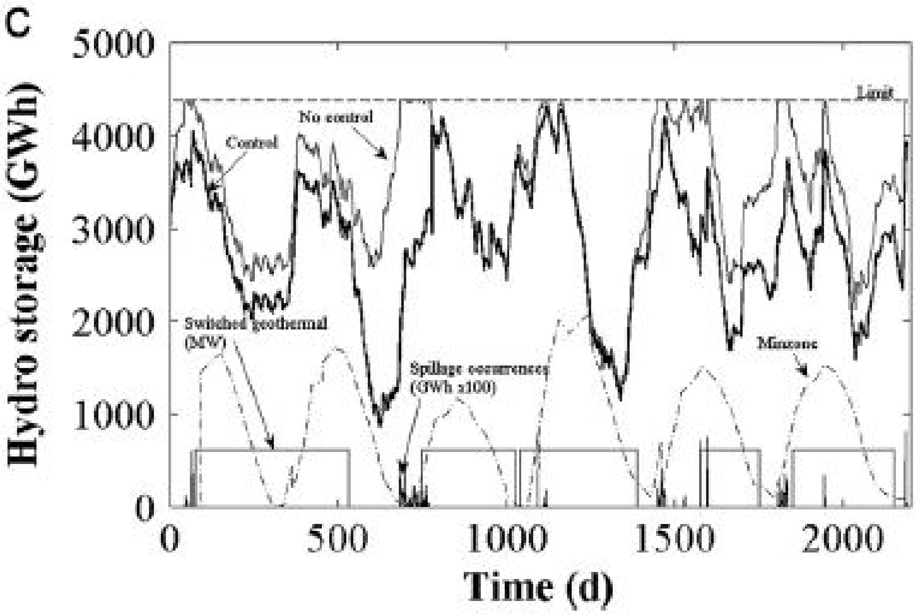
Effectively, the "switched" geothermal is performing the role of the partially loaded CCGT. Both MBIE and Mason's analysis highlight the importance of flexibility; the ability to store fuel from one (medium-term) time period to another, to manage the varying demand and inflows over the year. Hence their 620MW of switched geothermal is replicating the role of a CCGT, as well as some of the gas peakers. Mason still required an additional peaking role to supplement the switched geothermal, but the required energy from the peaking generation level was very low (~100GWh per annum, compared with ~1,000GWh from the low-emissions scenarios above). Mason used a 1,550MW pumped storage instead of gas peakers. We observe that the cost of a pumped storage scheme of this magnitude – requiring a storage capacity of 368 GWh, around 75% of Lake Taupo – would be very expensive, and logistically difficult to site (even if it were distributed). Mason's "transitional" solution of using gas peakers for the 100GWh per annum is much lower cost, although the business case

81 Mason, Page, Williamson (2013), "Security of supply, energy spillage control and peaking options within a 100% renewable electricity system for New Zealand", *Energy Policy*, Vol 60 (2013) pp324-333

for investment in 1,550MW of peakers (~$1.5b of capital cost) with a 0.7% load factor would be very challenging to say the least[82]. Our calculations suggests that this plant would require a wholesale price of $2,000/MWh on average during any period that it operated

New Zealand typically operates geothermal in baseload mode, typically because it is the most economically efficient use of the available resource (when it can fit into the market). This does not mean that partially loaded (or flexible) geothermal is not viable. It is, in fact, a topic of significant international interest as a way to better match supply with demand and to address the resource adequacy issue that demand brings. At a practical level, an 8MW geothermal in Hawaii was constructed in 2011 on the basis that it was to perform a flexible and dispatchable role. Further, some geothermal is offered into California's "flexible generation" auction, which requires it to be held back in the early afternoon to be able to ramp up when demand does. While we understand that a geothermal plant can be physically dispatched, the limits on this (in terms of how the wells respond), as well as the impact on operations and maintenance costs, will likely be a function of the duty cycle that is required. The duty cycle for the switched geothermal in Mason's solution (Figure 43) is relatively benign; although we caution this given our concerns about being able to anticipate the prospect of hydro spill (which triggers the geothermal to turn off).

Figure 43 - Storage levels and switched geothermal generation levels from Mason *et al*, 2013



We calculate that, for a geothermal plant to fulfil the mid-merit requirements implicit in MBIE and Mason's modelling, its LRMC would rise between $30/MWh and $40/MWh (depending on the site). For a geothermal in this role to have a similar LRMC to a CCGT,

82 The authors suggest that the "peakers" would have been required extensively to manage the 2008 dry year, and on 4-5 other brief occasions during the period. Our calculations suggest that this plant would require a wholesale price of $2,000/MWh on average during its operating period.

the carbon price would have to reach at least $130/t as an expectation over the investment period. Further, if the geothermal used in this role were to have a similar emissions profile to the existing plant today, Mason *et al's* solution would result in total electricity emissions of ~1.2Mt.

We note that if the broad shape of demand was matched, in future, using partially loaded geothermal in the shoulder seasons it would create an ability to manage hydro storage in dry years from a renewable source. This may be more cost effective than building wind and hydro to overcapacity in a high renewable system and spilling it in "wet' years.

Other low-emissions options

Other lower emissions options to provide low emissions options which support resource adequacy potentially exist. These include:

Storage options

1. **Batteries:** Given what we understand about battery technology today – especially its costs – it is more likely that batteries will be used to store energy for short periods – hours or days. It doesn't seem likely at this point that large battery banks would be used to store electricity in summer, when demand is lowest, until mid-winter, when demand is highest. However, they are likely to play a role in smoothing the daily electricity demand profile, and thus compete with OCGTs for the peaking role.

2. **Hydro paired with storage:** MBIE's modelling exhausts their relatively limited (~2,000GWh per annum) options available for additional stored hydro options. The only project of substance is Meridian's North Bank Tunnel project on the Waitaki system. Not considered in MBIE's modelling is the potential for up to 550GWh (5m of lake range) of additional storage in Lake Pukaki which is allowed for in consents under emergency conditions.[83] We are aware that there is some re-engineering required to make this available. More importantly, we have not analysed the likelihood that the consent could be amended to make this extra storage more readily available to assist with routine reservoir management, and thus reduce the need for additional mid-merit plant (by allowing the Waitaki system to more easily "shift" summer water to be available for winter demand). Determining the extent to which this would reduce the requirement for a CCGT to perform the mid-merit role requires more sophisticated reservoir modelling. Beyond this, additional hydro that could meet the mid-merit role would need to be rain fed (rather than snow fed) and contain substantial storage. We have not assessed how many of these options exist nationally, and the LRMC would be situation specific. Calculating an implied carbon price for this decision is problematic, as enhancing storage does not create any additional hydro generation, but simply loosens the constraints on shifting it through time.

3. **Hydrogen Storage**: From the perspective of resource adequacy, hydrogen is interesting as a storage technology. While hydrogen has a range of potential uses, the

[83] This is not "freely" available, and we understand would require some re-engineering, as well as consent changes, to make it readily available as a mid-merit support. See https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/Contingent%20Storage%20%20additional%20information.pdf

one we focus on here is often referred to as "power to gas". Hydrogen could be created via electrolysis from water, stored (for much longer than would be likely with a battery) and used to generate at some later point – either via fuel cell technology or directly through a gas turbine[84]. However, there are a number of questions about the life-cycle cost and feasibility of this use of hydrogen, which include:

(a) Firstly, the life cycle efficiency of the electrolysis (which requires significant amounts of electricity itself), storage and re-electrification process — is not high at 25%-35%[85], and the electrolysis process is still undergoing development. There are some estimates that hydrogen (as a fuel for generation) can be delivered at around NZD120/MWh[86], which would be equivalent to $7/GJ natural gas at a carbon price of around $150/t.

(b) Secondly, the storage implications of hydrogen are significant, although compressed storage are being developed.[87] With storage for renewable energy integration purposes, the EU have assessed underground salt cavern storage, and quotes uncompressed storage capacities of 8 million m3 for 1,300 GWh equivalent of hydrogen. We note this would be equivalent to over twice the storage capacity of Lake Taupo.

(c) A kg of hydrogen may require around 9 litres of water (as a feedstock) (Webber, 2007[88]). Whilst, when combusted for electricity later on, the water re-forms, the relocation of the water itself may cause consenting issues, especially with an increasing focus on water scarcity

As a form of storage, hydrogen does not appear attractive today, but may, with improving technology, become a real option in the future. It sits alongside other emerging energy storage techniques (e.g., compressed air) as a consideration for the future.

Alternatives to mid-merit gas generation

1. **Biomass fuelled CCGT or OCGT plant:** We note that BEC's scenarios include bioenergy powered generation as a potential technology but did not include it as an economic choice in either scenario. MBIE do not appear to consider bioenergy. Information of generation costs from biomass is difficult to come by, largely due to it being difficult to estimate the underlying cost of the biomass supply (including transport costs), although, as noted by Robertson (2006)[89], plant costs (including any fuel pre-

84 The power-to-gas process also envisions methane being created from the hydrogen by a process known as methanation.

85 Landinger *et al*, 2014, "Update of Benchmarking of large scale hydrogen underground storage with competing options", EU study.

86 Miller, 2017, "Hydrogen Production and Delivery Program", Plenary Presentation, DOE Hydrogen and Fuel Cells Program. Available from hydrogen.energy.gov.

87 Miller (ibid) reports tanks are being developed which can storage 34kg hydrogen at 800 bar.

88 Webber, M E, 2007, The water intensity of the transitional hydrogen economy, Environmental Research Letters, Vol 2, 2007

89 Robertson, K, 2006, "Estimating Regional Supply and Delivered Cost of Forest and Wood Processing Biomass Available for Bioenergy", Masters Thesis, University of Canterbury.

treatment) are likely to be a major influence on total delivered electricity price. However, we note that Robertson prepared estimates of the underlying fuel cost only for biomass supplies up to 4-8PJ, and found that these costs increased at the rate of approximately 0.5c/kWh per PJ. To completely supplant the firming role of a CCGT we estimate around 30PJ might be required[90]. This suggests that bioenergy may be a more likely option for peaker units with lower fuel requirements.

While there is significant development of gasification technology, Scion (2007) identified a range of challenges still associated with it, including the available of feedstock at sufficient quality and gas clean-up. More broadly, Scion note that for most biomass applications the continuity and guarantee of feedstock supply, as well as the effect of scale on cost, are significant issues that are yet to be resolved. As is the case today, bioenergy will likely continue to make sense as a form of heat and power generation at relatively small scale when co-located with the feedstock (e.g., wood processing). Whether the technology and feedstock issues can evolve for it to play a larger role in the NZ electricity industry is not clear to us, and requires more work.

Robertson's estimates of the levelised cost of electricity generation from biomass (either combustion or gasification) in the NZ context to be in the range \$120-\$180/MWh; which may be preferable to CCGTs at carbon prices of between \$170/t-\$280/t. These estimates are within those of Cox (2004[91], \$70-\$250/MWh); again the ranges indicate the variability of sources and transport costs. We note that more recent cost estimates (in the NZ context) have been difficult to find.

We note that biomass has a wide range of applications beyond electricity generation (including heat), and that the price (and availability) of the feedstock will be determined by the most economic use of this feedstock.

5. **Thermal with Carbon Capture and Storage:** Advanced supercritical coal (ASC) or Integrated Gasification Combined Cycle (IGCC) plant with carbon capture and storage, requiring carbon prices of over \$450/t, based on technology cost estimates today, but with significant uncertainties about technical feasibility at this point).

Any of the above options could plausibly contribute to the electricity system in the flexible role we have highlighted for gas. Indeed, it is more sensible that a combination of these emerge – a flattening of the demand profile through efficiency, more hydro storage, complemented by some dispatchable geothermal and bio-fuelled peakers, all meeting the low-carbon requirement. We have tentatively included estimated carbon prices, which suggest that carbon prices over \$130/t would have to be expected by investors in order to pursue some of these options.

Hence, theoretically, there are low or zero emissions solutions – across the supply and demand side - that could replace thermal in this particular role (and thus eliminate emissions completely), they are not practically or commercially available today at scale.

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90 Using Robertson's estimate of gasification efficiency of 30% (i.e., a heat rate of 12,000GJ/GWh), and assuming that ~2,000GWh of annual generation is required.

91

5.5 Transmission

When it comes to the marginal differences in transmission investment and cost between current expectations of grid investment to 2050 and what might be different under an up to >99% low emissions scenario, then four or five transmission regions are key. Using the Transpower definitions from their current Transmission Planning Report (TPR) four (of the 13 regions covered) are the most important: Auckland, Waikato, Central North Island and South Canterbury. It is possible that transmission in the Taranaki region will be important to the 2050 emission outcomes as well.

Transpower's TPR describes the grid upgrades that should be considered under various scenarios for the core grid backbone and then each transmission region. It has firm plans for the short term (up to 2022), firm plans for scenarios to the medium term (2032) and indicative plans post 2032.

Transpower's TPR is also the only long-term planning report that not only considers how much demand might grow, but where that growth might be. Transpower's TPR is relatively easy to compare to MBIE's Global Low Carbon scenario as they have similar total demand forecasts. While MBIE's GLC doesn't consider in detail where demand will grow it does identify where the generation options will be. Therefore, we can directly compare Transpower's TPR and MBIE's GLC to consider how Transpower's planning assumptions would be affected by lower emissions scenarios.

For reasons described further below, it is also relatively easy to extrapolate further to the very low emissions scenarios.

5.5.1 Comparison of planning assumptions for key transmission regions

In our view any significant differences between Transpower's plans and a scenario with even lower emissions will mostly affect the core grid, due to the concentration of low-emissions generation in particular regions. This is also where the biggest costs will be.

Auckland

The TPR forecasts greater peak demand growth in Auckland than most other parts of New Zealand. As Auckland is already a large load centre and significant extra demand is expected there, Transpower's TPR planning for the core grid is mostly about getting power to Auckland.

There are key differences between Transpower's TPR and MBIE's GLC on the generation side. MBIE tends to assume that new thermal generation is in Auckland, which is ideal for minimising electrical transmission investment. Transpower assumes that it will be mixed between Auckland and Taranaki, which is a scenario that has implications for core grid design.

Waikato

A significant feature of all the low emissions scenarios is significantly more wind and geothermal generation. When it comes to geothermal generation, it is forecasted by Transpower and MBIE to be concentrated around the Bay of Plenty, Central North Island

and South Waikato. Transpower's regional studies address getting power from potential geothermal centres to Whakamaru. The key low emissions scenario problem is how to get the extra generation out from Whakamaru.

Central North Island

As with geothermal in the South Waikato, the best wind resources are concentrated in the Lower North Island. Most large-scale windfarms will connect in to the core grid at or near Bunnythorpe, and most remaining large-scale windfarms will probably be in Wellington. Again, Transpower's regional plans consider how to get wind power to Bunnythorpe (or the transmission connection will be a cost to the windfarm project), and how to improve the connection between Wellington and Bunnythorpe. For our high-level assessment we assume that Bunnythorpe is the key node for wind generation.

South Canterbury

According to Transpower's TPR the only other place in New Zealand that has load growth significantly more concentrated than other parts of New Zealand is Canterbury. The TPR is anticipating significantly more irrigation and dairy processing activity in this area. If more process heat is delivered by electricity, then the demand forecasts for Canterbury could be even higher. Transpower is already considering this scenario and so, for this assessment, we consider that Canterbury and Southland-Otago will be sufficiently strongly connected to Benmore for Benmore to be considered the key node.

Benmore (South Canterbury and Southland-Otago) is also where the dry year hydro risk is most acute. If large pumped storage schemes were to be considered, then the South Canterbury region might be the best suited to their construction. This region has many isolated Southern Alp valleys that could use either Lake Pukaki or Lake Tekapo as their large tail pond reservoir.

Taranaki

Taranaki might also affect core grid planning. It would be ideal (for minimising electrical transmission investment) if any new peaking OCGTs were sited in Auckland or Huntly, as they could help support and stabilise voltage even when not generating. If a number of these plants were to be sited in Taranaki then getting the extra wind and geothermal power to Auckland, without something else providing voltage support and stability, becomes an issue.

Caveat

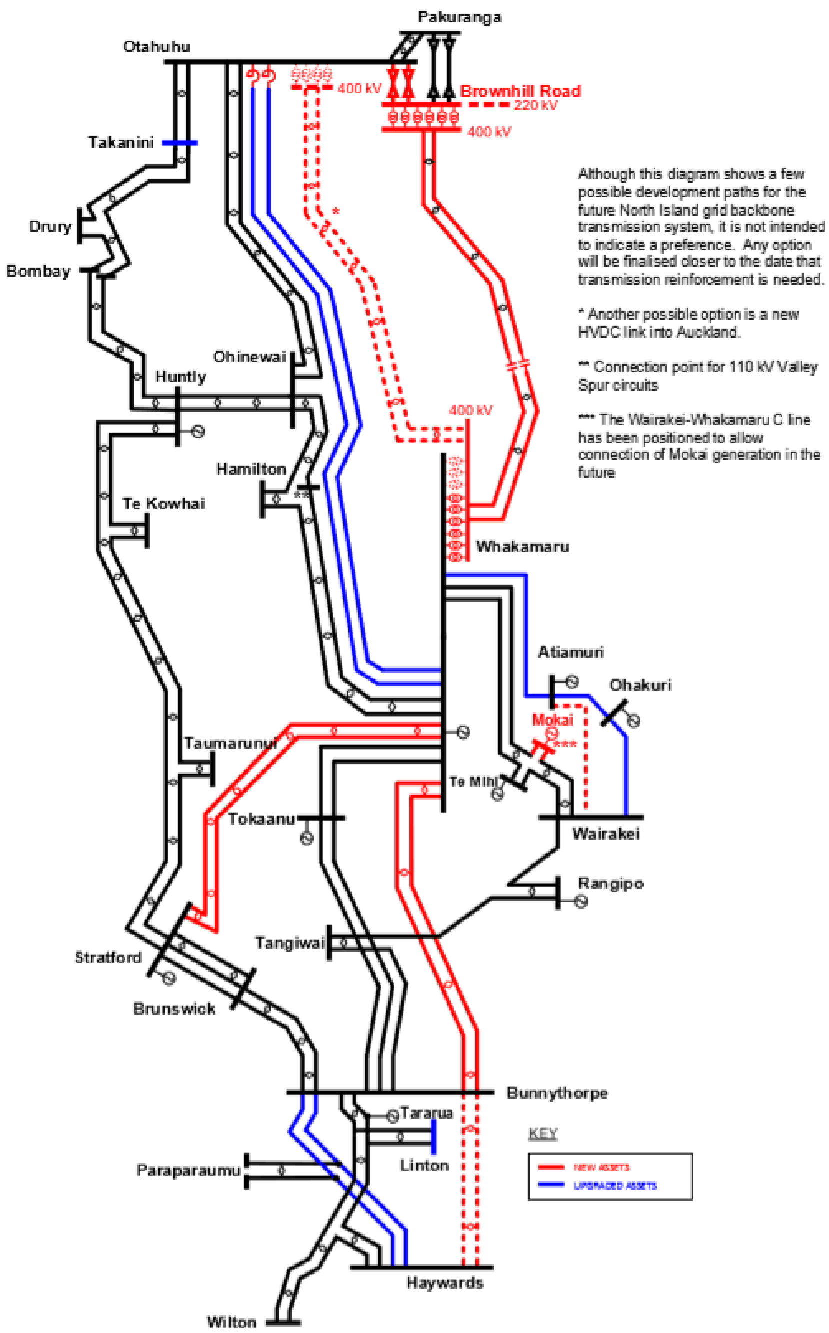
Our high level comparison of planning assumptions above provides a useful guide even for reasonably large variations in the assumptions above; although not to the extent of Vivid's aggressive demand predictions in their Innovative scenario (discussed further below). Also, if significant demand or generation were to be developed in areas of the grid that are currently quite weak, e.g. the West Coast, the East Coast and the Upper South Island then quite significant variations from the suggested investment, outlined below, may be required.

Transpower's TPR baseline post 2032

Transpower's post 2032 assessment provides a useful addition for this paper as it aligns with our purpose of considering a very low emissions outcome by 2050. Transpower's TPR considers developments that might be required to the North and South Island core grid backbones, and the HVDC, after 2032. Given that the South Island will be drawing dry year energy from the North Island under both the baseline and low emissions scenarios, i.e. Auckland/Taranaki thermal is replaced by Central/Lower North Island renewables, then it seems most likely that the TPR baseline would not need to be changed. This might only be required for changes in the assumptions described above for new significant generation and/or load in weak transmission areas of the South Island, or for pumped storage if this wasn't around Pukaki or Tekapo.

The baseline for North Island might need to be quite different.

Figure 44 Longer-term indicative North Island grid backbone schematic (beyond 2032) from Transmission Planning Report 2017



Transpower's post 2032 diagram shows new assets in red and upgraded assets in blue. The provisional plan has significantly upgraded capacity into Auckland, with upgraded capacity around the Wairakei ring, from Stratford to Whakamaru, from Bunnythorpe to Whakamaru and from Haywards (Wellington) to Bunnythorpe.

Assessment of potential variations from TPR to low emissions scenarios

Little analysis has been done on the locational costs of the scenarios considering New Zealand's low emission future, especially with significantly more wind generation from the same geographic region. It is outside of our scope, and the available time, to do an assessment of transmission options for the many scenarios and so we have had to pick what we think is a credible option to give an order of magnitude for the increase in transmission costs to enable a very low emissions future.

Transpower's TPR already assumes some increase in geothermal and wind, effectively entering the backbone at Whakamaru and Bunnythorpe respectively. It also has thermal generation from Stratford.

However, in the scenario where there is even more geothermal and wind, and where thermal is only providing very short term peaking, then the reinforcement from Bunnythorpe to Whakamaru may not be sufficient. Transpower will also be assuming that geothermal is substantially baseload and provides most of Auckland's baseload power. However, if some geothermal is providing a balancing service, then on windy days a much larger amount of power will need to get from Bunnythorpe to Auckland than Transpower is currently anticipating. Although on non-windy days that power will still need to be able to get from Whakamaru to Auckland.

In dry years, when it's windy, large amounts of power will need to go south from Bunnythorpe; and in dry years, when it isn't windy, large amounts of power will need to go south from Whakamaru. Currently, when power from the North Island goes South it comes from Stratford (Taranaki) and Whakamaru. In the scenario where most dry year reserve comes from geothermal then this reinforces the need for a much stronger connection than anticipated from Whakamaru to the Lower North Island.

A significant issue with getting power to the South Island in dry years is not only restrictions on the HVDC but also restrictions from Taranaki to Bunnythorpe and Bunnythorpe to Haywards. Transpower's post 2032 baseline considers upgrading those lines but, under the scenario where most generation from the region needs to be exported from Bunnythorpe then we question whether, under the low emissions scenario, Haywards is the right place for the Lower North Island termination of the HVDC. There may already be enough capacity between Bunnythorpe and Haywards to supply Wellington over the longer term and there may also be enough to get Wellington wind generation to Bunnythorpe.

Moving the HVDC convertor station from Haywards to Bunnythorpe would create a more direct route from wind surpluses to the South Island; and it would create the opportunity for a similar direct route north.

Otahuhu or Whakamaru

Under the low emissions scenario we consider that it would also be desirable to extend the HVDC further north from Bunnythorpe and establish a new HVDC convertor station. There is a question whether this would be at Otahuhu or Whakamaru. It could be both but convertor stations are expensive and multiple DC stations with multiple AC circuits in parallel can start to create dispatch and/or control system complexity. Of course, both potential limitations might be inconsequential by 2050.

A key determinant of where a single Upper North Island convertor station would be is Auckland voltage. The need to avoid further Auckland voltage problems through sending large amounts of power through large AC circuits with few local voltage sources might necessitate HVDC to Auckland. Transpower's TPR baseline also considers that this might be desirable, although only from Whakamaru in their case.

In this context significant solar DER with suitably specified and coordinated inverters, or perhaps even locally coordinated demand response, might significantly improve the Auckland problems also providing more optionality in transmission solutions.

Greater optionality would also be achieved if any OCGTs installed to manage peak shortfalls were installed at Huntly or, preferably, Auckland. Then they would either be able to provide occasional generation support for voltage or 'baseload' reactive power support as synchronous condensers[92]. Any OCGTs installed at Taranaki would exacerbate rather than mitigate Auckland voltage problems; as well as potentially requiring a transmission upgrade for the few times when the peaking capacity is needed.

There is also an option of installing a HVDC convertor station at Otahuhu. Under normal years this gives an express route from LNI wind to Auckland and a strong connection to CNI geothermal. However, in dry years then a significant amount of geothermal energy would be sent south via Auckland. In this counter-intuitive scenario the losses are unlikely to be much greater than an alternative approach.

Extra cost of transmission for low emissions

We are basing our cost estimate on a single option to solve a common issue arising from the low emissions scenarios, large volumes of wind export from around the Manawatu area. Many options could be taken into account, but we are only trying to establish an order of magnitude for the effect on electricity sector costs and energy prices. Many options might prove cheaper than the HVDC option we are considering here; and, by 2050, new flexible transmission technology will likely change the relativity and cost of options as well.

We make the following approximate estimates for scenarios which substitute a substantial amount of thermal in Taranaki (i.e. TCC) or the Upper North Island (i.e., Huntly) for (predominantly) wind and geothermal and assuming modest demand growth as per Transpower's projections. Specifically, we are referring to MBIE's GLC and BEC's Waka scenarios. We base these costs on the recent large projects:

- Whakamaru to Pakuranga 220kVAC (potentially 400kVAC – also known as NIGU)
- Pole 3 350kVDC thyristor pole replacement

92 Synchronous condensers are the same machines used for generation, but running instead as motors. In this mode they can dynamically provide voltage support by providing variable reactive power.

Using these projects for guidance the extra upgrades could cost up to $5 billion (real) over what Transpower might otherwise need to invest to 2050:

- Moving the HVDC convertor station from Haywards to Bunnythorpe
- Extending the HVDC from Haywards to Whakamaru
- Establishing a new HVDC convertor station at Whakamaru
- Extra AC upgrades to Auckland (or potentially extending the HVDC to Auckland rather than Whakamaru)

It is not possible to make a useful approximation of the transmission cost implications of:

- Mason *et al's* suggestion of large pumped storage. The location and distribution of 1,550MW of pumped storage could have a significant influence on the required capacity of affected regions.
- Vivid's Innovative scenario. This is such a substantial increase in demand, through electrification of heat and transport, that it would be critical to understand the location of these increases. Some low-grade heat conversions and transport are likely to be heavily distributed (i.e., in urban areas), but medium grade heat conversions could be concentrated in other locations. This makes it difficult to assess grid implications.

However, we are aware that Transpower is about to publish its analysis on the power system implications from large amounts of substitution to electricity from transport and process heat. This analysis will fill a gap in the current research.

5.5.2 Marginal cost and timing of transmission for low carbon

Generally, Transpower's long term planning forecasts and the low emissions scenarios we have investigated have a similar generation build pattern (at least geographically). The key difference between the low emissions path Transpower is forecasting against the even lower emissions scenarios is a huge wind build in the lower North Island. Generally then there is little incremental cost above Transpower's current plans except at the point where the lower North Island wind capacity exceeds the ability of Transpower's plans to export power north and south.

There is a secondary effect on the long term forecast due to locational differences that occur with the potential replacement of CCGT's with dispatchable geothermal and OCGTs. In fact, if the OCGT fleet were to be located substantially in the Auckland area, displacing TCC and any further GTs in Taranaki, then Transpower's long term forecast costs could reduce. The location of any OCGTs that are required to support peak and firm energy adequacy also has implications for system operation and ancillary services, which we discuss further below.

Based on the scenarios we have investigated, the export of power from Bunnythorpe and the associated regions will reach 2,500 – 3,000MW. To be clear that is not the generation (wind and other existing generation) that the region is producing but the amount that is being exported. This is around one third of New Zealand's peak demand forecasted for 2050. This is an enormous challenge for the transmission network.

We think that, under these scenarios, New Zealand will have three 'modes' of operation.

1. Low wind, normal hydrology – where geothermal, NI hydro and some wind will meet most of the North Island's energy needs with peak support from SI hydro and some

OCGT; and where SI hydro and some wind will meet almost all the South Island's needs.

2. Low wind, dry year – where geothermal, firm energy geothermal, some NI hydro, some SI hydro and some wind will meet most of New Zealand's energy needs with some firm energy and peaking support from OCGTs.

3. High wind – where North and South Island generation is reduced significantly, and large amounts of wind power are exported North and South from the lower North Island; balancing and peaking would be provided by NI hydro in the North Island and SI hydro in the South Island.

Mode 1 is easily catered for in Transpower's current long-term thinking, mode 2 is also substantially achievable with current plans. It is mode 3 that causes new demands on the transmission network.

As described above we are only considering one transmission option to determine an order of magnitude of marginal transmission cost to enable this future.

It is the volume of power that needs to be exported from a single location that leads us to the view that HVDC links will be needed to relatively efficiently and effectively transmit this power to the South Island (to meet substantial forecast demand growth in South Canterbury) and to Auckland. On balance, as so much of the new wind capacity will be around the Manawatu region and Wellington wind with Wellington load will be a relatively good match with the balance of power able to be met by the proposed Bunnythorpe to Wellington transmission capacity, we think Bunnythorpe is a better location than Haywards for a mid-point HVDC terminal. The Benmore terminal of the HVDC would remain and a new terminal would be required in Auckland.

Our cost assumptions for this upgrade are based on moving the current HVDC terminal from Haywards to Auckland and establishing a new Multi-Terminal Direct Current (MTDC) station at Bunnythorpe. New HVDC tower lines would be needed from Bunnythorpe to Auckland and from Bunnythorpe to Haywards.

We haven't attempted to properly cost these upgrades. Our estimates are based on the costs of transmission projects that have been done recently in New Zealand, especially NIGU and the Pole 3 upgrade. Our estimates are intended to give an order of magnitude but are no more accurate than that.

Table 3 - Rough estimates of HVDC upgrades

Item	Cost
Move HVDC terminal from Haywards to Auckland	$0.5 billion
New MTDC terminal at Bunnythorpe	$2.5 billion
New HVDC line from Bunnythorpe to Auckland	$1.5 billion

Item	Cost
New HVDC line from Bunnythorpe to Haywards	$0.75 billion
Total	**$5.0 - $5.5 billion**

The other key question is when this upgrade would occur in the move to a low emissions outcome. This is a complex question because transmission investments have significant economies of scale, which means they have traditionally been large investments done on the expectation of future use rather than current use. When demand is steadily growing then decisions about transmission are substantially decisions about when to commit to the significant cost. Uncertainty in the electricity industry now makes optionality as valuable as economies of scale.

This suggests that this investment should be left until the last possible point to decide. However, if the utilisation of existing transmission capacity gets too high before the capacity upgrade occurs then the outages necessary to complete an upgrade can require load curtailment. On a risk weighted basis, the consequence of investing in transmission capacity too late is worse than investing too early; but, obviously, investing when such a large investment proves to be unnecessary is untenable as well. We note that this is such a costly and significant decision that it may need to be elevated above the current process of Transpower proposal and Commerce Commission approval (after consultation), it is a strategic decision for New Zealand.

The other aspects that affect timing are planning, resource consent and procurement. Some of this could be done at relatively low cost to preserve the option to proceed but a decision would probably need to be made five years before a prudent forecast determined it would be required.

It is difficult to determine timing without more detailed analysis but using a rough estimate of transmission capacity from Transpower's System Security Forecast we can make some estimates of the timing of constraints on capacity out of the lower North Island.

Firstly, there are constraints on south transfer now. However, Transpower has firm plans to manage south transfer capacity (with significant South Canterbury load growth) until 2035. On the basis that the south transfer from Bunnythorpe isn't sensitive to the mix of generation at Bunnythorpe or north then this can still work, especially if some firm energy/peaking OCGT capacity is installed in the South Island (biofuel?).

As a very rough estimate around 400MW of extra wind could be built before constraints would bind for north transfer. Using MBIE's Mixed Renewables scenario this would mean the HVDC upgrades would be required by 2026, meaning a decision would be needed by 2021. However, this point can be deferred by changing the order of the generation build. The scenarios we have used have not considered transmission costs and, therefore, the build order is based on the generation only LRMCs, and the security of supply requirements. However, at the point where marginal wind triggers the need for the huge HVDC upgrade then marginal geothermal would be built first. If most of the geothermal generation build in the MBIE Mixed Renewable scenario were built before most wind generation then Transpower's plans to 2035 would still be appropriate.

If by 2030 the wind build indicated by all the very low emissions scenarios is still anticipated then the decision to build, in the order of, $5 billion (in 2017 NZD) would need to be made, for commissioning in 2035; and earlier if a commitment to significant wind was to be made earlier.

5.5.3 Transmission system operation (Ancillary Services)

The very low emissions scenarios for 2050 may create some significant challenges for transmission system operation. Issues might include:

1. The increasing use of D-Fig connected wind turbines, solar PV and electronic soft start motor controllers reduces inertia meaning relatively small shocks on the power system could cause large frequency deviations; and large shocks may become unmanageable.
2. The risk of trip of large HVDC transfers, and other significantly loaded transmission lines, will increase the need for instantaneous under-frequency reserves, and over frequency reserves for inter-island transfer.
3. The transmission of renewable energy long distances to large loads will increase voltage management problems in parts of the grid.
4. The volatility of wind generation and the need to substitute for instantaneous reserve after a generator/line trip will require more fast start, standby reserve.
5. Managing dry years with little discretionary thermal generation will require new sources of firm energy reserve.

As there is a need for these ancillary services, and technology will make it increasingly feasible to operate markets for these services, we anticipate markets will be developed, or further developed, for inertia/ultra-fast frequency response, instantaneous under-frequency reserve, instantaneous over-frequency reserve, voltage/voltage stability, standby reserve and firm energy reserve. As discussed under distribution these markets should also be open to DER (see section 6.3.1 for further discussion around DER).

Inertia/ultra-fast simulated inertial response market

There would need to be a North Island market and South Island market, and such a market would be designed to incentivise such things as:

- Ultra-fast response characteristics in DER (batteries/inverters),
- The direct connection of industrial motors,
- OCGTs designed and built to run as motors,
- Increased use of tailwater depressed hydro generators, spinning as motors,
- Wind generators trading off some shock loading on the blades for providing some inertia.

As inertia is increasingly being raised as a concern internationally with the uptake of solar PV and wind generation, and it has always been an issue in New Zealand, then this ancillary service should be investigated early. It would probably be best to look at a centralised procurement approach in the first instance, but the service should be open to DER.

Instantaneous under-frequency reserve

Eventually, at least once there is an intra-island HVDC link a locational IR market will be needed at least in the North Island. Currently there is an IR market in both islands, but it only covers the HVDC (inter-island) and single generators. A locational market enables intra-island transmission circuits to be covered as well, and allows a trade-off between partially loading transmission lines or providing IR.

There isn't a short run need to move to locational IR yet, but the market should be made accessible to DER (domestic and small commercial demand response and batteries).

Instantaneous over-frequency reserve

Ultimately this might need to be a locational market to mirror the under-frequency market. This is not a short-term issue. Over-frequency reserve is currently procured by the System Operator in both islands. This is still suitable but could be opened to DER.

Voltage/voltage stability

Voltage and voltage stability issues are locational and are an issue in New Zealand now, especially Auckland. Voltage and voltage stability is currently treated separately by Transpower who procures or provides voltage support services. A market would be designed to incentivise:

- Equipment that is currently used (e.g. capacitor banks, SVCs, statcoms, etc.)
- Voltage response characteristics in DER (inverters)
- OCGTs designed and built to run as synchronous condensers

As there are issues now, in Auckland and in some parts of the South Island, and DER (solar PV with invertors) are steadily being installed, then this service should be reviewed now. This ancillary service should be priced and opened up to a market response including to DER.

Standby reserve

New Zealand doesn't currently have a standby reserve market, and this isn't a short-term issue. In the long-run a standby reserve market may need to be locational to provide back up to big HVDC links.

If, in the long-run, peak demand capacity is to be met by a very low load factor OCGT fleet then this mechanism may be required to facilitate this outcome. It should be offered to DER as well (extended demand response and batteries) as this could potentially avoid the need for some OCGTs.

6. Demand-side Options

6.1 Demand and Resource Adequacy

There are a number of ways in which the shape of the demand profile can better support resource adequacy. We consider three broad categories:

- Demand Response
- Conservation
- Efficiency

These definitions overlap heavily but it is a useful categorisation that helps us understand the different motivations for changes to demand and also the different ways in which the demand-side can help address resource adequacy.

6.1.1 Demand Response

As outlined earlier, all modern electricity systems will plan to be able to meet the highest demand point over the year (the left-most point in Figure 12). As can be seen from this chart, however, this peak is concentrated into a very small number of half hours. This creates a need for capital investment in a generator (or storage) that will have a very low load factor.

The low frequency with which the highest demand periods of the year occurs points to the merit of relying on demand response, whereby it may be more beneficial for the system overall if consumers can be enticed into efficiently reducing demand during this small number of peak periods.

The Federal Energy Regulatory Commission defines demand response as:

> *Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*

The FERC definition is sufficiently generic to suggest that demand response may go beyond that just concentrated on the highest 10-20 hours of the year. It could perform the role of "flattening" demand over the whole year, if that is the efficient thing for consumers to do. Indeed, demand response has different forms depending on the length of advance notice that can be given for demand to respond (if any) and the duration that the load reduction is required for. Each form of demand response is used for different purposes:

- **Scheduled demand response**: Here, consumers contract their ability to drop load for a predetermined period of time in response to advice from the purchaser[93]. The ripple

[93] Transpower's current demand response program is an example of this. Consumers receive a signal from Transpower about the impending need for their demand response, and only get compensated if they reduce load. But they are not obliged to respond. There are more "firm" forms of demand response possible in the

control of hot water is an example. This was historically carried out by distributors for controlling peaks. Now it is possible for other aggregators to use newer technology to control a wide range of loads and deploy these for any purpose.

- **Frequency armed demand response ("interruptible load")**. This is an ancillary service designed to protect the stability of the system when a major component (generator or the HVDC) has failed. The System Operator contracts interruptible load for instantaneous reserve in the wholesale market. Some ripple controlled hot water load is offered into the instantaneous reserves market on this basis. In New Zealand EnerNOC has been active in this form of aggregation. Further frequency armed response is mandated as a last resort response when frequency falls to critically low levels[94].
- **Voluntary demand response based on price signals**. In this case consumers exposed to high transmission, distribution or energy prices may drop load if the price is sufficiently high and the inconvenience is correspondingly low. At the mass market level, New Zealand's extensive rollout of smart meters has enabled a range of tariff structures – including a full exposure to half hourly wholesale prices - to be offered to mass market consumers.

Demand response is the category into which distributed storage most sensibly fits. The motivation for distributed storage is to reduce demand at peak times. Distributed storage can come both in the form of electrical storage (e.g., batteries) or thermal storage (e.g., hot water heaters). In both cases, the "charging" of the storage can occur when electricity price is low, but is then released to the consumer when price is high[95].

Demand response during system peaks can reduce the need for gas peakers. MBIE's scenarios were the only ones to model demand response, with nearly 500MW of demand-side response (compared to around 160MW today) substituting for the peaking role of gas and diesel peakers.

Transpower currently contract ~140MW of demand response to manage grid storage and have a target of 650MW. On the basis that this is available for Transpower's use it could equally become available for use in energy management. EECA's energy efficiency measures have had the effect of reducing demand from consumption in a variety of ways which is a more permanent form of demand response often as a result of changing to energy efficient devices and bringing in better insulation.

New Zealand market, where the capability to reduce load can be routinely offered in to the wholesale market. If the price is sufficiently high, the demand reduction is formally "dispatched" by the system operator, and faces similar performance obligations to those faced by generators.

94 This is known as Automatic Under Frequency Load Shedding (AUFLS). Every customer directly connected to the grid (EDBs and major industry) must nominate two blocks that guarantee 16% of their load is shed (for each block) if frequency falls to these critical, last resort, levels. The Electricity Authority has initiated an Extended Reserve Market that it hopes will lead to voluntary emergency demand response rather than rely on mandated AUFLS.

95 Technology is now widely available for solar customers to use excess solar power during the day to effectively "overheat" their hot water cylinder, thus reducing the cylinder's demand for electricity at night when the solar panels are not producing. This is the same optimal behaviour as using an electrochemical battery to charge and discharge.

6.1.2 Conservation

Conservation is when consumers decide not to consume for a range of price and non-price reasons. Hence conservation is, in some ways, a more general form of demand response, but one which is not necessarily solely motivated by price. While much conservation behaviour is ad-hoc, New Zealand has a long experience with organised conservation campaigns.

The nature of hydro generation is such that the potential for running out of hydro storage emerges slowly over weeks as opposed to shorter events that may be managed by demand response. This slow-moving nature of hydro shortages allows for consumers to be informed of the need, and a range of conservation behaviours to be encouraged.

Conservation Campaigns have been used in New Zealand numerous times, most recently in 2001, 2003 and 2008. Some of these have been led by central government and others have been industry led. In each case there has been a degree of collaboration. In 2010, as a result of concern about the way conservation campaigns had unfolded previously, they were formalised into the industry code[96]. They are now officially established based on pre-defined storage levels, and consumers are compensated.

Hence officially activated conservation campaigns are a formal part of New Zealand's resource adequacy framework, specifically targeted at very low inflow sequences which draw down storage levels to a point where there is at least a 10% chance of running out of storage altogether[97]. The extent to which they contribute to resource adequacy is uncertain, in that it relies on consumer response for the call for conservation.

Prior to the current market arrangements there had been public conservation campaigns which shed a light on what is possible. The CEO of the Electricity Authority, Carl Hansen summarised the outcomes of previous conservation campaigns as follows:[98]

> *[Historically] large movements in spot prices during times of low inflows created commercial incentives on spot market purchasers (e.g. retailers and industrial consumers) to argue for ad-hoc interventions to reduce spot prices. This was particularly the case for parties that hadn't hedged physically or financially. In NZ these parties lobbied Cabinet Ministers, often via the news media, for interventions to require generators to reduce spot prices or for the removal of the spot market. They also lobbied the Government to run 3 public advertising campaigns asking consumers to voluntarily save power (called conservation campaigns in NZ). These campaigns have typically reduced electricity demand by [7 – 10%] but reduced spot prices by [50%] or more.*

Since introducing a suite of measures (outlined in section 3.1.4) aimed at reducing the public calls for campaigns and accompanying lobbying the calls for activating public policy campaigns has abated despite several years of low inflows having occurred.

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[96] Part 9 of the Electricity Industry Participation Code.

[97] Ibid, Rule 9.23

[98] Carl Hansen, Chief Executive, New Zealand Electricity Authority *Role of the regulator in security of supply Presentation to the World Forum of Energy Regulators (WFER)* Istanbul, 26 May 2015

6.1.3 Efficiency

Energy efficiency refers to the consumer's ability to deliver the same service (heating, lighting, entertainment) at a lower consumption of energy (in this case, electricity). This may be enabled by a range of things, including technological improvement or investment in efficiency-increasing measures (e.g., insulation or double glazing). While not typically considered a demand "response", energy efficiency plays two important roles that relate to both resource adequacy and also a low-emissions future:

- **Reducing demand growth**: Reducing long term demand growth prolongs the country's ability to use existing generation and reduces the need for new generation (which may, at the margin, be emissions-intensive). We expand on this point in Chapter 5, but investment in new generation will take place in a "merit order", with the lowest cost investments occurring first. If there is a possibility that, at some point, lower cost renewable options are exhausted, energy efficiency will help us prolong reaching that point, which may allow technology to emerge which changes the merit order in favour of new, lower cost, low-emissions generation.
- **Reducing demand growth at particular times of year**: As discussed above, a significant part of the resource adequacy challenge is to "shift" energy from times when demand is low (e.g., summer) to when demand is high (e.g., winter). We highlighted in Figure 11 that winter demand is approximately 2,000GWh higher than summer. Hence it follows that energy efficiency investments which reduce peak demand will assist resource adequacy. Winter peaks are substantially the result of lighting and heating load, both of which offer significant energy efficiency opportunities (LEDs for lighting, and heat pumps and insulation for heating). Investment in these technologies may reduce the amount of "shifting" that the supply side needs to do, particularly over long periods (weeks) where the only practical options currently are fuel storage (hydro or thermal).

6.2 Drivers of Electricity Demand Growth

We break the various drivers of demand growth into the following components:

- growth resulting from an increase in underlying activity (economic and population growth, driving more households and businesses); offset by increases in energy efficiency and/or industrial closure
- fuel substitution into electricity for transport (electric vehicles, buses, trains and trucks); we note that the different scenarios provide differing levels of clarity about the scope of the transport figures
- fuel substitution in and out of electricity for heat.

It is important, when discussing drivers of electricity demand, to distinguish between "inherent" demand (the consumer's need for light, heat, motive power etc.) and the demand for fuel that this implies. The translation between fuel and the final energy form is where efficiency counts[99]. The ability for models to properly distinguish the role of efficiency depends on whether inherent demand and fuel (in this case, electricity) is separated in the model.

6.2.1 Scenario summary

The scenarios highlighted earlier provide a wide range of total demand growth outcomes. The ultimate impact of any particular demand growth projection on emissions will be a function of:

- the degree to which consumers switch away from emissions intensive ways, to electricity, for servicing their energy needs (which is outside the scope of this report)
- the degree to which these electricity needs can be met with low-emissions supply, which is covered in Section 5.

The rate of electricity demand growth and where it comes from in the economy (e.g. industrial, commercial or domestic use) has a direct impact on emissions. Investment in generation is ultimately a function of expected demand growth (which flows through to price expectations). The pressure on supply-side resources, and the rapidity with which low emissions sources may get developed is a function of demand growth. Hence it is of interest to understand what the underlying drivers of different growth scenarios might be.

All scenarios foresee demand growth of at least 0.9% CAGR (BEC Waka), and up to 2.1% in the case of Vivid's Innovative scenario - a range of demand outcomes in 2050 which vary by nearly 30TWh (75% of today's total demand)[100]. Given that this range has significant implications for generation investment, this section cover two important aspects of electricity demand:

- the underlying drivers for the growth in demand
- where this demand will be located relative to supply, as that has significant implications for the trade-off between local forms of distributed supply (e.g., behind-the-meter connected PV, or distribution scale energy resources) versus grid supply.

Figure 45 illustrates the different scenarios assumptions about growth drivers.

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99 An obvious example of the difference is household space heating. In the US, over the period 2000-2009 the *need* for heating (as described by the average floor area of a new house) in new houses increased 30%; but the overall efficiency of heating increased 21% over the same period (including better window design and insulation) to leave the total heating requirement for households relatively unchanged. See Residential Energy Consumption Survey (2009), available at http://www.eia.gov/consumption/residential/.

100 We note that these projected growths are substantially above the growth rate observed over the past 10 years (0%), and, in Vivid's case, well above any compounding growth rate observed at any time in the last 50 years.

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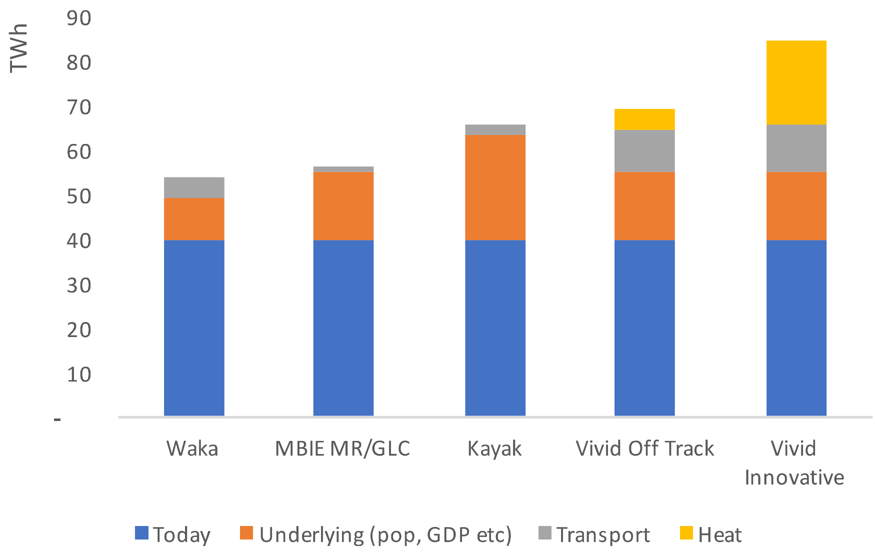


We briefly comment on each of the categories.

Underlying Growth

Changes to demand in this category require a translation of additional people (or households) and economic activity (GDP) into electricity consumption. The former is typically normalised as electricity consumption per household, the latter is generally referred to electricity "intensity", expressed as GWh/$GDP.

Table 4 GDP and population growth rates for each scenario

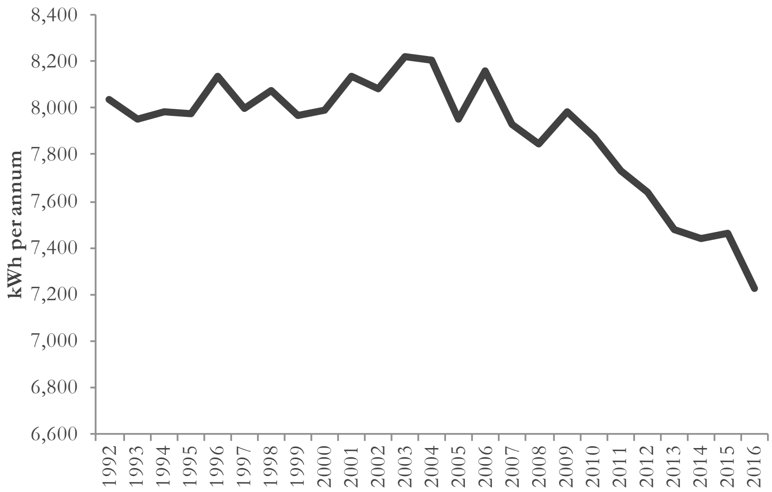
	BEC Kayak	Vivid OFF	MBIE MR	MBIE Disruptive	BEC Waka	Vivid INN
CAGR in GDP relative to 2014	+2.1%	+2%	+2%	+2%	+1.6%	+2%
CAGR in population	+0.9%	+0.9%	+0.7%	+0.7%	+0.6%	+0.9%

The range in underlying drivers (population and GDP) gives rise to a wide range of potential growth values (between 10TWh and 23TWh). The absolute values of assumed economic and population growth are only one factor. Assumptions about structural change within the economy, and energy efficiency uptake in each sector[101] can mean quite different energy

[101] BEC's "Deep Dive into Energy Targets" reports a 47%-54% reduction in heating and air-conditioning demand between now and 2030 as a result of energy efficiency (relative to a no-efficiency improvement baseline). Similar figures were not available for the other scenarios

outcomes, even for the same total growth. Similarly, at the household level, the same population growth can result in different consumption growth depending on assumptions made about efficiency at the household level (insulation, appliances etc.). While these assumptions are a topic in themselves (see, for example, Batstone 2012), we note that recent history suggests that, since 2007, efficiency has largely offset the increase in the inherent demand (i.e. the change in the number of households, size of households, and any proliferation of appliances within the household) resulting in no absolute growth in residential demand. The impacts of efficiency over the last ten years may have reduced demand by up to 1,400GWh, relative to a counterfactual where the long-term trend in household consumption had continued. The question of whether this trend continues is open, but the degree of efficiency impact to date is potentially significant, when compared to the factors driving future growth.

Figure 46 - Average Household Demand 1992-2016.



Source: MBIE, StatsNZ

We believe there is much more work to do to understand the impact of efficiency on future electricity demand projections in the residential sector the commercial sector and the industrial sector. The scenarios did not provide sufficient detail, in our view, about the potential role of efficiency to take pressure off future need for electricity generation. However, we reiterate that all scenarios presumed an underlying growth rate of at least 0.9% for the entire 35 year period; BEC was the only set of scenarios which "stretched" the underlying assumptions to any degree, and demonstrated that a plausible range of population, economic growth and efficiency assumptions gives rise to a range of 14,000GWh in growth projections which is equal to the full range of Vivid's heat assumptions. To translate that into emissions, BEC reported that its different growth assumptions accounted for around 4Mt of emissions reductions by 2030 in Waka, which did not occur in Kayak[102].

[102] "Over 50% of Waka's additional [8Mt] of Waka's additional emissions reductions are due to lower underlying growth – i.e., lower population growth, lower economic growth and a structural shift in the economy away from energy intensive industries". BEC, 2017, "Deep Dive into the NZ energy and transport sector emissions". While BEC reinforce that this is not a suggestion to aspire to a low-growth world, we

Agriculture

While both MBIE and Vivid provide commentary around future growth in energy demand emanating from the agricultural sector, none of the scenarios explicitly refer to the potential of irrigation demand growth which has a significant effect on electricity specifically. Increased electricity growth from agriculture (let alone irrigation) is not transparent in any scenarios, as it is combined with other industrial sectors.

However, agriculture now makes up 9% of total electricity demand, and is the fastest growing sector of demand that is reported by MBIE in its "Energy in New Zealand" publication. We acknowledge here that predicting future growth is problematic, as it requires assumptions about a range of matters – the extent of continued growth in agriculture (including the growth in land to be irrigated), and the efficiency of pumps etc. That said, Transpower has recently considered the impacts of irrigation on its load forecasts, as part of its 2015 Transmission Planning Report. For example, this led Transpower to revise upwards its 2030 peak demand forecast for South Canterbury by nearly 20%.

As the irrigation season extends from September to May, but is highly contingent on rainfall, this could have a substantial effect on the annual profile (and level) of demand. We believe this is an issue which warrants greater attention, especially considering the underlying driver of irrigation demand on the electricity system is also an underlying driver of supply (through hydro catchments)[103].

Industrial

Most scenarios assumed a general continuation of the decreasing energy intensity trend, at a rate reflective of that observed for the past 10-15 years. This underlying narrative is one of greater growth in low energy intensity sectors of the economy (e.g., financial services) than in energy intensive sectors. By 2050, this resulted in between 37% and 50% reductions in energy intensity compared to today. BEC's Waka demand forecast was the most aggressive of these, implicitly assuming a more aggressive structural shift in the economy away from energy intensive industries. As discussed above, the combination of low absolute growth forecasts, and this structural shift, was a significant contributing factor in its low forecast demand growth.

While we have not analysed it here, MBIE's "Tiwai off" scenario explicitly considered a world where Tiwai exited in 2018, reducing electricity demand by nearly 5TWh. This resulted in the Tiwai Off scenario achieving the same emissions as the Global Low Carbon scenario by 2050.

Transport

Despite the wide range of uptake scenarios (400,000 vehicles in BEC's Kayak, through to 3.5m vehicles in Vivid's Innovative) the resulting range of impacts on growth – while not immaterial – were the smallest of the three underlying driver categories. Electric vehicles are

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believe it indicates the potential for energy efficiency (rather than fewer people and/or lower economic activity) to limit emissions.

[103] See slides 89-105 of Meridian's 2017 Investor Day Presentation for an assessment of this dual dynamic in the context of a changing climate.

substantially more efficient than fossil fuelled vehicles (in terms of energy use per km driven); and we expect that a trend of increasing efficiency will occur between now and 2050.

The scenarios suggest a range of 5% to 95% penetration of electric vehicles in the light fleet. In New Zealand, electrification already extends to buses, trains and some large recycling trucks. The economics of switching from petroleum products to electricity for transport is beyond the scope of this chapter, but we note that it will be a function of consumer preferences, battery costs and range, and the relativity of the oil price to electricity. This wide range of uptakes is indicative of the sheer uncertainty we face with respect to these variables, let alone how they will interact with each other in determining consumer buying choices.

Figure 45 illustrates that at the most aggressive end of the spectrum a 95% penetration of electric vehicles (3.5m) would add 11TWh of consumption to the electricity sector.

While all scenarios discuss the potential effects of electric vehicle charging on the daily profile of demand, only MBIE specifically model it:

"Total EV energy demand is allocated by hour of the day based on the following assumptions:

- 80% of charging occurs between 11pm and 5am
- 10% of charging occurs between 5pm and 11pm
- 10% of charging occurs during the day evenly allocated between 9am and 5pm"[104]

These assumptions suggest that EV owners are generally motivated to charge between the hours of 11pm and 5am. If this this pattern proves to be true, and MBIE's profile of charging is approximately correct, it does imply some substantial changes to the demand profile by 2050. If this provided new resource adequacy challenges, our expectation is that pricing of EV charging would adapt to reflect this.

Heat

As discussed above, MBIE and BEC's assumptions about the electrification of heat are inherent in their underlying growth figures. Vivid present this sector separately, to highlight the significance of the heat sector. We repeat their figures[105] below:

Table 5 - Vivid's electrification of heat scenarios.

	Current level of electrification	Off Track 2050	Innovative 2050
Low Grade Heat	41%	75%	95%
Medium Grade Heat	5%	15%	19%
High Grade Heat	6%	6%	34%

Source: Vivid

[104] MBIE, 2016, "Energy Modelling Technical Guide".

[105] Table 5, page 25 of Vivid, 2017, "Net Zero in New Zealand", Technical Report.

The underlying drivers of the electrification of heat are beyond the scope of this report. Vivid have cited the evolution of both air-source and ground-source heat pumps and their potential to deliver low-grade (<100deg) heat across residential and commercial settings, as well as for more industrial-scale heat pumps in medium grade heat (100-300deg) applications. In the medium grade setting, we note that low emissions heat from electricity may compete with biomass[106].

6.2.2 Summary

All scenarios contemplate underlying drivers which could fundamentally change the nature of demand – especially its profile over the day and the year. But, generally speaking, we find all scenarios somewhat limited in illuminating the extent to which this happens. For example, MBIE's assumption of 80% EV charging during the 11pm-5am period may have a dramatic effect on the profile in high uptake scenarios. Vivid's assumption of low-grade heating electrification may have a significant effect on winter demand, when ambient air temperatures are much lower, which could make resource adequacy with renewables significantly more challenging. Without greater transparency of those changes, it is difficult to anticipate the extent to which they affect resource adequacy.

In the next section we dive deeper into the changing nature of demand precisely because the underlying nature of demand in the future (i.e. out to 2050) is not well probed in these, and many, modelling exercises. As demand morphs into demand net of own generation and storage and as consumers make a wider array of choices it becomes more important for the implication of these decisions to be better understood. The reason there is electricity supply with its ancillary services is to meet demand continuously. The transformation in the sector revolves around the changes on the demand side first and foremost so to understand what supply will look like in the future it is important to consider the changes on the demand side first.

6.3 Distribution

The scenarios outlined above make only very aggregated predictions about decisions being made at the consumer or distribution level. Demand, as described above, is the aggregation of millions of individual decisions about the consumption and – increasingly – the storage and production of energy. These decisions are not simply decisions about consumption of energy (net of small scale generation) but are specific to the time of the consumption, which creates individual load profiles, and specific to a geographical point, which creates location effects.

The scenarios tell us at an aggregate level how the central, grid-based system will respond to the evolving decisions about consumption, storage and production of energy made by consumers at their point of connection to the system (typically, the distribution network). Here we explore these decisions further

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106 It is not clear to us how Vivid arrived at the figures of 5-19TWh. We would caution assuming this is *additive* to the other scenarios; for example, BEC's underlying demand model includes technology switching and may assume some electrification of low temperature heat (e.g., heat pumps).

6.3.1 Distributed Energy Resources (DER)

Distributed Energy Resources are resources that are distributed throughout the power system, usually in the distribution network, that provide energy services to the power system. We use the term very broadly and use the term to not only mean the provision of energy but of services ancillary to energy supply. This means DER also includes Demand Response where DR is providing an ancillary energy service.

Improving the access, utilisation and integration of DER is important in helping reduce carbon emissions for three reasons:

1. Where DER is producing energy, it is increasingly likely to be from a low carbon source, especially solar and wind. These low emission energy sources can be encouraged by a carbon price but can also be encouraged by recognising, financially, other contributions they make to energy services.
2. DER, including DR, enables a dynamic demand side that can respond to economic and control signals to match supply and demand. This two-way dynamic supply and demand matching enables more low carbon supply to meet demand, reducing supply side emissions.
3. In overseas markets that have had a large amount of DER, especially solar PV, significant problems have arisen that have required expensive retroactive action, e.g. in Germany solar penetration lead to difficulties in absorbing the extra generation, high voltage problems and the lack of inertia[107] is increasingly a concern.

As low emission generating technologies rely on power electronics (such as inverters) to be able to connect to the power system and can be paired with an energy storage system (such as batteries) to 'move' the generation to periods when the system most needs it, then these technologies can provide a range of services from highly local and simple to more exportable and complex. In addition, providing energy services doesn't require a generating source. Batteries and inverters can provide most generation services without an active generating source and inverters can provide some services by themselves.

6.3.2 Power Electronics

To understand the progression of DER use it is important to understand and recognise the role power electronics (rectifiers, inverters and converters) have in the transformation of the electricity industry.

- A rectifier is a device that is used to convert AC to DC. Rectifiers have been necessary ever since electronic appliances have been available[108]. Without rectifiers DC devices that are impractically large to run on batteries (e.g. TVs and desktop computers, etc) could not exist as they couldn't plug into the AC electric power system[109]. Even small

[107] Inertia resists change in frequency in a power system, if power system frequency can change too quickly the system can become unstable.

[108] Technically earlier as glass valves were used prior to electronics.

[109] AC to DC conversion could only be done by using capital and energy inefficient AC motor to DC generator sets.

appliances would have to use interchangeable batteries rather than using rechargeable batteries.

- A DC/DC converter is an electronic device that can be used to convert one DC voltage to another. Prior to the DC/DC converter rectifiers had to be used with transformers to supply low voltage DC for electronic appliances. This made power supplies bulky. With increasingly small, efficient and cheap DC/DC converters (with rectifiers) then there is now no device too small to plug in. The prevalence of these small power supplies has now allowed plug in DC supplies alongside AC supplies, e.g. wired in USB ports for charging.
- An inverter is a device that converts DC to AC. This is more complex than converting AC to DC. Any device that produces DC must use an inverter to push that power into the AC network. Inverters work by very quickly switching a DC supply in opposite directions. Originally, they did quite coarse switching and used filtering to create a smooth AC output. Increasingly they are switching the waveform even faster allowing very fine control of everything the AC does.
- An AC/AC converter is a device that converts AC at one specification (say voltage) to AC at another specification (a different voltage). Transformers are still the cheapest and most efficient of changing voltage at high power but for low power applications AC/AC converters can be cheaper. AC/AC converters can be designed to change other aspects of the AC power supply as well, e.g. frequency. These converters can be designed to take a low specification AC power supply as an input and provide a high specification AC output.

Much is made of the transformative effects of solar PV and batteries, but the industry has already gone through a transformation thanks to rectifiers, with many more devices now plugged into the electric power system. The solar PV/battery transformation is only possible due to inverters. It is the reducing cost/increasing quality characteristic of solar panels, batteries and inverters that is driving the distributed generation transformation in electricity.

While it is increasingly cheap to purchase a high specification inverter the incentive in New Zealand currently is to match solar installations with the cheapest, generally fit for purpose, inverter available. In the simplest case an inverter only converts DC to AC within the supply specifications of New Zealand.

The highest specification inverters are capable of much more. They can manage frequency and voltage, they can smooth power flow, reduce power factor[110] (and losses) and improve the quality of the AC supply (harmonic attenuation). In combination with a battery they provide redundancy and can provide active stabilisation of the network[111]. A high specification solar/battery/inverter package can provide all the services of a grid scale generator.

110 Inefficient current flow.

111 An emerging concern in grids with large amount of solar PV is the lack of inertia. Spinning machines (such as conventional generators or motors) have inertia and resist changes in the power system. This gives time for the system to react to faults and prevents failure of the whole system. Batteries and inverters don't have inertia, but they could use energy from the battery to very quickly provide active power stability when faults occur.

This raises a critical point as we explore the fundamental choice between local energy source or grid supplied. Some distributed generation is capable of competing on a level playing field with other types of generation to the extent that it can provide the equivalent of grid generation services but solar PV with low specification inverters do not. The provision of solar PV incentivised to provide only low specification inverters is a barrier to low emission DG in the sense that it still requires support from the grid or distribution network. The level playing field also needs to be extended to flexible demand and smart appliances.

It is worth noting that the inverters described above could also supply the in-house AC supply. This would allow unbundling of services on the primary side of the inverter. A wide range of voltages (much wider than the currently regulated range) could be tolerated on the primary side as well as much greater tolerance to frequency and power quality. The inverter/converter package could manage the power quality on the secondary side.

The package could become a 'set-top box' for electric energy, with the downstream supply (potentially at different voltages and types, e.g. 230V AC and USB DC) meeting a high specification (potentially with home automation) and the upstream complexity (different supplies, voltages and sources of service, e.g. legacy power system (AC), local solar/battery (DC), community solar/wind/hydro/battery (AC and/or DC)) managed by the 'set-top box'.

6.3.3 DER in devices and appliances

The first point where, working upstream, DER can be selected by consumers is with individual devices.

It is increasingly common to be able to purchase devices that have their own low carbon energy source, i.e. PV solar panels, especially for outdoor devices such as garden lights. These devices may be relatively high price, in the sense of a per kWh cost, but are low total cost. They are often economic, despite the high price of equivalent energy, because they are convenient, often avoiding the need for high capital cost wiring and are easily relocated at low cost. Consumers can make efficient decisions about devices, ceteris paribus, because the costs, benefits and decision rights are all held by the consumer. Importantly, the consumer, while not being aware they are making this assumption, can assume that their power supply and devices all meet coordinated and compatible standards.

The desire to reduce power bills and the desire to reduce emissions both factor to some degree in consumer decisions around connected or self-supplying, solar-powered devices.

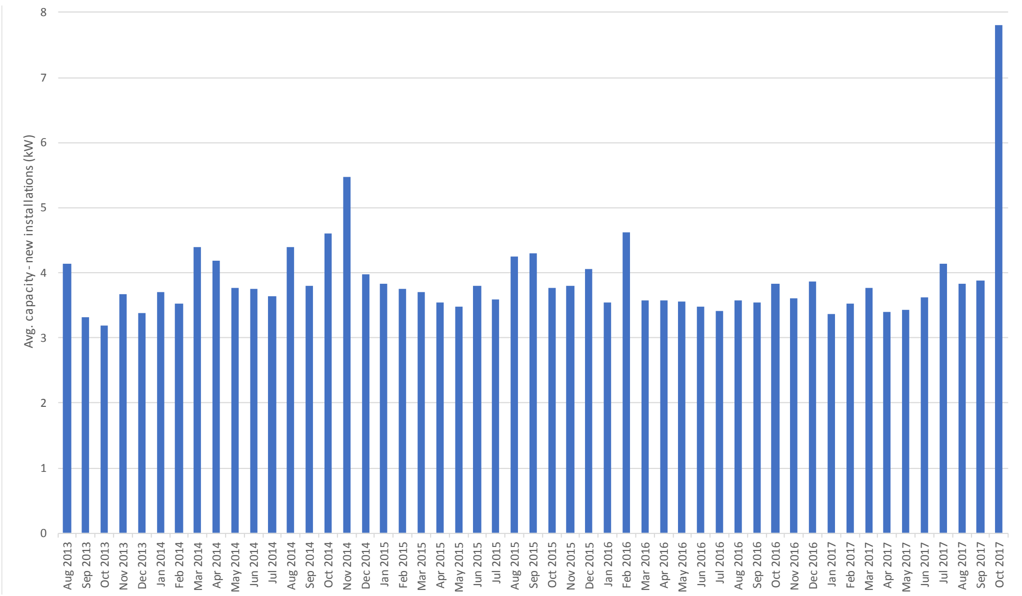
Solar powered devices and appliances are, often, the cheapest of solar powered devices as they will use, or can be designed to use, DC electricity and can, therefore, directly connect to their DC solar panels and batteries. Where solar panels need to connect to an installation's mains, as a building scale solar array and/or demand management battery must do, there is a need for DC to AC conversion.

6.3.4 Buildings and installations

The decision to choose local, low emission DER, e.g. a PV solar installation, within a building or installation is like the decision made to acquire any device or appliance; where the consumer consumes all the produced energy themselves. Then the consumer is, effectively, a reduced load and the consumer gets full relief from variable energy and lines charges from the solar input, i.e. their meter readings are lower. Batteries and smart appliances can help ensure the consumer is able to allocate their solar generation to only their own use. With simple inverters the consumer remains substantially a consumer of other distribution services (i.e. voltage, frequency, power quality), but high specification inverters can substitute for these services and provide service upstream as well.

At the times of day when solar output from an installation exceeds the installation load, and energy is exported, then the accrual of costs, benefits and risks becomes complex while the reward system for the DER export becomes simpler. DER exports on retail tariffs are usually only paid a 'buy' price for electricity. For any exports the DER owner does not get paid the full sales cost of energy and receives no reduction on lines charges (because that capacity is still required for when the sun isn't shining). Therefore, most solar panels tend to be relatively small (see Figure 47) in New Zealand, usually sized to the point where output is equal to or less than the load.

Figure 47 - Average installed capacity of solar – all ICPs[112]



There is a case for the low reward for low emission DG export. Particularly where they use inverters that don't produce any network services, as the distribution system must remain capable of meeting peak capacity, and there is no guarantee that low emission DG will be producing during network peaks (which are typically winter evenings, where there is, for example, no solar resource available). The transmission and distribution must still be built to the same capacity as it would otherwise have been. Similarly, as the DER installation isn't necessarily providing all energy services when they are required, then the wholesale market and the power system must provide the same services as they otherwise would.

Given that low emission DER installations can provide capacity and energy services, such as matching supply and demand, voltage support, power factor control, frequency and voltage

112 This includes all ICPs, not just domestic, except for October 2017 the average is quite low.

stability, and power quality improvement (with high quality inverters and/or batteries), then it is worth exploring whether these high specification installations are able to compete on the same basis as other providers of capacity and service.

To compare directly to a grid scale generator:

- Grid generators get paid the marginal cost of energy to maximise consumer benefit reflective of the time they generate and the location. DER gets the average cost of energy, which generally doesn't reflect the time of generation and is only generally reflective of location[113].
- Grid generators are dispatched, which tightly controls what they do but ensures that the generating output is consistent with their offers and ensures the grid generators are not generating at a price lower than their offered price. DER does not get dispatched and is free to operate, within the constraints of local distribution, but does not get economic signals to optimise operation[114].
- Grid generators are dispatched to manage system constraints in real-time and the price they receive recognises the extent to which their injection mitigates or exacerbates the constraints. If DER is installed in areas where constraints may occur, they will generally either be: not permitted, or will have operating constraints. Similarly, if the injection from DER mitigates, or is capable of mitigating, constraints the contribution is generally not recognised.
- Grid generators can earn revenue from ancillary service markets if they meet the market requirements for that ancillary service. DER cannot access these markets regardless of whether they meet the requirements or not.
- Grid generators are required to provide reactive power support and support voltage over a defined voltage range. Neither grid generators nor DER get paid for this service, but DER is not required to meet the Code requirements for reactive power and voltage support.

Some revenue is not available to DER and the efficiency signalling (through an averaged 'buy' price) is watered down as well. These issues aren't limited to low emission DER, nor is low emission generation necessary to provide some service (i.e. fossil fuels could be used for DER, a DER installation might have only a battery and inverter system or inverters can be used by themselves). However, if the marginal cost of higher specification inverters and batteries is less than the marginal benefit of potential grid services then there would be stronger, and more efficient, incentives to install distributed solar or other low emission generation in locations, and for times, when it would be beneficial. It would also provide some incentive for smart appliances, which could also supplement the provision of network services, e.g. frequency management.

113 Although lines companies are investigating cost-reflective pricing.

114 Generally, not a problem for solar only installations but potentially limits battery optimisation.

It would be possible to assess the scale of the potential uptake of low emission DER if DER had the same incentives as grid-scale generators. However, this analysis is out of scope, but a couple of indications of the potential scale of the benefits are described in Appendix 1.

Aside from the payment issue is the question of whether new regulation and standards are required for DER network services. Overseas experience has shown that sudden uptake of solar PV has led to significant power system issues. In Germany, for example, the large uptake in solar PV led to both voltage problems and problems with coordinating supply. Both problems had to be addressed retroactively, and now new PV installations must (i) have an inverter with a prescribed voltage characteristic, (ii) must be configured to trip at 50.2Hz, and (iii) there are now incentives for battery storage to assist supply coordination.

It would be difficult to determine now what standards for network service inverters should be required to provide in New Zealand. New Zealand is a relatively small, islanded power system and will have some different problems from large, interconnected, continental systems. Inertia, for example, could be a much bigger problem here than overseas. Voltage could be a problem in some areas in New Zealand but not others.

We note that overly onerous technical requirements might deter efficient DER. We note also that an alternative to regulation and rules is economic signalling and incentives.

6.3.5 DER in the distribution network

Upstream from individual consumers, decisions can be made about the use of low emission DER at the distribution substation, and in the distribution network. In fact, it may be more efficient to locate larger DER installations further upstream, rather than within a customer's premises. Two likely sources of benefit relate to economies of scale, and diversity.

There are potential economies in siting batteries, and potentially high quality (grid service type) AC converters, further upstream due to diversity. While long term average energy needs are additive, peak demand needs vary greatly from installation to installation, both in terms of the size of the peak but also timing. Even where there is a common reason driving peak behaviour (such as getting home from work for domestic consumption) there is still a significant difference in the exact timing of peak demand between homogenous loads. For example, where a single house is connected to a distribution substation then the transformer in that substation needs to be sized for the possible peak demand of that single house (about 15kVA). However, if 100 houses are connected to a single substation then the transformer can be sized for more like 3kVA per house.

Therefore, where the capital cost of equipment is driven by the required capacity, which is the case for the battery capacity[115] and the associated high specification inverter/converter, then significant cost savings can be made.

This means that the incentives for low emissions DER could be stronger, and more efficient, if communal arrangements could:

[115] There are two dimensions to the battery sizing choice. One is the power capacity the battery must have to supply the peak demand of load and supply. The second is the energy storage required to smooth the load and/or supply. Diversity assists with the first sizing dimension but not so much the second.

- Share the benefits of a common battery/inverter,
- Coordinate the contribution of DER injections with battery optimisation,
- Coordinate and optimise any demand management systems (demand response), and
- Allow for peer to peer trading of DG (e.g. solar) surpluses and shortages within the community.

These are some of the purposes of emerging technologies such as smart grids and blockchain transactions.

Under such a system the reasoning that DER should get a lower price (due to still needing full service from the network) no longer applies. Such a system does reduce the need for network service up to, and including, the point where a communal system could disconnect from the power system.

At present the ability of a suitable community of consumers to form such a collective system is limited. It is also difficult for generic third parties to provide services for such a system. Currently, the best placed organisations to provide these services (due to asset ownership) are lines companies or embedded network owners, and some lines companies are pursuing the technology and infrastructure to offer these services. However, the incentives for the asset owners are complex.

We note that distributors are pursuing more cost-reflective and service based pricing than has been the case in the past. The Authority is following this with interest as they see efficient distribution pricing as one of many issues that needs to be better if we are to have an efficient sector in the future. Thus far the work is focused on network services remaining bundled. If networks services are priced on an individual basis, and there is truly open access to networks, it would become possible for alternative suppliers of individual services to aggregate DER providers and on sell these services to consumers - in competition with distributors. By way of example the individual services we are referring to include the balancing of supply and demand, voltage/reactive power, frequency, power quality, and potentially stability support. Unbundling all such services may be expensive but there is also expense in not unbundling the services, in the sense of not achieving ways to provide these services more cheaply and, potentially, better. Appendix 1 provides a couple of examples of the benefits of using DER for service more broadly.

The issue of what the distribution service is, and how it could be priced, is complex and beyond the scope of this study. In fact, the concept of DER competing for distribution services is only emerging – certainly in New Zealand.

In keeping with open competition for all power system resources it's worth noting that grid connected generators have mandatory requirements for some aspects of their specification, e.g. mandated reactive power and voltage ranges. Which comes back to the question of whether DER should also have to meet these requirements. The reason grid connected generators have these requirements is that, up to the 1990s, all internationally available generators could meet the requirements; and there was little marginal cost for investors to meet the standards. However, as new technologies came in that couldn't meet these standards, equivalence and dispensation arrangements have been put in place to allow for economic non-compliance. Renewable distributed generation is not normally able to meet these standards and there is a marginal cost to providing them, as there is increasingly for grid scale technologies. As we expect smart, flexible demand and greater tolerance to variable power quality to be part of future solutions as well, then it makes sense to us that economic signalling would be preferable to bright line rules.

The current wholesale electricity market provides economic signalling for energy and instantaneous reserves now, although with some aspects of the network service provided either off-market (e.g. voltage support) or through bright line rules (e.g. reactive power capability). However, even for the economic signalling that the current market provides there is a need to link from the grid, through the distribution network, to local smart networks and building management systems.

6.3.6 Distribution System Operator (DSO)

The notion of a distribution-level system operator arises because the combination of DER and unbundled services have the potential to lead to a more efficient system (and more emission friendly load profiles) if distribution level security coordination and economic dispatch is provided separately from the network owners. This is the model currently partially deployed at transmission grid level[116]. In this context the primary purposes of a DSO are to:

- ensure all power system resources (including DER) have competitive access to common infrastructure, optimised for all competing resources, and at a reasonable cost for monopoly assets, and
- coordinate DER (including smart, flexible demand) so that participant's preferences for security, quality and reliability are maintained, while recognising each load's and generating source's influence and preferences on marginal cost and marginal benefit.

The term DSO is a similar concept to a Transmission System Operator (TSO) but is a different role. When it comes to system operation, the transmission network is different from the distribution network. While a TSO could perform the role of DSO, it is not a straight forward extension of the TSO role. Neither does there need to be a single DSO, there could be regional DSOs, and this may even be desirable for performance benchmarking.

As the value of all parties that own assets in the power system are directly affected by the system operator, the debate over the independence of the DSO is the same debate as that over the independence of the System Operator[117] in wholesale markets.

While a DSO might have jurisdictional responsibility for a distribution region it would not necessarily have operational control over the whole region. The first local smart networks

116 In New Zealand the System Operator is not separate from the Transmission Asset Owner (both are Transpower). However, this was only agreed to after assurances, rules, policies and procedures were put in place designed to ensure the System Operator had operational and governance separation from the rest of Transpower sufficient for it to perform the SO function as if an ISO. In addition, long run investment decisions are under the mandate of the Commerce Commission, and transmission pricing decisions are under the oversight of the EA, where they may be under the ISO in other jurisdictions.

117 Ditto

could be communal systems as described above. It seems desirable to let these local smart networks develop dynamically, in which case the role of the DSO would be to:

- licence local smart network operators while requiring:
  - competitive open access between monopoly infrastructure owners
  - security performance aligned with consumer preferences
  - the efficient dispatch of DER (including flexible demand)
  - correct local and global optimisation
- provide the correct pricing signals to smart grids and other users to facilitate choice between local DER and using grid energy and services
- provide the correct demand signals to the transmission network and wholesale market reflective of the above[118]

6.3.7 Benefits of a DSO

In its Smart Power paper[119] the UK's National Infrastructure Commission concluded that, in addition to being a key enabling function for the UK meeting its carbon equivalent emissions target of 80% reductions by 2050, consumers could save £8 billion per year if 'smart power' was done right. The NIC described 'smart power' in the UK context as being:

- **Interconnection** with countries with cheap supplies of renewable sustainable electricity, e.g. Iceland
- **Storage**, and particularly ensuring that energy storage solutions can compete on the same basis as conventional generation, and
- **Demand flexibility,** using automation and control technology to make use of inherent demand flexibility (and flexible consumer preferences) to manage the balance between supply and demand.

In discussing how to maximise the benefit of 'smart power', and in the context of DSO, the NIC recommended:

"Recommendation 5: Enabling the transition to more actively managed local networks should be a government priority. By Spring 2017 DECC and Ofgem should consult and set out how and under what timeframe this transition should best take place."

In our view the role of DSO, as we have described above and with optimisation modelling, not only maximises the benefit of smart technology but also enables the level playing field of competition between traditional (predominantly supply side) solutions and DER (storage, distributed generation and/or flexible demand). Such a levelling of the playing field would be more likely to facilitate low emission DG, where it is economic, than the current approach.

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118 Recognising that the future transmission network and wholesale market is likely to be bigger than it is currently, as it could include sub-transmission and zone substations (defined by electrical characteristics not ownership).

119 "National Infrastructure Commission report – Smart Power" - undated

7. The trade-off between emissions, resource adequacy and cost

7.1 Marginal cost triggers of abatement

In our general discussion above, we have noted the level of carbon prices that have given rise to certain decisions. We have also highlighted, however, that in many cases it is the *trajectory* of carbon prices that has influenced the decision. A cursory glance at Figure 40 illustrates two carbon price trajectories (MBIE MR and BEC Kayak) that, while ending in 2050 within $25/t of each other, they spend much of the period modelled substantially more different.

From the model's perspective (as a proxy for an investor's decisions), the carbon price that matters for each decision is both the price at the time the decision is made, as well as the series of prices that occur throughout the horizon of the economic analysis of that decision (appropriately discounted to reflect the time value of money). This is the same for an investor, although the models above know the carbon price with certainty (whereas an investor would need to form a view, and consider uncertainty and risk).

So while we can observe that the MR scenario reduces emissions slightly to 4.9Mt in 2050, with a carbon price in 2050 of $83/t, the $83/t plays only a very small role in the emissions outcome. It is the series of carbon prices factored into each decision by the model are what matter (of which $83/t is only the last occurrence).

This observation highlights the great difficulty with marginal abatement cost curves: the relationship between emissions reductions and the carbon price is a multi-dimensional one, where time is one of the dimensions, and the profile of future carbon prices is another. However, in the interests in succinctly summarising the results of the preceding section, we simplify this as follows:

- Since our primary interest is in a low-emissions electricity sector, we are interested in the decisions that reduce emissions. The key decisions are the decommissioning of gas plant[120].
- Due to their plant life assumptions, we know that MBIE's scenarios present a critical decision point for TCC in 2025, and for HLY5 in 2033. Also, BEC's scenarios assume the critical decision points for these plants are in the period 2030-2040 (assuming 2035 as a mid-point).
- Hence, we will assess the <u>discounted</u>[121] <u>average</u> carbon price as at 2025 and 2035 for each of the scenarios to give the reader a guide as to the level of the carbon price – as a single number – which is operative at the time key decisions are made.

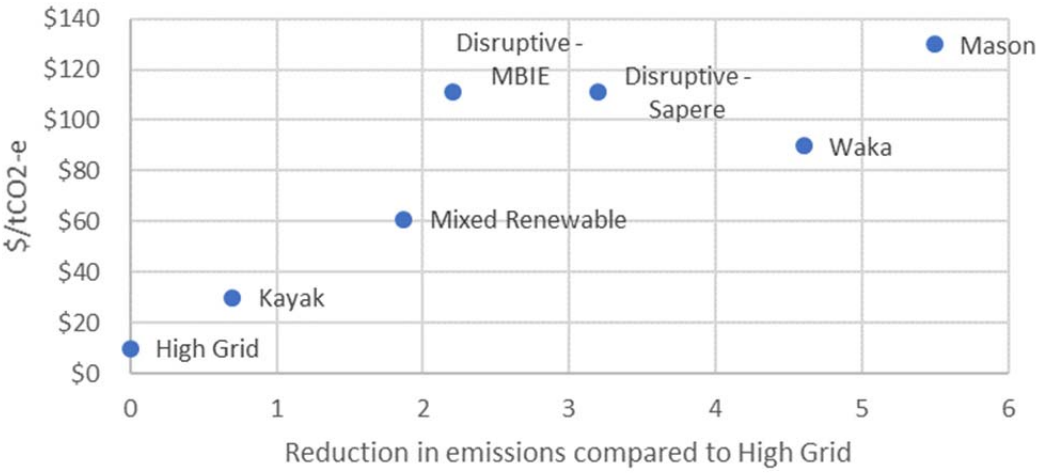
120 On the assumption that the Huntly Rankine units will be decommissioned within the time frame irrespective of the carbon price

121 Assuming a discount factor of 8%, and assuming a constant consumption of fuel during that period

- As a "status quo" scenario, it is not useful to use today's emissions, so instead we will use the 2050 outcome of MBIE's "High Grid" scenario. The High Grid scenario is useful in that it assumes a flat profile of carbon prices of $10/MWh, and ends in 2050 with sector emissions of 6.7Mt pa.

The results of this calculation are illustrated in Figure 48.

Figure 48 Marginal abatement cost curve based on carbon price decision points



We acknowledge that these are not true "marginal abatement costs", as the carbon prices illustrated in the chart are not values that represent indifference between investing to reduce emissions, and not investing. However, given the numerous difficulties with interpreting abatement cost curves, we do not feel that this compromises the insights at all.

The points certainly do not describe a smooth relationship between the carbon price and emissions reductions. As already discussed, this represents the many different assumptions inherent in the scenarios, including:

- The level of demand growth experienced
- Assumptions about the attractiveness of refurbishment versus retirement
- The availability of firm, renewable resources as a replacement for gas at the time the decision is made
- Whether carbon prices are sufficiently high enough to decommission cogeneration that exists as part of an industrial process

We prefer that this chart was interpreted as points within a zone of carbon prices that may lead to these emissions reductions.

7.2 Uncertainty

All of the analysis above is based on what we know today. While it is tempting to form a view on which fuels will make up future supply there is significant uncertainty about the costs and the technological practicality of the options considered in the scenarios discussed above. The costs of some technologies are moving favourably (e.g., solar, batteries and wind) while others need more research in the electricity context (e.g., biofuels and CCS).

Some of the key sources of uncertainty are:

- geothermal emissions of future developments. There is a significant range of potential emissions which depend on the technology used, and the field chemistry;
- the extent to which additional storage in existing hydro sites would improve resource adequacy in a low-thermal environment;
- the availability, cost and benefit of further storable hydro sites (especially those not subject to snow-fed catchments);
- the technological feasibility (and therefore cost) of CCS, which could be a viable alternative for the mid-merit hydro-firming role
- the potential for energy efficiency to "flatten" load across the year and, to some extent, across the day, making inter-temporal decision making easier
- the commercial viability of gas production and accompanying distribution networks if they are only serving a large number of low load-factor gas peakers
- the availability of renewable resources to supply high-growth scenarios
- the prospects for biomass-fuelled plant, in terms of both the cost and supply of feedstock for biomass feedstock.

Each of these topics are worthy of further research in their own right but those studies are outside the scope of this report. If the sector is to deliver very low emissions, further research on these topics may provide the answers to maintaining resource adequacy at the least cost.

In parallel to these issues there are additional sources of uncertainty which exist in markets for fuel, power and carbon:

- **Fuel risk:** reservoir risk vs the ability to obtain sufficiently flexible contracts for gas.
- **Market risk:** how the wholesale market dispatches and rewards plants, specifically their flexibility characteristic, as well as other sources of revenue (e.g., retail customers, or futures markets).
- **Carbon risk:** Investors make decisions not knowing the future carbon price, and thus will make judgments and incorporate risk.

Any investor in power stations has to account for these risks today. When making an investment decision, ideally:

- The investor must believe the price, for all periods where the generation investment will be called on, will be sufficient to make a return on fixed costs and
- The investor must be confident that the plant will be called on to run often enough to make a return on fixed costs; and/or
- The investor must believe they can manage their revenue risk with hedging arrangements that are sufficient to recover fixed and variable costs; and
- The investor must be confident that any fuel supply arrangement will support the necessary running regime to capture prices above short run marginal cost and manage the risk on hedges sold.

These risks are interconnected with the transition to low renewables: markets for firming fuel (e.g., gas) will be affected by an overall decrease in the demand for gas, as well as the transition of gas demand from baseload to flexible fuel arrangements. Expectations of future carbon prices will depend on investor's views on the extent to which the country's carbon targets will be met with low-cost emission reductions (in any sector). Finally, and most relevant to decreasing emissions in the electricity sector, the volatility of wholesale prices in a very high-renewables system is likely to increase. Renewable generating stations (geothermal, wind, run-of-river hydro) have low (or zero) short-run marginal costs (SRMC), and are offered in to the system in that way. As the proportion of low-SRMC generation increases, wholesale prices will be supressed below current levels for longer periods of time[122]. While advocates of strong scarcity pricing in energy-only markets may argue that the incidence of very high prices would increase to keep the overall average price constant, we do not believe that the potential resulting distribution of prices has been considered in any depth, and whether further market measures may be required to solidify scarcity pricing.

With the prevalence of hydro, New Zealand faces the very real prospect of prolonged periods of very low prices before a sufficient number of high price periods are observed to provide investors in peaking plant an adequate return on investment. This may deter investment in peaking plant.

We stress that these decisions are about the underlying efficiency with which the given plant will "fit" into the system, as rewarded by the wholesale price in the current market design, and as enabled by the underlying fuel arrangements. Even jurisdictions where central or provincial governments make investment decisions face the question of whether an investment is efficient (on behalf of the taxpayer).

We now focus on two specific issues of risk which seem central to maintaining resource adequacy while transitioning to very low emissions – managing the dry year hydro risk while decommissioning thermal plant.

7.2.1 The dry year problem

Internationally, the concern about increasing renewables focuses on the capacity issue – the extent to which we can be assured that the system can meet periods of high demand (net of intermittent renewable generation). The scenario is clear, as the time period concerned is of very short duration. Solving this problem can involve leveraging distributed and grid-based flexible resources, even energy-limited devices such as demand response and batteries. The requirement to contribute is very short, so demand responders will only sacrifice consumption for a short period of time, and distribution and grid-scale batteries are unlikely to exhaust the limitations of their storage capability.

As discussed in Section 4.1, New Zealand has a relatively unusual resource adequacy characteristic, associated with its own, very large, medium-term battery – hydro storage. While our hydro resources make significant contributions to peak adequacy, the storage limitation (4,000GWh, compared to a current annual system demand of 40,000GWh) introduces a constraint on hydro's ability to flexibly shift energy through time. Further, the

122 This has been observed in Ontario, for example, where wholesale prices average approximately CAD16/MWh in 2016 – see http://www.ieso.ca/power-data/price-overview/global-adjustment. See also discussion in Jenken, Beiter and Margolis (2016) "Capacity Payments in Restructured Markets under low and high penetration of renewable energy", Report for NREL.

"charging" of the battery is highly uncertain, as it is driven by the weather and consequential decisions by generators. We also identified that, if demand grows in a manner that reflects the current seasonal profile (winter peaking), the need for inter-seasonal shifting will increase, further beyond the capability of current hydro generation.

Section 4 discussed at length the current role of thermal plants as mid-merit or hydro firming support, and clarified that this role is demanded as a result of both the *actual* insufficiency or renewable fuels over a period of time, as well as the *risk* of insufficiency of renewable fuels over a period of time. The time dimension itself is uncertain. This means that solving the resource adequacy problem requires two "products": one (peak adequacy) which can be clearly defined and measured, the other which is shrouded in weather-induced uncertainty and perceptions of risk.

Hence the utilisation of these plants – and thus the emissions - in any given year, will depend on the overall amount of weather-dependent fuel received by hydro, wind and solar, as well as the timing of that fuel. Even preserving a particular thermal plant in the future for years which experience less than "normal" or average hydrological flows may not necessarily result in that plant only operating in "dry years" (depending on the precise mechanism used to make the plant available), as discussed earlier.

The scenarios above achieve emissions reductions by decommissioning – to different degrees - existing CCGTs (TCC and HLY5) and the Huntly Rankines, while simultaneously constructing sufficient flexible peakers. Our quantification (using the WCM and WEM) suggests that even the lowest emission systems in 2050 had sufficient gas peakers to manage a dry year. This has some insights and qualifications worth highlighting:

- The reliance on peakers to manage the dry-year risk is sensible as the number and available of alternative options is much lower than for the peak capacity issue. Batteries are unlikely to provide inter-month (let alone longer) storage. Demand side response (over and above the existing Official Conservation Campaigns) seem limited to some industrials who may be able to curtail production for a number of weeks or months. Hence we expect that gas peakers will be vital to – at the very least – the transition to a low emissions electricity supply chain, until options such as hydrogen storage, biomass peakers or CCS become viable and economic.
- But the challenge for peakers is an economic one; while they have the lowest capital cost (making them a less risky proposition), investors need to be assured that the extent to which they are called on, and the price they will earn, is sufficiently reliable to commit to the investment. The expected load factor for peakers ranged between 0.7% (Mason *et al*), 4%-6% (MBIE) and up to 14% (BEC). These load factors may challenge the investment case; the lower end suggests there is a reasonable likelihood that the peaker may not run for a number of years (during which time operations and maintenance cost will continue to be incurred). Financial contracts may be struck with other market participants – who want to be insulated from the market impacts of a dry year – may be sufficient to give investors this certainty. However, the willingness-to-pay for these contracts is a complex interplay of price level, frequency and duration; the expectations of which is subject to an anchoring bias around current or recent market conditions.
- We note that it is plausible that gas peakers, in fact, get progressively isolated to the dry-year role. If batteries and demand response collectively emerge to be competitive or superior to gas peakers in managing peak adequacy, gas peakers may not realise the

scarcity rents associated with peak scarcity, and be purely reliant on dry years for revenue streams. This reinforces our characterisation above of there being two products here; eventually, gas peakers may only be competitive in one.

- We observe that the same arguments apply to the fuel contract required to support the peaker's operation, as well as the gas distribution network. All parts of the gas supply chain incur substantial fixed cost, and will find pricing that fixed cost challenging in such a low load-factor, and intermittent, environment. Huntly has been able to provide a large part of this dry-year service to due to the relative simplicity of the way a coal stockpile works. That said, the coal storage solution is not without its cost.
- Until now, the dry-year problem has been managed through a very small number of plants. The scenario heralded by our low-emissions, with over a 1,000MW of flexible peakers, illustrates the possibility that in the future dry year risk could be managed by a range of different participants. This possibility highlights that the relatively simple coordination possible now (as evidenced by the contractual arrangement between Meridian and Genesis) may be a lot more diverse in the future.
- The exact timing of this transition as indicated in the scenarios should be treated with caution. Perfect foresight, partial equilibrium models have the benefit of being able to both optimise the timing and coordinate the investment in the replacement generation so that resource adequacy is not compromised during the transition. The reality for any retirement of thermal plant will be that this will be done at a time when the market can best manage the transition. the new investment must, of course, be based on a view that there is "room" in the market for the new investment to be economic. Here, good market signalling about other market participants' decommissioning intentions is important. We can see clear signalling from Genesis about the future of the Huntly Rankines, and Contact's statements about the most recent TCC refurbishment decision also provides valuable information about the longer term intentions for that plant. Resource adequacy was maintained through the decommissioning of two Huntly Rankine units, Otahuhu and Southdown. Effectively, the market achieved this by pre-building generation (geothermal, wind and gas peakers).

Ultimately, the dry year problem is a complex problem that, despite the WEM, is difficult to succinctly capture in metrics. It will remain as a key part of the New Zealand energy landscape, and the risk management problem that the industry must collectively solve.

7.3 Impact on consumer pricing

Above, we have highlighted the different pathways to reducing emissions, which principally are driven by different levels of the carbon price.

Here we turn our attention to the potential impact of these changes on consumer prices. This is not just to assess the economic impact on consumers, but also to test whether prices rise to a level where there may be a dynamic consumer response that is insufficiently addressed in the scenarios we have discussed above.

The energy component of retail prices will not only depend on the degree of competition, but to summarise all potential consumer offers and tariff structures as a single "price" is a significant over-simplification. However, there is value in doing this, even if just to illuminate the underlying dynamics which we need to anticipate.

A common method for long-term pricing is to assert that the energy component of the retail price (averaged across all sectors) at any point in time must be close to the LRMC of generation. The underlying philosophy is that, if the average revenue that generation investors earned on the marginal investment was any less than this equivalent price, then investment would not take place. Hence the average energy component of the retail tariff must rise to the LRMC of the next generation investment in our merit order, for investment to be triggered.

There are some shortcomings in this framework, but there are few other methods available to systematically produce long-term price forecasts. But, for completeness, we consider the critical considerations as:

- Often the LRMC-based price forecast is asserted to be a forecast of *wholesale* electricity prices. We believe this is a potentially erroneous assumption. Few generation investments would be sold on the wholesale market; it is far more likely that they are sold on medium-term contracts, either through the electricity hedge market[123], or to retail customers. Each of these options has difference risk-return trade-offs compared to the wholesale market, and – in all likelihood – will attract higher prices than the wholesale market will deliver (on average)[124]. Hence we believe that it is more robust to conclude that the LRMC-based approach is an estimate of future contract prices, which *may* deviate from future wholesale prices, even in the long-run.
- The LRMC for a given power station, based on our methodology discussed above, is the *levelised* price over the life of the power station that must be earned to cover fixed and operating costs and make a return on capital. If an investor believed that (real) prices would rise over the life of the power station, then the price required at the time the station is commissioned can be lower than the levelised price, as long as the shortfall early on is offset by a price higher than the levelised LRMC in the later years (all adjusted for discounting). Hence we may see investments occur *before* contract prices rise to the LRMC. Put another way, a forecast of future LRMCs, associated with the investments at each point in time, may overstate the average contract price at that point in time[125].

Noting these factors, we still believe it is insightful to observe the LRMC projections associated with the different potential pathways to very low emissions. MBIE calculate the LRMC in 2050 for each of their scenarios, which we use here. Again, we use the “High Grid” scenario as a counterfactual where no emissions reductions are achieved, and the system remains approximately with its current emissions profile.

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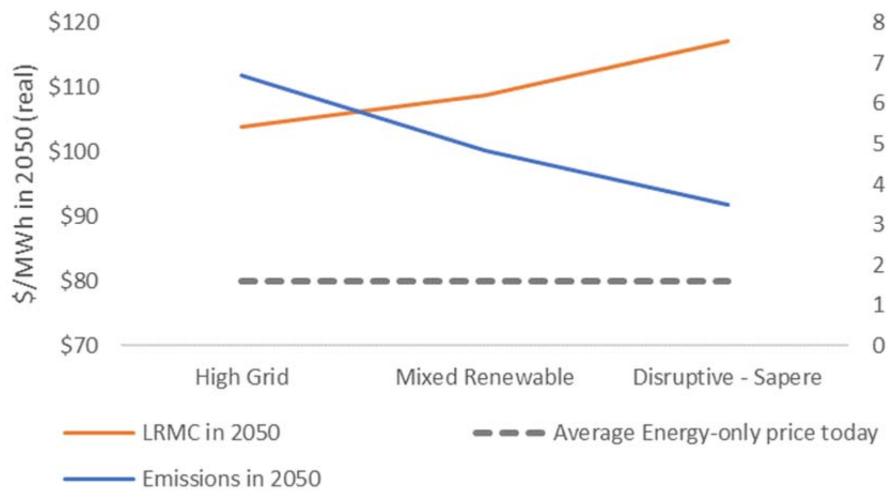
123 This may be either bilaterally negotiated over-the-counter (OTC) contracts or sold into the electricity futures market (on the Australian Stock Exchange)

124 This is because we generally expect contracts will attract a risk premium reflecting the underlying risk aversion of the contract buyer. This premium may be reduced through the presence of risk-neutral speculators in the contract market. Numerous attempts have been made to estimate this premium, but such an analysis *ex post*, for what is fundamentally an *ex ante* contract decision, is fraught with difficulty.

125 The associated assumption here is that contracts stuck to support the generation investment are of a sufficiently short duration to allow the generator to enjoy the benefit of rising prices over the life of the station. We believe this is a reasonable assumption in either the OTC/ASX or retail case.

Figure 49 - Emissions vs MBIE's Long Run Marginal Cost estimates in 2050



In Figure 49 we compare the average price expectation in 2050 with an approximation today's energy-only component of consumer prices - $80/MWh[126].

The LRMC estimates suggest that the average price rise for consumers, in real terms, between now and 2050 is between $25/MWh (2.5c/kWh) for a modest reduction in emissions, and $40/MWh (4c/kWh) for the deeper cuts in our amended version of the Disruptive scenario. As discussed above, achieving deeper cuts (e.g., using flexible geothermal instead of gas peakers) will, based on what we know today, set the marginal technology at approximately $140/MWh, which would imply a 75% increase over today's prices.

Well before 2050, we are suggesting that DER and demand response will be competing directly with distribution for distribution level electricity services. To the extent that a higher carbon price encourages more DER, such as solar PV, there will also be a net reduction in system operation and distribution costs. Total cost would rise but we see no reason why any uplift in costs would be significant within the uncertainty of predicting outcomes to 2050. We assume no discernible effect on distribution costs on consumer prices for higher contributions of DER.

All of the scenarios we have based our assessments on have thousands of megawatts of wind located predominantly in the lower North Island, therefore all scenarios will have costs in the order of $5 billion for transmission upgrades to export the wind energy to load centres. Based on a typical scenario of $300 million of extra annual transmission revenue requirement across an energy base of 65TWh then transmission would lift consumer prices by about 0.5c/kWh. Scenarios with larger demand forecasts would allocate the transmission costs across a bigger energy base but would also need some extra transmission capex. Within the

126 This is a mid-point between the ASX futures price and 30% of MBIE's reported average domestic tariff (28c/kWh) in the Quarterly Retailer Survey. The 30% figure is the Electricity Authority's approximation of the component of the overall tariff that relates to generation (see page 7 of https://www.ea.govt.nz/about-us/media-and-publications/electricity-nz/)

uncertainty of forecasting out to 2050 and the margin of error we use 0.5c/kWh for all scenarios. However, we stress that in the scenarios with very large conversion of process heat to electricity we can make no assessment of the extra transmission costs as we have no indication of where this extra load would be located.

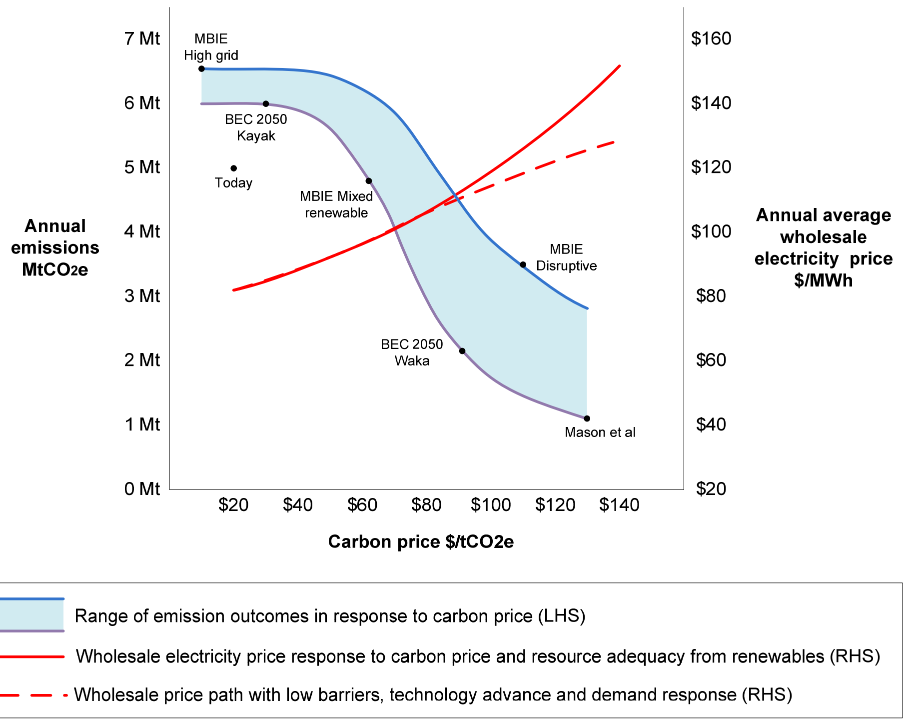
We caveat these estimates with the observation that, as discussed above, markets with high penetrations of low-SRMC, and intermittent renewable generation are likely to give rise to substantially more volatility than observed today. Hence, the risk premium applied to fixed-price, variable volume retail contracts (the predominant contract form in mass market retail today) may very well rise as higher renewable penetrations occur. This would result in an additional uplift in retail prices over what is presented in Figure 49 above, as the retailer would be insulating the consumer from wholesale volatility to a greater degree than currently.

Of course, this may have a dynamic response from customers:

- More customers, aided by automated demand response, may be incentivised to choose spot-based contracts, and/or
- The level of prices may incentivise other consumer investments (e.g., solar + batteries, use of EV storage)

If the market design evolves sufficiently to correctly signal the value of energy flexibility to consumers, this dynamic response may, in fact, result in the demand side contributing to low-emissions resource adequacy, thus providing a lower-cost trajectory than our supply-side analysis suggested. This trade-off between carbon prices, electricity prices and emissions is illustrated in Figure 50.

Figure 50 Emissions/carbon price relationship in 2050 and impact on wholesale electricity prices



Here we plot the pairs of carbon prices and emissions outcomes for the scenarios we have explored in Chapter 5. We don't see a marked fall in emissions until the carbon price gets above $60/t. As we move from $60/t to $80/t we see the effect of the removal of CCGTs. Further emission reduction are achieved as the use of thermal for resource adequacy is replaced with renewable sources of energy on the supply side and greater dynamism on the demand side. The lowest point we reach is the Mason *et al* solution where emissions have declined to solely emissions from the geothermal process. As we discussed earlier, in the Mason *et al* situation even the direst situations are addressed by renewable energy sources or demand response.

Also shown is the progression of wholesale energy prices relative to carbon prices as discussed above. The broken red line represents the last point made above i.e. that consumers would respond to rising wholesale energy prices and the demand side will be far better able to do this in future.

8. The regulatory framework to support a very-low-emissions electricity market

8.1 Our approach to any regulatory challenge that arises

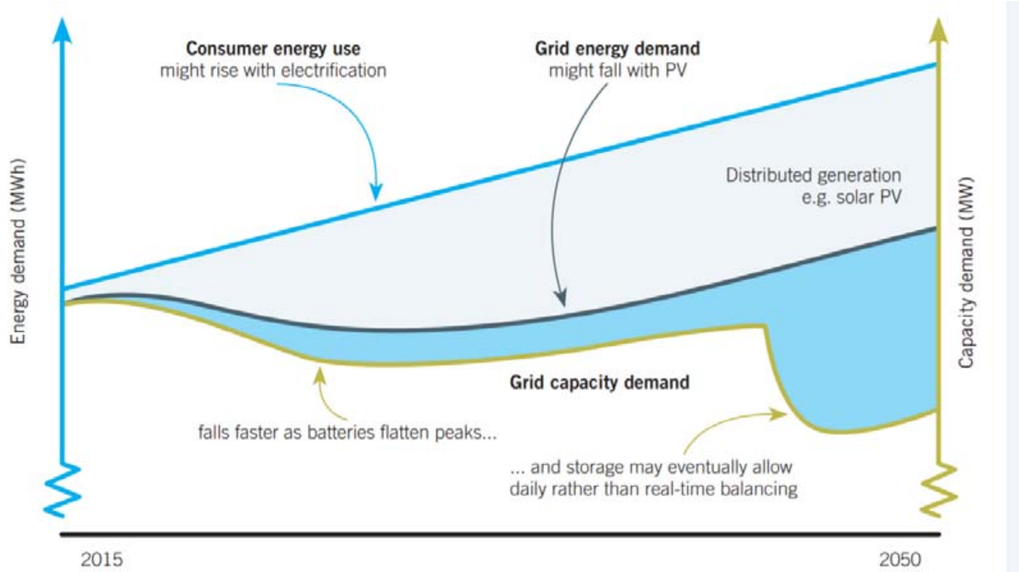
Figure 50 gives a view of the emissions levels that we can expect relative to carbon prices in 2050. It also shows the corresponding wholesale electricity price we expect taking into account the impact of the carbon price in any thermal running and the LRMC requirements of renewable plant used to maintain resource adequacy. Thus we have provided a view of the scope and cost for reducing emissions in the electricity sector based on carbon prices and the cost of resource adequacy with less thermal in the system.[127] In this section we consider what steps regulators and policy makers should consider with a view to accommodating a very low emissions electricity sector by 2050 or to increase the likelihood that a very low emissions outcome will be achieved by 2050.

We have discussed a number of trends that will inevitably change the emission profile of the sector to some degree without any significant step changes to the way the sector is organised. The most notable trends traversed above include the increased investment in renewable generation driven by cost competitiveness, the decommissioning of larger thermal units at the end of their economic lives and the devolution of decision making to the mass market. Small scale domestic consumers are now making decisions about the purchase of electric vehicles, small scale generation and small scale battery storage. Battery storage combined with small scale generation has the capacity to shift consumption intraday and thereby change the traditional consumption only load shape.

Transpower offer a stylistic picture of the potential net effects of technology on demand which is consistent with our understanding of the changes that are coming. They identify that whatever increases in consumption may take place, for example the electrification of transport or industrial heat, demand will be offset by small scale generation and load shape will be aided by greater use of storage to flatten peaks

127 The current government has clearly signalled its intention to target a zero emission economy by 2050 and is taking steps to set that up as a clear goal underpinning this government legislative agenda. Principle steps include bringing the target into law and appointing a Climate Change Commission charged with overseeing the pathway to a zero emission economy.

Figure 51 Potential effect of technology on demand[128]



Under current policy settings, ongoing decisions may lead to higher renewable electricity generation, a flatter load profile and, with it, lower emissions. The greater level of renewable generation will be a combination of grid scale generation and small scale generation. A key factor in those decisions will be the carbon price emanating from an economy-wide ETS; we presume that such an ETS will reflect the marginal abatement cost to the economy as a whole. The way the current model of the ETS works we have no certainty about what the carbon price will be at any point in the future.

The challenge that remains is to identify what else will have to be done to reduce the "friction" in the market and lower barriers against the trends that we have discussed above so the sector can deliver economically efficient resource adequate low emissions outcomes by 2050.

8.2 Regulatory Challenges

8.2.1 Carbon prices

Since 2008 the principle tool for sending a signal to fossil fuel emitters in the New Zealand electricity sector is the ETS. A number of changes have been made and a number of potential changes are in the pipeline. The new Government formed in later 2017 has signalled that it intends to continue to rely on the ETS and, accordingly, in our analysis we consider outcomes that might occur given various carbon prices. However, we observe that, even if the carbon price is indicating that further emissions reductions from the electricity sector are efficient, these reductions will not necessarily occur because the carbon price is only one input into investment decision making.

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128 Transpower *Transmission Tomorrow* May 2016

The regulatory challenges are whether the settings in the ETS lead to price outcomes that fully reflect the cost of carbon emissions and that investment decisions (including contracting decision) that impact on emissions levels will take other factors into account. .

8.2.2 Regulated distribution businesses and Transpower

The Commerce Commission has also moved to take into account changes in the electricity industry as it affects their regulation of regulated businesses. It reports:[129]

> *We are very aware of the potential for significant change to arise from the combination of falling costs, improving performance and increasing capabilities of some new technologies, new business models (especially in the spaces currently occupied by EDBs, electricity retailers and generators), and evolving consumer preferences. These developments present opportunities and challenges for EDBs, and have the potential to deliver significant benefits to consumers.*
>
> *It is not clear how EDBs will respond to these changes and opportunities, but it seems that the boundaries between participants in different vertical segments of the electricity market may be blurred, which may require changes to legislation or regulations.*

The Commission goes on to describe changes it has made aimed at accommodating these trends such as allowing distribution businesses to recover the cost of assets more quickly.

Clearly the Commerce Commission is focused on changes under its purview in the current regulatory environment and its ability to respond to emerging technologies. However, we observe that the market environment is likely to be significantly different in 2050 and the possibilities far wider than will be covered by focusing on just responding to emerging technologies. Already consumers are not confined to being at the end of the supply chain and more dramatic changes to the way the market is organised may be required. Distribution system operation is still largely orientated towards minimising distribution investments and supplying a bundle of network services. That may not be the appropriate model for the sector by 2050 and with high degrees of renewable energy especially small scale.

An example of a way the Commerce Commission could facilitate more innovation that may lead to lower emissions would be to drive the provision in Part 4 that requires distributors to consider distribution alternatives when looking at requirements for new capacity. It is not a trivial issue and has been the focus of a lot of attention at grid level for some years. This example illustrates the fact that more could be happening in the path to innovation under current regulations and the reluctance to act lies equally with the regulator and the distribution sector.

Another example of a barrier to demand response from a parties other than distributors is the asymmetric incentives for lines businesses to spend capex (where distributors are assured of a return they rather than opex (which is a pass through cost). This is a good example of

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129 Commerce Commission *Input methodologies review decisions Topic paper 3: The future impact of emerging technologies in the energy sector* 20 September 2016

issues that undermine incentives for pursuing demand response solutions for distributors that the Commission could address.

There will be other examples of matters the Commission can pursue. Our point is that the Commerce Commission has a role ensuring that innovation is accommodated, changes in the demand side are accounted for and, in the end, barriers to economically efficient outcomes are reduced.

8.2.3 Elements of the current electricity market design

The Electricity Authority has a number of programmes aimed at enabling greater demand side participation in energy and ancillary services. While these are not targeted at emissions specifically they will facilitate a more efficient demand side. To the extent that a more efficient demand side has a flatter load shape, this will contribute to a lower emissions outcome in the electricity sector as it reduces the need for thermal peaking plant. Current projects the Authority has underway include:

- With greater competition in mind the Authority is actively seeking to accommodate a shift to more efficient distribution pricing, multiple trading relationships, multiple participants in the market and more fluid data exchange and a default distribution agreement.[130] The Authority has also requested the newly formed Innovation and Participation Advisory Group (IPAG) to undertake the Equal access project. The Authority says an effective open or equal access framework is critical to reducing barriers to the uptake of technology and innovation in new ways of doing business. They plan to assist with competition for traditional network services, open access to distribution networks, peer to peer trading platforms and more diverse sources of electricity supply and demand response. These initiatives will accommodate innovation in the market which, while not be targeted at lower emissions will lower barriers to activity that leads to reduced emissions.
- The Authority is considering moving to real time pricing in the wholesale market.[131] This will likely better align short-term energy pricing signals to the true scarcity of energy, and more appropriately reward flexible plant that can respond over this timeframe.

We are supportive of the Authority's initiatives; we suggest that there are additional aspects of the market design evolution which may need to be considered:

- The increase in wind and solar (and consequential decline in spinning thermal plant) may make inertia a scarce commodity. The Authority could investigate how inertia could be procured and priced. We understand that ERCOT is currently investigating a "synchronous inertia" product as part of their ancillary service procurement. This is an example of the sort of steps that are being taken in other jurisdictions.

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130 Electricity Authority *Enabling mass participation Response and next steps* 4 October 2017

131 Electricity Authority *Assessment of real-time pricing options* 2 April 2016 and *We've decided to develop details of a dispatch-based real-time price* August 2016

- Managing frequency and system ramping may need to evolve to align with changing supply volatility. Currently, frequency management relies on frequency keeping, free governor response, 6 second and 60 second reserve. With increasing penetration of wind and solar, the requirements to measure short-term changes in supply will become increasingly important. Some of these changes in supply are predictable (e.g., solar ramping up and down with sunrise and sunset), which has motivated California in introduce a Flexible Ramping product. Unexpected variability in wind and solar (due to weather conditions) may lead to significant changes in supply which require reserve products in between the 6/60 second response times for instantaneous reserve, and 5 minute dispatch.
- We understand there are currently barriers to the participation of batteries in frequency keeping; at least until a fleet of batteries is sufficiently large to provide the full frequency keeping "band". The current frequency keeper selection methodology favours plant that can provide the whole frequency keeping band, despite the industry having accommodated multiple frequency keepers.
- The current approach to must-run dispatch plant is an off-market approach that is not reflected in efficient pricing. Generators who wish to be dispatched as a priority when the price lowers to $0/MWh pay in a "must-run dispatch auction". The economic interpretation of this is that the marginal value of generation is effectively negative, but market clearing prices are prevented from falling below $0/MWh. Hence storage devices (batteries, flywheels, and pumped storage), which are incentivised to charge during low price periods and discharge during high price periods, are not receiving efficient signals. With increasing renewables comes the increased incidence of $0/MWh prices. While solutions to this problem (e.g., allowing negative generation offers instead of the must run auction) are not without their complications, this is an area for research.
- We note that The Electric Reliability Council of Texas (ERCOT) has implemented an operating reserve demand curve (ORDC) to strengthen scarcity pricing. With an increasingly renewable environment, an ORDC strengthens the signal for discretionary, flexible plant, and expands the reserve market beyond the current 6s/60s definition. At times, an ORDC may reward a wider set of plant that is able to increase output over short timeframes should a significant variation in demand or supply eventuate (beyond the N-1 criterion). We believe that an ORDC is worthy of consideration in anticipation of scarcity events triggered by large changes in supply output, beyond that considered under the current contingent event definition.

8.2.4 Ensuring resource adequacy in a high renewable system with a dynamic demand side

The natural seasonal shape of New Zealand demand is converse to the natural shape of hydro supply. (Refer to Figure 32) The seasonal shape divergence has been addressed historically through a combination of hydro storage and thermal generation. In extreme situations the demand side has been asked to participate in changing the shape by reducing demand and there are now incentives on retailers to take steps to avoid that situation. Changes in technology, energy efficiency and fuel choices will also make the demand profile more conducive to management. But, fundamentally, the collective effect of higher winter demand, the prospect of low inflows, and limited hydro storage, requires a flexible source of discretionary generation to be available to the system, in order to reliably meet demand.

Similarly, intraday shape throughout the year is addressed through a combination of hydro response and thermal peakers (refer to Figure 11). However, the presence of even moderate quantities of intermittent generation means that the capacity to fill this role has become more critical. The demand side will increasingly provide the solution to the problem that it has historically created. As Transpower observes "residential usage accounts for 32% of electricity demand and is a disproportionate driver of winter peak demand and network investment".[132] The combined use of domestic scale generation and storage (including the storage and charging regime of electric vehicles) has the ability to reduce demand and flatten the load profile. To the degree that this occur higher renewable penetration and, as a consequence lower emissions, becomes more likely.

Even with the changes to the demand side a flexible form of generation is required to maintain resource adequacy. To date, hydro (in the short terms) and thermal (in the medium term) have filled this role. The degree to which such generation is required in the future depends on many developments, including access to more hydro storage, batteries (for short-term flexibility), demand response, the incentives to operate geothermal at lower load factors, and changes to the profile of demand. Demand side solutions are less well advanced, less modelled, less well understood and less certain than supply side solutions to the shape mismatch but if that could be changed the supply side problem and resource adequacy challenge would be less than it would be under current arrangements.

The regulatory challenge will be for the Code and security of supply arrangements to keep up with the challenges and opportunities that emerge from a combination of more intermittent supply side and a more dynamic demand side and allow innovation to flourish.

8.2.5 Transmission and system operation recommendations

In Section 5.5 we discussed the implications on the transmission grid of some of the low emissions scenarios we considered. Given the wide range of possible renewable generation configurations, especially wind, we have a number of suggestions relating to transmission:

1. Transpower to include long-term planning reports for very low emission scenarios in their Annual Planning Report. (We understand that Transpower may be about to publish a report on Transmission in a very low emissions scenario, including with significant transport and process heat substitution.)

2. The supply of all ancillary services should be open to the demand side and DER.

3. The market should consider new markets (probably a procurement approach in the first instance) for inertia/ultra-fast response and firm energy reserve; and review the market for voltage/voltage stability to include DER and generation solutions.

4. The market should provide some mechanism to collectively consider longer-term market development plans for a low emissions future.

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132 Transpower *Transmission Tomorrow* May 2016

8.2.6 Efficient coordination of Distributed Energy Resources (DER)

In section 6.3 we worked through the concept of DER and how dramatic the potential changes are amongst consumers at the distribution level. Historically the distribution service has bundled connection, transport (capacity, throughput, resilience), losses, voltage, frequency, power quality and demand response (DR). As the demand side becomes more fragmented and has the potential to be more flexible that flexibility will become more valuable. The proliferation of small scale generation and storage combined with the improving ability to remotely manage individual consumer load is referred to collectively as distributed energy resources (DER).The ability to aggregate and harness these resources (within the boundaries agreed to by individual consumers) will become part of the solution to balancing supply and demand as we head towards 2050.

Improving the access to, utilisation of and integration of DER is important in helping reduce carbon emissions for two reasons:

1. Where DER is producing energy, it is increasingly likely to be from a low carbon source, especially solar and wind. These low emission energy sources can be encouraged by a carbon price but can also be encouraged by recognising, financially, other contributions they make to energy services.
2. DER, including DR, enables a dynamic demand side that can respond to economic and control signals to match supply and demand. This two-way dynamic supply and demand matching enables more low carbon supply to meet demand, reducing supply side emissions.

In overseas markets that have had a large amount of DER, especially solar PV, significant problems have arisen that have required expensive retroactive action, e.g. in Germany solar penetration lead to difficulties in absorbing the extra generation, high voltage problems and the lack of inertia is increasingly a concern.

There may be times when agents other than network owners place the highest value on DER. If the coordination of DER is led by someone other than the network owners greater efficiencies and lower emissions outcomes, where economic, would follow. There is also the issue that the utilisation of DER may create more uncertainty for system operation at the grid level. The role of coordinating DR and facilitating efficient outcomes for its use will be best provided by independent distribution system operators (DSOs) in the same way the transmission System Operator operates separately from the transmission owner at the grid level.

The purpose of a DSO would be to:

- ensure all power system resources (including DER) have competitive access to common infrastructure, optimised for all competing resources, and at a reasonable cost for monopoly assets, and
- coordinate DER (including smart, flexible demand) so that participant's preferences for security, quality and reliability are maintained, while recognising each load's and generating source's influence and preferences on marginal cost and marginal benefit.

Other elements that will support greater efficiencies at mass market level include cost reflective and service based distribution pricing. By this we mean that the value of using distribution services at a particular time and at a particular location is signalled to consumers and owners of DER.

Cost reflective pricing, and open access (even down to consumer level), dynamic arrangements around short and long term efficient operation of the power system will facilitate a future where low carbon distributed generation may be integrated into the power system at not only minimal total cost but maybe even lower total cost. In addition, signalling the desirable and undesirable outputs from DER (e.g. capacity injection when it increases costs, or high voltage) would prevent significant problems from occurring, as has happened in other jurisdictions with large amounts of solar PV integration.

Cost reflective pricing can also incentivise demand response to system peaks and reserve, potentially also encouraging firm energy capacity in the long term. This can help reduce the need for thermal peaking to ensure security of supply with a power system with highly intermittent renewable generation.

Review of mandated electrical standards

In parallel with moving to more dynamic, cost reflective distribution there will need to be a review of the mandated electrical standards. The standards will need to apply at some point at consumer's installations as equipment is built to meet these standards and may only work within these standards. However, the standards need to reflect that a consumer may be able to self-provide aspects of the standards and the whole service need not be provided from the bulk supply power system. Alternatively, consumers will mostly be reliant on an agent or installer to ensure they receive supply to their equipment and devices within standards and, therefore, how the requirement to provide good advice and equipment applies to these agents/installers.

Study of distribution alternatives and its economic/regulatory framework

The problem of the distributed generation and DER undermining the recovery of revenue on potential uneconomic distribution lines requires further study to determine:

1. The scale of the potential problem, and then either
   (a) If the scale is small, incremental, pragmatic improvements to the current regulatory framework,
   (b) If the scale is large, a complete overhaul of the regulatory and economic framework around using private and community-based DG and DER as an alternative to distribution lines is required.

We note that this is a problem for DG in general and not, specifically, low emission DG. However, in an economic environment of high oil prices and carbon prices at a sufficient level to effect change, then such DG is likely to be solar, mini- or micro-wind and/or mini- or micro-hydro.

Transparency of information

Change can be expedited, and the need for change made more obvious, with the provision of transparent information. DER and distributed generation can be encouraged by providing the information that allows providers and agents for DER to assess areas where:

- The transmission and distribution network may need reinforcement,
- Parts of the transmission and distribution network could be economically displaced, or
- Consumers are having supply or power quality problems.

Identifying these areas would allow the providers and agents of DER to market directly to consumers or groups of consumers where DER could accrue more benefits than other areas. The transparent information also assists the agents and providers of DER with evidence where any upstream benefits from the DER are not being recognised by upstream providers.

There are two sets of information which could be made more transparent, information about the investment/disinvestment opportunities in the transmission and distribution network, and information about local power supply and quality.

A group in Australia, including electricity market regulators, private institutes, government departments and electricity networks, has taken a lead in the transparency of network investment. Through the Energy Networks Association, a set of maps (including online, interactive maps) "provide transparent and up to date information to identify opportunities for distributed generation, energy storage and other non-network solutions to address network capacity constraints and reduce costs for customers." These Network Opportunity Maps (NOM) are published by the ENA[133] (Australian). Ultimately, independence might prove to be a concern for who produces the NOM, but this is an initiative that helps encourage efficient investment in DER. Significantly the first NOM were financially supported by the Australia Renewable Energy Agency's (ARENA) Emerging Renewables programme.

The second set of transparent information that could be made available is smart metering data. Smart metering data would enable potential providers of DER equipment to assess the customers who might be best matched to different renewable generation or battery profiles, enabling a provider to assess the potential level and timing of net import and export for comparison to the network opportunities and wholesale market signals. Smart meters also measure power quality (voltage, voltage stability, total harmonic distortion, etc.) and can also indicate where other benefits from DER can accrue.

There are privacy concerns with the open access of smart metering data but the Green Button initiative[134] demonstrates how smart metering data can be made available to consumers and their nominated agents for exactly this purpose. The Green Button initiative "is an industry-led effort that responds to a 2012 White House call-to-action to provide utility customers with easy and secure access to their energy usage information in a

133 http://www.energynetworks.com.au/network-opportunity-maps

134 http://www.greenbuttondata.org/index.html

consumer-friendly and computer-friendly format for electricity, natural gas, and water usage."

The Green Button initiative allows for utilities and third party developers to be certified to access the Green Button data, or produce applications that are certified to access the data.

8.2.7 Will the current energy only wholesale market deliver resource adequacy in a low emissions environment?

A key feature of an energy only market is that all plant relies on the energy prices when they generate to get a return on investment i.e. there is no payment for making capacity available. (refer to section 3.1.3) As the utilisation of a plant drops, the higher the price required (when it is run) in order to cover fixed costs. The phenomena that prices may not go high enough often enough to justify retaining plant required for resource adequacy is referred to as the "missing money problem". Any regulatory steps aimed at curbing high offer prices from plant that makes itself available to support resource adequacy risks exacerbating the missing money problem thereby reducing the availability of peaking capacity.

A great deal of renewable generation is "must run" generation in the sense that if it doesn't generate the fuel source is wasted or "spilled". Must run generation tends to be offered to the market at $0/MWh and is reliant on the cleared price being set by higher priced generation (a mix of thermal plant and stored hydro) for its revenue. As the proportion of generation coming from "must run" renewable generation rises there may be a softening effect on wholesale prices. In that case there would also be a damping effect on investment signals. Even if scarcity prices became more frequent they may still have little effect on average annual prices and, as a consequence on hedge and retail markets i.e. whether resulting average annual prices would be high enough to attract new investment.

It is possible that bilateral contracting between major suppliers for capacity may serve to keep stand-by generation available and that has been the case in recent years. However, if lower average annual wholesale prices do result from higher levels of renewable energy lower contract prices may also soften which would, in turn deter investment in flexible plant.

The time may come when current market design and bilateral financial contracting for dry year risk not enough to keep existing capacity or encourage new capacity (regardless of its emissions profile) into the market for the purpose of resource adequacy. The bilateral contracting approach may also struggle with coordination if the potential supply of dry year adequacy becomes less centralised, and is dispersed amongst numerous small investors. In the context of the focus of this report the question is whether the absence of a targeted mechanism that would encourage *low emissions solutions* to the resource adequacy problem is a barrier to achieving lower emissions by 2050. With that end game in mind we suggest that serious consideration be given to evolving the market design to accommodate >95% renewable generation on the supply side, while reliably dealing with the dry year issue, even if the demand side becomes far more flexible and better coordinated. The market may have bear down on this issue earlier than 2050 if current owners of thermal plant seek to decommission them. Whatever the catalyst is we think that the market should enter into a discussion about whether the current energy market will be fit for purpose to manage the transition to a highly renewable system as we describe it here.

Measures might include a capacity style or firm energy market designed to meet New Zealand conditions, a reserve energy scheme, obligations on retailers to account for their physical supply or other mechanisms that will efficiently deliver the physical supply needed in a system with high renewables.

A number of capacity mechanisms operate around the world today but each is tailored for the circumstances in their market (essentially a market failure unique to that market). In broad terms

> *electricity capacity markets work in tandem with electricity energy markets to ensure that investors build adequate capacity, in line with consumer preferences for reliability.*[135]

Pfeifenberger (2009) offers these lessons from other markets for the design of mechanisms intended to address market failures while maintaining resource adequacy:

> *Have a clear understanding of the resource adequacy needs and the drivers of these needs*
>
> *Explicitly account for*
>
> - *discrimination between existing and new resources*
> - *participation by demand-side and renewable resources*
> - *locational constraints and transmission interties*
>
> *Avoid capacity payment mechanisms that just add revenues for existing resources or address a perceived lack of long-term contracting in the energy market*
>
> *Avoid providing out-of-market payments to some resources (including long-term contracts) that oversupply the market and distort both short- and long-term investment signals*
>
> *Where mechanisms are introduced outside the energy market be sure that they will address deficiencies in energy and ancillary service markets*

The regulatory challenges are to assess:

- whether the evolution of exchange traded and over the counter (OTC) financial instruments will be sufficient to deliver resource adequacy and the necessary investment in renewable solutions in a very low emissions sector
- whether a mechanism accompanying the energy only market will be required as the sector moves to very low emissions supply side.

8.2.8 Conclusion

In this paper we have found that based on knowledge available in 2018 a very low emissions sector in 2018 is most certainly possible. We suggest that many changes may occur that will make it more achievable and achievable at a lower cost than we envisaged based on 2018 assumptions.

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135 Peter Cramton, Axel Ockenfels, and Steven Stoft *Capacity Market Fundamentals* 26 May 2013

In this section we have suggested that several major changes should be considered pre-emptively to support the transformational change and ensure it delivers maximum net benefits. We think extending current arrangements could be too limiting to accommodate the more dramatic change to a very low emissions sector with a dynamic demand side. The challenge is that the regulators are not seeking to achieve low emissions they are intent of maintaining economic efficiency as investment and behavioural changes occur.

It raises the question whether a more fundamental review of the structures in the sector is required. See for example Appendix 2 two examples of historic legislative processes that may be outdated and may not be covered by the Authority or the Commission. We suggest that the full breadth of arrangements in the sector are tested as an integrated system to see if they are fit for purpose once the sector's transformational changes come fully into force. This might be a role suited to the Climate Change Commission.

The electricity sector in New Zealand already produces relatively low emissions per capita compared to other OECD countries. Our work shows that the energy component of retail tariffs (i.e. wholesale electricity prices) rises steadily as emissions fall. Further reductions in emission may be more easily achieved we show because of likely reducing technology costs and behavioural responses facilitated by the falling technology costs. It appears to us that the marginal abatement cost for a very low emission sector (down to ~ 1MT p.a. based on 2018 assumptions) makes the goal achievable as long as the key changes raised in this part are considered and acted on. We find that the electricity sector is well placed to contribute to a move towards a very-low-emissions economy.

Appendix 1 Indicative benefits of solar DER

Indicative benefits of solar DER

The following two examples are given as the possible value of solar DER where either the marginal benefit of avoided cost is not signalled to the installers of DER or where barriers create a preferential option for one type of asset owner over another. This may result in a disincentive for investing in DER which, for reasons proffered earlier, can help both directly and indirectly in the transition to low emissions.

Auckland voltage

One of the reasons why DC approximations work for transmission is because voltage is quite constant over the transmission network and the marginal effects of voltage support can be managed without substantially reducing the efficiency of LMP. In Auckland this condition is more weakly met than in other parts of the New Zealand network.

Voltage tends to be fairly constant throughout a transmission network because generating plants, which are active voltage sources, are distributed throughout the network. Auckland, New Zealand's largest load region, has no large voltage sources since the retirement of Contact Energy's Otahuhu power station and Mercury's Southdown plant; and even with these plants voltage has been an issue in Auckland. Since these shutdowns, Auckland's voltage support has relied on Genesis Energy's Huntly power station. When Genesis announced the retirement of the two Rankine units at Huntly (now scheduled for 2021) the System Operator identified that Auckland would have potentially unmanageable voltage, without these units, under moderate peak demand growth.

In its long list for consultation[136] Transpower (as System Operator) has identified the need for up to 150MVAr of reactive power support to manage the needs of the Upper North Island, ideally this would be dynamic support (fast reacting to system conditions). Currently, there has been 18MW of solar DER installed in UNI, which is growing continuously. If these installations had been incentivised to install high specification inverters they would be capable of 18MVAr of dynamic reactive power support, just from the inverters. If they were also generating, either directly from the solar panels or from a battery, then they would also be providing many distributed active voltage sources, giving increased voltage support.

Given that the cost of alternative dynamic support options on the transmission network might exceed $2,000/kW, then recognising the potential contribution of solar PV and the associated inverters could significantly improve the financial viability of solar installations even with the cost of higher specification inverters.

The same voltage contributions could also be valuable within the distribution network, and in many other networks outside of the UNI, but are currently not recognised.

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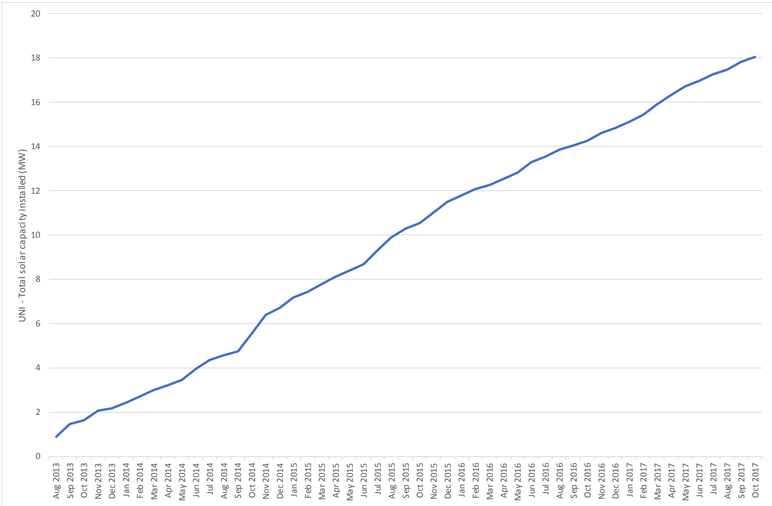
136 "Waikato and Upper North Island Voltage Management Long-List Consultation, including invitation for information on non-transmission solutions" Transpower New Zealand Limited, July 2016

Figure 52 - Chart Total installed solar capacity in UNI



Avoided Cost Of Distribution

Local DER can avoid the need for distribution network investment. In fact, with appropriately sized solar panels and battery storage, and especially with demand management, a DER can avoid the need for distribution service entirely. At a rough estimate of $30,000 for a DER installation that would be self-sufficient for a rural home then with an approximate cost of $20/m[137] for overhead distribution line, then if a self-sufficient DER could avoid the need for 1.5km of overhead line (and far less is it also avoided a distribution substation) then, ignoring the degree to which existing assets are sunk costs, the capital would be better allocated to the DER than to the power line.

If there are a relatively close group of electricity consumers, then the case could be even stronger. While the cost of the solar panels would scale relative to the increased load, there are opportunities to save on battery and inverter costs through diversity. With an entire geographic group of consumers there is also a good chance of displacing the need for a distribution substation.

However, distribution service need not be displaced altogether to avoid distribution investment. The key challenge with remote distributions is to provide the required capacity[138] within acceptable power quality (usually an acceptable voltage range). With DER technology consumers can take capacity at a wider range of voltage (or other power quality criteria) avoiding the need for network augmentation. Not to mention that storage, inverters and flexible demand[139] can all provide competing service to the network.

Currently retail pricing does not recognise any of these dynamics.

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137 Derived from the Commerce Commission's information disclosure "Performance-summaries-for-electricity-distributors-May-2017.xlsx"

138 Not necessarily only peak capacity. Networks can struggle to avoid low voltage during high demand but can also struggle to avoid high voltage during low demand.

139 Storage and demand response can smooth demand thereby smoothing voltage variance, while inverters can actively support voltage.

Appendix 2 Legislative/regulatory barriers

Continuance of supply

Around the end of the second World War the Rural Electrical Reticulation Council was set up to subsidise the connection of electricity to remote rural communities. When a distributor, which at the time were Power Boards and Municipal Electricity Departments, received an application for a rural connection then, if the new supply was calculated to be uneconomic, then the RERC would award a subsidy.

The RERC was disestablished by the Electricity Act 1992 in which the RERC had to be disestablished, under Part 5 of the act, and would cease to exist on 31 March 1997, under clause 55 of that part.

As many lines had been subsidised, and under fears that these lines would be removed by newly commercialised distributors, a transitional arrangement was put in place where the new distributors had an obligation to continue to supply any connections that had been connected to a licenced electrical authority prior to 1 April 1993, unless approved by the Minister or by every consumer connected to the lines to be removed. This clause 62 of the Electricity Act 1992 would terminate on 31 March 2013.

Concerns about the potential cessation of services to uneconomic powerlines had not abated by 2010 and clause 62 of the Electricity Act 1992 was replaced by an enduring obligation under subpart 3 of part 4 of the Electricity Industry Act 2010.

For distributors with legacy obligations to continue supply (described under clause 105(1)), the new obligation is (clause 105(2) of the Electricity Act 2010):

"(2) A distributor to whom this section applies must, in relation to the place referred to in subsection (1), either—

(a) supply line function services to the place so that the place is within the distributor's network; or

(b) supply the place with electricity from an alternative source."

Cessation of the obligation can now only occur under clause 106(1) of the Electricity Industry Act 2010:

"(1) A distributor's obligation under section 105(2) comes to an end with respect to a place if—

(a) the landowner and (if the landowner is not the consumer) the consumer, or the Minister, agree in writing to the obligation coming to an end; or

(b) the obligation is assigned to, or assumed by, a successor in business to the distributor."

The way the legislation reads means that the distributor has an obligation to supply, which doesn't seem to conclude even if line function services aren't taken. Presumably the distributor must supply line function services to the boundary of a property even if supply is not taken. Furthermore, to cease the obligation the landowner/consumer or the Minister must agree. This implies that first the cessation of the obligation must be proposed by the distributor. This seems to mean that, while the distributor doesn't have a unilateral right to cease the obligation, it does have a unilateral right to keep the obligation.

In the situation where a consumer, or group of consumers, wishes to self-supply some line function services through DER or demand response, then the distributor can claim to still have the obligation to supply full line function services and, presumably, charge the consumers accordingly. In the case where consumers with embedded DER are providing line function services back to the distributor, then the distributor not only has no obligation to recognise the contribution but can charge those services back to the consumer.

Consumers that establish a self-sufficient local energy service can avoid the distributor's charges by disconnecting completely. However, at the distributor's discretion, this does not appear to remove the obligation to supply. Presumably then, a distributor can maintain a competitive alternative supply to the disconnected consumers which other consumers must pay for.

Despite this *prima facie* concern with the continuance of supply regulations, we have since learned from MBIE[140] that the regulations are also problematic for distributors. Consumers are unwilling to agree to supply from an alternative source out of concern that, once the existing lines are removed, the alternative supply will prove unsatisfactory and the line would not be restored.

These regulations were supposed to be temporary so that uneconomic lines could transition to new supplies. Not only have these transitions not occurred but now alternative providers are unable to compete, and even incumbent distributors are sometimes unable to move consumers to alternative supplies.

To enable a transition to economic DER alternatives will need a careful balancing act between transition time, unbundling of network services, the removal of cross-subsidies and averaging in distribution pricing, consideration of sunk costs and opportunity costs, and consumer engagement.

Electricity (Safety) Regulations 2010

Consumers with suitably specified DER[141], or with special devices fitted, can take electricity supply at a wider range of voltage[142]. As maintaining supply within prescribed voltage limits is typically the limiting factor of distribution lines, then allowing consumers to take supply at lower voltage and/or with a greater voltage range can potentially allow for greater supply capacity without the need for network upgrades. However, the Electricity (Safety) Regulations 2010 explicitly prohibits this.

Clause 28 of the Electricity (Safety) Regulations 2010:

"28 Voltage supply to installations

140 At a stakeholder's presentation of draft results on 6 December 2017.

141 The DER could provide voltage management services as well.

142 Universal power supplies or Uninterruptible Power Supplies can typically take supply between 100 to 250 volts.

(1) The supply of electricity to installations operating at a voltage of 200 volts AC or more but not exceeding 250 volts AC (calculated or measured at the point of supply)—

(a) must be at standard low voltage; and

(b) except for momentary fluctuations, must be kept within 6% of that voltage.

(2) The supply of electricity to installations operating at other than standard low voltage (calculated or measured at the point of supply)—

(a) must be at a voltage agreed between the electricity retailer and the customer; and

(b) unless otherwise agreed between the electricity retailer and the customer, and except for momentary fluctuations, must be maintained within 6% of the agreed supply voltage.

(3) A person who supplies electricity commits an offence and is liable on conviction to a level 2 penalty if he or she supplies electricity to an installation in breach of this regulation."

Where standard low voltage is 230 volts.

No consumer can negotiate a larger range of voltage, but standard low voltage users cannot negotiate any voltage.

These regulations were designed as consumer protection given the historical nature of distribution and technology. However, with modern technology the voltage specification can become increasingly negotiable. There are other aspects of power quality that also become increasingly negotiable with modern technology.

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