Distributed Energy Resources – Understanding the potential

Main report

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Glossary

Abbreviation	Stands for
BESS	Battery Electric Storage System
DER	Distributed Energy Resources
DG	Distributed Generation
DR	Demand Response
EDB	Electricity Distribution Business
EV	Electric Vehicle
FIR	Fast Instantaneous Reserve
FK	Frequency Keeping
IPAG	Innovation and Participation Advisory Group (an advisory group to the Electricity Authority)
IR	Instantaneous Reserve
MFK	Multiple Frequency Keepers
OCGT	Open Cycle Gas Turbine
PV	Photo Voltaic (solar panels)
SIR	Sustained Instantaneous Reserve
THD	Total Harmonic Distortion

1. Introduction

Transpower, in its role as system operator, has commissioned the authors to investigate DER in a New Zealand context. In its work on the future of electricity (Te Mauri Hiko), Transpower has identified how critical DER, and its potential flexibility, is to achieve New Zealand's greenhouse gas emissions goals.

This can be achieved both by supporting renewable supply growth to electrify transport and industrial process heat, and to directly reduce emissions from the electricity sector. Transpower is seeking to advance the discussion about how the electricity industry and market may need to evolve with increased penetration of DER.

The timing of this work is significant. Transpower analysis suggests there could be significant uptake of DER within 5 years. The authors analysis confirms this. Our assessment also suggests that higher specification equipment would be needed than might otherwise be installed to unlock the full value potential of DER. To ensure that the best decisions are made for DER technology, investment signals for the services DER can provide should be put in place now.

The Authors also note that innovative business models are already installing high spec DER at scale today.

1.1.1 Case Study

International experience with DER deployment suggests that large amounts of DER can be installed quickly (in power system terms). Overseas, these bulk deployments have been driven by subsidies. However, what is clear is that there is a demand for DER; subsidies reduced the price point dramatically, but the demand was there. This implies that similar DER penetration could happen anywhere once a certain point in the confluence of supply and demand is met, i.e. where all DER value streams are made available and the cost of supply compares well to the value opportunities.

In Whakamana i Te Mauri Hiko this is assessed as occurring before 2035 but there are reasons to believe that it could be sooner than we think. solarZero is a business model already successful in New Zealand where full access to all DER value streams is not yet available. As a case study solarZero shows us that we will need to be ready for DER sooner than we might think.

DER Case Study – solarZero

Access to DER isn't something that is *going to happen* or *might happen if regulations change and barriers are lowered*. DER is already being aggregated and deployed commercially and at scale in New Zealand. solarZero[1] have demonstrated that the price point of the equipment, and the possibilities with their software, have already allowed it to set up and operate DER at commercially in New Zealand.

[1] solarcity (inc 2009) developed the solarZero energy service, a way for domestic homeowners to switch to solar without paying any product or installation costs, in 2014

Integration of DER onto the system has been talked about for years. The idea of system operators or distribution system operators harnessing the flexibility from micro generation with batteries, discretionary EV charging and remotely controlled demand management was integral to the early thinking about smart grid. An official definition of Smart Grid defining its elements was set out in the Energy Independence and Security Act of 2007 (EISA-2007) approved by the US Congress in January 2007.

The EISA's definition of smart grid expressly included:

- Deployment and integration of distributed resources and generation, including renewable resources.
- Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.
- Integration of ''smart'' appliances and consumer devices.
- Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.

Even so, still in 2020 the idea of harnessing the flexibility of DER continues to be seen as a potential, something that will emerge in the future. The idea of identifying the barriers to more adoption of the flexibility DER offers and, by virtue of identifying it, lowering those barriers was the subject of the Equal Access project conducted by the Authority's Innovation and Participation Advisory Group (IPAG) in 2018. IPAG referenced similar work in other jurisdictions saying:

DER investment is happening in NZ, albeit at a slower pace than other countries, but the lesson is that the DER market has to be allowed to develop

IPAG went on to identify 13 actions that needed to be taken , principally by the Commerce Commission and the Electricity Authority, to allow bilateral contracting to occur amongst all providers/suppliers and markets for DER to emerge.

And yet, here is a case study where the potency of DER is actually being accessed commercially and at scale in New Zealand now. solarZero is providing a smart solar energy system as a service available to all NZ homeowners. They already have 3000 combined solar/battery sites active and can remotely manage discharge from the batteries attached to rooftop solar arrays as required. They can also control discretionary load in the house to optimize total net load. That flexibility can be on sold to distributors or retailers. Alternatively, customers can deploy that flexibility for their own use such as having the system automatically charge their own EVs at the time of day when grid supply is at the cheapest if they wish. solarZero say:

From a world-first, custom-made smart battery, to a web-based monitoring platform that gives you total control, the technology is ground breaking.

And solarZero's new monthly subscription service is equally revolutionary. It's like Netflix for your roof, except you stream the sun.

Each of our systems are individually programmed to optimise the efficient use of power according to household usage patterns. This programming is designed to *reduce cost for the consumer and maximise the solar generated from the system to be fully utilised.*

solarZero's system works as follows. It:

- Includes a combined solar array and smart battery system with no upfront cost
- Is charged for on the basis of a fixed monthly fee which covers ongoing management, monitoring and maintenance of the system.
- Provides the home owner with a price protected rate for grid energy capped at 8c/kWh (plus GST, lines charges).

solarZero guarantees savings over the life of the system. They are able to do this because the cost of these systems now competes favourably with grid supply. They are able to aggregate the flexibility of all of their aggregated systems and monetise that flexibility further offsetting the costs.

What is particularly noteworthy is that solarZero has achieved this even despite the barriers in place identified by IPAG.

Figure 1 and Figure 2 shows how the interaction between solar output, domestic load and battery charge/discharge works using the solarZero system for summer load and winter load respectively.

Figure 1 Average daily battery energy flow - summer

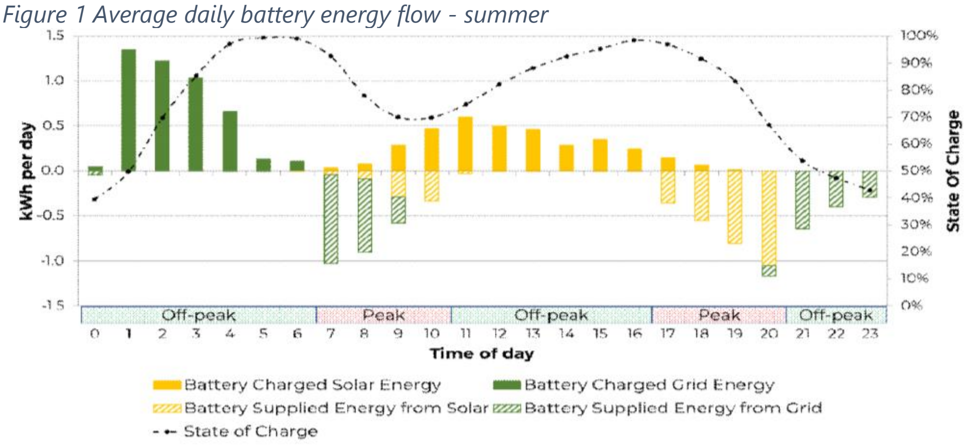


Figure 2 Average daily battery energy flow - winter

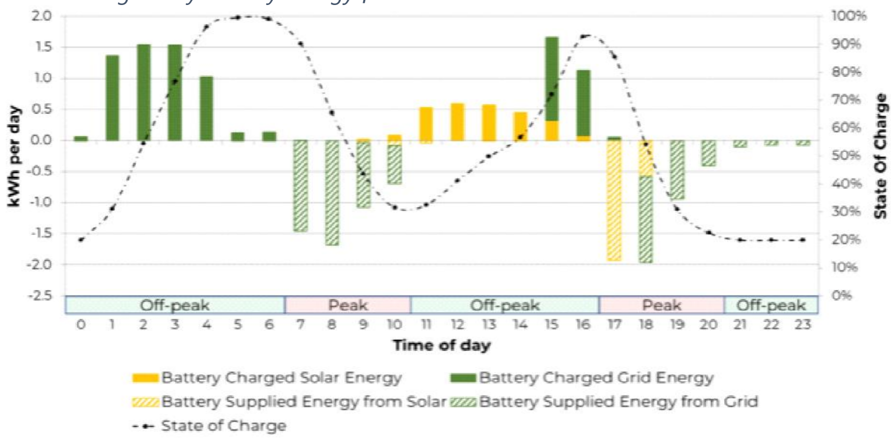
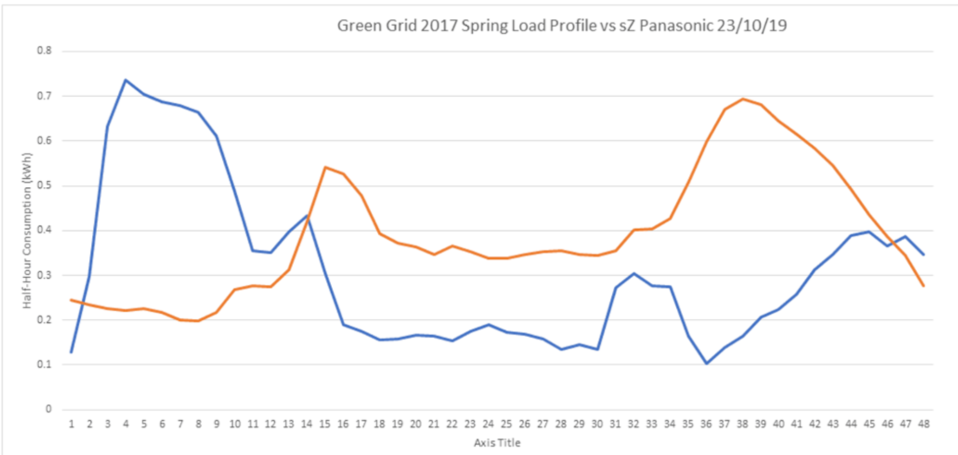


Figure 3 shows the impact on actual grid demand across the solarZero fleet compared with average household demand as estimated by Otago University via the Green Grid project. The dominant battery in the fleet is a 3.6kW inverter with a 6.3kWh battery. The solar/battery system results in a reduction of peak load from around 2.5kW to around 0.6kW. The system makes this change to peak demand every single day, in other words the battery system permanently alters the demand profile on the network. Further, solarZero is able to alter the demand profile in response to economic signals and always aiming to optimise value for customers. The average overall annual savings for a household is in the order of \$230/yr (around 12%). The savings are made up of lower total net kWh demand, the cost benefit from redistributed net grid demand across each day and reduced lines charges.

Figure 3 Comparison of household demand; solarZero vs a standard New Zealand home.



If this is what can be achieved in a system that has still not been adapted for the possibilities that DER offers for network capacity and/or energy management then the future for DER looks very bright indeed.

1.2 What is DER?

There is not a universal definition for DER. Mainly variations in definitions for DER hinge around whether demand response (DR) is included or not. In this paper the discrete dispatch of smart load control to manage the power system definitely meets a plain English definition of DER.

Therefore, our definition for DER includes:

- DG (e.g. solar PV, within the distribution network or within consumer premises).
- BESS (within the distribution network or within consumer premises).
- DR.
- EVs (both as a smart load and potentially BESS).
- DER related ancillary equipment (equipment that may be required as a consequence of DER up take, e.g. harmonic filtering stations).

1.3 A three stage approach

1.3.1 Establish the potential value of DER

First, a rough estimate was made of the value potential for DER. The value opportunities were quantified by service, e.g. reactive power/voltage, capacity, energy, etc, looking forward as far as practicable; and quantifying the high level, direct costs (including opportunity costs) for DER providing such services.

1.3.2 Evaluate the potential supply of DER

Second, the incentives and need (supply and demand) of the value opportunities were considered. This stage extended the assessment from stage 1 developing them into supply and demand functions. This informs possible efficient levels of DER investment in the various services and the implied efficient price. This describes, theoretically, what could be achieved through price incentives.

1.3.3 Identify the barriers to greater access to and deployment of the flexibility DER offers

Third, the transaction costs and barriers to the supply of and procurement of all forms of DER in the marketplace were investigated. Where barriers to entry or other market failures might discourage the efficient level of aggregation then mandatory mechanisms for DER coordination may be warranted, especially in the short-term.

1.4 The context for this report

In Whakamana i Te Mauri Hiko, Transpower identified the significant impact DER is likely to have to the NZEPS. Transpower realises that this has implications for the energy market, transmission utilisation, dispatch, security, reliability, and the stability of the NZEPS. Historically, Transpower, in its role as system operator has had substantial certainty and control over supply resources, and demand has been mostly predictable except at the margin. Given that system operators worldwide are tasked with maintaining secure supply of electricity, an energy service critical to modern economies, they are typically conservative and prefer clear rules and visibility of supply resources.

However, given that DER can provide services across wholesale and retail electricity markets, ancillary services, transmission and distribution, and that New Zealand has some time to consider the integration of DER into the NZEPS, the SO is interested in all integration approaches. Hence, the fundamental question that underlies this report is "What could be achieved through incentives?"

The author's insights are based upon analysis done for this report and previous analysis. Our analysis is 'first order approximation' and there is considerable uncertainty over the time horizon we have considered (up to 2050). Nevertheless, we believe that, to achieve the objective of encouraging debate and further analysis in DER, we need to 'take a position' on our insights despite the analytical uncertainty.

1.5 The role of incentives

Incentives can be thought of interchangeably as prices or pricing. However, incentives can sometimes be delivered more efficiently through other means, such as rules or standards. Prices can also be delivered through many methods such as two-way markets, one-way markets, exchanges, tariffs, cost allocation, and contracts; and all these methods are used in the New Zealand electricity industry.

The authors have not considered how incentives would be most efficiently applied, but focus on the case for incentives, the level of incentive and what that could mean in terms of DER investment and getting access to the new flexibility DER offers.

A form of incentive not considered is subsidies. In this case, behaviour is influenced by the contribution of money to achieve an unquantified social or economic benefit. The incentives considered are reflective of the opportunity costs of the supply of services that consumers, in aggregate, are willing to pay for and where DER can potentially provide the services cheaper and/or to a higher quality (where that higher quality would be valued by consumers).The opportunity costs of services do include factors external to the NZEPS where those externalities are explicitly priced, i.e. carbon pricing.

1.6 Building on previous work

The authors have based this work on previous work done in New Zealand and have also used international literature.

The following groups and work have been used directly or indirectly:

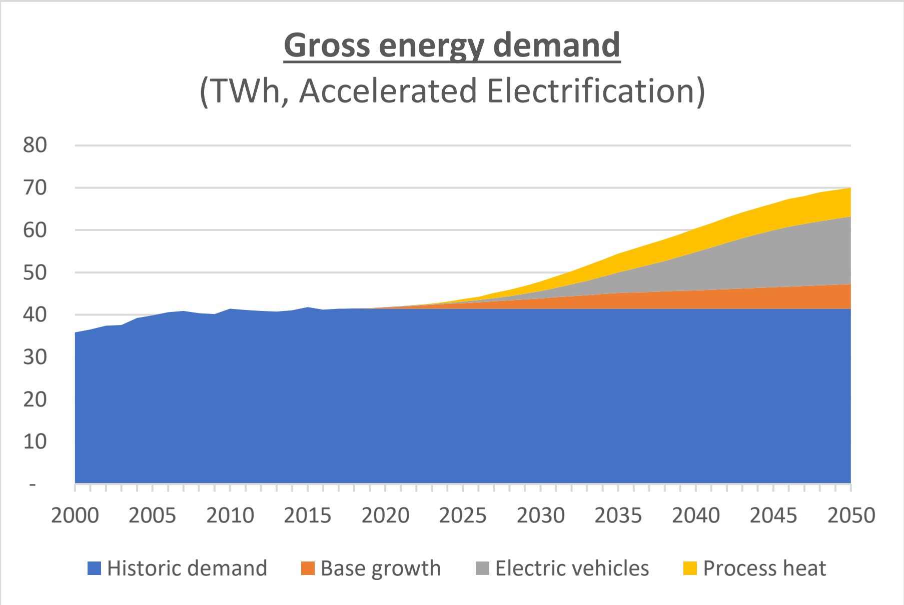
- Te Mauri Hiko and Whakamana i Te Mauri Hiko (Transpower)
- IPAG (Electricity Authority)
- Productivity Commission
- Interim Climate Change Commission
- MBIE EDGS and input data
- BEC TIMES modelling

1.6.1 Whakamana i Te Mauri Hiko

We have relied heavily on Whakamana i Te Mauri Hiko for forecasts of demand growth and DER penetration.

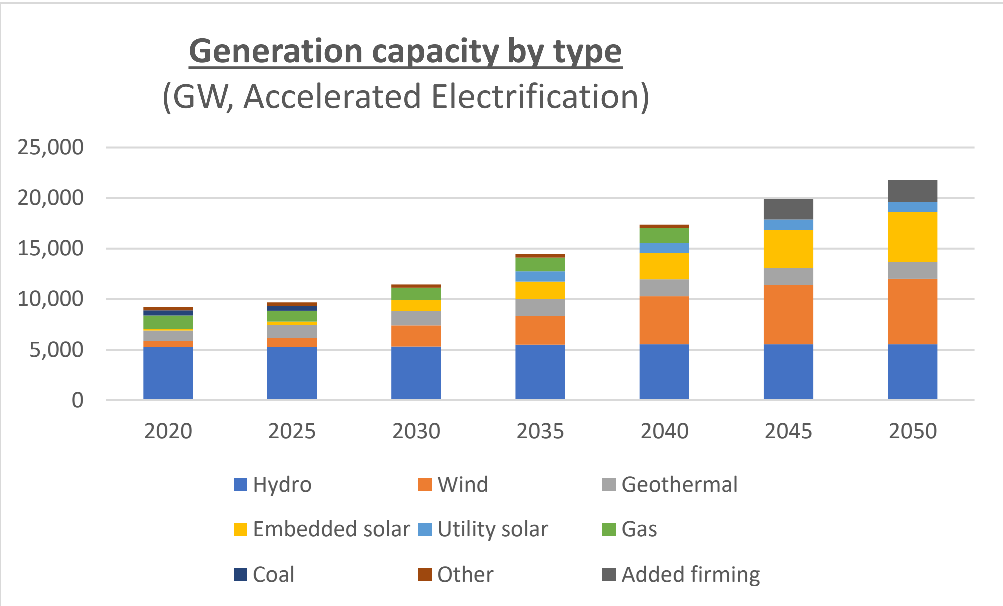
Key among the forecasts are energy demand (Figure 1) and generating supply capacity (Figure 2).

Figure 1 - Gross energy demand 2000 to 2050



Source: Te Whakamana i Te Mauri Hiko

Figure 2 - Generation capacity 2020 to 2050



Source: Te Whakamana i Te Mauri Hiko

Based on the underlying data from the charts above we have determined the following levels of DER penetration for DER on a capacity basis.

Table 1 - DER penetration 2020 to 2050[2]

Capacity (MW)	2020	2025	2030	2035	2040	2045	2050
Non-DER supply	9,094	9,336	10,410	12,728	14,761	16,118	16,898
DER supply	119	341	1,050	1,715	2,615	3,797	4,905
Batteries - total	100	300	700	1,150	1,900	2,600	3,200
Batteries – small scale	100			750	1,200		2,500
Batteries – utility scale				400	700		700
DER Penetration without batteries	1.3%	3.5%	9.2%	11.9%	15.0%	19.1%	22.5%
DER Penetration with batteries	2.4%	6.4%	14.4%	18.6%	23.4%	28.4%	32.4%

Source: Whakamana i Te Mauri Hiko and Sapere analysis

We have assessed DER penetration with and without batteries. Generally, batteries will either be associated with a solar installation but whether part of a solar installation or standalone they would generally operate to offset deficits in renewable generation. In our analysis, we have assumed batteries to be part of solar installations rather than entirely standalone. Nevertheless, batteries could potentially export at the same time that embedded solar is exporting. In a situation such as this, which could eventuate on a sunny day with little wind, two-way flows in distribution networks would get very high.

1.6.2 IPAG

We are building on work already done in the sector. IPAG has already considered the issues, and particularly the barriers to DER participation. We have adapted one of IPAG's frameworks to guide the development of the DER value streams.

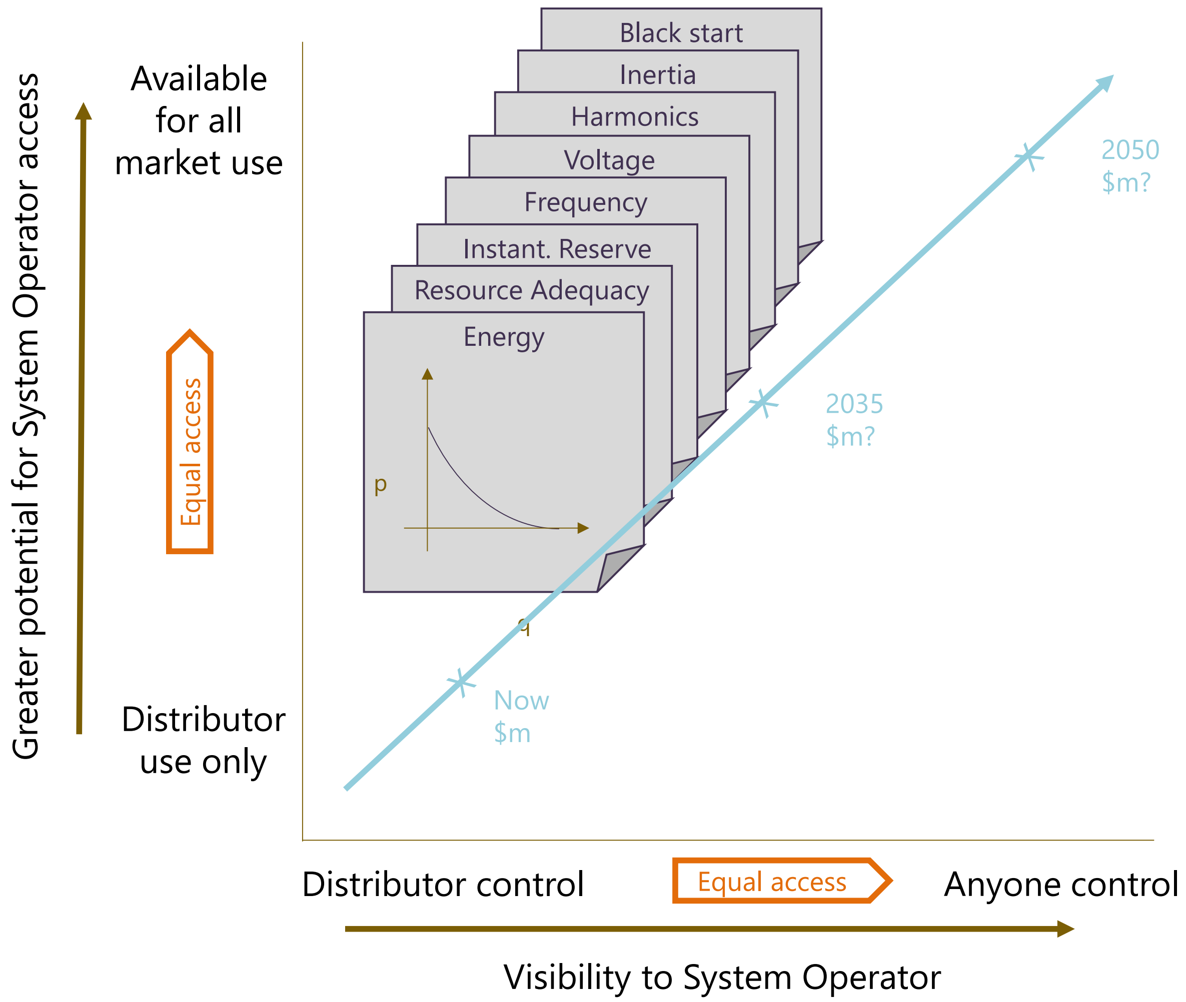
IPAG identified that distribution networks will be essential in any DER services provided beyond the meter, and yet large amounts of uncoordinated DER could cause significant distribution network problems. In the short-term, distribution networks will need to be conservative in how they grant access to DER export. Distribution networks will be open to using DER for network services but, again in the short-term, will have a preference for DER which they can coordinate. However, many services that DER can provide are not the responsibility of distributors. As open access arrangements for

[2] These estimates for battery deployment are slightly higher than those provided by (ICCC, 2019). According to the ICCC report, 850 MW of battery capacity is deployed by 2035 in the 100% renewable electricity scenario. In their fast tech/high demand sensitivity analysis, battery deployment reaches 1,100 MW by 2035.

coordination and multiple use are developed, distributors can use DER that is not directly coordinated by them and DER can be applied to its most valuable use.

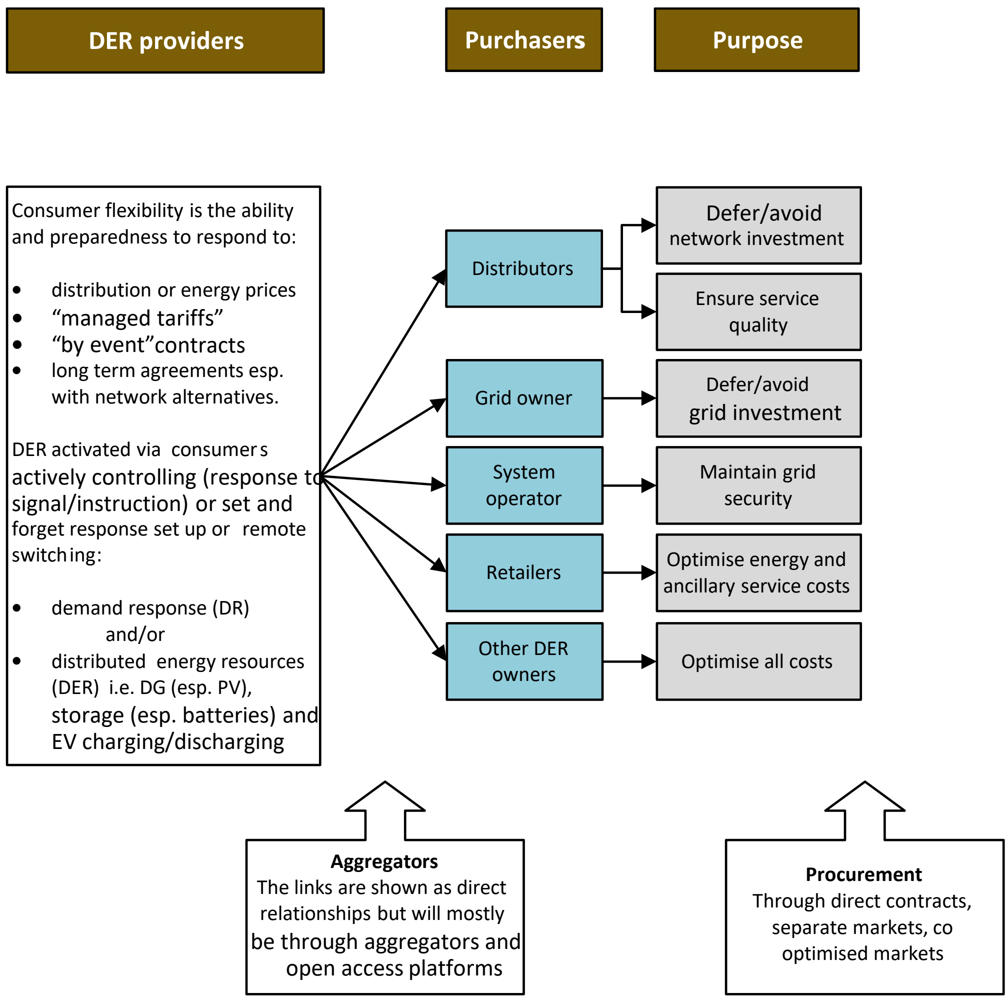
IPAG indicated that the value of DER would increase significantly as its deployment moves along two continuums, one from distributor use to universal use and one from distributor control to anyone's control (IPAG, 2019, p. 33). We demonstrate value progression against these continuums in Figure 3. This framework also demonstrates the value streams we have considered.

Figure 3 - Value continuum framework for DER



IPAG identified that distribution networks will be essential in any DER services provided beyond the meter, and yet large amounts of uncoordinated DER could cause significant distribution network problems. IPAG identified the relationships between parties that might use DER service and how the ownership and control would flow as shown in Figure 4.

Figure 4 - DER service flows



To IPAG's framework we add the value streams identified from section 2.

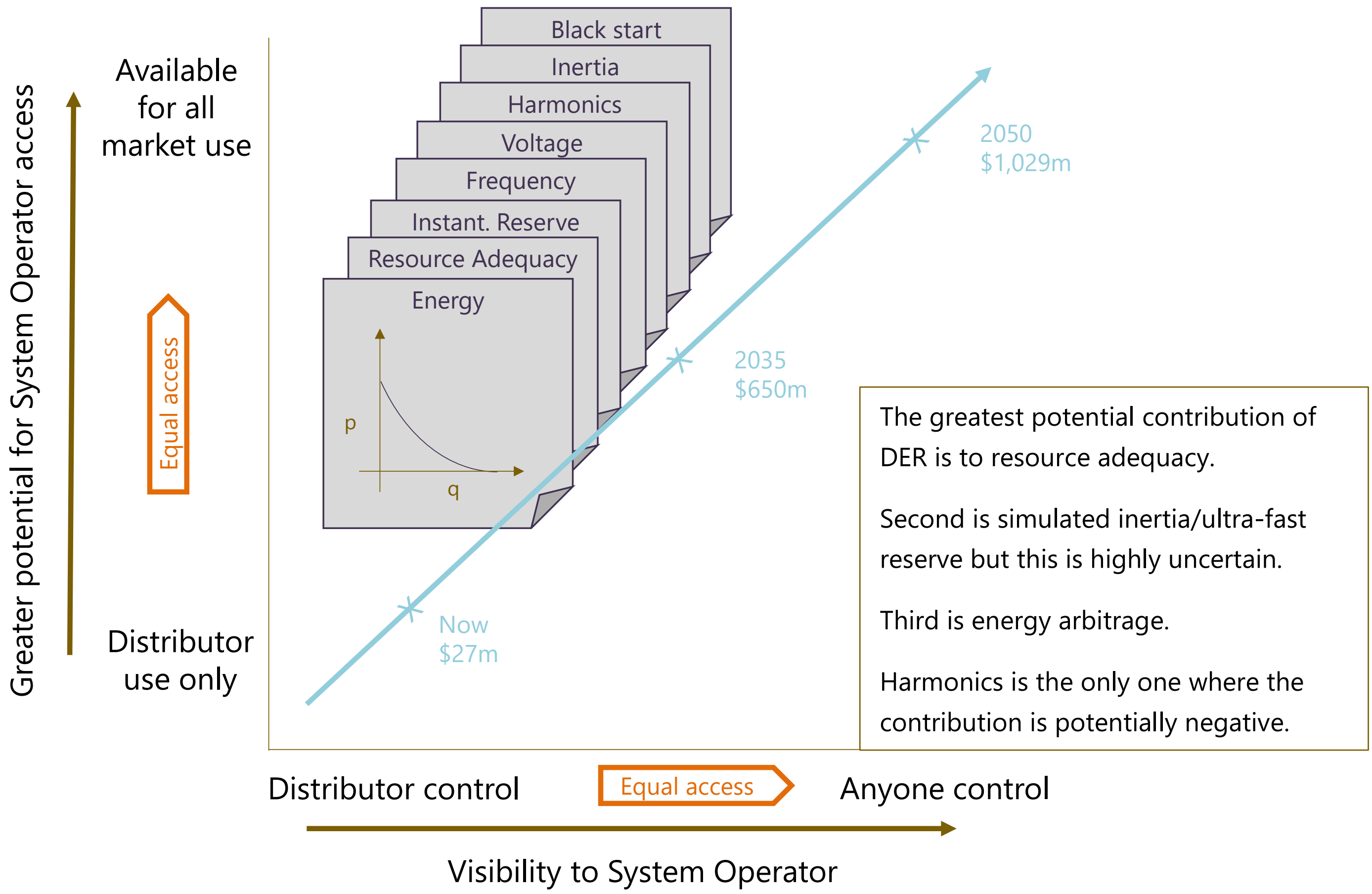
2. The potential value of DER

This is an assessment of the value potential, not an assessment of how much of the potential is taken up by DER. The latter will depend on the detail of the value potential (the demand curve) and the cost of DER for progressive levels of DER service and scale (the supply curve) – we investigate these in in section 3. It will also be affected by transaction costs and barriers to entry, which we look at in section 4.

We started this assessment based on previous assessments of value and categories of value stream. We based our early assessment on Transpower's paper on distributed BESS (Transpower, 2019a). The Transpower paper was an early assessment on value streams in New Zealand, which were based on work by the Rocky Mountain Institute. The RMI work has been referenced internationally. The value streams we have covered are:

- **Energy arbitrage** - the value that could be captured by buying and storing electricity when it is offered at low cost on the market and selling it back into the market when demand is highest
- **Resource adequacy** - the electricity system's ability to incentivise most efficient investment in solutions that can ensure that electricity demand can be reliably met at every point in time and over time, especially to meet peak and dry year energy needs.
- **Instantaneous reserve** – provision of generation held in reserve or of interruptible load in order to halt a decline in system frequency caused by an unexpected supply interruption.
- **Frequency keeping** – the service required to manage short term supply and demand imbalances to ensure that the system frequency is maintained in each island within a normal band
- **Voltage** – management of voltage to enable network capacity or deliver electricity to consumers to an acceptable quality.
- **Harmonics** - the abatement of a form of interference on AC voltage and currents.
- **Inertia** – providing shock absorption when a disturbance in the power system causes a rapid change in system frequency.
- **Black start** – the ability to re-start any part of the transmission or distribution network that is out of service.

We estimate that the total value opportunity for DER can increase from $27m per annum currently to $650m per annum by 2035 and $1,029m per annum by 2050 (see figure below); this represents an annual average growth of 13% over the entire period. The value increases faster in the first half of the time- horizon (by 2035), reflecting a higher DER and battery capacity growth over that period. Furthermore, by 2050 some of the DER value streams may be reduced with the advancement of the smart grid. For example, it is almost certain that over the long term, smart grid technologies will be able to dispatch resources in real time, significantly reducing the need for frequency keeping.



We have assessed the individual value contributions of the services. However, in the case of voltage, we have not been able to completely disaggregate the value stream from resource adequacy, therefore, the value stream for voltage is not additive.

The breakdown of the potential opportunity by value streams is as follows (per annum NZD):

Table 2 – Summary of per annum value streams

Value stream (million)	**2020**	**2035**	**2050**	**Additive**
Energy Arbitrage (small-scale DER)	$3	$21	$70	Yes
Resource Adequacy	$24	$588	$861	Yes
Instantaneous Reserve	$0	$20	$20	Yes
Frequency Keeping	$0	$1	$0	Yes
Voltage	$0	$10	$14	No
Harmonics	$0	-$1	-$7	Yes
Simulated Inertia	$0	$21	$85	Yes
Black Start	$0	$0	$0	Yes
Total	**$27**	**$650**	**$1,029**	

We find that the greatest potential contribution of DER is to resource adequacy. This is mainly due to avoiding investments in gas-fired generation, transmission and distribution infrastructure that would otherwise be required to support the increase in peak demand resulting from greater electrification of the New Zealand economy over the next decades.

The second highest potential is simulated inertia/ultra-fast reserve, but this is highly uncertain. This will depend on future supply and demand technologies and how much electronically connected plant replaces spinning machines that are directly connected to the power system. Most inertia is provided by grid connected generators but significant changes in demand side technology could also have an impact.

The third greatest potential is from energy arbitrage. This value arises from the same driver as the resource adequacy value, i.e. the growing electrification of the economy with a consequential increase on peak load. This provides increased energy arbitrage opportunities through battery storage.

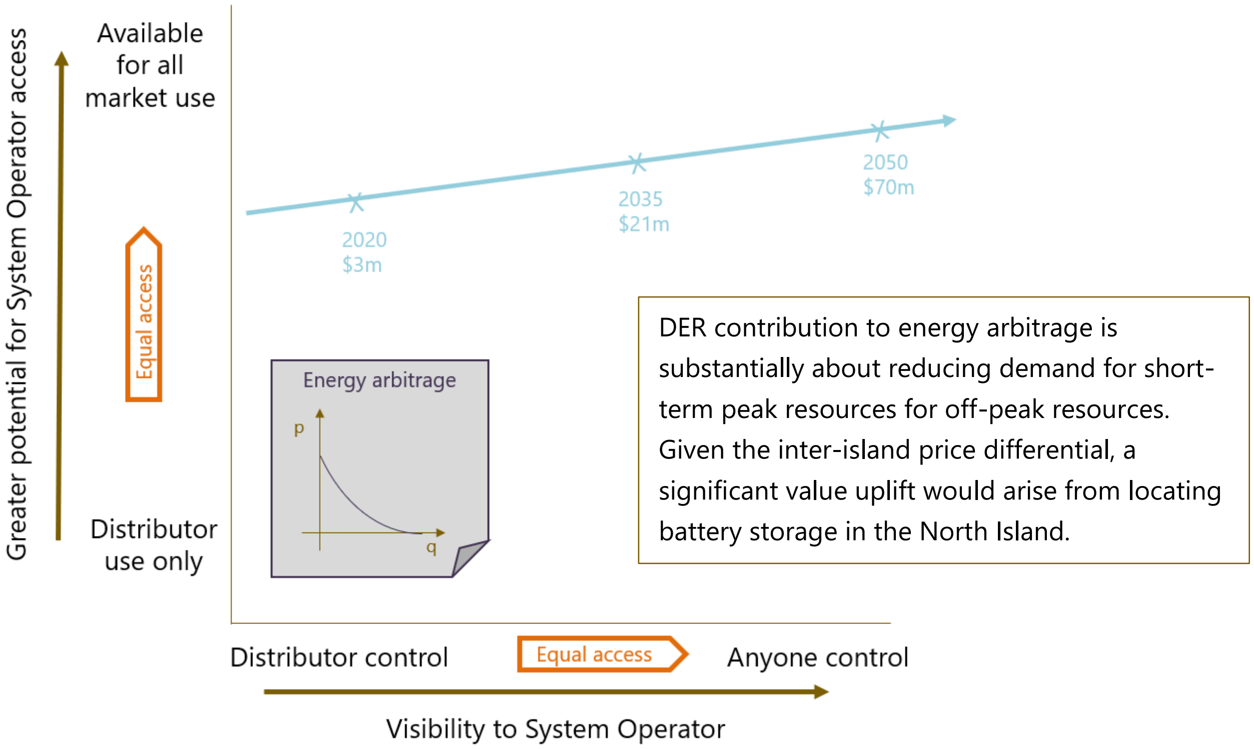
Harmonics is the only value stream where the DER contribution could potentially be negative. Harmonics are not currently a significant issue. If harmonics do become a problem in the future, this will almost certainly be due to the export of DER produced energy deep into the distribution network.

Time and place also matter. The contribution of DER is negative for most value streams if the DER technology (in significant volume) is in the wrong place and/or operated at the wrong time.

2.1 Energy arbitrage

2.1.1 Summary

The figure below illustrates the possible opportunity from small-scale DER.



2.1.2 Value stream assessment

Energy arbitrage refers to the value that could be captured by buying and storing electricity when it is offered at low cost on the market (i.e. at off peak hours) and selling it back into the market when demand is highest (at peak hours). The value is therefore assessed in terms of direct benefits to owners of DER (as opposed, for example, to avoided investment costs due to other DER services).

In New Zealand, there is considerable variation in energy arbitrage by region and season depending on the hydrological season. To account for hydrological variations, we determined average daily price differentials between off-peak and peak[3] based on 2015-2019 data of half-hour wholesale prices by zones.[4] This is similar to the approach taken by (Transpower, 2017b) but using more recent data from the EMI portal.[5]

Table 3 - Average prices and price differentials ($/MWh), 2015-2019

Zone	Off-peak (1)	Morning peak (2)	Day time	Evening peak (3)	Evening	Morning diff (2)-(1)	Evening diff (3)-(1)
UNI	72	109	100	108	89	37	36
CNI	69	103	94	101	84	34	32
LNI	70	100	92	98	83	30	28
USI	74	101	93	98	86	27	24
LSI	70	91	85	89	79	21	19

Source: Sapere analysis based on Electricityinfo data

Based on the figures in the table, we determine a long-term average price differential of $33/MWh in the North Island and $23/MWh in the South Island.[6] If we assume 4h of peak demand per working day, the unit value of energy arbitrage is therefore $33/kW or $23/kW in NI or SI respectively, or a mid-point of $28/kW.[7]

To determine the total possible energy arbitrage value that DER can provide, we use the projected capacity of battery storage as outlined in Table 1. The estimates are as follows:

Table 4 - Energy arbitrage value stream ($m)

Type of battery storage	Unit	Value in 2020	Value in 2035	Value in 2050

[3] Morning peak periods are 7am-9am and evening peak periods are 5pm-7pm. Off-peak period is midnight to 7am.
[4] Upper North Island (UNI), Central North Island (CNI), Lower North Island (LNI), Upper South Island (USI), Lower South Island (LSI).
[5] https://www.emi.ea.govt.nz/
[6] The estimates by (Transpower, 2017b) were $30/MWh in the North Island and $15-20/MWh in the South Island.
[7] Note that this is higher than the estimates in (Transpower, 2017b), which provides a range of $10/kW to $25/kW.

Small scale	$m/yr	$2.8	$21	$70
Utility scale	$m/yr	--	$11.2	$19.6
Total possible value – upper bound	**$m/yr**	**$2.8**	**$32.2**	**$89.6**

Source: Sapere analysis based on battery storage estimates from Whakamana i Te Mauri Hiko

2.1.3 Locational aspects

The inter-island differences in energy arbitrage ($33/kW and $23/kW in NI and SI respectively) suggest that a significant value uplift would arise from locating battery storage in the North Island.

2.1.4 Relationship to other value streams

The potential for energy arbitrage depends on how the daily load profile may change with a greater deployment of DER and other changes between supply and demand that drive the differences between daily troughs and peaks in the future. There is a strong relationship to resource adequacy where the response of DR and BESS could significantly increase the utilisation of the power system by flattening demand.

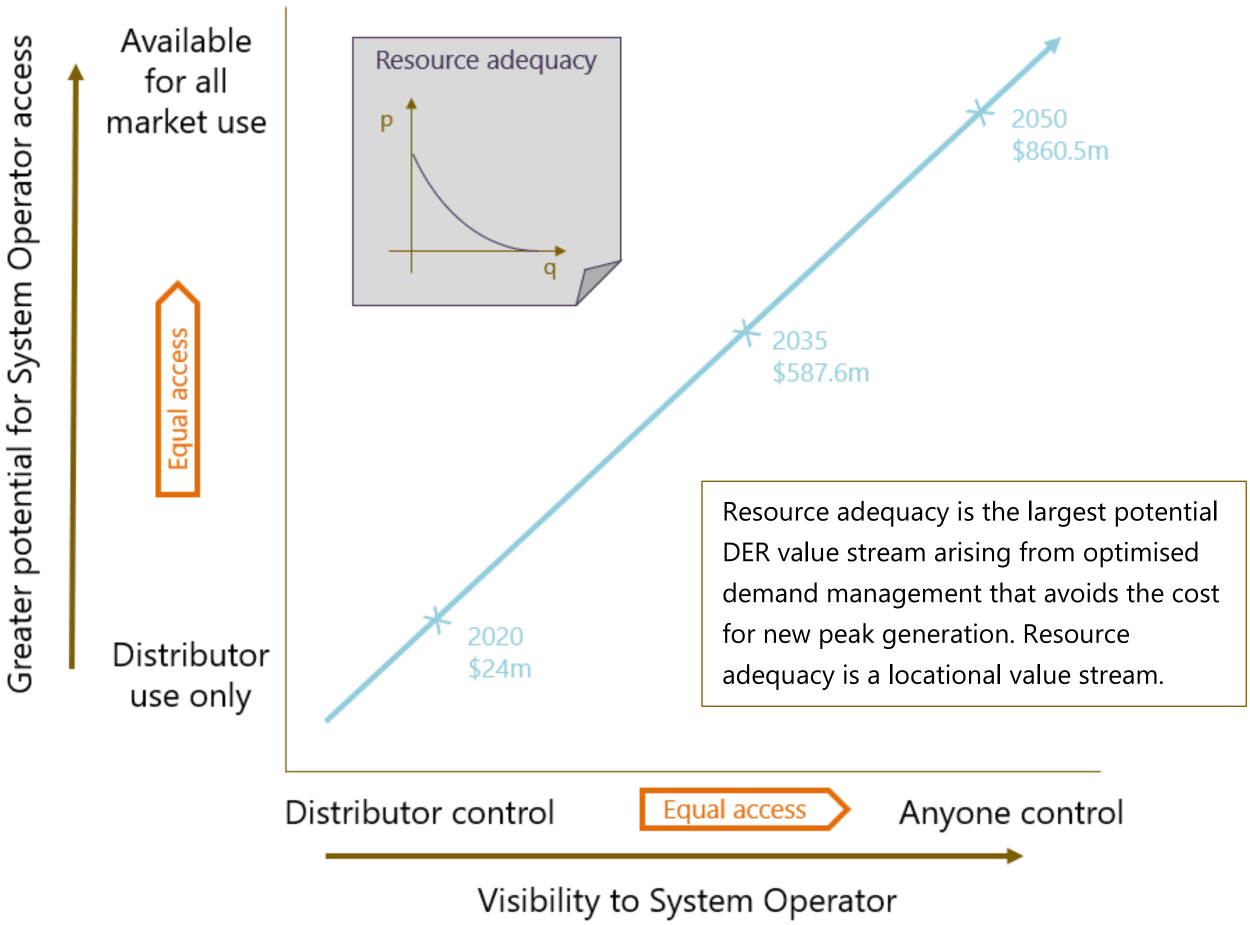
With regards to the impact on pricing, we observe that there will still need to be a peaking price signal to enable resource adequacy by DER; even though energy prices may fall overall, a peaking price signal would still be required to meet growing capacity needs. An electricity price differential between peak and off-peak hours would therefore remain, although it may change depending on the cost of the marginal peak generator and how long-run capacity is signalled.

Other factors can also cause peaks and troughs, such as the variability of wind generation. However, providing these factors are increasingly predictable, which you would expect, then future smart grids should be able to flatten these effects as well.

In our assessment we have assessed resource adequacy on the basis of the baseline prediction of peak demand from Whakamana i Te Mauri Hiko. The residual energy arbitrage is also based on this scenario and, therefore, the value streams are additive.

2.2 Resource adequacy

2.2.1 Summary



2.2.2 Value stream assessment

We define resource adequacy the electricity system's ability to incentivise most efficient investment in solutions that can ensure that electricity demand can be reliably met at every point in time and over time, i.e. the system incentivises most efficient investment to meet peak and dry year energy needs (hydro firming). Historically, the peak -energy need has been substantially addressed through flexibility on the supply side (with the conspicuous exception of load control). In the future, consumers – households, commercial or industrial users – will become much more involved in the decision making around how and when their DER is utilised, and the price at which they are prepared to respond. We expect the bulk of the management of the DER will be conducted by aggregators or distributors or retailers rather than actively conducted by the consumers.

Meeting New Zealand's emissions reduction commitments will require significant electrification of the economy, particularly transport and industrial process heat. Without changing the way we generate and consume electricity, electrification will cause a significant increase in peak demand, requiring additional electricity system investment.

Transpower estimates that in their base case scenario, peak demand will grow from 7.5 GW today to 8.9 GW in 2035 and 10 GW in 2050.[8] The base case assumes that electricity demand will increase by 68 percent by 2050, [9] reflecting the important role that electrification will play in meeting NZ's climate change commitments.

New Zealand has traditionally been able to meet peak demand with its flexible hydroelectric schemes. Meeting peak demand in New Zealand in the future, however, could be particularly challenging due to potential peak demand growth and the increasingly intermittent renewable generation base. Therefore, more solutions will be required to respond cost-effectively to peak demand pressures. we

The benefits of using demand-side management solutions include increased network asset utilisation, increased ability to accommodate intermittent generation, and enhanced network flexibility in the face of uncertain future development. Together, these benefits will to reduce the overall investment required in generation and network assets.

We look at the following demand-side management mechanisms for ensuring resource adequacy as defined above:

- Management of peaks through demand-side solutions such as battery storage, demand-side response (e.g. smart appliances) etc.
- Management of peaks through smart EV charging (and TOU).

We consider the value of demand-side management mechanism by estimating avoided cost of providing power during peaks through traditional supply chains.

In the context of DER services, the total cost of avoided peak demand when viewed across the entire load profile is made up of two components: (i) the avoided cost of peak thermal generation and associated transmission and distribution costs, less (ii) the additional baseload generation cost to provide the required energy that is shifted from peak to off-peak hours. We assume the marginal peaker to be an OCGT plant, and the marginal baseload generator to be a geothermal plant (as it is cheaper than wind), with the following cost assumptions:

Table 5 - Cost assumptions for an OCGT peaker

	Unit	Value	Source
OCGT capital cost	NZD	$110,000,000	Based on recent projects
OCGT plant lifetime	Years	20	
OCGT plant capacity	MW	100	
OCGT plant load factor	%	10%	(Lazard, 2018)
OCGT fixed cost	USD/kW pa	USD 12.5	(Lazard, 2018)

[8] Page 61 in (Transpower, 2020)

[9] This estimate of electricity demand growth is broadly consistent with estimates by ICCC, MBIE and the Productivity Commission.

OCGT variable cost	USD/MWh	USD 7.35	(Lazard, 2018)
OCGT fuel price	$/kWh	USD 0.012	Based on USD 3.45/MMBTu as per (Lazard, 2018)[10]
OCGT emissions factor	tCO2/GWh	195	Uses a conversion factor of 54.02 ktCO2/PJ
Carbon price	NZD/tCO2	2020 – $34 2035 - $75 2050 - $200	Future projections are based on Figure 3-21 in (Productivity Commission, 2018)
Transmission lines lifetime	Years	100	
Distribution lines lifetime	Years	60	
OCGT total capex + opex (excl. carbon price)	**$/kW/yr**	**$143**	
Transmission cost	**$/kW/yr**	**$69.27**	Assumes $1.8 for 1,821 MW as per Transpower email on April 28
Distribution cost	**$/kW/yr**	**$97.79**	Assumes $2.5 for 1,821 MW as per Transpower email on April 28[11]

Table 6 - Cost assumptions for a geothermal plant

	Unit	Value	Source
Capacity	MW	100	
Capex	NZD	$471,200,000	Sapere analysis
Connection cost	NZD	$7,500,000	Sapere analysis
Fixed cost	% capex	66%	
Variable cost	% capex	10%	
Load factor	%	97%	
Incremental load factor to offset peak	%	10.3%	
Emissions factor	tCO2/GWh	62[12]	NZ Geothermal Association

[10] Note that this value might be on the lower end as it reflects gas prices in the US market
[11] This is based on a prorating of relative asset base growth through time for distribution businesses compared to incremental transmission investment. Although this method is credible, we have not been able to check the actual calculations performed by Stakeholder Strategies.
[12] Reflects median emission factor for NZ geothermal operation

Total incremental cost (excl. carbon price)	**$/kW/yr**	**$74.2**	

Note that the total incremental geothermal cost above was estimated in proportion to the energy component of generation that is shifted from peak to off-peak hours. This means that the relevant load factor is not the full 97%, but only 10.3% (=100 MW OCGT * 8,760h * 10% divided by 100 MW Geothermal * 8,760h * 97%).

On net, therefore, we estimate that the current cost of 1 MW avoided peak for 2020 is $240,447 p.a. We note that this is higher than Transpower's estimate of $149,041/MW p.a.[13] and reflects the carbon price assumptions in the table above. As carbon prices increase the cost of 1MW of avoided peak rises to $245,136 in 2035 and $259,432 in 2050.

Our annualised estimate of avoided cost does not capture the ability to address the dry-year problem. We note, however, that the problem could be addressed through an overbuilt of solar generation combined with distributed battery storage. An overbuild of solar would provide energy to meet the winter energy margin even at winter load factors. Batteries ensure that this solar energy can be usefully deployed in the short run. Absent solar overbuild, the dry-year problem would require long-term back-up from batteries (which would require at least 2,700 GWh of battery storage[14] and around 1,000 MW of charge/discharge capacity). Although this would be technically possible, it is not seen to be economically viable. Operating batteries of this scale in a hydro-firming mode,[15] is estimated to incur a marginal emissions abatement cost of $89,000/t CO_2e (ICCC, 2019) – a figure that is prohibitively expensive.

Smart EV charging and TOU

Smart EV charging refers to the deferral of EV charging and moving it to off-peak periods.

Time of Use (TOU) refers to price incentives provided by electricity providers to incentivise consumers to shift their load from peak to off-peak periods or alleviate their load (e.g. through battery storage).

It is estimated that smart EV charging together with TOU can reduce New Zealand's winter evening peak demand in 2035 by 1.9 GW compared to today (Transpower, 2020). If we assume that peak demand avoided follows the same trend as peak demand (i.e. 2.8% annual growth based on 2020 and 2035 load profiles with smart EV charging and TOU),[16] then peak demand avoided in 2050 is 2.8 GW.

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[13] This is the annualised value of $1.58 billion saved for each 1GW avoided (Transpower, 2020), assuming a rate of 7% over 20 years – note the longer lifetimes of transmission and distribution lines would further reduce this number. Transpower's estimates reflects avoided cost of gas-fired generation, and transmission and distribution investment costs. Our estimates include both fixed and variable costs.

[14] As indicated in (ICCC, 2019)

[15] This means that the battery would need to be charged when prices are low and discharged in a 1-in-5-year event when lake storage levels are low in winter.

[16] These load profiles were modelled by Transpower for their update to the Whakamana I Te Mauri Hiko report (Transpower, 2020)

The value of smart EV charging and TOU arises from avoiding infrastructure investments that would otherwise be required to support the increase in peak demand. The table below provides the estimates.

Table 7 - Resource adequacy value stream from smart EV charging and TOU

	Unit	2020	2035	2050
Peak capacity avoided	MW/yr	0	1,911	2,872
Avoided peak costs	**$m/yr**	**$0**	**$468**	**$745**

Source: Sapere analysis based on data from Whakamana i Te Mauri Hiko

Demand-side management

We estimate the potential peak capacity that can be avoided through demand-side management using the 2020 and 2035 daily load profiles modelled by Transpower for the case where smart EV charging (+TOU) is not used (Transpower, 2020). The estimation covers the following steps:

- Calculate non-transport demand and EV charging demand at peak hour (just before 8pm)
- Calculate the average non-transport demand and EC charging demand
- Determine net peak demand by taking the difference between the two values above
  Subtract hydro contribution to net peak demand (except four units at Maraetai) on the basis that this contribution would not be replaced with demand-side management alternatives. This is because removing hydro would come at a substantial cost, and that the marginal operating costs of hydro generators are low even in the long run. We remove 4 units from Maraetai (~140 MW) on the basis that Maraetai was designed for peak capacity in excess of credible river peak flows.
  Based on 2016 data on NZ demand and hydro generation, we estimate that hydro contributed 73% to net peak demand.[17]
- The resulting capacity provides measure of the potential peak capacity management through demand-side solutions.

The table below summarises the potential value from demand-side management for resource adequacy purposes, viewed separately from smart EV charging. As we discuss further below, there is an interaction between the two values (that for smart EV charging and using EV battery for demand side management), which means they are not additive.

Table 8 - Resource adequacy value stream from demand-side management only

	Unit	2020	2035	2050
Peak capacity avoided (MW)	MW/yr	100	750	1,571
Avoided peak costs	**$m/yr**	**$24**	**$184**	**$408**

Source: Sapere analysis using load profiles from Whakamana i Te Mauri Hiko

2.2.3 Locational aspects

We had considered having a separate value stream for capacity, which is often used to describe the ability of the power system to meet the capacity needs of every location on the power system. This clearly fits within the definition of resource adequacy. Especially with increasing levels of DER with a much more complicated economic framework for choosing both how and where energy is delivered, it is unhelpful to separate network and supply capacity (including DER). Therefore, resource adequacy is a locational service as it must ensure that electricity demand can be reliably met at every point on the power system at all times and over time.

2.2.4 Relationship to other value streams

Smart EV charging removes some of the peak load potential that could otherwise be managed through demand-side mechanisms. This means that the values estimated separately for smart EV charging and demand-side management (DSM) are not additive as they would over-state the total resource adequacy value.

To address this issue, we estimate the value for demand-side management based on the steps described in the *Demand-side management section* above, but using the 2020 and 2035 daily load profiles modelled in (Transpower, 2020) for the case where smart EV charging (+TOU) are used (as opposed to the case without smart EV charging).

The table below summarises the results for the case where smart EV charging, TOU and demand-side management solutions are available at the same time. Our estimates indicate that most of the resource adequacy value is provided by smart EV charging.[18]

Table 9 - Resource adequacy value stream from smart EV charging, TOU, and DSM

	Unit	2020	2035	2050
Total peak capacity avoided	MW/yr	100	2,397	3,317
Total value	**$m/yr**	**$24**	**$587.6**	**$860.5**

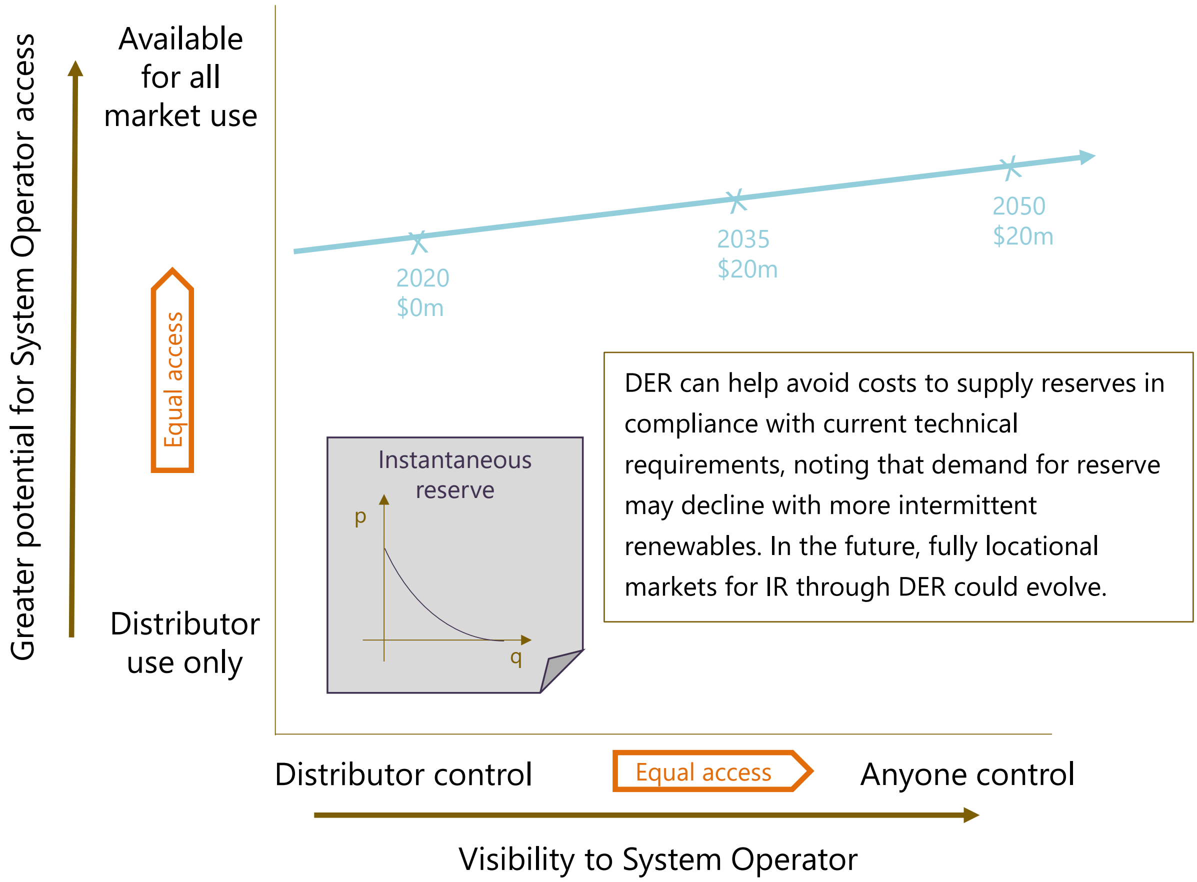
Source: Sapere analysis based on data from Whakamana i Te Mauri Hiko

Although the difference is a little semantic, and there will be some value overlap, our assessment of resource adequacy values is substantially separate from energy arbitrage. Resource adequacy is about maintaining adequate peak capacity in the future, whereas energy arbitrage is substantially about reducing demand for short-term peak resources for off-peak resources, i.e. energy arbitrage is mostly about offsetting the need for *current* thermal peaking resources whereas resource adequacy value is mostly about offsetting *future* peak needs. However, the highest peak prices will signal long-run peaking needs, so there will be some overlap but not material to our conclusions, in our opinion.

[18] This is consistent with the finding of a report by Imperial College London, which notes that smart EV charging is the most flexible of all of the demand-side technologies examined (Strbac, et al., 2012).

2.3 Instantaneous reserve

2.3.1 Summary



2.3.2 Value stream assessment

Instantaneous reserve is generation that is held in reserve or load that can be interrupted in order to halt a decline in system frequency caused by an unexpected supply interruption (e.g. due to generation or transmission interruptions). In New Zealand, two distinct IR products are procured in the wholesale market for each island separately.

The Fast Instantaneous Reserve (FIR) is intended to counter an under-frequency event,[19] and is made up of spinning reserve and interruptive load. It must be provided within 6 seconds after the event and sustained for 60 seconds.

The Sustained Instantaneous Reserve (SIR) aims to recover frequency to or above 49.25 Hz after an under-frequency event. It must be provided within 60 seconds after the event, and sustained for at least 15 minutes for spinning reserve or, if it is interruptible load, until the provider is instructed by the SO to cease the provision.

[19] E.g. due to the tripping of single or multiple generating units or HVDC trips in bipole or single pole mode.

In the future, smart grid technologies are expected to make demand response, such as responsive load and storage (stationary or mobile batteries), available as a source of instantaneous reserve. Smart grid communication and control should enable a continuous demand response to an under-frequency event, which is in contrast to the current binary response of interruptible load afforded by relay technology that trips load at a pre-defined frequency (Transpower, 2015).

A study by Imperial College London[20] on NZ energy futures determined that there are mainly two flexible demand technologies that would be well placed to provide frequency response services – smart refrigerators and electric vehicles (Strbac, et al., 2012). For EVs, the service can be provided by controlling the charging of EVs, e.g. interruptible charging for a short period of time. For refrigerators, the service can be provided by changing the duty cycle of appliances.[21]

In addition to flexible demand, frequency management services could be also be provided by battery storage systems. A recent study on distributed battery energy storage systems in New Zealand shows that if such systems are appropriately configured, they can respond faster than current providers of instantaneous reserve, recovering frequency faster and stabilising the system with fewer oscillations (Transpower, 2019a).

Based on EMI data on cleared reserves, we estimate that the average IR capacity for the South Island is 100 MW. For the North Island, we note that in a recent report, EA suggested that the Government's target of 100% renewable generation in a year of average hydrology by 2035 would result in a significant reduction of instantaneous reserve required — from around 400 MW of SIR at times of capacity scarcity to potentially 140 MW, although the HVDC link flows could set the SIR requirement at a higher level in those cases (EA, 2018). We agree that more renewables probably mean smaller units and lower risk, thus reducing the need for reserve, but this also depends on how much any reduction in inertia affects the rate of change of frequency in an event.

To recognise that sometimes the HVDC would set the risk, we adopted a 200 MW figure for 2035 and 2050. Although this is a high-level assumption, significant changes to it would not materially affect our conclusions with regards to the DER opportunities that can bring most value.

For the purpose of this report, we assume that the IR capacities do not change over from 2035 through to 2050. On this basis, our estimates reflect the upper bound value of the opportunity, as we do not expect IR demand to go up from current values.

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[20] This study was commissioned by Meridian.

[21] Domestic refrigerators generally keep the refrigerator temperature between two set points. Once the internal temperature reaches a pre-set maximum point value, the compressor starts and the refrigerator starts to cool, and stops when the refrigerator's internal temperature reaches the minimum required temperature. The cycle then repeats. The compressor typically has a duty cycle of 20 percent to 30 percent. The inclusion of smart refrigeration control changes the refrigerator's duty cycle length as the frequency changes. A frequency drop due to loss of generation decreases the refrigerator's duty cycle, which in turn means that the refrigerators can contribute to frequency stabilisation by reducing their aggregate load. The need for the refrigerator to continue to contribute system balancing means that average energy use for each appliance should reduce as the system frequency reduces.

We estimate the DER value from providing IR services in terms of avoided costs of needing to supply reserves in compliance with current technical requirements (e.g. SIR for 15 mins); in the future, we expect that these requirements would be reduced with an increased use of smart grids that will optimise the deployment of DER for IR purposes. Currently, IR services cannot be practically provided by existing DER sources as the Code does not allow small providers to offer IR services.

As we discuss in section 2.7, it is also possible that a market for simulated inertia/ultra-fast reserve could also at least partially displace the IR markets. Using 2019 data on final reserve prices,[22] we estimate that the cost of providing FIR and SIR were $71.83/kW and $54.31/kW in the North Island and South Island respectively. For simplicity, we assume that the capacities for FIR and SIR are even, i.e. the FIR and SIR reserve prices are added together. Although this assumption is not entirely accurate, it provides a conservative upper value assessment of the IR opportunity for DER.

We determine the potential value opportunity from DER providing IR services to be as follows:

Table 10 - Instantaneous reserve value stream

	Unit	2020	2035	2050
IR capacity provided by DER – NI	MW/yr	0	200	200
IR capacity provided by DER – SI	MW/yr	0	100	100
Total value	**$/yr**	**$0**	**$19.8**	**$19.8**

Source: Sapere analysis based on Electricityinfo data

2.3.3 Locational aspects

FIR and SIR are currently locational markets with separate prices in the North and South Islands, although reserve sharing can also be used across the HVDC. In the future fully locational markets for IR could evolve by using DER to proactively replace the loss of load from an AC transmission circuit trip, similar to how special protection schemes work currently. Using reserve located in the island where needed means that HVDC capacity does not have to be limited to allow for a trip event if the HVDC cannot self-cover. The market clearing model can make an economic optimisation between limiting HVDC capacity or scheduling more IR. With highly distributed provision of IR (through DER) the same could be done for other transmission circuits. For example, currently the total capacity of the transmission circuits from Waikato to Auckland is limited to the level where the capacity lost from any one circuit can be shared across the other circuits (N-1). With significant local IR available in Auckland then the market clearing model could utilise more capacity from the circuits by scheduling local IR where economic.

However, the major barrier to these devolved reserve markets is that frequency cannot be the common control signal. A different signal is needed to react to an AC circuit trip. For these locational

[22] From https://www.electricityinfo.co.nz/

reserve markets to become reality a reliable, fast signal would need to be available for AC circuit trips. If this were a telecommunication signal, it would need to meet high standards of reliability.

2.3.4 Relationship to other value streams

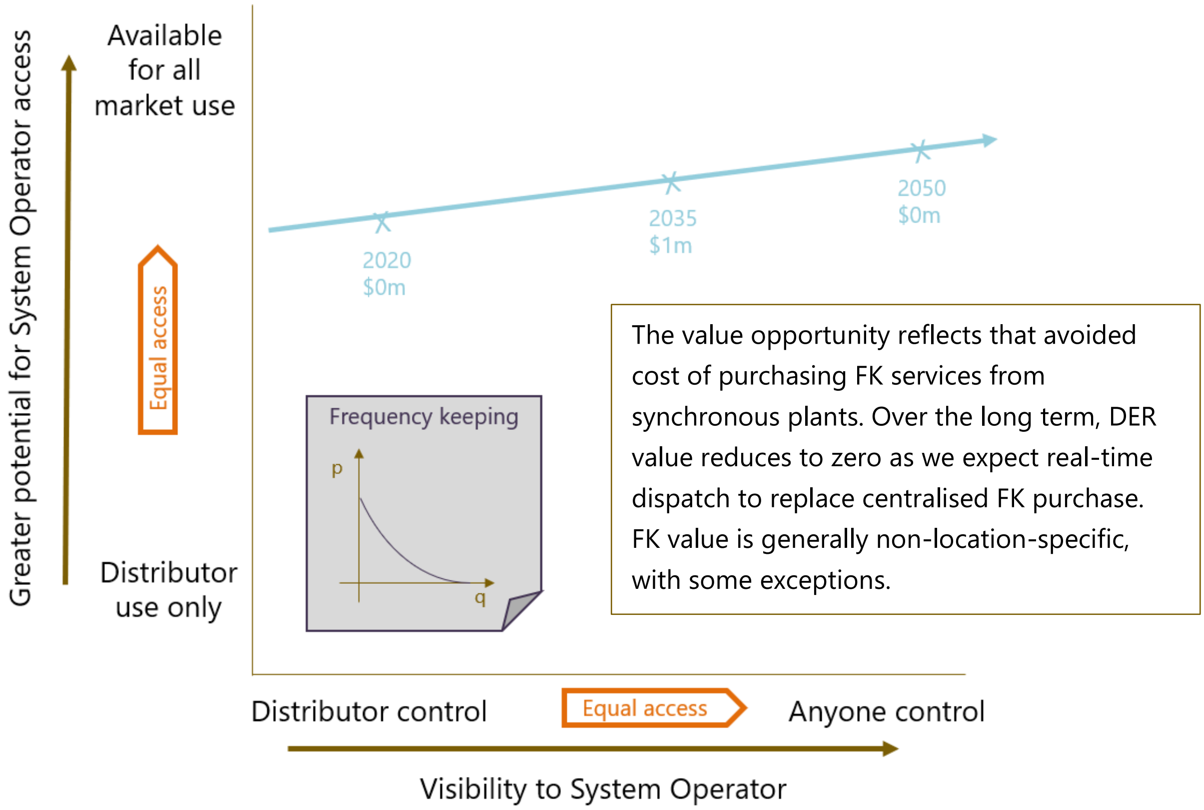
The potential IR opportunity depends on the level of system inertia – in a system with high inertia, frequency changes at a slower rate for supply and demand imbalances, making instantaneous reserve response less necessary, especially FIR, while in the system with low inertia more FIR would be required.

In our report we assume that the level of system inertia is held constant so that assumptions about inertia do not overlap our IR assessment. (see section 2.7).

The scale of IR opportunity could also have implications for system capacity and resource adequacy needs (for peak demand and hydro firming). If local reserve is used to manage n-1 for transmission capacity instead of partial loading, where economic, then the utilisation of network capacity could increase.

2.4 Frequency keeping

2.4.1 Summary



2.4.2 Value stream assessment

Frequency keeping services are required to manage short term supply and demand imbalances to ensure that the system frequency is maintained in each island within a normal band, i.e. between 49.8 Hz and 50.2 HZ. This service is usually provided by one or more generating units capable of quickly varying their output (hydro and thermal plants) in response to instructions from the System Operator. The range over which current frequency keeping providers must be able to adjust their output is known as the frequency keeping band. From 1 May 2016, this band is 15 MW in each island.[23]

While they are both frequency management services FK and IR are different services. FK varies continuously to balance imbalances between supply and demand to try to keep the frequency close to 50Hz between dispatch instructions. To do this in a stable way it is either provided by a single provider or coordinated by a central control system. IR restores frequency to a level after a loss of supply event. As it is provided quickly by multiple independent providers, to function in a stable way it deliberately does not try to restore frequency to 50Hz. The level frequency restoration that is reached is determined by the stability characteristics of the plant dispatched to react to an event.

[23] Previously, there was a 20 MW and a 10 MW band in the North Island and South Island respectively.

We note that a higher proportion of intermittent sources of energy (generally connected to the system by power electronics) to traditional synchronous generation would result in lower system inertia, which in turn could increase the requirement for frequency keeping capacity. Normally we would also expect supply and demand imbalances to increase with higher demand. However, to remain consistent with our assessment of inertia (Section 2.7) and the use of DER to flatten demand (Section 2.2), we assume that the rate of change of frequency in the future does not change.

Battery energy storage systems (BESS) could play an important role in providing frequency keeping services. Most commentators assess DER on the basis that active power curtailment is generally available for wind and solar-PV generation in case of over-frequencies (when they are generating), but that these sources of generation cannot guarantee a power reserve in case of under-frequencies. BESS can help overcome this issue, thanks to their ability to absorb large amounts of active and reactive power simultaneously and in a very short time (Ortega & Milano, 2016).

While BESS may be the best way to ensure FK even when there is no wind or sunshine, we disagree with the assessment that active wind and solar generation cannot provide power in the case of under-frequency. If this were true, the same could be said for the provision of frequency services from traditional generation. Partial loading of generating plant is the way in which frequency services are provided by that plant. While it is sometimes true that there is no opportunity cost in partially loading, say a hydroelectric turbine, there can be. As long as the value extracted from frequency services is at least equal to that from any other use then partially loading wind or solar is a valid economic choice.

In New Zealand, there has been a progression in the way frequency keeping services have been provided, from an island-centric to a national procurement of service. Up until 2013, frequency keeping services were purchased by the System Operator from a single provider. Subsequently, dispatching of multiple frequency keeping providers (MFK) was introduced in 2013 and 2014 in the North Island and South Island respectively. Since the introduction of the new HVDC bipole control system in 2013, it has been possible to transfer frequency keeping between islands. Trials have been done to enable frequency keeping services to be procured from available providers at a national, rather than at an island level. This is something that could be done in the future.

At present, only four generating companies meet the system operator's technical and access requirements for MFK.[24] It is technically feasible for currently installed DER to meet the technical requirements but the System Operator does not currently permit access below a certain size. On this basis, we assume that by 2035 the potential opportunity for DER to provide frequency keeping service is the entire frequency keeping band of 15 MW. However, over a very long-term horizon, it is almost certain that future dispatch technologies will be able to dispatch resources in real time, significantly reducing the need for FK. On this basis, we assume that by 2050 the value of DER providing frequency keeping is likely to be zero. The dispatch technology that achieves this will include faster supply response (including from DER), better real-time supply and demand prediction (through fast information and AI prediction) and faster optimisation and dispatch automation.

However, achieving this would require market development. There is currently little incentive for intermittent generators to improve their load forecasts, or for demand to improve its forecasting or

[24] Mercury, Genesis, Contact and Meridian.

for generators to improve their speed of response to dispatch instructions. Currently such incentives would probably yield little benefit but as technology improves the speed of information and the ability to forecast, control, and respond, new market incentives would be warranted. These are not just incentives for DER, though, but are market design issues.

We determine the maximum DER value from providing frequency keeping by 2035 based on the current cost of providing the service. The maximum potential opportunity by 2035 is the total avoided cost of purchasing FK from synchronous plants. We are not saying that DER would offset current FK providers but that is the maximum opportunity.

Based on 2019 Transpower data on frequency keeping costs,[25] and assuming a 15 MW cap on the service provision, we determine an average cost of $77.11/kW p.a. This means that by 2035 the potential opportunity from DER providing frequency keeping services is $1,156,667 which is gradually reduced to zero by 2050 when real-time dispatch replaces centralised FK purchase. For 2020, the infrastructure and rules to enable DER to participate does not exist and, therefore, there is no opportunity for DER.

Table 11 - Frequency keeping value stream

	Unit	2020	2035	2050
FK capacity provided by DER	MW/yr	0	15	0
Total value	**$m/yr**	**$0**	**$1.16**	**$0**

Source: Sapere analysis based on Transpower data on frequency keeping costs

2.4.3 Locational aspects

In normal conditions, frequency keeping is not a location-specific value stream given the ability to transfer frequency keeping between islands through HVDC.

However, in some conditions, the value can become island-specific, mainly due to two factors: (i) the HVDC link is not always in full service, and (ii) the ability to transfer frequency keeping between islands is limited by pre-determined minimum and maximum values.

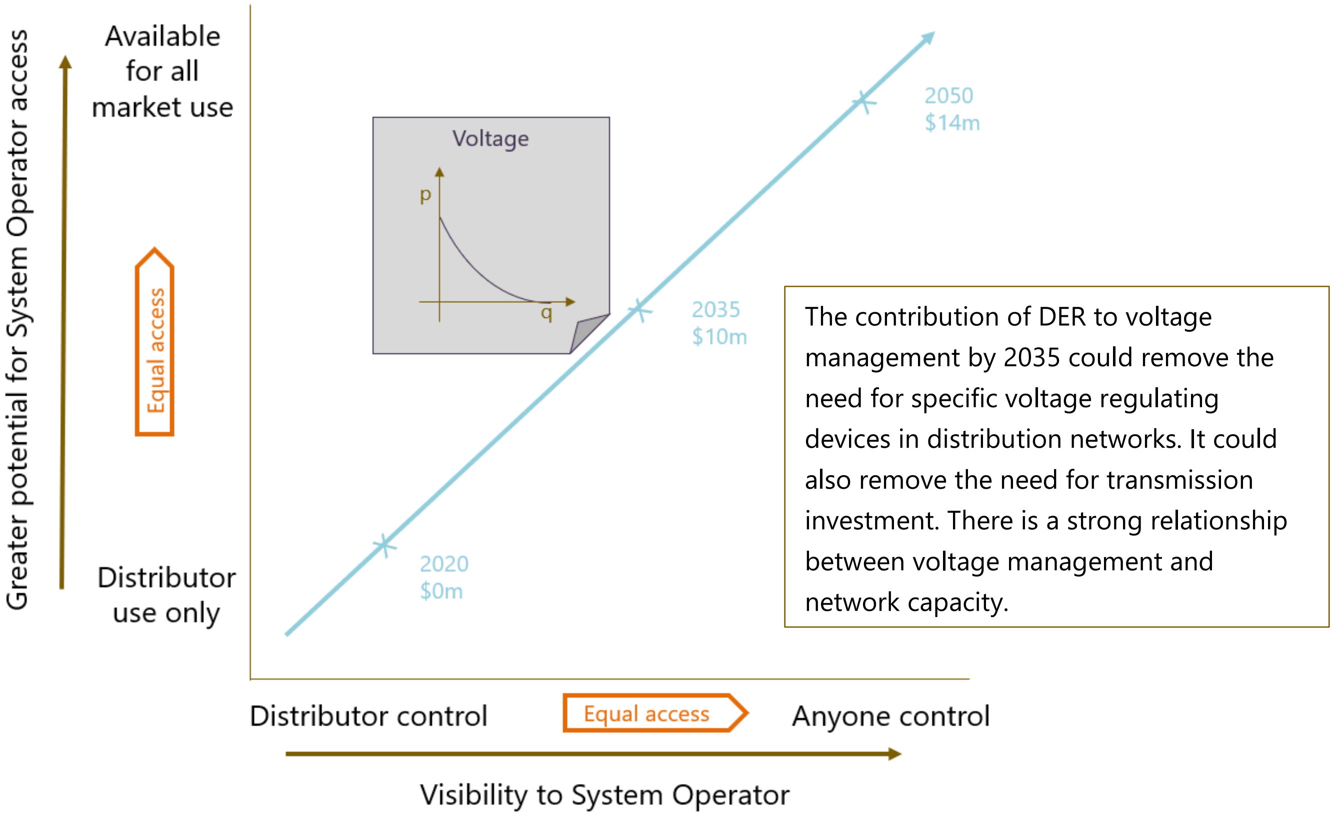
2.4.4 Relationship to other value streams

Our assessment of FK is done on the basis that is a separate ancillary service market as it is currently managed and, therefore, the value stream is additive.

[25] https://www.transpower.co.nz/system-operator/electricity-market/frequency-keeping

2.5 Voltage

2.5.1 Summary



2.5.2 Value stream assessment

In distribution networks voltage can be the main driver of capacity restrictions. In this value stream, however, we are looking at the value DER can provide in controlling voltage. Voltage control requires significant investment in New Zealand. The upper North Island, as New Zealand's largest load region with little local generation, has significant investment in static voltage control and compensation in the transmission network. The upper South Island, while a much smaller load has weak transmission and little local generation, also has relatively significant investment in voltage management at transmission level.

Much of New Zealand has low population densities with distribution lines often having to serve many customers over long line distances. There is significant investment in voltage management in distribution networks as well.

In Whakamana i Te Mauri Hiko, Transpower identifies that a voltage management project developed in response to the closure of the Southdown and Otahuhu power stations (in Auckland), and the prospect of closure of the Huntly Rankine units, are essential to the long-term transformation of the transmission network. Despite significant DER offsetting some transmission flows, grid scale renewables are going to need to be transported to Auckland and with the eventual decommissioning of the Rankines, Transpower has developed the Waikato and Upper North Island Voltage Management (WUNIVM) project – stage 1 and stage 2. Stage 1 will:

- Install a ±150MVAr dynamic reactive device in Auckland.
- Install a ±150MVAr dynamic reactive device in Waikato.
- Install a post-fault demand management scheme across Waikato and the UNI.
- Do preparatory work for stage 2.

A Grid Upgrade Proposal has been made to the Commerce Commission for stage 1 to be completed by 2023, at a cost of $145m (Transpower, 2019b). Stage 2 would install series capacitors on the two Brownhill – Whakamaru circuits. Stage 2 is required because when the significant transmission capacity into Auckland is highly loaded low voltages can occur. Stage 2 is expected to cost $65m - $135m ((Transpower, 2020), p.46).

DER can help in a couple of ways. DER can provide reactive power, potentially more flexibly than a synchronous machine and as well as a statcom. The most important way in which DER can add value to low voltage management is as an active generation source. If DER is encouraged to generate when voltage is low, which is also going to be when regional demand is high, then just the provision of active voltage will help lift voltage. However, DER could export reactive power as well.

DER can also help with high voltage. By incentivising batteries to charge and demand response to consume when voltage is high, and regional demand is low, DER could add load to the transmission circuits and reduce their net capacitance. DER can also consume reactive power to help.

The WUNIVM stage 1 project will now go ahead. However, we assume that if there had been price signals in place, then the distributed solar generation already installed in the Waikato and Upper North Island regions could have offset 50MVA$_r$ of the stage 1 project. This is a rough estimate. According to the Electricity Authority, there is 65MW of distributed solar in the Central and Upper North Island. We do not know how many of these have batteries, which would be necessary to ensure active generation at peak times. Although the number of batteries is likely to be a small proportion of the current solar installations, there may have been more batteries installed if there had been a voltage price signal. Such a price signal could also lead to the sizing and capability of inverters to provide voltage support if it is economic to do so. To the extent that reactive power can contribute to the Upper North Island voltage issues, solar inverters could be installed to generate reactive power at any time without a battery.

There is significant investment in voltage management within distribution networks. Based on EDBs information disclosures to the Commerce Commission there are 649 voltage regulating transformers and 279 capacitor installations in the New Zealand distribution network as at the end of the 2019 disclosure year (Commerce Commission of New Zealand, 2020). Voltage regulating installations can use one, two or three voltage regulating transformers in each installation. The most common configuration, and the one we are going to use as an average, is two per installation, which gives 325 voltage regulating installations. Collectively we have valued these assets dedicated to voltage control at around $60 million on a replacement cost basis. We assume that these distribution voltage control assets would increase proportionally with demand growth in the absence of an alternative form of control.

In 2020 there is insufficient DER to be able to make a meaningful difference in voltage management within distribution networks. However, with the levels of penetration of DER expected, even by 2035, then DER definitely could. The best voltage regulation probably comes through active generation from a battery or solar panel, but their inverters could vary reactive power output at any time. However, to assist with managing voltage the DER output has to not only be incentivised to invest in technology that can coordinate voltage and follow a stable voltage characteristic but has to be coordinated in real-time to set up workable voltage profiles throughout the transmission and distribution networks. When utilised in this way DER is not only helping to manage voltage but is also optimising the import and export capacity of the power system.

We determine the following annualised values for voltage control.

Table 12 - Voltage value stream

	Unit	2020	2035	2050
DER value from voltage	$m/yr	$0	$10	$14

Source: Transpower and EDB data and Sapere analysis

2.5.3 Locational aspects

Voltage is a locational service. The voltage at any point in the power system is a function of active and reactive power import and export, the influence of other active voltage sources and the characteristics of the lines that connect them. Voltage needs to be managed within a range that allows for the correct operation of both power system and consumer equipment at every point this equipment is connected, however, in the future in locations with only power electronic connections, these ranges could be broadened. Therefore, voltage has to be managed at each location in a coordinated way.

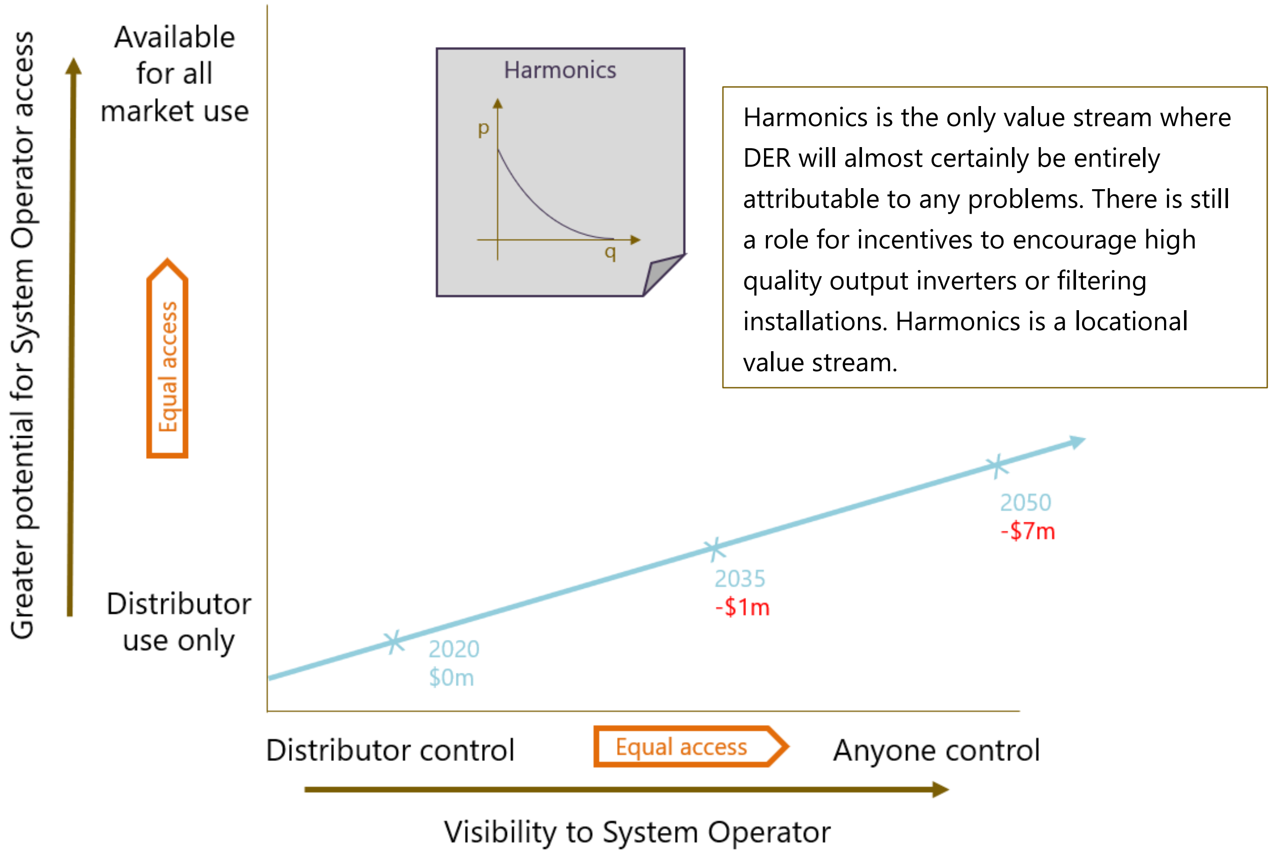
Voltage may need lifting, when loads are high on power lines, or may need lowering, when loads are light and/or DER exports are high. Voltage and DER export and loads need to be coordinate to also optimise capacity at each location. Under the scenario where there is significant DER export then distribution networks will have voltage profiles, at times, running in the opposite direction to which they currently operate. This has implications for distribution network design and the coordination of protection.

2.5.4 Voltage - relationship to other value streams

The management of voltage to equipment specifications is strongly related to the effective capacity within distribution networks; and voltage can also limit transmission capacity. We have based this value stream on voltage regulating equipment that can be separately identified, but there is other equipment, on-load tap changers for example, where voltage management costs could also be reduced. In fact, the design of the power lines themselves is a major influence of voltage. Overall, the very general way in which we have priced capacity means that voltage management costs are already captured in that figure. We have tried to separately identify here what specific value is attributable to voltage control, but this value is not additive to the total value of DER.

2.6 Harmonics

2.6.1 Summary



2.6.2 Harmonics value stream assessment

The New Zealand power system is not only designed to work on Alternating Current at 50Hz, but it also needs the AC waveform to resemble, quite closely, a sine wave. Digital switching devices, as in electronic controllers, rectifiers, and inverters, can introduce a form of interference on the AC sine wave. The combined effect of these forms of interference is called Total Harmonic Distortion. If THD get high enough then many devices and items of electrical equipment can operate incorrectly or fail.

Harmonics is probably the only value stream where, if problems occur, it will be almost entirely due to DER. Therefore, in aggregate, harmonics may be a cost to DER. However, given differences in DER equipment performance there should be benefits in creating incentives to encourage higher specification DER and recover costs from poor performing equipment. This could also encourage harmonic filtering solutions where they are required.

So far harmonic problems have not occurred in New Zealand except in relatively isolated examples. This is despite the proliferation of electronic power supplies for appliances and equipment. We are not aware of harmonics causing significant problems overseas. This is probably because the electronic equipment meets international standards of limits on THD and diversity of equipment probably also helps. Most of these electronic power supplies have also been relatively small.

The mode under which harmonics could become problematic is where there are large amounts of DER export back-feeding through relatively small distribution networks. When DER exports back into the distribution network it offsets the electrical current that would be required to supply the load. Sufficient DER export can push the current back upstream until the point where it is supplying all local demand it can. These points where the DER export current stops being able to supply further upstream and, therefore, where the upstream current is not required to supply further downstream are called null points. The current flows around these null points is low. However, the upstream current does not necessarily offset harmonics, and if the harmonic currents are not abated by travelling through the network (known as attenuation) then the harmonic distortion could be too high compared to the light current near null points.

While this effect is theoretically possible it has not been noticed much overseas with high concentrations of DER export. However, this could be because other limits, i.e. voltage, are limiting DER export before the harmonic effects become serious. The risk is that addressing voltage limits on DER export results in exports which are then limited by THD. This risk is theoretically observed in (Sun, Harrison, & Djokic, 2012, p. 4). Or, it could be that natural attenuation in distribution networks is enough to reduce harmonics to acceptable levels even near null points.

Harmonics could also manifest in areas where they are unexpected due to unfortunate combinations of electrical characteristics of distribution and consumer equipment. The more there are larger digital switching devices in the network the more chance there is of these sporadic THD events. They are difficult to diagnose and exceedingly difficult to fix.

From section 1.6.1 the level of penetration of DER by 2050 would mean significant back export from DER within distribution networks. At this level of penetration (22% of generation capacity), we would expect null points associated with every DER connection with the possible concentration of harmonic distortion at these null points. However, we would expect the distribution network to attenuate the majority of the harmonic injections, we have assumed 90% attenuation. In 2035 the level of DER penetration is 12% of generation capacity and we assume at this level only about half the connected DER would contribute to null points in the distribution network. Based on filtering costs and effectiveness for the HVDC we assess the value impact for harmonics in Table 13.

Table 13 - Harmonics value stream

	Unit	2020	2035	2050
DER value from harmonics	$m/yr	$0	-$1	-$7

Source: Transpower data and Sapere analysis

2.6.3 Locational aspects

Harmonics would need some form of locational pricing. The problem is ultimately caused by the performance of invertor/rectifier equipment at the DER location, but solutions may also need to be encouraged at points where THD exceeds thresholds. We expect, if harmonics manifest as a problem, this will predominantly be near null points in the distribution network, but isolated examples could occur anywhere that an unfortunate combination of electrical characteristics exist.

As of today, there is no reason to apply a price to harmonics. However, problems could emerge by 2035 and, if they did, then there would need to have been a dynamic signal encouraging power electronics with lower THD performance in areas that could develop the problems. This would require early engineering studies to establish the likelihood of harmonic problems to assess if, and when, dynamic prices should be applied.

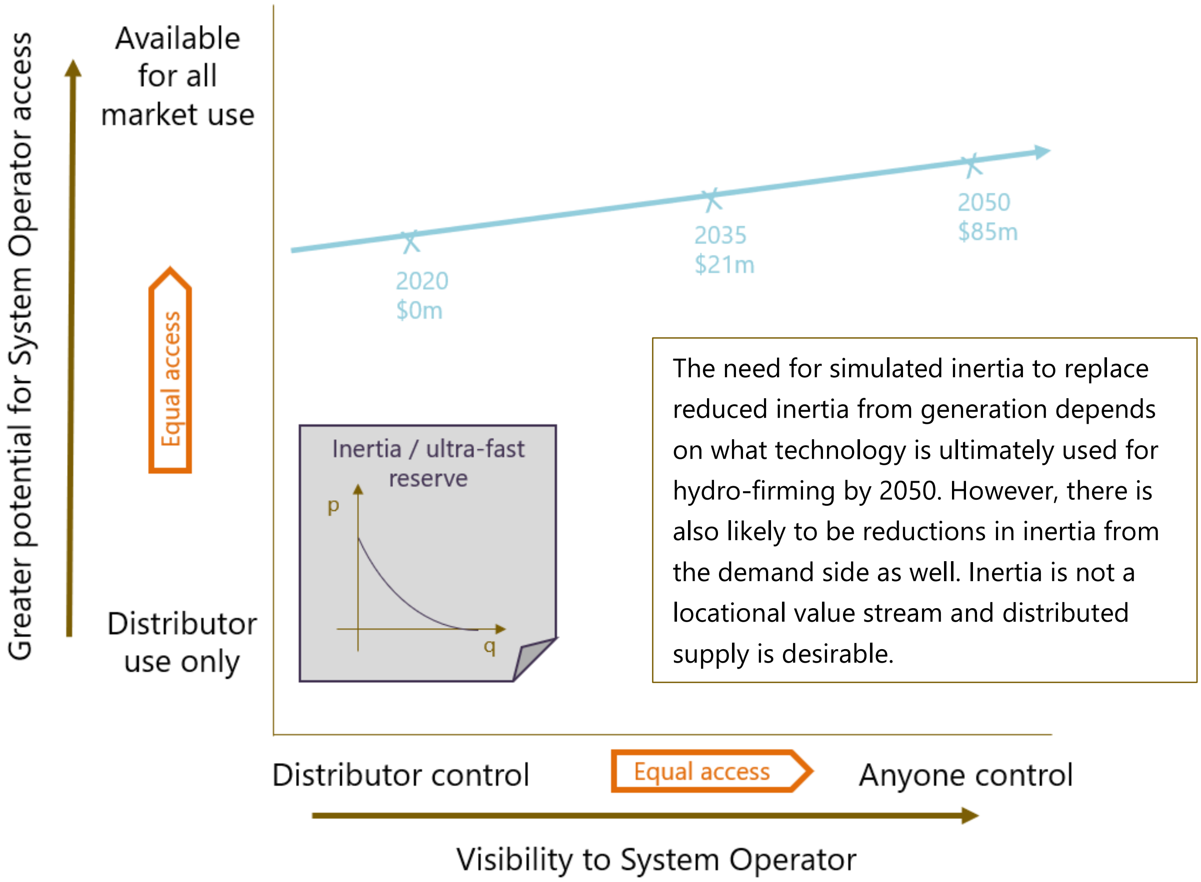
Overall, we think DER related harmonics will be a distribution network problem, if at all, but there could be isolated problems on the transmission network. There will also be more grid-scale power electronics and so there could be adverse interactions that occur on the transmission network.

By 2050, the prevalence of power electronics is likely to mean that there would be a general dynamic signal to encourage high harmonic performance from power electronics. However, the general harmonic performance of power electronics is also likely to be significantly better than today. If there is still a residual harmonic distortion issue in the distribution networks then both dynamic and static locational signals will be required to encourage solutions, such as filtering or other forms of harmonic attenuation, at points likely to have problems, i.e. probably export null points. A dynamic signal would be required to encourage investment in solutions and a static signal to guide operation as the null points ebb and flow with the export and import balance from DER.

2.6.4 Harmonics - relationship to other value streams

Generally speaking, harmonics problems are not related to other value streams. However, as the predominant form of THD might be caused near null points in the distribution network resulting from DER export then value streams that might affect this would then also indirectly affect THD. For example, if higher value was placed on self-consumption through local energy storage than on export then the reduction in exports would reduce the opportunity for null points where harmonics might then form a high proportion of the current compared to the fundamental. Nevertheless, by 2050 with 22% of generating capacity forecasted to come from distributed solar, there will be DER export and the opportunity for harmonic distortion is likely. We consider that the negative potential value contribution of harmonics to DER value streams is additive.

2.7 Simulated inertia/ultrafast reserve



2.7.1 Simulated inertia/ultrafast reserve

If there was no inertia in our power system, then any mismatch between supply and demand would cause the whole system to either stop dead or speed out of control instantly. Inertia is the characteristic of mass that resists changes in movement caused when force is applied to that mass. Traditionally, machines connected to the power system are effectively linked to the frequency of the power system and provide inertia.

Power electronics completely remove the relationship between a generator’s mechanical speed and frequency, e.g. in the case of many wind turbines, or connect generating sources with no mechanical rotation, e.g. in the case of solar. These types of generating capacity provide no inertia and the concern is that the replacement of inertia-less generation for machines that provide inertia will lead to uncontrollable swings in frequency for relatively low mismatches in supply and demand such as when a generator trips off.

Significant inertia is also provided by the demand side. There are large numbers of electrical motors in the demand side ranging from industrial motors and pumps, to commercial (predominantly in heating, ventilation and air-conditioning), and to domestic appliances (again particularly in refrigeration, heat-pumps and air-conditioning). In the past these have mostly been induction motors giving way to synchronous permanent magnet motors. However, to improve efficiency, increasingly these synchronous permanent magnet motors are using inverter speed controllers, which use power electronics, and provide no inertia.

Power electronics can operate so quickly that they could provide a very quick response to any changes in frequency. This is technically ultrafast reserve but could be designed to simulate inertia. We would design it to simulate inertia because this not only provides ultrafast frequency response but also provides frequency stability.

Two things are relevant to deciding whether inertia might become an issue in the future. One is how much the force might change (or torque in a rotating system) which is directly proportional to the power that might be lost by a generator trip (causing under-speed, i.e. under-frequency) or the power that might be lost due to a load trip (causing over-speed, i.e. over-frequency). While the size of generating units could get generally smaller as the large thermal units are displaced, we will still need to allow for potential failures of one pole of the HVDC (when operating in single pole mode) or bipole trips. When the HVDC is acting like a generator in one island it is acting like a load in the other. Therefore, the requirement to manage the HVDC means that we would expect the forces driving under-frequency and over-frequency to be roughly the same out until 2050.

The other factor to assess is what the change in system inertia (or moment of inertia in rotating systems) might be over the same period. This can be complicated as different synchronous machines have quite different moments of inertia. Rather than try to do a detailed assessment of the change in inertia due to the change in generating units and their specific characteristics we have simply assumed that the capacity of generation is proportional to its moment of inertia for a simple assessment. To do this we have tabulated the generation supply forecasted in Whakamana i Te Mauri Hiko that is likely to be synchronous. The results are shown in Table 14.

Table 14 - Forecasts of synchronous generation

Synchronous generation (MW)	2020	2025	2030	2035	2040	2045	2050
Hydro	5,275	5,280	5,296	5,482	5,527	5,527	5,527
Geothermal	997	1281	1431	1681	1681	1681	1681
Gas	1,372	1,058	1,240	1,373	1,473	0	0
Coal	500	500	0	0	0	0	0
Other	337	337	337	337	337	0	0
Added firming	0	0	0	0	0	2,051	2,212
Total with added firming	**8,481**	**8,456**	**8,304**	**8,873**	**9,018**	**9,259**	**9,420**
Total without added firming	**8,481**	**8,456**	**8,304**	**8,873**	**9,018**	**7,208**	**7,208**

Source: Whakamana i Te Mauri Hiko and Sapere analysis

If the plant that is added to provide hydro firming from 2045 is synchronous then there is a small reduction in inertia by 2030 but then it increases strongly. At this point in time our best guess is that the added hydro firming would probably be OCGTs. OCGTs would provide a lot of inertia and could be emissions free, running on hydrogen, ammonia, renewable fuel, etc. Alternatively, by 2045, the added firming could be provided by a new form of energy storage with asynchronous power electronics connection. If the added firming is connected by asynchronous power electronics, without incentives for simulating inertia, then there would be 1GW less of generation that provides inertia than we have today.

Of course, this is just the supply side, there could also be significantly reduced inertia on the demand side. According to one study in Great Britain the demand side contribution of inertia is 20% of the system total (Bian, et al., 2017). This could be higher than New Zealand due to the level of industrialisation, especially as New Zealand's largest industrial load (Tiwai Point Aluminium Smelter) has little inertia for its size. However, New Zealand has concentrated agriculture which would employ many induction motors, which is presumably where much of the demand side inertia comes from.

If we use 20% as a rough estimate then New Zealand has 1,700MW of supply side equivalent inertia in the demand side. This might be expected to increase as demand increases. However, only a small amount of the electricity demand forecasted in Whakamana i Te Mauri Hiko is due to general demand growth, roughly a 12% increase by 2050. Most demand growth is due to the electrification of transport, which charges through asynchronous power electronics, or industrial process heat. Process heat is expected to be provided by high temperature heat pumps, which are likely to be invertor controlled for efficiency, or direct heating, which has no inertia.

Given that there could be an increasing prevalence to replace existing motor stock with electronic controlled versions (giving speed control, soft-start, power factor correction and overall efficiency improvements) then there could well be a reduction in demand side inertia. Making a forecast for a reduction in inertia with so much uncertainty is impossible. Therefore, we simply estimate that a 1,000MW of supply side synchronous equivalent inertia could be reduced from 2020 levels by 2050 from both the supply and demand side. As the forecast from Whakamana i Te Mauri Hiko suggests that there will be no inertia loss from the supply side by 2035 then we make a very rough estimate that half of the inertia loss is from the demand side and half of that is lost by 2035, which gives 250MW of supply side synchronous equivalent inertia reduced.

For the purpose of valuation, we assume that the cheapest alternative to simulated inertia is synchronous condensing OCGTs (open cycle gas turbines that can be run up and then left running as synchronous motors). Using a capital cost of $1.1 million/MW gives the value stream for inertia in Table 15.

Table 15 - Simulated inertia value stream

	Unit	2020	2035	2050
DER value from inertia	$m/yr	$0	$21	$85

Source: Whakamana i Te Mauri Hiko and Sapere analysis

These numbers are based on maintaining frequency response to the level around that we currently have. However, there could be benefit in increasing system inertia using simulated inertia/ultrafast reserve and/or having a progressive function of frequency correction. It would be possible for DER technology to respond to a frequency event first as if inertial and then progressively replicating traditional governor action in a continuous stable function. The current IR products of FIR and SIR do not encourage innovation in the supply of reserve. Ideally the reserve market formulation would incentivise speed of response to frequency events, stability of response to frequency change, progressive change to frequency correction, and sustained duration of response to the extent that each was valuable. At present these characteristics are specified based on traditional generating units.

2.7.2 Locational aspects

Simulated inertia/ultrafast reserve would be an island-based value stream, as IR currently is. There are probably benefits to having simulated inertia highly distributed. This should make, not only the whole power system more stable in responding to frequency events but should stabilise the response of parts of the transmission and distribution network affected by circuit outages. The more time protection systems and back up supply systems have to operate the less load should be affected by any outage.

2.7.3 Simulated inertia/ultrafast reserve - relationship to other value streams

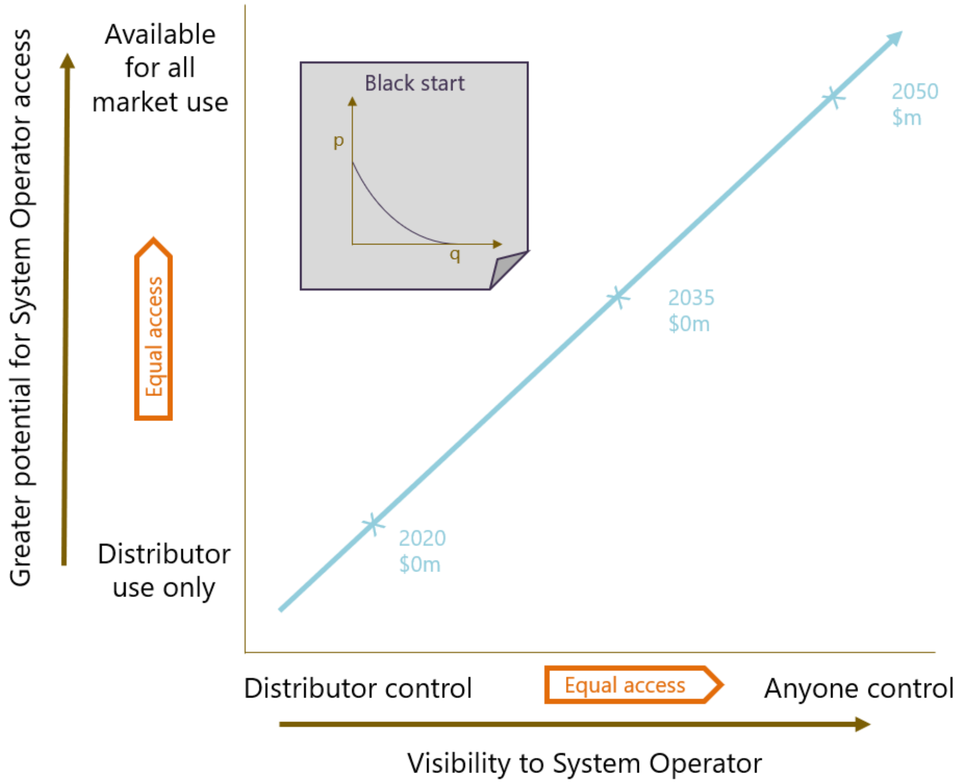
Simulated inertia/ultrafast reserve is strongly related to capacity and reserve as a value stream.

It is related to capacity because the choice of capacity has a strong influence on system inertia, i.e. through the choice of synchronous generation or asynchronous power electronics. If, for example, generation capacity was best met through distributed solar but OCGTs were still needed for inertia then OCGTs might still be the best choice. However, providing DER could meet all the requirements for generating capacity and could provide simulated inertia cheaper than synchronous motors[26] then DER would be the better choice. This is indicated in our assessment above, if all of the added firming capacity forecast from 2045 in Whakamana i Te Mauri Hiko was synchronous then there might be little value from simulated inertia. At the opposite extreme, if all the added firming capacity were provided by a new asynchronous power electronic connected technology then there would be considerable value in simulated inertia.

Despite the relationships between simulated inertia and capacity and reserve, our value assessments were independent of them. Instead our maximum value potential for simulated inertia was based on the both the technology that might be available in 25 years for bulk energy storage, and the loss of inertia from the demand side. As such, the value assessment for inertia is entirely additive.

[26] We make this comparison because in the absence of any inertia in the system, inertia would have to be added. We assume this would be through building synchronous motors.

2.8 Black start



Black start (starting a blacked-out grid up again) is rarely required. It is so rare that even if substantial value were able to be unlocked to improve black start, the expected value of the benefits would still be negligible.

3. The potential supply of DER

The authors analysed the types and volumes of DER that could be economically encouraged through the value opportunities above. To meet these opportunities DER types had to not only be a cheaper alternative but also meet the specification to contribute to that value.

We have performed this analysis by reforming the 'value stack' as it is often referred to in the literature as a residual demand curve. Residual in the sense that, in the absence of DER offsetting the need for the value stream at a cheaper cost with the correct capability, the value stream would need to be met by the remaining grid supply power system.

We also needed to build a residual supply value curve. This is because some DER produces energy (i.e. PV solar) while the rest does not. To compare DER on the same basis then we had to include self-supply within the supply cost of any DER that incorporates PV. The supply cost curve is a residual curve in the sense that the values indicated are the residual costs of the DER technology once any energy producing elements have 'self-supplied' at the level of price that would underwrite a highly renewable power system (thermal peaking costs are an avoidable cost in the demand curve).

The supply curve also needs to be constructed after not only price, but DER capability is considered. As some DER cannot offset demand peaks, for example PV by itself, then it cannot be used to avoid peaking generation, transmission, and distribution. The supply curve is built from the cheapest resources up providing that the DER resource has the required capability at that point in the demand curve.

3.1 Building the demand curve

The demand curve was substantially constructed around our conclusions from section 2. The price and potential volume become a tranche in the demand curve. Values are stacked in the demand curve to capture all of the value that could be realised by DER.

A problem in doing the value comparison is that some components, such as for transmission and distribution, are usefully priced in $/kW whereas energy producers are usually defined in $/kWh or $/MWh. We needed to have a comparable unit. Overall $/kW was more useful but converting the variable costs of energy resources to a present value was potentially confusing on a time series analysis. In the end we landed on $/kW p.a. as a unit that was directly relevant to DER and gave an indication of the annual value that could be avoided in the year of analysis per kW.

The following points were identified on the value stack and added to the demand curve as appropriate to create the curve.

3.1.1 Total grid system cost

The point total grid system cost was based on a high retail electricity cost converted in to $/kW p.a. $394/kW is the price at which, using our assumptions, it is cheaper to purchase entirely from the grid rather than use DER. At any price below this then DER can start to economically offset grid costs.

3.1.2 Frequency keeping

Frequency keeping is added to the demand curve at the price and volume identified in section 2. As such it only appears in our 2035 demand curve.

3.1.3 Instantaneous reserve

Instantaneous reserve is added to the demand curve at the price and volume identified in section 2. As such it does not appear in our 2020 demand curve.

3.1.4 Offset new lines and generation

This is the value assessed under Resource Adequacy in section 2. In this section we have described it as offsetting new lines and generation to recognise that different stakeholders are responsible for parts of the potential avoided costs through using DER to reduce peak capacity needs in the future.

In 2020 the potential to offset new peak capacity has been set at a notional 100MW. Currently it is not obvious what volume of new generation and capacity could be offset. This number does not affect our 'market clearing'. The volumes for 2035 and 2050 are 2,397MW and 3,317MW respectively, taken directly from section 2.

3.1.5 Offset thermal peaking

Offsetting the variable costs of thermal peaking generation is part of the way we have looked at energy arbitrage. At a price equivalent to $90/MWh then DER with discretionary capability can reduce the contribution of thermal peak generation of up to 250MW.

3.1.6 Offset voltage management assets

The cost of voltage management assets can be offset by DER with the capability to manage voltage (through discretionary reactive power generation or as an active voltage source) at the effective price and volumes identified in section 2.

These costs are only separately avoided to the extent that new lines and generation have not been avoided as we assume that the costs for new transmission and distribution includes the cost of voltage management. For this reason, offsetting voltage management costs does not appear in the 2035 demand curve as the volume of new generation and lines is greater than the volume of potential voltage management.

3.1.7 Harmonic filtering

Harmonic filtering is technically a cost of DER and would have been more correctly applied as a supply side cost. However, as the potential need for harmonic filtering increases as the total of all DER increases it cannot be applied as a constant per kW cost. Therefore, it has been included as a negative avoided cost on the demand curve.

It has been applied at the costs and volumes assessed in section 2.

3.1.8 Hydrofirming

This part of energy arbitrage, the ability to offset the contribution of thermal fuels to dry hydrological seasons, was added to form the bottom of the demand curve. It is based on the volume of PV solar panels, if the output were able to manage short-term resource adequacy, that could offset 3,100GWh of winter energy margin even at winter load factors. The price is based on the variable costs of $90/MWh of thermal generation being avoided 1 in 4.5 years.

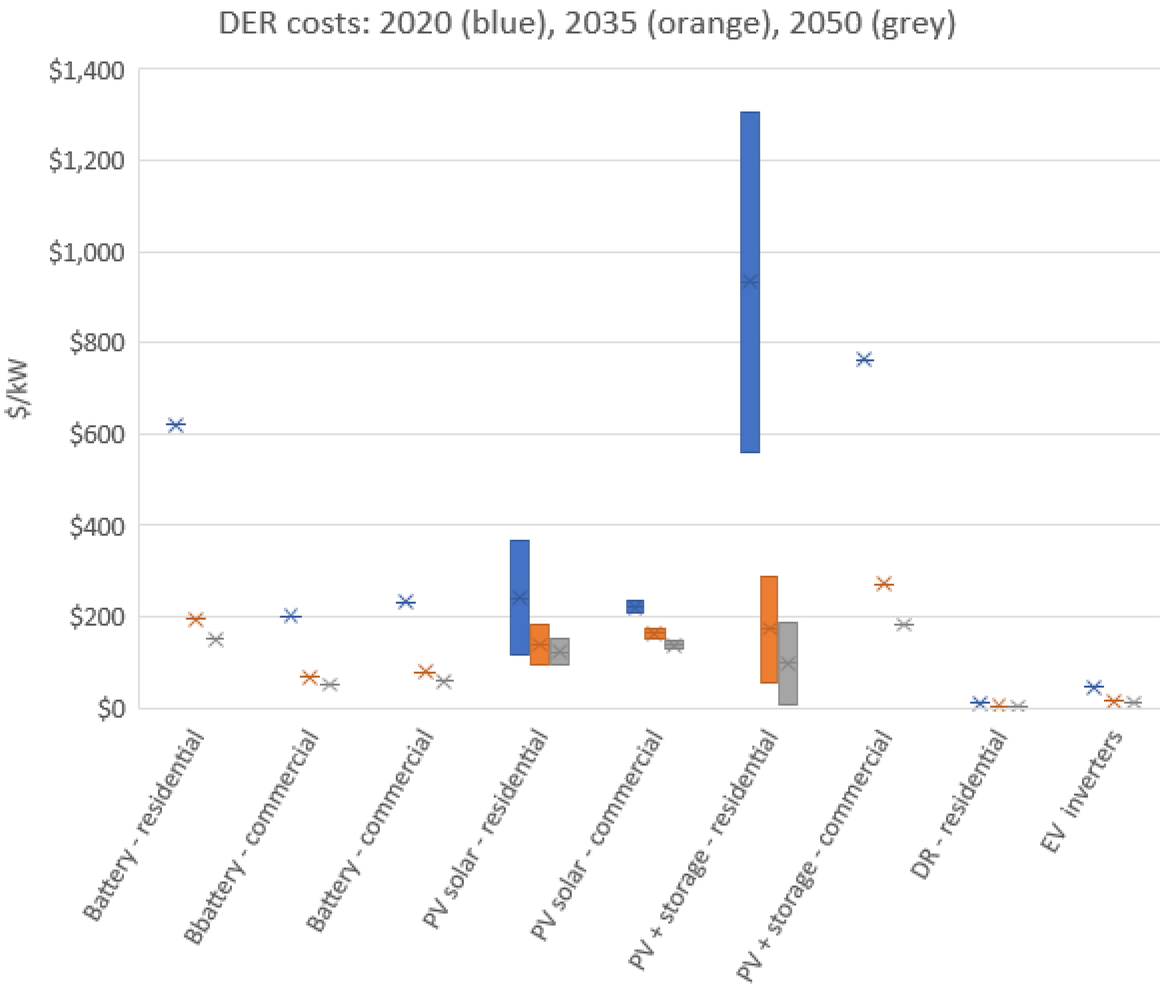
The winter energy margin is held constant over the period from 2020 to 2050 as the volume contribution of hydroelectricity is not forecast to change much over that period.

3.2 Building the supply curve

Supply curves were determined separately for different DER options in 2020, 2035 and 2050, using experience curves (i.e. annual technology cost reductions) estimated from available sources such as Lazard, US National Renewable Energy Laboratory (NREL), local NZ sales data, EECA and other. The supply curves are measured in terms of annualised $/kW per available DER capacity.

The figure below illustrates the cost point or range estimates (as applicable) for different DER technologies.

Figure 5 - DER costs in 2020, 2035 and 2050



Different DER technologies can provide similar or different system services. The residual supply curve is built by mapping the service required at a certain point on the residual demand curve to the available DER technologies at that point. Where technologies provide the same system service, the residual supply curve picks up the cheapest option.

The shaded cells in the following matrix illustrate the service we assume a specific DER technology is able to provide theoretically. Note that not all of these services are necessarily provided in 2020, 2035 or 2050, either due to a specific DER technology not being available on the market yet (e.g. demand response by smart fridges in 2020), or due to some services no longer being required as a result of smart grid deployment (e.g. frequency keeping in 2050).

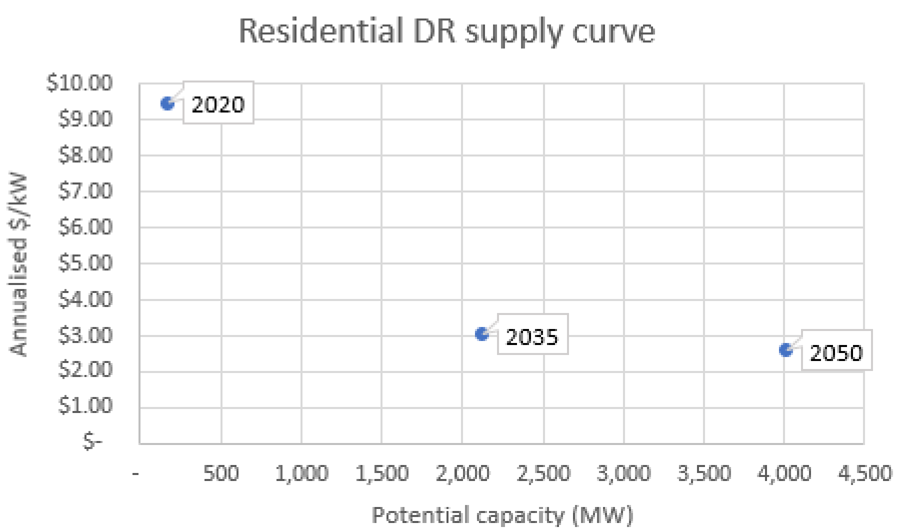
Table 16 - Mapping of DER technologies by system services

	Hydro firming	**Offset thermal peaking**	**Offset lines/ transmission**	**Voltage management**	**Instant. Reserve /Inertia**	**Freq. keeping**
DR - residential						
EV inverters						

Battery - residential						
Battery - commercial						
PV system - residential						
PV system - commercial						
PV + storage - residential						
PV + storage – commercial						

3.2.1 Residential demand response

Figure 6 - Residential DR supply curve



Residential demand response technologies reflected in the residual supply curve include the following technologies: EV battery charging, smart air conditioners, smart dryers and smart fridges. Note that this is not the full set of DR options – here, we only look at the marginal potential compared to what is already in place. Given that water heaters are already controlled in NZ, water heaters are not included in the supply curve, although they do and will continue to play an important role in the providing demand response capacity. However, the control of water heating will have to change to allow more flexibility and to optimise its value. The issue of controlled water heating is discussed in more detail in section 4.

To determine available DER capacity, we assess the number of smart appliances that may be available in 2020, 2035 and 2050. However, not every smart appliance will be running at the same time even during peaks. Notwithstanding that the point of DR is to guide consumption to specific times, we assume a 13% diversity factor, based on residential peak diversity.

To determine available EV storage capacity we use MBIE data on current and projected EV registrations. To determine available capacity from smart appliances we use EECA historical sales data for highly efficient appliances and make assumptions about future uptake based on our own judgement. We assume that highly efficient appliances would have smart technology built-in.

Table 17 - Demand response capacity

	Unit	2020	2035	2050
EV charging	% total DR capacity measured	6%	45%	34%
Smart dryers		10%	8%	9%
Smart ACs		85%	24%	29%
Smart fridges		0%	24%	28%
Total capacity	**MW**	**174**	**2,124**	**4,013**

The cost assumptions are based on (i) current price differentials for EV charger hardware and software controls and smart appliances, and (ii) assumed experience curves, as per the table below:

Table 18 - Demand response cost assumptions

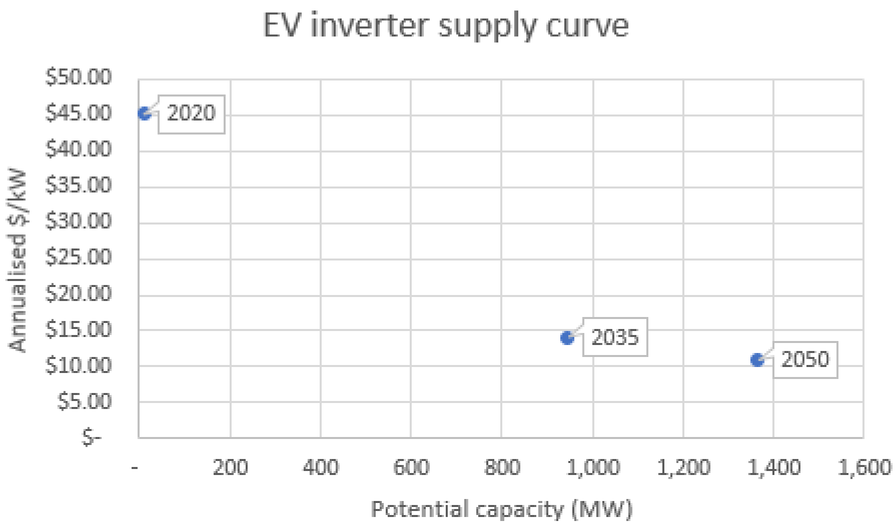
	Unit	2020	2035	2050	Source
Experience curve	Average annual cost decline, %	-10%	-7%	-2%	Battery storage experience curve as per (Schmidt, Melchior, Hawkes, & Staffell, 2018)
EV charging	Incremental annualised cost, $2019/kW	$9	$3	$3	Assumes $164 based on USD100 in 2015 as per (Rocky Mountain Institute, 2015)
Smart air conditioning		$9	$3	$2	Assumes $348 in 2019 based on existing sales[27]
Smart dryer		$18	$6	$4	Assumes $303 in 2019 based on existing sales[28]
Smart fridge		$9	$3	$2	Assumes same incremental cost as smart AC given similarity of technologies
Weighted average cost	**$2019/kW**	**$9.5**	**$3.04**	**$2.6**	Costs weighted in proportion to capacity shares of different smart appliances

[27] https://www.homedepot.com/p/Emerson-Single-Stage-5-2-Day-Programmable-Thermostat-P150/207173074 and https://store.google.com/us/product/nest_learning_thermostat_3rd_gen?hl=en-US

[28] https://www.whirlpool.com/laundry/dryers/electric.html?plp=%253Arelevance%253Acategory%253ALaundryDryersElectric%253Acategory%253ALaundryDryersElectricDryerMatchesTopLoadWasher&plpView=grid

3.2.2 EV inverters

Figure 7 - EV inverter supply curve



EV inverters enable power to be injected back into the grid during peak times. If this is implemented alongside smart EV charging, whereby, for example, a 3 kW EV battery is charged during off-peak hours, a total net reduction of 6 kW in peak generation could be achieved.

The potential capacity for EV inverts is assumed to be the same as for EV battery charging, i.e. 10 MW in 2020, 945 MW in 2035 and 1,365 MW in 2050. The cost assumptions for EV inverters are described below.

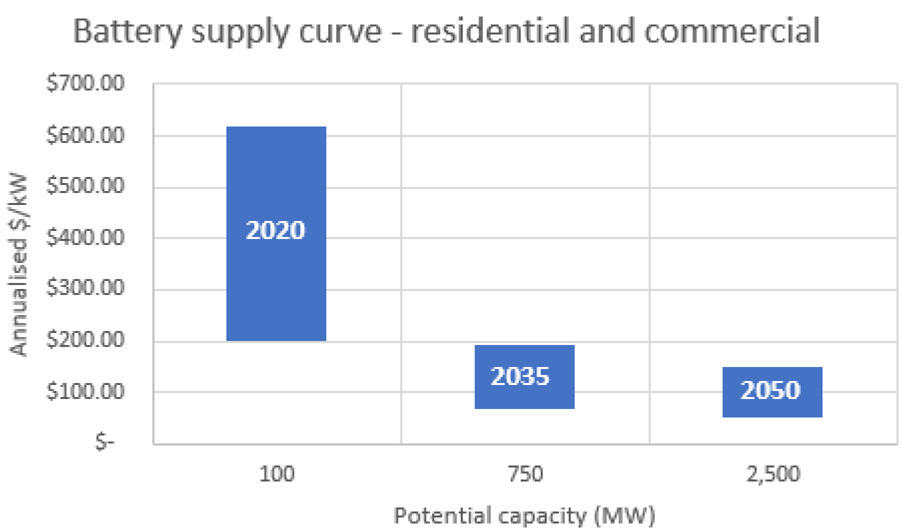
Table 19 - EV inverter cost assumptions

	Unit	2020	2035	2050	Source
Experience curve	Average annual cost decline, %	-10%	-7%	-2%	Battery storage experience curve as per (Schmidt, Melchior, Hawkes, & Staffell, 2018)
Battery inverter lifetime	Years	15	15	15	(MBIE, 2016)
Battery inverter	Incremental annualised cost, $2019	$306	$96	$74	Difference between the cost of bi-directional battery-based inverter and PV inverter (2016USD 2,739) as per (Ardani, et al., 2017)
O&M cost	% capex	1.8%	1.8%	1.8%	Assumed to equal the figure for residential battery
Battery inverter	**Incremental annualised**	**$45**	**$14.1**	**$11**	

	cost, $2019/kW				

3.2.3 Battery – residential and commercial

Figure 8 - Battery supply curve, residential and commercial



The figure shows a range of battery costs, reflecting different battery sizes. The lower-end cost is for a commercial 0.5 MW/2 MWh battery, whereas the higher-end cost is for a residential 6 kW/25 kWh battery. The detailed cost assumptions are provided in the tables below. The total potential capacity are based on estimates of distributed battery storage from (Transpower, 2020a).

Table 20 - Residential battery cost assumptions

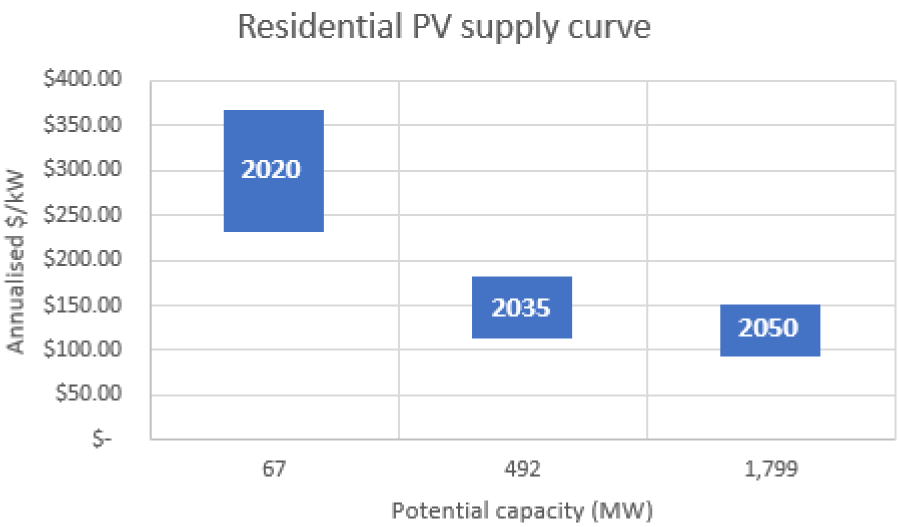
	Unit	2020	2035	2050	Source
Experience curve	Annual reduction in cost over the period	-10%	-7%	-2%	(Schmidt, Melchior, Hawkes, & Staffell, 2018)
Battery lifetime	Years	10	10	10	(Lazard, 2019)
O&M costs	% capex	1.8%	1.8%	1.8%	(Lazard, 2019)
Battery cost (6 kW/ 25 kWh)	**Annualised $2019/kW p.a.**	**$619**	**$193**	**$150**	Assumes an average cost of 2019 USD 18,750 as per Hawaii and Germany case studies in (Lazard, 2019)

Table 21 - Commercial battery cost assumptions

	Unit	2020	2035	2050	Source
Experience curve	Annual reduction in cost over the period	-10%	-7%	-2%	Based on (Schmidt, Melchior, Hawkes, & Staffell, 2018)
Battery lifetime	Years	10	10	10	(Lazard, 2019)
O&M costs	% capex	1.4%	1.4%	1.4%	(Lazard, 2019)
Battery cost (1 MW/ 2 MWh)	**Annualised $2019/kW p.a.**	**$232**	**$78**	**$59**	Assumes a total cost of 2019 USD 1,505,700 as per CAISO standalone battery case study in (Lazard, 2019)
Battery cost (0.5 MW/ 2 MWh)		**$201**	**$67**	**$51**	Assumes a total cost of 2019 USD 1,306,600 as per CAISO PV + storage case study in (Lazard, 2019)

3.2.4 PV system – residential

Figure 9 - Residential PV supply curve



PV system costs show a range of values depending on system size. We estimated costs for system sizes ranging from 3 kW to 10 kW as per the table below.

Table 22 - Residential PV cost assumptions

	Unit	2020	2035	2050	Source
Experience curve	Annual reduction in cost over the period	-3%	-5%	-1%	Based on residential capex estimates from (NREL, 2019)
PV system lifetime	Years	252	25	25	(MBIE, 2016)
O&M cost	% capex	0.8%	0.8%	0.8%	Estimated based on data from (NREL, 2019)
PV system cost (3 kW)	**Annualised $2019/kW**	**$231**	**$114**	**$94**	Assumes a total cost of $8,000 in 2020[29]
PV system cost (5.6 kW)		**$249**	**$123**	**$102**	Based on 2016 capex of USD 11,673 as per (Ardani, et al., 2017),
PV system cost (6.2 kW)		**$343**	**$170**	**$140**	Based on capex estimates from (NREL, 2019)
PV system cost (10 kW)		**$368**	**$183**	**$151**	Assumes USD 28,800 capex as per (Lazard, 2019)

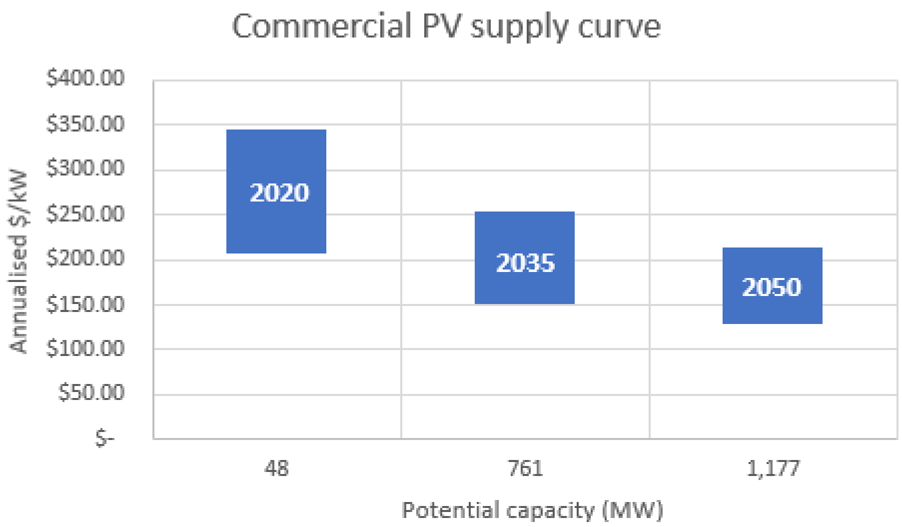
Residential PV capacity was estimated based on projections of electricity generated by rooftop solar based on (ICCC, 2019) projections of 1,180 GWh in 2035 and (Transpower, 2020b) projections of 4,470 GWh in 2050. For 2020, we assume that 70% of residential solar ICP connections[30] are standalone PV systems. We also assume that the proportion of households with solar that have PV systems without batteries is 70%, 55% and 53% in 2020, 2035, 2050 respectively. The 2035 and 2050 figures are based on assumptions of the number of households with solar and solar + batteries as per (Transpower, 2020b).

[29] https://www.mysolarquotes.co.nz/about-solar-power/residential/how-much-does-a-solar-power-system-cost/

[30] Data on ICP connections as per Electricity Authority's EMI platform

3.2.5 PV system – commercial

Figure 10 - Commercial PV supply curve



Similar to residential PV, costs for commercial PV depend on the system size. We estimated costs for commercial systems ranging from 0.1 MW to 1 MW as per the table below.

Table 23 - Commercial PV cost assumptions

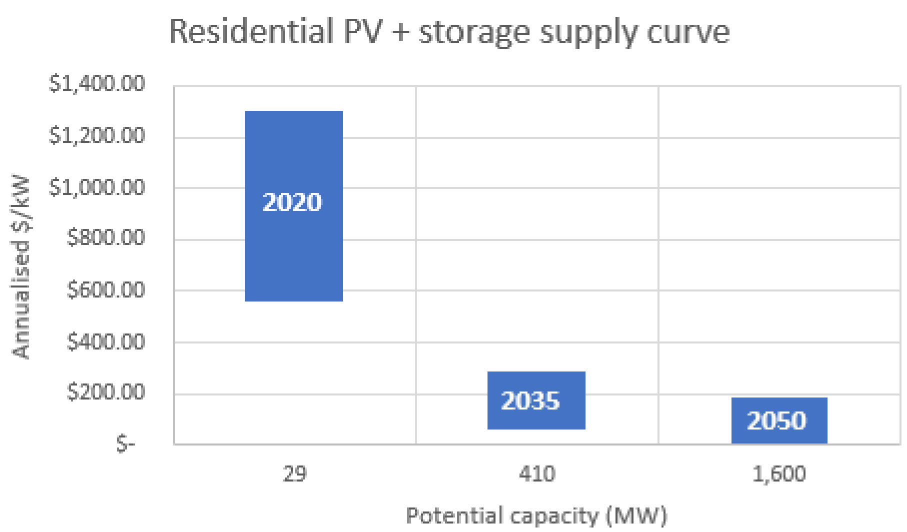
	Unit	2020	2035	2050	Source
Experience curve	Annual reduction in cost over the period	-6%	-2%	-1%	Based on commercial capex estimates from (NREL, 2019)
PV system lifetime	Years	252	25	25	(MBIE, 2016)
O&M cost	% capex	1%	1%	1%	Estimated based on data from (NREL, 2019)
PV system cost (0.1 MW)	**Annualised $2019/kW**	**$232**	**$171**	**$144**	Assumes 2018 USD 1.95/W as per (Fu, Feldman, & Margolis, 2018)
PV system cost (0.2 MW)		**$218**	**$160**	**$135**	Assumes 2018 USD 1.83/W as per (Fu, Feldman, & Margolis, 2018)
PV system cost (0.5 MW)		**$208**	**$153**	**$129**	Assumes 2018 USD 1.75/W as per (Fu, Feldman, & Margolis, 2018)

PV system cost (1 MW)		**$205**	**$151**	**$127**	Assumes 2018 USD 1.72/W as per (Fu, Feldman, & Margolis, 2018)

Commercial PV capacity was estimated based on projections of electricity generated by rooftop solar based on (Transpower, 2020b) projections of 1,120 GWh and 1,980 GWh in 2035 and 2050 respectively. The 2020 figure was based on EA EMI data on commercial solar ICP connections through to April. We also assume that the proportion of commercial dwellings with solar that have PV systems without batteries is 93%, 89% and 82% in 2020, 2035, 2050 respectively. The 2035 and 2050 figures are based on assumptions of the number of commercial dwellings with solar PV and those deploying solar and batteries as per (Transpower, 2020b). This figure is extrapolated from estimates of commercial dwellings with solar PV, and solar PV + storage as per (Transpower, 2020b)

3.2.6 PV + storage – residential

Figure 11 - Residential PV + storage battery supply curve



The range of costs in the figure above reflects different PV + storage configurations and reflect the annualised $/kW technology costs less electricity cost savings from being able to inject power back into the grid. For wholesale electricity prices, we used MBIE projections in the Global Low Carbon scenario in the 2012 Energy Outlook modelling (MBIE, 2012). These prices are $105, $150 and $152 $/kW respectively. The cost assumptions are summarised below.

Table 24 - Residential PV + battery storage cost assumptions

	Unit	2020	2035	2050	Source
Experience curve	Annual reduction in cost over the period	-10%	-7%	-2%	Weighted average of experience curves for standalone PV and standalone battery, assuming battery cost out of total PV + storage system cost is 46% (small

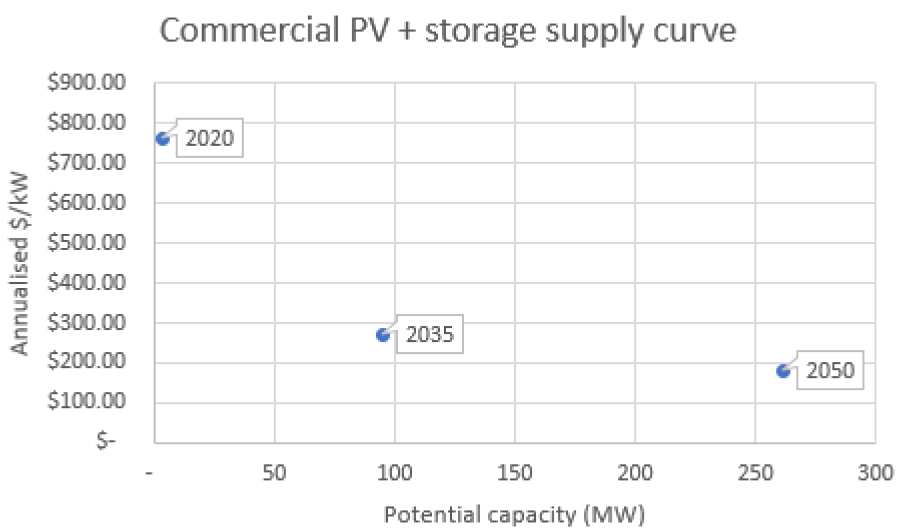
					battery) or 68% (large battery), with the proportions derived based on data from (Ardani, et al., 2017)
Battery lifetime	Years	10	10	10	(Lazard, 2019)
PV system lifetime	Years	25	25	25	(MBIE, 2016)
O&M costs	% capex	1.3%	1.3%	1.3%	Weighted average of O&M costs (as % capex) for standalone PV and standalone battery
PV (3 kW) + battery (6 kW)	**Annualised $2019/kW p.a.**	**$561**	**$57**	**$8**	Assumes a total cost of $17,000 in 2020[31], and nets out electricity cost savings
PV (5.6 kW) + battery (3 kW / 6 kWh)		**$711**	**$104**	**$44**	Based on 2016 capex of USD 21,029 as per (Ardani, et al., 2017), and nets out electricity cost savings
PV (5.6 kW) + battery (5 kW / 20 kWh)		**$1,305**	**$290**	**$188**	Based on 2016 capex of USD 36,016 as per (Ardani, et al., 2017), and nets out electricity cost savings

Residential PV + storage capacity was estimated using the same electricity generation assumptions as per residential PV systems, and assuming that the proportion of households with solar that have PV systems with batteries is 30%, 45% and 47% in 2020, 2035, 2050 respectively.

[31] https://www.mysolarquotes.co.nz/about-solar-power/residential/how-much-does-a-solar-power-system-cost/

3.2.7 PV + storage – commercial

Figure 12 – Commercial PV + battery storage supply curve



Similar to residential PV + storage systems, the cost estimates above for a commercial system (1 MW PV / 2 MWh battery) are netted of electricity cost savings. The detailed cost assumptions are as follows.

Table 25 - Commercial PV + storage cost assumptions

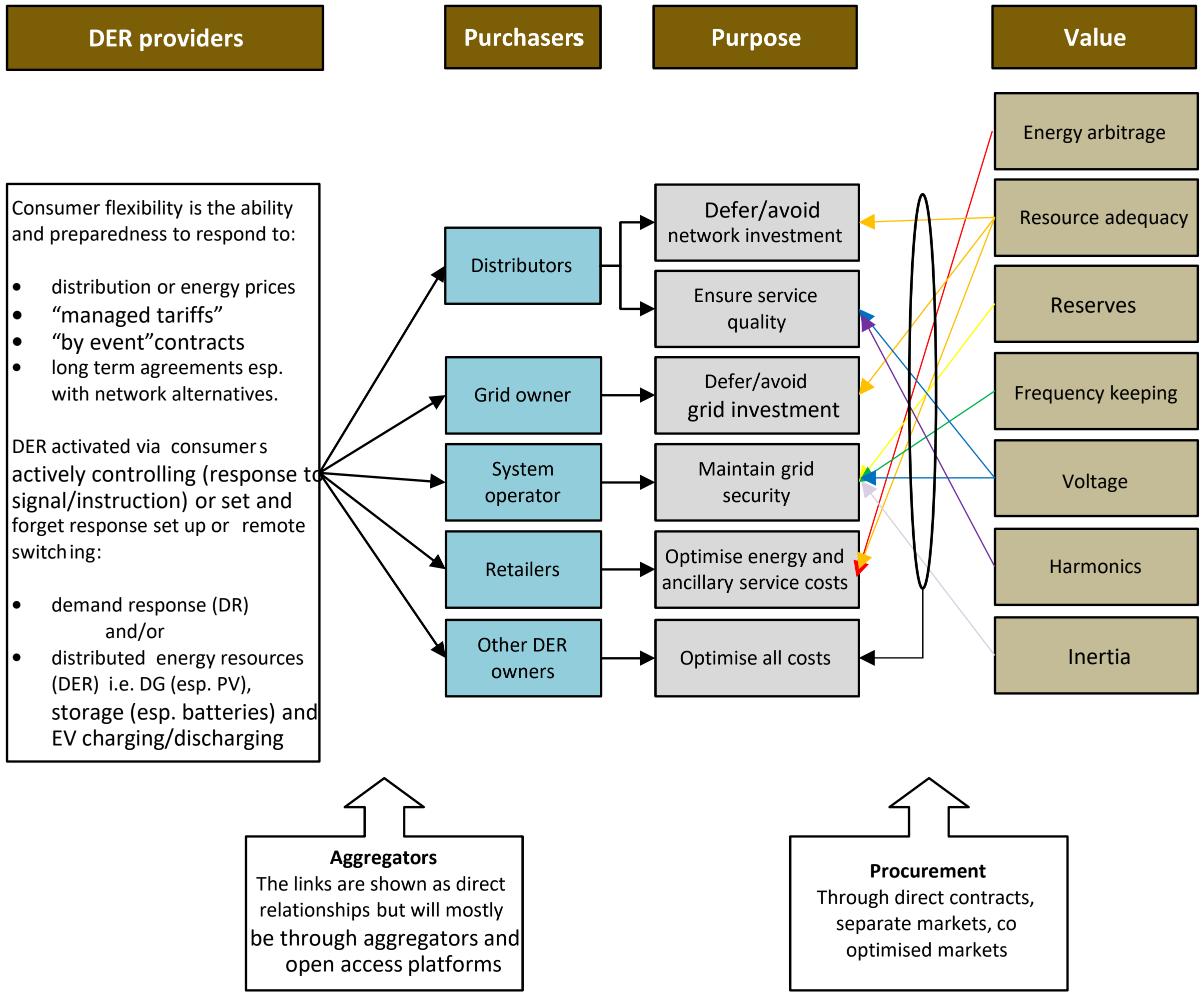
	Unit	2020	2035	2050	Source
Experience curve	Annual reduction in cost over the period	-8%	-5%	-2%	Weighted average of experience curves for standalone PV and standalone battery
Battery lifetime	Years	10	10	10	(Lazard, 2019)
PV system lifetime	Years	25	25	25	(MBIE, 2016)
O&M costs	% capex	1.2%	1.2%	1.2%	Weighted average of O&M costs (as % capex) for standalone PV and standalone battery, assuming battery cost is 47% total PV + storage system cost
PV (1 MW) + battery (0.05 MW / 2 MWh)	**Annualised $2019/kW p.a.**	**$763**	**$272**	**$182**	Assumes a total cost of USD 4,086,500 in 2019 as per (Lazard, 2019), and nets out electricity cost savings

Commercial PV + storage capacity was estimated using the same electricity generation assumptions as per commercial PV systems, and assuming that the proportion of commercial dwellings with solar that have PV systems with batteries is 7%, 11% and 18% in 2020, 2035, 2050 respectively.

3.3 Interpreting the supply and demand curves

In this section, we investigate the detail of the value potential (the demand curve) and the cost of DER for progressive levels of DER service and scale (the supply curve). As well as 'clearing' the supply and demand curves, we identify the 'customer' for the demand service as described in Figure 13.

Figure 13 - DER purchase and value interactions



The two-way multiple value streams and many-to-many relationships in combination with many owners, including third parties, will make DER transactions more complicated than much of the industry is used to.

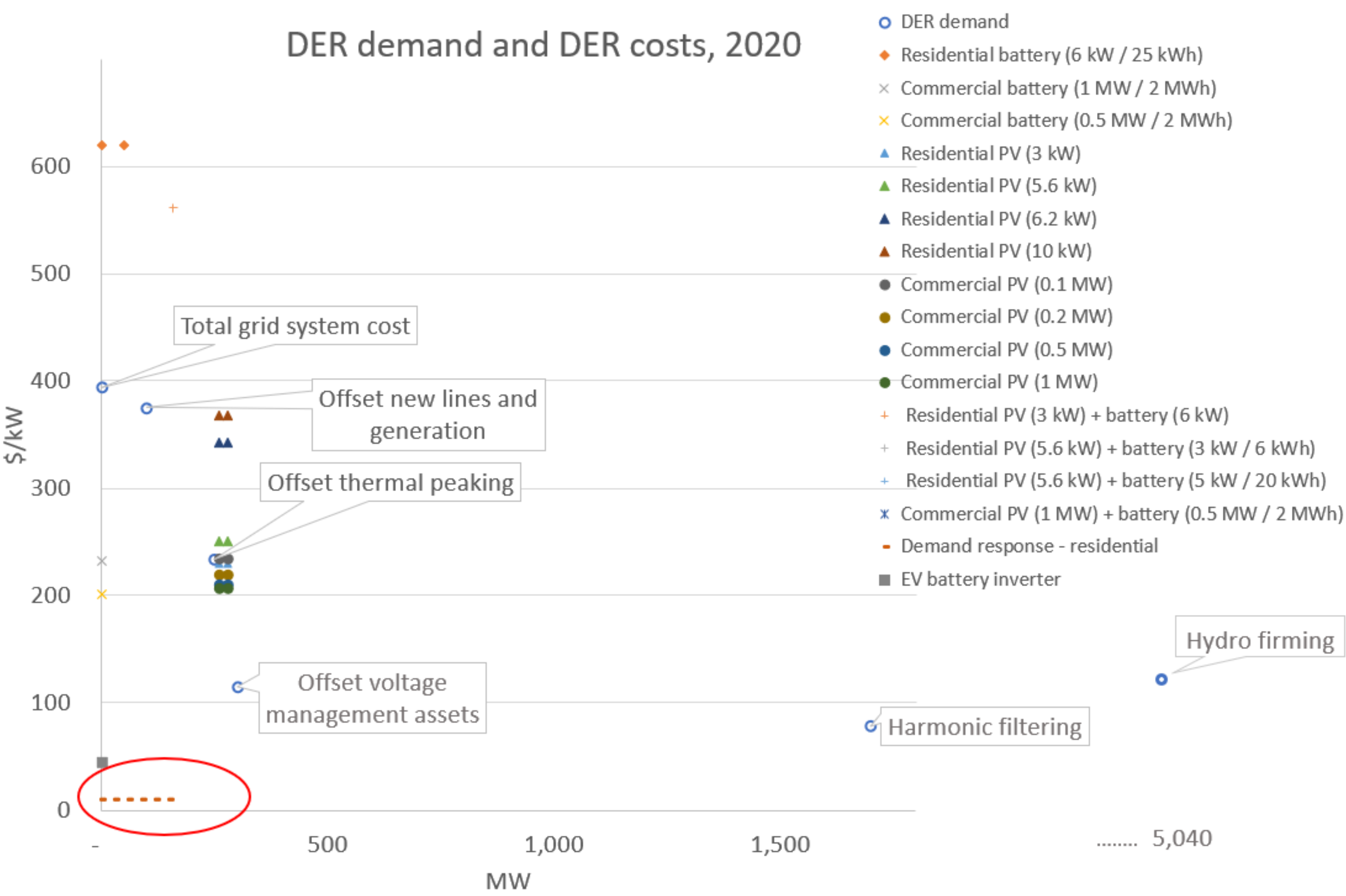
The supply and demand curves we have developed are not strict supply and demand curves, as they do not represent different tranches of cost and opportunity for homogenous service. Different DER technologies have different capabilities, and different avoided power system costs require different capabilities to offset them. Our approach to this is to combine the power system avoidable costs in one demand curve despite a heterogenous service specification for each. In determining the supply curve, we have had to construct it with two criteria being:

- Resources that can meet the specification to avoid the costs at that part of the demand curve, and
- The cheapest resources to meet demand with progressively more expensive resources added.

3.3.1 2020

The supply and demand curve we have developed for 2020 is shown in Figure 14.

Figure 14 - Supply and demand curves for DER value add for 2020



In 2020, three technologies are clearly economic in avoiding power system costs and which can meet the specification at the point on the demand curve where they are potentially deployed – demand response and EV batteries. As discussed above, other technologies like PV + storage systems are being deployed despite the seeming costs being too, high but are unlikely to be taken up in volumes significant enough to affect our conclusions here.

Of the three technologies that are clearly economic, one is not practically available. Despite the low marginal cost of using EV batteries for electric power system service, and the potential that EV batteries are considered to have in the literature, none are yet available that can integrate with the electric power system beyond demonstration models.

By our assessment, 174MW of demand response could be deployed to offset the need for new lines and generation and offset thermal peaking costs. This capacity is in addition to water heating capacity that is currently ripple controlled. In 2020 this is not smart demand response but simple solutions, such as the use of timers either internal or external to suitable appliances (air-conditioning, clothes-dryers, EV charging), to shift demand. We assess that there is insufficient DR volume to intersect the demand curve and fully offset thermal peaking, but it could certainly reduce the need significantly.

Our assessment could be overstated because we do not know how many of these appliances are already being used to shift demand. However, we have not considered commercial demand response as New Zealand has little data on the makeup of commercial load. Given that a significant amount of commercial load is HVAC and refrigeration, the volumes available for commercial DR might be even more significant again, although the opportunity costs of using commercial DR might be higher. We have not been able to assess this.

On a straight financial basis, the incentive for DR does not need to be particularly strong at $9/kW p.a. In theory, passing wholesale electricity prices through to end-use consumers should be enough to gain significant demand response. We expect in practice this would not be the case. Transaction costs and barriers to efficient price response are probably significant factors relative to the low cost of DR – we investigate this further in the next section. If this is the case, then a peaking pricing signal up to the avoided cost of transmission and distribution would increase the likelihood of DR take-up in 2020. In our view, home automation and smart appliances will substantially reduce transactions costs for DR, and we would expect a much stronger response by 2035 and stronger again by 2050.

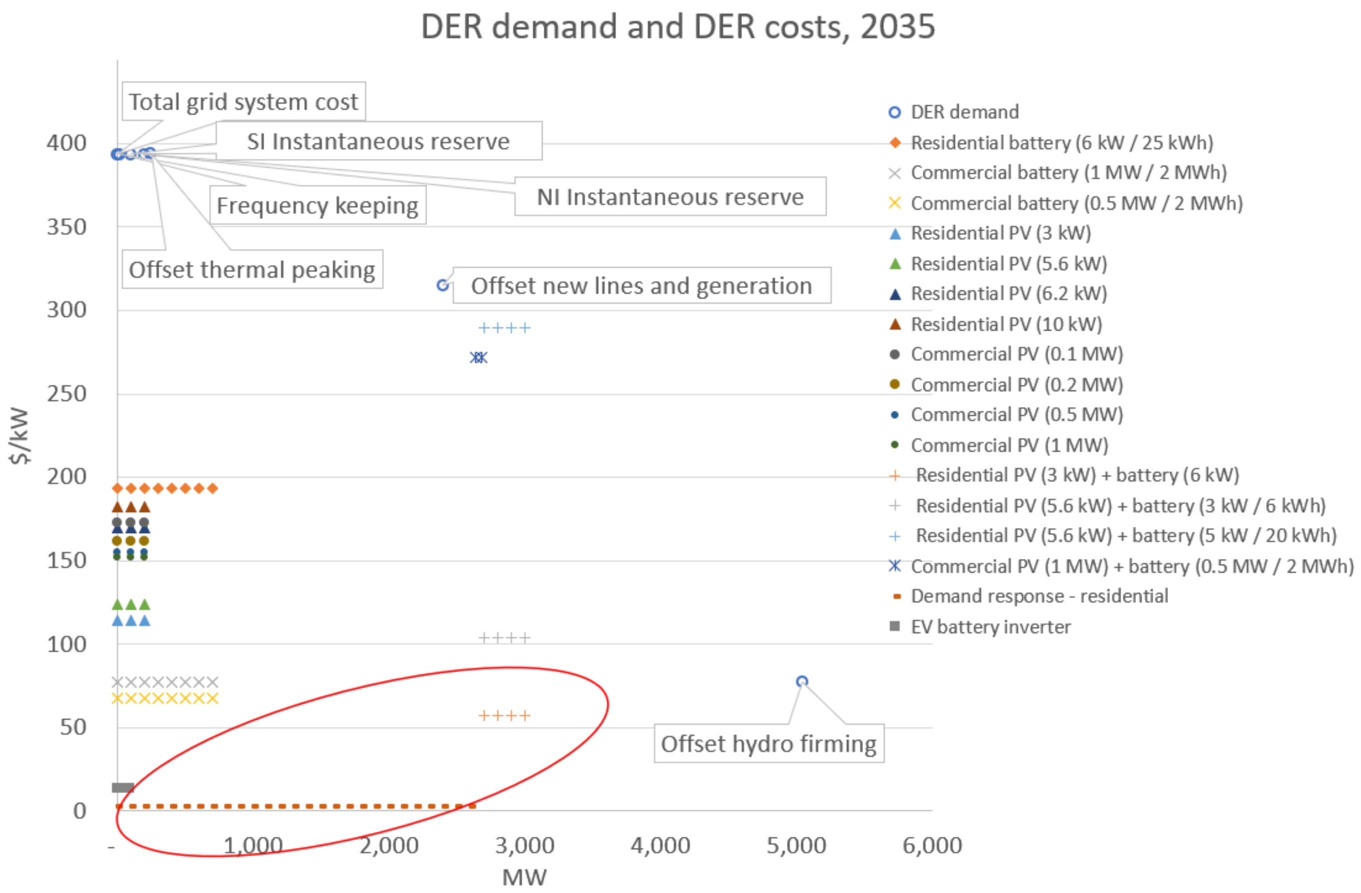
There is a case for signalling the full cost of peak avoidance through to the potential investors in DER for the transition from 2020 to 2035.

Lastly, we also estimate that up to 48 MW of commercial PV could contribute to voltage management, and there is a case for signalling the full cost of voltage management too in the transition from 2020 to 2035.

3.3.2 2035

The supply and demand curve we have developed for 2035 is shown in Figure 15.

Figure 15 - Supply and demand curves for DER value add for 2035



By 2035 many DER technologies are cheaper than building new lines and generation or thermal peaking. However, not many combinations can meet the specifications to add them to the supply curve. Demand response becomes the cheapest DER technology and is potentially large enough to offset the need for new lines and new peaking capacity. EV batteries remain competitive but the opportunities are relatively marginal, and the EV battery volumes are still not large. However, EV batteries are likely to be paired with PV installations. We expect a substantial contribution from residential PV systems with batteries.

We assume smart technology becomes relatively common by 2035. This is not just the automation and communication technology, but also the increasing use of inverter-controlled compressors for heating, cooling, and refrigeration. With the fine load control offered by digital inverters, increased efficiency and multiple thermal storage options (e.g. fridge/freezer, water heater, space heating), it becomes plausible that consumer preferences can be maintained at a maximum loading with a coordinating home automation system. Individual homes may exceed maximum loads at times, but large numbers of automated smart homes should lead to reliable load control in aggregate. Our assumptions for residential DR capacity are not conservative but, again, we have not considered commercial DR.

Many DER technologies are competitive for frequency keeping, reserve and offsetting thermal peaking but not many can offset the hydro firming problem characteristic of the NZEM. PV and battery systems in sufficient numbers, particularly in conjunction with DR, can produce significant energy even in winter, with the residual residential load then significantly lower than baseload demand. By 2035, small-scale PV and battery systems are cheap enough that, even with elevated prices only every four to five years, they are still forecast to be cheaper than maintaining large thermal power stations on standby with the associated fuel supplies or stockpiles. However, having a surplus of PV and battery capacity during periods of normal or wet hydrology has significant implications for the wholesale market.

3.3.3 Transition 2020 to 2035

Our assessment suggests that significant volume of PV and battery systems will be economic by 2035. To achieve this however, there will need to be leading price signals to encourage these systems, so that there is confidence there will be sufficient DER capacity before peaking generation, transmission and distribution investments are made. Time with these systems operating will be necessary to ensure that they can provide the necessary reliability to offset peak investment in the supply system. Although, reliability from DER at the aggregate level will come predominantly from large numbers.

By our assessment, small-scale PV and battery systems become theoretically economic from around 2024 if they have the correct incentives. This is the year when the estimated (annualised) cost of small-scale PV + storage systems can provide energy below a (very high) price of $300/MWh.

To maximise the optimal take-up of PV and battery systems (and to encourage DR), the following incentives would be required by 2024:

- A frequency keeping price incentive (subject to transaction costs)
- Instantaneous reserve price incentives (subject to transaction costs)
- Short-run peak price incentives for energy
- Long-run peak price incentives for energy
- Peak transmission price incentives (possibly including an explicit voltage price in some locations)
- Peak distribution price incentives (including a component provided through a voltage price incentive)
- And possibly a new type of reserve or inertia price incentive.

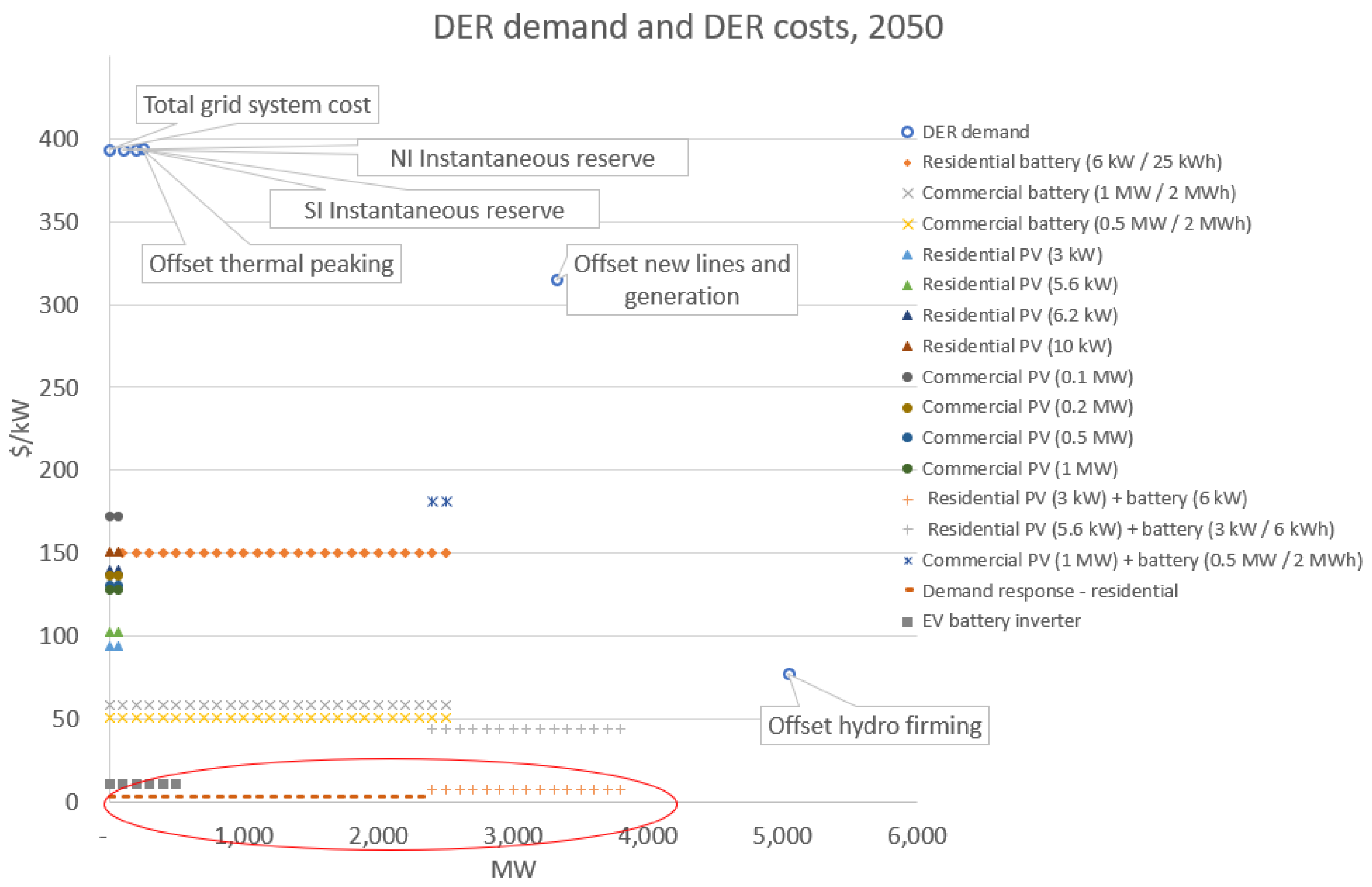
By 2024 these price incentives will need to reflect the marginal cost of the potential avoided costs above, but after that can fall to the LRMC of PV with battery.

By 2035 these incentives cannot be static or blunt incentives. If they are, the DER response to small residual peaks may cause more problems than they solve. A key problem to solve will be how to apply incentives that lead to progressive and stable DER response. The peak pricing incentives also need to be locational. Building DER in large volumes in certain places will again cause more problems than are solved. There will also need to be a way of coordinating distribution network voltage profiles.

3.3.4 2050

The supply and demand curve we have developed for 2050 is shown in Figure 16.

Figure 16 - Supply and demand curves for DER value add for 2050



The case in 2050 is an extension of 2035 except that, in all likelihood, new technologies will be making a difference. Nevertheless, PV and battery installations are forecast to fall in price to such an extent that they are almost economic without accessing any value except self-supply. This is reflected in the low residual cost of PV with battery shown above. DR continues to be the cheapest way of offsetting the need for new peaking generation, transmission, and distribution. EV batteries are cheap DER resources but cannot make a marginal contribution to offsetting hydro-firming unless paired with PV.

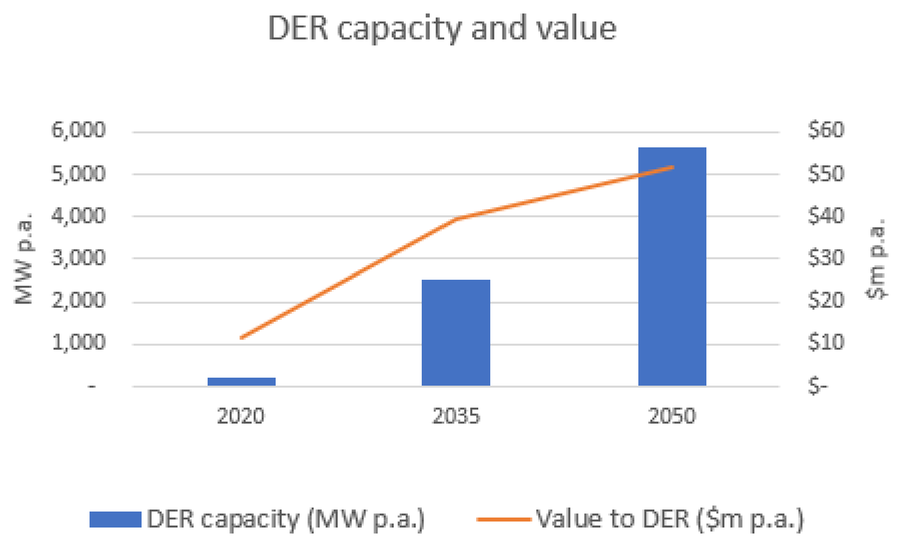
PV installations with batteries can potentially make a significant contribution to even the hydro-firming problem as long as a method for setting wholesale and DER prices can be developed that rewards a very large renewable capacity, which is periodically required, while spot prices generally tend to zero or the variable cost of renewables O&M . However, at these levels of inverter connection, harmonics are likely to be a problem at times. By 2050, assuming the technology has not changed more dramatically than we can predict, there will need to be a price incentive for harmonics to either encourage inverters with extremely low levels of Total Harmonic Distortion, or to signal the need for harmonic filtering stations.

3.3.5 Summary of findings

Based on our analysis of residual demand and supply curves for DER technologies, we find that the total value that can accrue to DER service providers increases from $11m p.a. in 2020 to $40m p.a. in

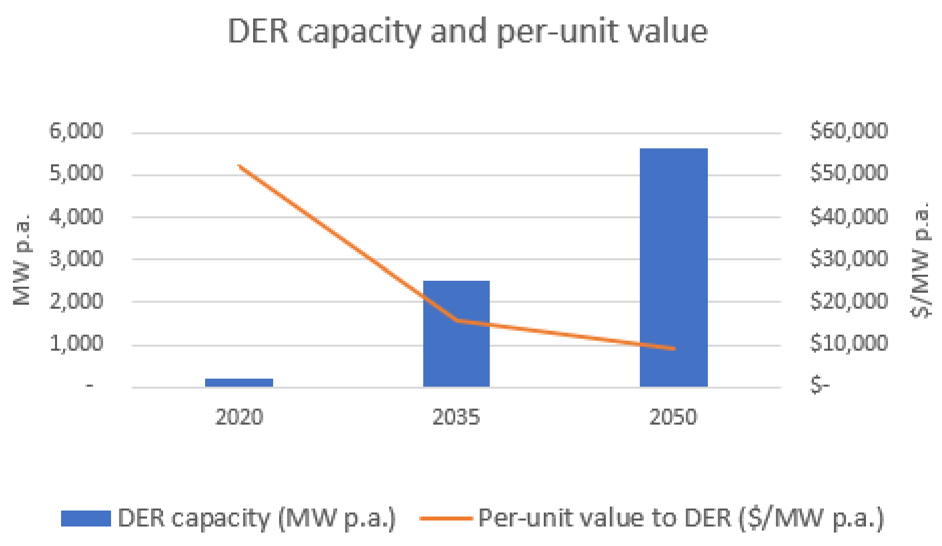
2035 and $52m p.a. in 2050. Total available DER capacity increases from 222 MW in 2020 to 2,524 MW in 2035 and 5,613 MW in 2050.

Figure 17 - Total DER capacity and value accruing to DER service providers

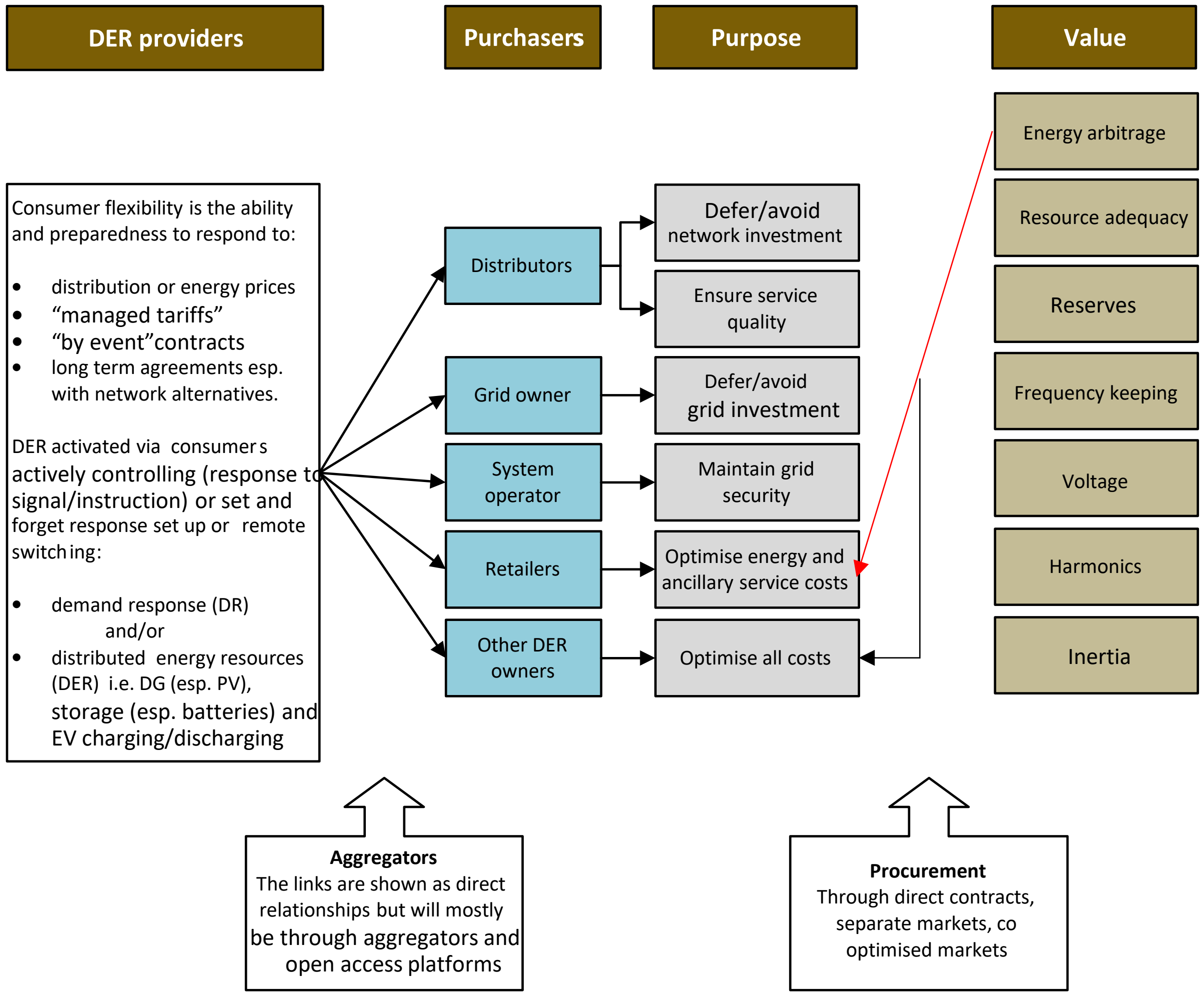


At the same time, we find that on a per-unit basis ($/MW p.a.) the value accruing to DER service providers declines from $52k/MW p.a. in 2020 to $9k/MW p.a. in 2050. This reflects a significant drop in technology costs on the one hand, and on the other - an increase in DER service capacity provided.

Figure 18 - DER capacity and value accruing to DER service providers on a per-MW basis



3.4 Energy arbitrage



Energy arbitrage is the shifting of consumption from a high price period to a low-price period. The price incentives are there to try to encourage utilisation of cheaper resources before more expensive ones. If we put this explicitly in the context of a future of low emissions electricity generation, this means trying to shape load so that renewable resources are used rather than thermal fuels. In New Zealand this means meeting peak energy demands using renewable resources and, the more important (in New Zealand), having capacity for dry hydroelectric seasons.

3.4.1 2020

In 2020 we have assessed the level of incentive to encourage DR as $9/kW p.a. Given that, for the demand curve we assessed the opportunity to offset thermal peaking at $118/kW p.a., then DR looks strongly economic. We assess a potential of 180MW of DR offsetting some of the 250MW of thermal peaking.

However, despite DR being economic for a very long time (and in fact, New Zealand having a lot of success with DR in the form of ripple control), DR response never seems to have reached its potential. Part of the challenge is that most end-use consumers do not face peak price signals for energy. Although even if they did, energy arbitrage only benefits from differences in prices where DER should be rewarded at any time thermal peaking is avoided (generally when prices are over $90/MWh). Just passing on peak prices to all consumers is also problematic and would create many issues. However, even allowing for these aspects, DR take-up is well below what we would expect, this suggests transaction costs or barriers are issues, which we explore in section 4. It certainly does not help that current DR systems (such as ripple control) are a blunt instrument and load control is a binary operation, i.e. completely on or completely off. Both of these problems will be addressed by technology.

3.4.2 2035

By 2035 the cost of DR is even cheaper and should be easier to use. Smart technology, which is currently only available in the top-of-the line appliances, should be more mainstream, especially the load monitoring and management software. Inverter-controlled compressors should also become more prevalent with heating element controllers as well. Energy efficiency should also help make more use of thermal storages in residential and commercial loads, as desired temperatures will take less heating or cooling to be maintained.

Costing around $3/kW p.a., up to 2,600MW has the potential to offset a significant amount of new capacity in peaking generation, transmission, and distribution. Although DR is cheap, there may still need to be a price premium on the incentive to encourage its use or discourage exceeding a certain capacity at a certain time. The approximate cost of thermal peaking (around $90/MWh) should be more than enough.

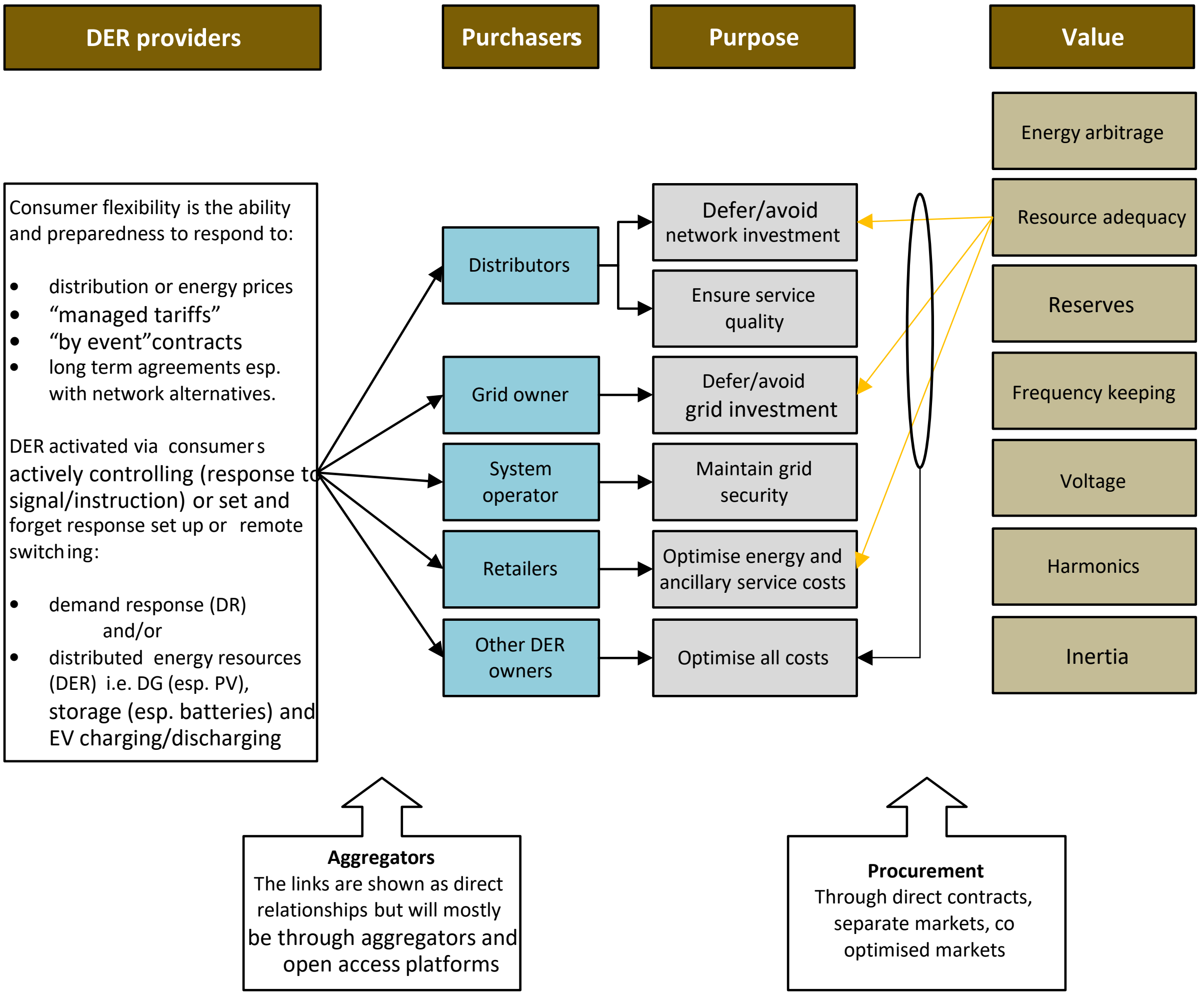
By 2035, there is potential for around 400MW of small-scale residential PV and battery with price incentives at the level of $57/kW p.a. By making a significant number of homes partially self-sufficient, even in winter, this DER helps offset hydro-firming thermal generation. However, this requires the wholesale NZEM and the DER price incentives to reward a large renewable capacity for occasional use. The cost of PV panels and batteries falls to the point by 2035 that redundant DER capacity is preferable to maintaining redundant thermal power station capacity with the attendant fuel burn every four to five years. Obviously, this capacity is also available to address any other supply shocks.

3.4.3 2050

By 2050, only 2,300MW of DR is required in our assessment due to the reduction in peak needs by 2050. In practice, the volumes could vary greatly but the low cost (at $3/kW p.a.) means that it makes sense to deploy DR for any power system capability it can provide.

By 2050, our assessment shows 1,500MW of residential PV capacity with battery installed requiring just $8/kW p.a. This price level shows that PV and battery costs are almost economic just from self-supply. This level of DER is enough to provide around 1,600GWh of winter energy margin.

3.5 Resource adequacy



Resource adequacy means having sufficient generation, transmission, distribution and/or DER to meet consumer demand at all times at all places. DER can help offset the need for new grid-scale peaking generation, transmission, and distribution capacity by reducing residual peak demands. In a future of electrification of transport and process heat offsetting the need for thermal peaking generation reduces emissions.

3.5.1 2020

As at 2020, there is no real need for 'full' peak pricing incentives as demand has been relatively flat and there is yet to be a significant drive to electrification, although EV sales are becoming significant. DR is theoretically economic at levels well below 'full' peak pricing, but few residential or commercial customers have peak pricing incentives beyond for electric hot water, space heating and some commercial refrigeration. The model for ripple control/pilot wire systems is one way of providing the incentive to consumers. Consumers are guaranteed a lower price, through controlled retail tariffs, in return for making their load control available to an aggregator. This is a successful model, although few consumers might realise they have made the choice to be controlled; and the technology, and model, is relatively unsophisticated. It is also inconsistently applied. Consumers with gas water heating have reduced electricity peaks but are still charged on uncontrolled tariffs.

Early in the transition from 2020 to 2035, perhaps as early as 2024, we assess there will need to be efficient resource adequacy incentives to ensure the take-up of PV plus battery installations. This is not a trivial exercise as these incentives need to be applied across energy, transmission, and distribution signalling peak-shifting contributions at the right times and at the right places.

3.5.2 2035

By 2035, EV battery storage, DR and small-scale PV with battery installations will all be economic ways to meet resource adequacy. By 2035, the pricing of peak needs should be able to fall to the marginal cost of DER but before then, around 2024 in our assessment, 'full' peak pricing incentives will need to be implemented. These will need to be applied across four purchasers of the service.

Energy companies will need to incentivise a peak signal at times and at places that offset the need for new thermal peaking generation. These incentives will need to be applied to all consumers without creating major disruption, price shock or social inequity.

Transpower will need to incentivise a peak signal at times and places that offsets the need for new peak transmission capacity. This peak incentive will need to be able to be applied to end-use consumers again without causing a price shock to consumers. At places, some of this capacity signal may need to be applied as a voltage incentive.

Distributors will also need to incentivise a peak signal at times and places that offsets the need for new peak distribution capacity. Again, without causing a reactionary response from consumers that destabilises any potential for gains. As voltage is a significant driver of distribution capacity, particularly deep in a distribution network, part of this incentive will need to be a voltage signal.

Potential aggregators will need to be able to access the above incentives and structure business models around meeting the power system need with consumer-friendly technology and infrastructure.

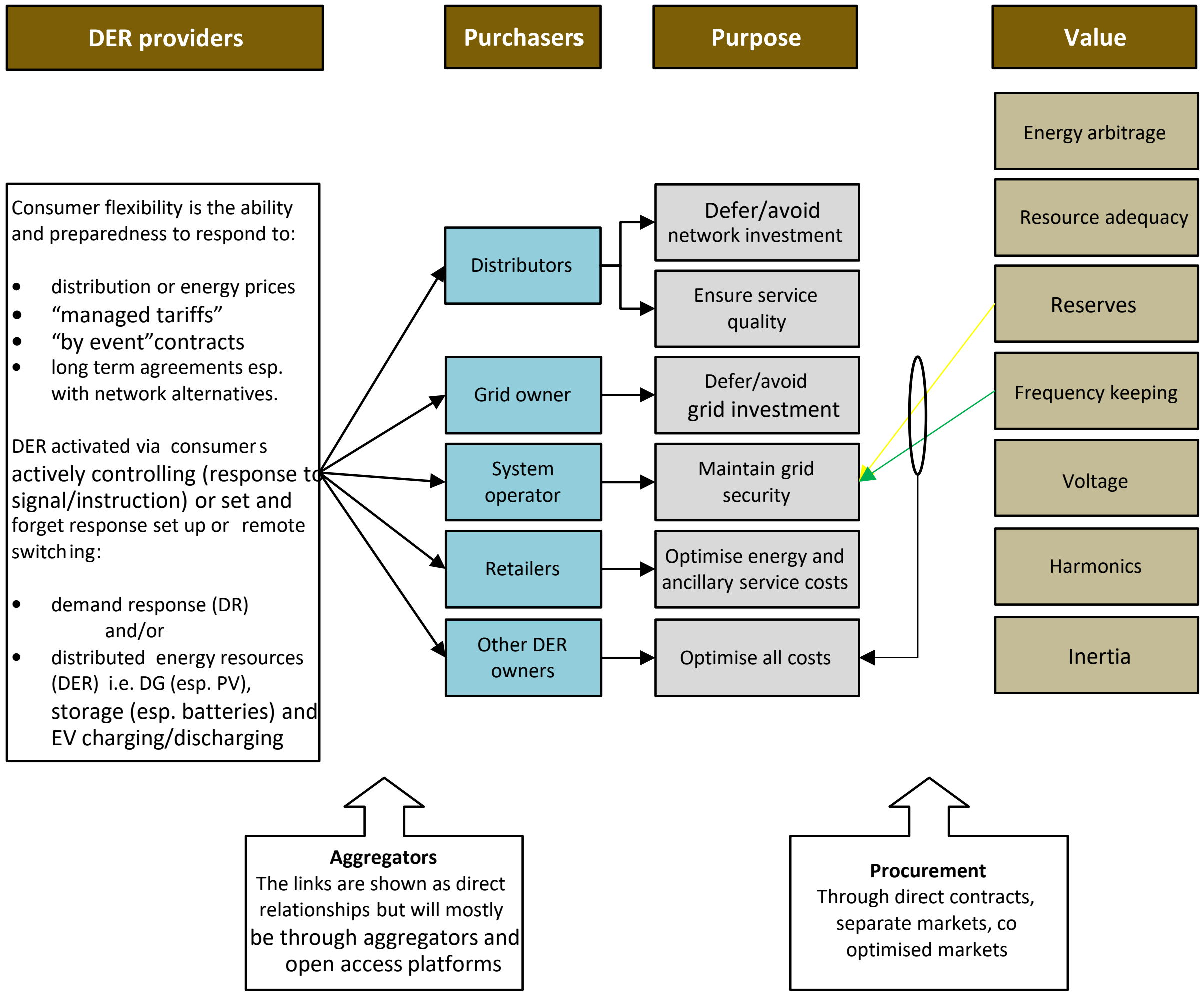
We assess the full cost of peaking at $240/kW p.a. Of that a price premium of $73/kW p.a. needs to be signalled through the energy market over the cost of baseload renewable generation (i.e. geothermal at around $71/kW p.a. instead of OCGT capacity at $144/kW p.a.). $69/kW p.a. needs to be signalled through a transmission peak incentive, and $98/kW p.a. through distribution on average. Although, incentives will need to vary over time and at different places.

After PV and batteries become financially economic with the full value stack available. peak price incentives can fall to the marginal cost of residential PV plus battery.

3.5.3 2050

By 2050 the price incentives will be able to fall even lower with even greater take up of DR and PV with battery.

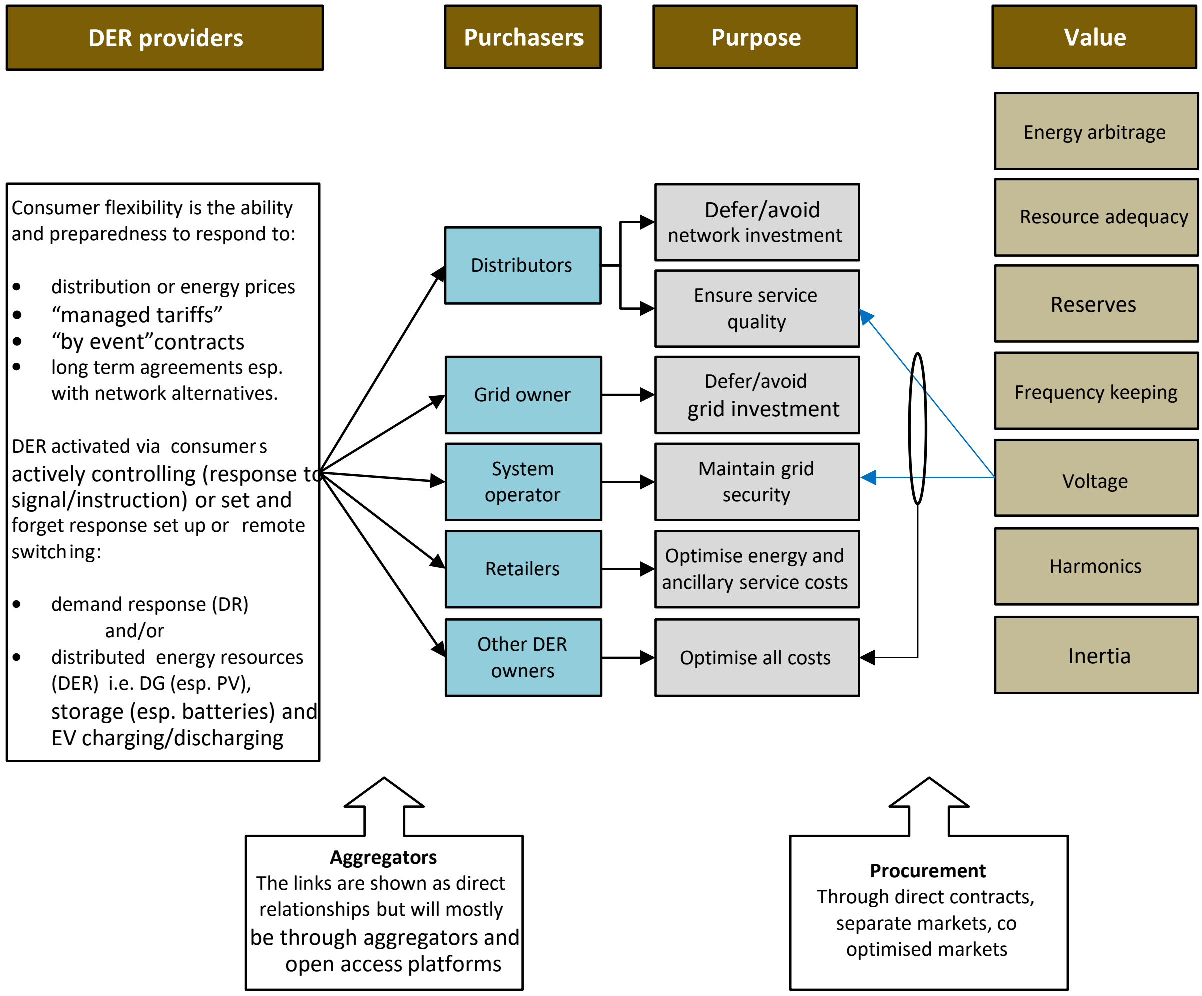
3.6 Instantaneous reserve and frequency



For instantaneous reserve for 2020, 2035 and 2050 and frequency keeping in 2035, we have only assumed that the current level of price in these markets becomes available to DER. This would either be through DER getting access to these markets, or those incentives being passed through to DER through some other mechanism, for example, aggregation.

However, the value from these services are quite low, and so transaction costs may have a significant impact on whether these price incentives are actually worth passing through. Aggregation and automation would probably reduce transaction costs over time.

3.7 Voltage



In practice there is little contribution to avoiding voltage management costs that could be done in 2020. By 2035 and 2050, significant levels of current and future voltage management assets could potentially be displaced. However, voltage management is integral to transmission and, especially, distribution capacity.

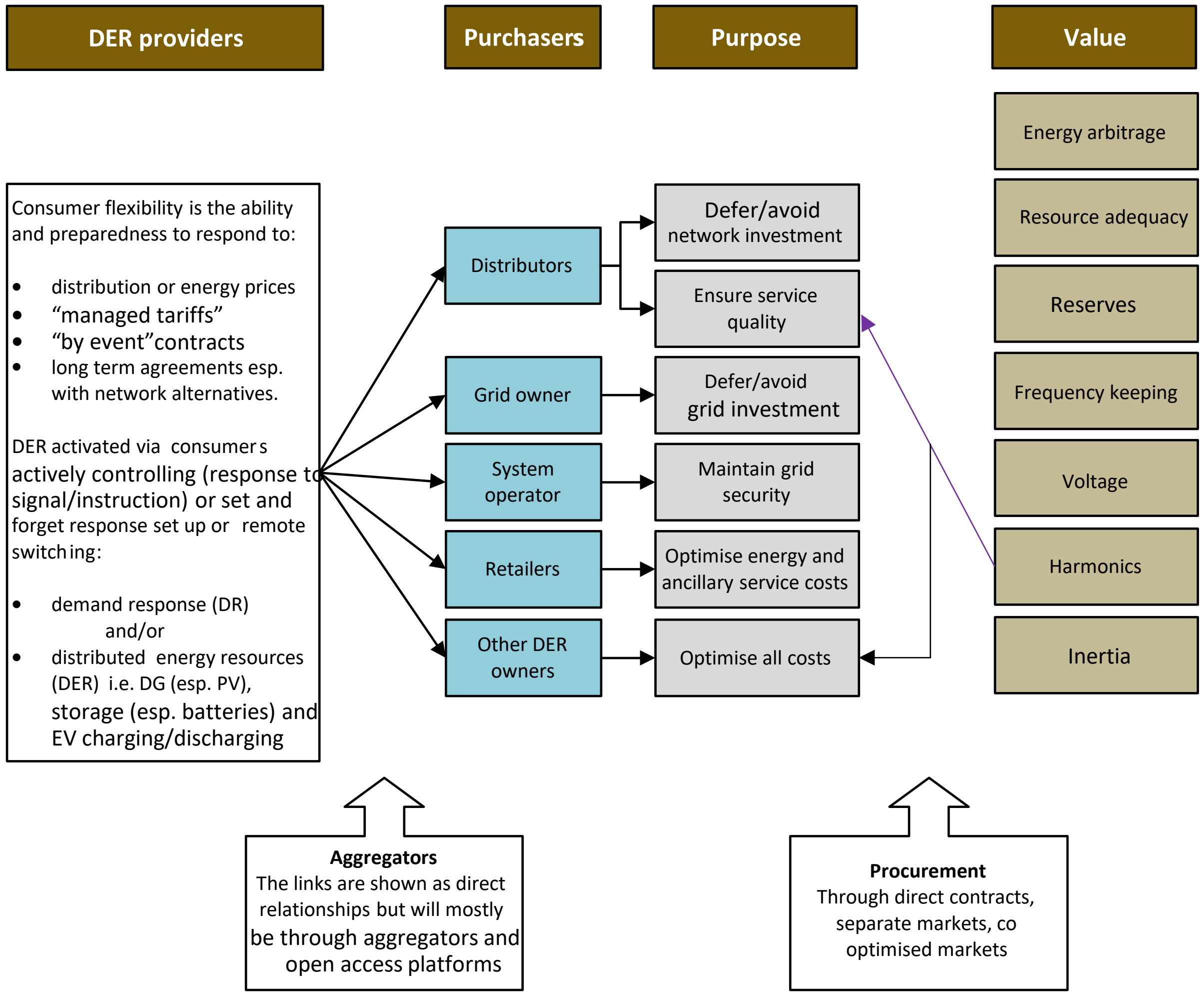
In 2050 there could be 90MW of voltage management asset that is explicitly avoided but most voltage management cost could be avoided in 2050, and entirely in 2035, through combing voltage management with resource adequacy.

We assessed the price incentive level to avoid explicit voltage management assets at $28/kW p.a. This is made up of voltage regulators and capacitor stations within distribution networks. However, large numbers of active voltage sources in the distribution network could reduce the costs surrounding powerlines, transformers, tap changers and many aspects of network design. Therefore, we assess that at least $28/kW p.a. of the $98/kW p.a. incentive for avoiding new distribution lines would need to be signalled through a voltage price. This will be a complicated incentive to design because it will need to incentivise response not just to low voltages but also high voltages, it will also need to coordinate reactive power response as a consequence or through a separate incentive. The incentives will also need to be locational and dynamic over time.

It may be that the most efficient way of delivering sustainable voltage management, rather than designing a complicated incentive scheme, may be to incentivise participation in a coordinating system. Alternatively, especially in the short term, incentives to invest in DER technology with defined voltage response characteristics may be most efficient.

There may also be a case for part of a transmission cost avoidance incentive to be made up of a voltage or reactive power response signal.

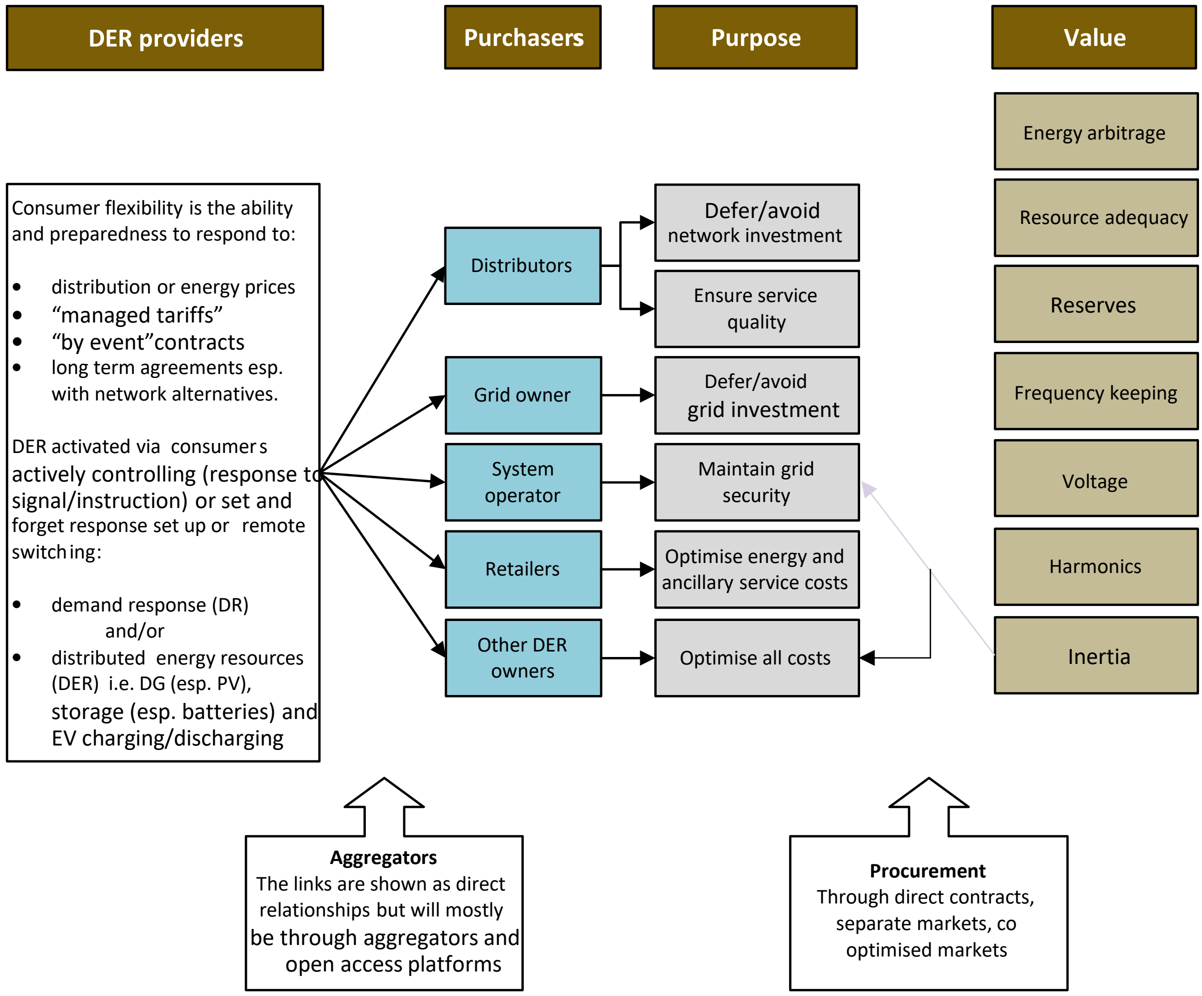
3.8 Harmonics



The degree to which harmonics will become an issue depends on the characteristics of distribution networks, the degree to which DER exports to the power system and the harmonic performance of the DER power electronics. Based on current assumptions as DER approaches levels of 1,700MW then price incentives of -$1/kW p.a. (a cost on DER) should be enough to pay for harmonic filtering stations where required, or higher performing inverters if they are cheaper. The negative incentive increases to at least -$2/kW p.a. as DER penetration approaches 5,000MW.

The need for an incentive is not urgent as levels of DER would need to reach the levels where significant export can occur. However, it is likely that harmonic performance will need to be addressed well before 2035. The effects of THD are likely to be entirely within distribution networks but there could be isolated problems on the transmission network as well.

3.9 Simulated inertia/ultrafast reserve



If simulated inertia becomes a desirable product then we assess it would be worth up to $94/kW p.a. Whether it is required depends on the prevalence of power electronic connected rotating plant in the demand side and, especially, in the supply side. It also depends on the level of risk (tripping of plant) that needs to be covered in the future. If it was required, then significant capacity of PV plus battery systems are likely to be available by 2050 when problems might be most likely to occur (approximately 1,000MW depending on how hydrofirming is provided by 2050).

Uncertainty would make it difficult to decide when, or if, to apply an incentive although system studies would help. A potential way to future proof current decisions might be to consider how best ultrafast, programmable energy storage could support frequency management now in a flexible dynamic way. If frequency management markets could be made more flexible and dynamic now, then incentives could evolve as the market evolves.

4. Identify barriers

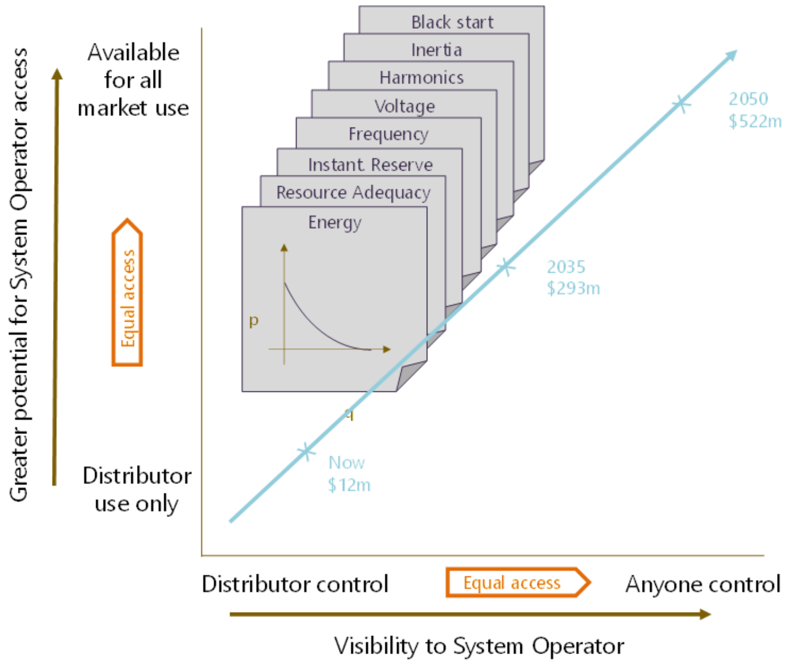
The Electricity Authority's Innovation and Participation Advisory Group (IPAG) has done a considerable amount of work looking at the current market arrangements and whether they are fit for purpose to allow DER to be accessed and utilised for network, transmission or energy management. IPAG presented their **Equal Access** paper to the Authority board 6 December 2018. The board considered that work and sought further work especially on how consumers could provide services to more than one provider of electricity services at a single ICP. The resulting draft **Advice on reducing barriers to customer access to multiple electricity services** was discussed at IPAG's meeting 4 December 2019

Both papers started with a discussion about how the idea that a consumer with greater flexibility is more of a resource that can be utilised than has been the case in the past. They comment on the opportunities this creates both for the individual providers of services and the parties who would aggregate and utilise them.

The framework for our valuation was derived from the IPAG work. IPAG observed two dimensions:

- The dimension reflected in the x axis on Figure 19 below is who can get access to and remotely control DER for their purposes. To date most utilisation of consumer flexibility has taken the form of remote load control which has been accessed by distributors. The Change would be to allow control by many agencies rather than just distributors.
- The dimension reflected in the y axis on Figure 19 below is the uses DER can be put to. To date most utilisation of consumer flexibility has been for network optimisation which makes sense given that access has been controlled by distributors. If control were accessible to any user it follows that, where there is value, uses may be other than network optimisation.
- Also reflected on Figure 19 is the breadth of services that DER could be deployed if they have the right scale and location (where applicable)
- Figure 19 notes the increasing value as control and use of DER flexibility expands as discussed in paper 1.

Figure 19 - Framework for considering potential access to, and uses of, 8 forms of DER



4.1 IPAG identified a framework for thinking about DER barriers and transaction costs

Barriers and transaction costs inhibiting providers of DER and potential users of DER arise because they need to be able to identify each other, navigate the logistics of accessing the service, need to be able to agree a price for the service and need to be able to make/receive payment. The fact is that institutional arrangements, protocols, rules and systems we use were not set up with this sort of dynamism in mind.

IPAG describe the overriding issue by noting that to get the best out the flexibility DER offers will require a new set of relationships, some of which would be multiple relationships for DER providers, to be established. This is understandable as the industry goes from a simple one-way relationship involving a service supplied by a single provider to two-way relationships potentially with multiple providers.

In Figure 20 below IPAG distils out the elements of a fully functioning DER market and this is the taxonomy we have adopted throughout this report. Different purposes for the use of the flexibility DER could assist with are set out on the right-hand side. Even though these seem comprehensive they do not pick up on the categorisation we have used for our report. For example, “ensure service quality” and “maintain grid security” aren’t further broken down into the 8 individual components we use as shown in Figure 19 above.

Figure 20 also identifies that the purchasers of DER flexibility are aligned with different purposes. This introduces one of the big barriers and causers of transaction costs for the deployment of DER flexibility. Those purchasers need to be able to compete for access and then get control over DER flexibility and, under current arrangements, they can’t readily.

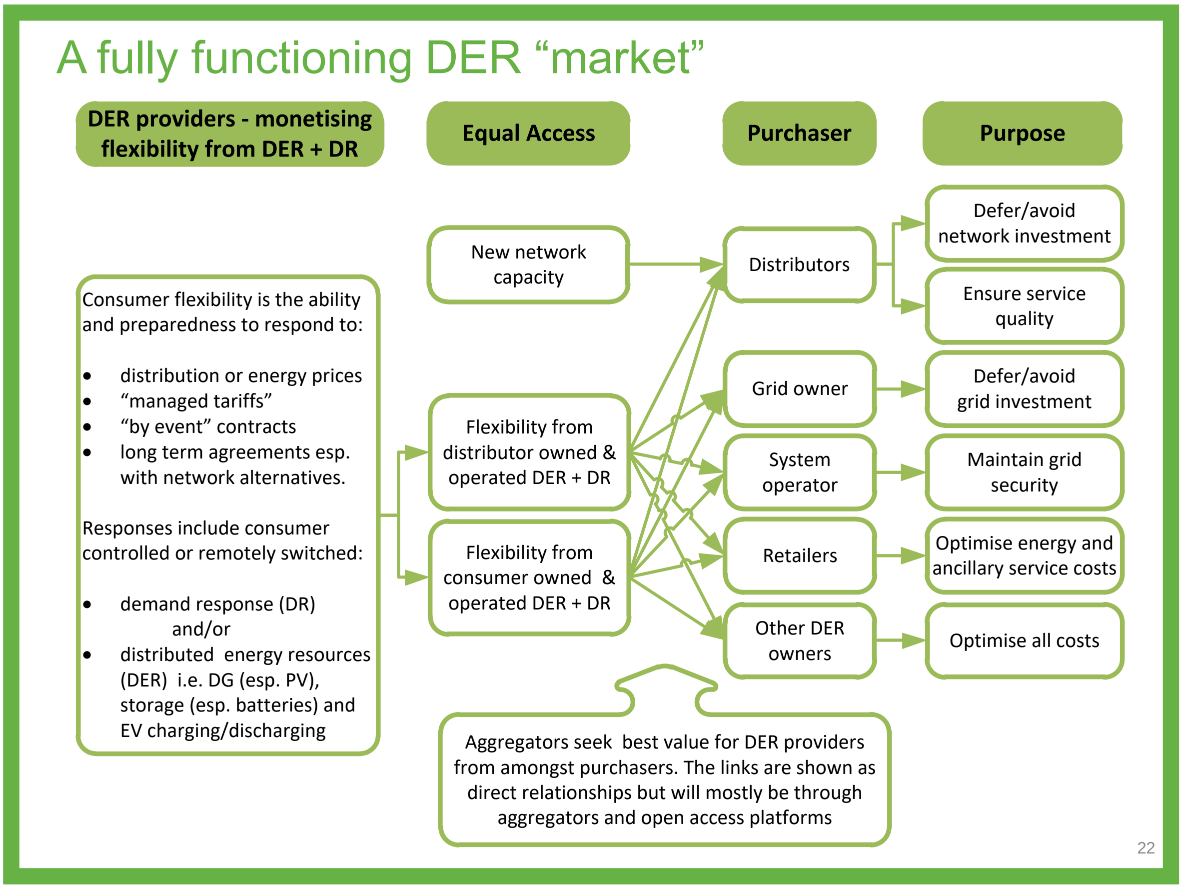
Competing for access and then gaining control over the DER is further complicated when we turn to the sources of DER flexibility on the left-hand side of Figure 20. Not only will there be many small-scale providers the form of access and control they allow will vary.

Consumers aren't just the individual consumers. As IPAG notes the following can be thought of as DER providers:

- Electric vehicle manager
- Peer-to-peer platform (not a complete retailer)
- Smart switcher
- Flexibility service provider

Figure 20 broadens the providers to include all forms of aggregators. Aggregators are agents who seek the best value for DER providers from amongst purchasers.

Figure 20 – IPAG's framework for a fully functioning DER market



IPAG unpicked the DER "problem" into 13 separate problems. At the heart of these lies some core issues:

- Technical information about procurers' requirements are not easy to find. In this case procurers include distributors and other parties who might deploy DER flexibility

- 5 separate input services need to be improved to allow for DER to be "traded" between providers and all potential users of DER[32]
- Price signals for providers offering their services are not well formed or, where they are formed, well signalled.
- Distribution pricing does not signal the cost of DER to network operation (congestion and voltage excursions for example) or its value to distributors
- Distributors have a technological, contractual and access hold over existing demand response in the form of hot water heating manged by ripple control

Pricing or price signals are a particular sticking point. Prices include the possibility of dynamic prices for DER services updated daily through to time-of-use prices set to reflect peak demand periods and left unchanged. The more dynamic prices might be of more interest to aggregators who would package these up for consumers than individual consumers themselves. It seems unlikely that consumers would directly control their DER in response to dynamic price signals. It is far more likely that electronic devices would be set to operate routinely or remote switching used to harness DER flexibility.

The only pricing for flexibility at present comes from distributors in the form of a choice to choose an uncontrolled tariff or a controlled tariff that gives access to remote switching of hot water heating by distributors. For example, Vector offers Auckland customers on their standard time of use charge a 20% difference between controlled and uncontrolled peak variable distribution charges. That differential is reflected by retailers in their bundled delivered charge.

Currently there is approximately 734MW of hot water heating controlled by distributors nationally. In our second paper we identified that an additional demand response of 174MW could be available now if the DER market was opened up. This increases to an additional 2,124MW in 2035 rising to 4,013MW in 2050. This capacity of demand response includes EV charging, smart dryers, smart air conditioners and smart fridges.

With remote switching it may be that consumers are unaware of their DER being controlled. If multiple purchasers are to be able to access different components of a consumer's load, then arrangements will have to change as will the input services required to support transactions.

The will to resolve all of the problems identified by IPAG is complicated by the "chicken and egg" question of whether to change arrangements to accommodate a nascent market in DER or wait until DER penetration reaches a significant level causing a clear need to change arrangements. IPAG note

> Regulators will not be able to ease hard rules on the electricity industry, which may also include DER providers, unless consumer benefits are certain and the system is reliable

IPAG said, of the input services it identified needed to be addressed:

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[32] IPAG identified the 5 input services as:

- Electricity network services (connection and use of system)
- Provision of certified meter data
- Central reconciliation & settlement
- Addressing existing meter APIs and relays (including control of customer load)
- Data communications services (to isolated sites)

> IPAG's Equal Access recommendations noted the significant pool of benefits available from broad deployment of DER and demand response. Without input services/ACCES, Equal Access/Open Networks will still be worthwhile, but will not be able to unlock the full benefits. Ensuring sub-ICP service providers can access the required input services is an important part of unlocking the flexibility of DER.

IPAG has done a good job of documenting the barriers to the supply of and procurement of all forms of DER in the marketplace given the potential value we have assessed here. However, we are still left with the chicken and egg situation, between the transaction costs for parties wanting to supply DER, or aggregate what is there, and the mechanisms that would enable those parties making supply service.

Barriers to entry or other market failures might discourage the efficient level of aggregation so transitory (mandatory) mechanisms for DER coordination may be warranted, especially in the short-term. The steps regulators might take include transitory mechanisms to encourage the market to develop as well as permanent changes to institutional arrangements.

4.2 Summary of transactions costs identified in value assessments

In this section we focus more on transaction costs, including the cost of complexity, inhibiting the deployment of incentives to encourage DER. In this context a transaction cost is a cost incurred when seeking out and securing a trade in a market place. As discussed above, the institutional arrangements that we have were not set up to facilitate the trades that are required to harness the potential for DER to assist with all of the tasks players in the market perform.

Typically, transaction costs are broken into three broad categories:

1. Search and information costs. These costs are the costs of finding information about buyers and sellers and what prices for the good trades at.
2. Bargaining and decision costs. These are the negotiating costs and costs associated with developing bespoke contracts.
3. Policing and enforcement costs. These are the costs associated with monitoring compliance by the counterparty and enforcement if there is a potential breach of the contract.

4.2.1 Energy arbitrage and resource adequacy

Energy arbitrage is the shifting of consumption from a high price period to a low-price period. This necessarily requires market settings that enable prices for low and high loads to be discovered. Similarly, adequate price signalling is also necessary for DER to displace thermal for resource adequacy purposes; this is in addition to DER providers needing to demonstrate they can meet reliability standards. In attempting to address these requirements, several transactions costs arise ranging from the complexity of the pricing contract to the availability of market settings allowing transactions to take place. As mentioned previously, we distinguish between three types of transaction costs: search and information costs, bargaining and decisions costs, and policing and enforcement costs.

Summary

Table 26 - Transaction costs for energy arbitrage and resource adequacy

Search and information costs	Bargaining and decision costs	Policing and enforcement costs
• Residential flat physical prices mean peak/trough pricing is not signalled. TOU is a mechanism provide price signalling, but introduces risk that electricity bills go up • Costs for searching information required to make decisions on DER technology investment choices • Cost of getting information to be able to optimise your load, e.g. what time of the day should one switch peak energy to (resource adequacy)	• Transaction cost is striking complex TOU deals • It also arises from information asymmetry between potential DER providers and market incumbents (retailers and distributors) • Bargaining cost to cut through to peer-to-peer transactions • Cost to establish locational pricing regime • Cost of demonstrating that DER technology collectively meets reliability standards to offset transmission and distribution (resource adequacy) • Cost of an adequate metering system	• Cost of demonstrating that DER technology collectively meets reliability standards to offset transmission and distribution (resource adequacy)

Search and information costs

In section 3, we highlight the issue of peak pricing to encourage the take-up of DER for offsetting thermal peaking generation, transmission and distribution costs. We note, for example, that although demand response (DR) is currently economic ($9/kW p.a.) for offsetting thermal peaking ($118/kW p.a.), DR take-up is below our expectations.

Part of the problem is that currently most end-use consumers do not face peak or trough price signals for energy beyond limited signals from distributors for electric hot water, a bit of space heating and some commercial refrigeration. Among other factors, such market settings are the outcome of a relatively flat demand over the last decade.

Some form of price signalling that identifies the highest value of DER and the time it is of value is required. Even at its most simple transparent competitive time of use (TOU) pricing would match providers and users thereby realising the potential value. There are several ways in which it could be implemented, and they reflect a trade-off between predictability of pricing and dynamic spot-reflective pricing. This means that the way in which TOUs are designed is significant because they can introduce the risk that electricity bills may go up (the TOU opportunity cost). Therefore, any peak price signal incentives by energy companies, Transpower or distributors to offset the need for thermal peaking generation, transmission capacity and distribution capacity respectively, will need to be applied in a way that does not cause a price shock to end consumers.

Bargaining and decisions costs

There will be a cost associated with the search for information required to make decisions on DER technology choices. Our analysis in section 3 revealed that technology costs can vary significantly depending on system specifications (e.g. PV capacity or battery size). The costs may also differ by geographical location, e.g. reflecting locations-specific solar irradiance factors. Furthermore, declining technology costs mean that potential investors in DER must also form expectations about future costs to allow them to make optimal decisions on the timing of their investments.

There is also an information asymmetry between potential DER providers and market incumbents. For example, generators have much better insight into price drivers, and can anticipate forward prices better, especially in times of scarcity when they can exert market power. In the absence of real-time pricing, this is a transaction cost for DER providers as they would need to invest resources to gain the knowledge that incumbent generators/retailers already have on electricity price drivers.

Furthermore, distributors have better knowledge of issues arising on their network, and where investments will need to take place. If this information were open, it could encourage greater innovation for how network support could be provided: competing DERs could provide the required service in a way that would offset the distributors' upfront costs of owning and controlling assets otherwise.

Another transaction cost is that for implementing adequate metering systems. Energy arbitrage or daily load management would require half-hour metering, or a separate metering channel to measure DER consumption. Although smart meters have been extensively rolled out in New Zealand, they do not necessarily include high-end functionality such as real-time information on electricity consumption, or interfaces with smart appliances.[33] These features would necessarily add cost either to retrofit existing meters, or to buy new ones. Furthermore, potential DER providers may have concerns around the privacy of personal data collected from smart meters. The Privacy Commission notes that one way to deal with the latter issues is to aggregate the data collected from the smart meters (Privacy Commission, 2017).

Lastly, in the absence of easily accessible aggregator platforms, DER providers are faced with high bargaining costs to cut through to peer-to-peer transactions. Currently, retailers and distributors do not allow peer-to-peer transactions, although the rules are being reviewed. In the future, potential aggregators will need to be able to structure business models around meeting the power system need with consumer-friendly technology and infrastructure.

Policing and enforcement costs

For DER providers of resource adequacy, another transaction cost arises from the requirement to demonstrate that DER technologies as a whole meet reliability standards to offset transmission and distribution. A mean specification that, for example, single invertors are 80% reliable collectively,

[33] https://www.eranz.org.nz/fileadmin/user_upload/Smart_meters_summary_-_update_July_2017.pdf

means that, as long as DER providers are randomly distributed, it will never be the case that 20% of inverters fail at the same time. Collectively, the reliability of DER providers is expected to be higher unless there is a common mode of failure. Investors in DER will need to show that there isn't a common mode failure potential, however this could be difficult to do.

4.2.2 Instantaneous reserve and frequency keeping

In section 2, we determined that the potential opportunity for DER to provide instantaneous (IR) and frequency keeping (FK) services in the medium and longer terms is low. This means that transaction costs may have a significant impact on whether price incentives are worth passing through. The transaction costs mainly reflect the complexity of IR and FK technical requirements, and the requirements for participants in the IR and FK markets.

Summary

Table 27 – Transaction costs for instantaneous reserve and frequency keeping

Search and information costs	Bargaining and decision costs	Policing and enforcement costs
• Costs to understand technical requirements for IR and FK services	• The Code does not allow small providers to offer IR or FK services • Cost of participating in the IR or FK market	• High cost for DER providers to demonstrate technical compliance

Search and information costs

Providing IR and FK services is complex. This creates high transaction costs for potential DER providers, who would need to invest significant resources to gain the technical knowledge that incumbents already have. Such knowledge could include the relationship between capacity and available reserve and performance of available capacity (for IR), or understanding the technical requirements for connecting to a multi-frequency-keeping system, and the impact on the equipment (for FK).

Bargaining and decision costs

Currently the Code does not allow small provides to offer IR or FK services, mainly due to the high transaction costs for establishing the technical requirements as discussed above. Clearly, if a cost-effective way is found to address the issue of technical knowledge, the restriction in the Code would need to be removed.

DER providers of IR or FK services would also have to face the costs of participating in the respective markets, and particularly the costs of offering, settlement and reconciliation. Alongside cash-related costs, such as the opportunity cost of cash held as collateral for trading, resources would also need to be spent on gaining familiarity with trading rules and on understanding risk exposure.

Policing and enforcement costs

The high cost for DER providers to demonstrate IR and FK technical compliances is the major impediment to their participation in the FK and IR markets. One way to address this issue could be through the provision of training and certification on specific technical issues. However, more analysis would need to be undertaken of the benefits from such programmes, given that the potential value opportunity for DER in this space is estimated to be low.

4.2.3 Voltage, harmonics and inertia

Table 28 - Transaction costs for voltage, harmonics and inertia

	Search and information costs	Bargaining and decision costs	Policing and enforcement costs
Voltage	• Currently there are no direct price signals for voltage. The indirect price signals on reactive power is inadequate given that reactive power does not directly address voltage.	• Cost of designing a voltage pricing regime • DER cost of proving that DER are helping with voltage management	• Cost of voltage/reactive power metering • DER provider cost of demonstrating technical compliance • Distributor cost of defining the technical compliance
Harmonics	• Cost of identifying harmonic problems, causes, beneficiaries	• Cost of designing an harmonics pricing regime • DER cost of proving harmonic compliance	• Cost of harmonic metering • DER provider cost of demonstrating technical compliance • Distributor cost of defining the technical compliance
Inertia	• Cost of identifying inertia problems, causes, beneficiaries • Cost of integrating simulated inertia, ultra-fast reserve with existing frequency markets (may mean completely redesigning all frequency-related system operation)	• Cost of designing an inertia pricing regime • DER cost of proving inertia compliance	• Cost of defining simulated inertia, ultra-fast dispatch • DER provider cost of demonstrating technical compliance • SO cost of defining the technical compliance

Search and information costs

Voltage profiles are complex to understand. However, harmonics and the role of inertia in the power system are even more complex. All three topics also need specialised study and information. Unless distributors, in the case of voltage and harmonics, or the system operator, in the case of inertia, signals the implications of DER penetration on these value streams then bad decisions will be made. This will be either in investing in technology, and/or in locations, where DER may exacerbate problems incurring costs, or through the failure to invest in DER technology, and/or locations, where DER might be the best option to manage problems.

Bargaining and decision costs

For all of voltage, harmonics, and inertia there are existing ways of doing things that may not be the best way of doing things in the future. For each of these value streams trying to manage them as they are currently managed could lead to missed economic opportunities[34]. An installer of DER could face significant bargaining costs in trying to get acceptance of innovative use of DER and face significant cost in the engineering studies to prove that any solutions are reliable and safe.

Defining the service and fair price are also likely to be difficult with these value streams.

Policing and enforcement costs

For each of these value streams metering and compliance are issues. Voltage is relatively easily measured but the value that constitutes the correct output would vary for loading conditions and other voltage sources. It could be difficult to discern the effect that the metered DER is causing compared to other factors in the distribution network.

The same problem occurs with harmonics. This could be complicated further if simply measuring Total Harmonic Distortion is not sufficient and individual harmonic frequencies need to be monitored. While a programmed simulated inertia to ultrafast reserve characteristic may need many data points to verify. The data requirements for fine metering of harmonics and ultrafast reserve could be prohibitive.

Ultimately, it might be best, rather than metering, to rely on type testing and the law of large numbers and to, instead, monitor aggregate outcomes. This would be a challenging transition.

[34] For example, using traditional distribution assets to manage voltage rather than the voltage management capability of DER, limiting the uptake off DER rather than encouraging higher harmonic performance or harmonic filtering, and using traditional frequency management products to manage higher rates of change of frequency rather than integrating the potential of programmable, fast-response DER.

5. What next?

5.1 Change is inevitable and profound

Even without incentives from other value streams, there will be significant investment in DER. In the absence of economic and technical coordination the deployment of DER, and the industry reaction to it, will cause significant costs to the economy and frustrate decarbonisation goals. The economic and technical integration of DER and distribution networks with grid supply resources will be as profound a change as New Zealand's transition to an electricity market in 1996.

Waiting for international solutions may be too late, especially as key international jurisdictions with DER experience are already 'playing catch up'.

5.2 Factors for change

Using the 1990's development of the electricity market as a blueprint, the authors note some key factors for successful change:

Industry leadership

With dominant resources and motivated for change ECNZ underpinned the WEMDG study and Transpower provided significant technical development into nodal pricing. Mistrust of ECNZ led to the Government inspired WEMS study. The two studies lead to a very well-designed wholesale market.

Broad support

While individual motivations were quite different, the New Zealand Electricity Market was broadly supported by most stakeholders.

Stakeholder engagement

While not perfect, the combination of WEMDG and WEMS involved stakeholders in the design process.

5.3 Major questions

Where does the industry leadership come from for DER integration into the current system and arrangements, where the problem is economically and technically complex, and the solution could be a world first?

Is there broad enough support for a difficult transition and, if not, how can that be secured?

What is the process to involve an even more diverse set of stakeholders than in 1996, which now needs to include innovators, aggregators, and technology developers?

5.4 Other issues and questions

As far as the authors are aware, ours if the first analysis to try to quantify DER costs and the specific value opportunities in the New Zealand market. Further empirical study would assist future decision-making.

The discussion needs to occur on electricity market design where:

- Security and reliability may be economically provided by an 'overbuild' of DER.
- Aspects of transmission and distribution may transition from substantially monopoly to substantially competitive arrangements.
- Coordination of DER may require incentives for capacity within transmission and distribution networks. That discussion should also include voltage.

Further discussion is required on the role of price incentives in coordinating DER investment and operation. It should also be recognised that broad price incentives might cause 'rate shock' on those that do not have the resources to respond to the price incentives.

Further investigation and study should be done on inertia, harmonics and voltage coordination using DER.

Discussion on frequency market design should consider whether DER, and other technology, could provide a higher standard of service at lower cost than existing technology. And, especially if inertia is reducing and warrants incentives to encourage more inertia and substitutes.

It would be advantageous for the industry to better understand, and have better visibility, on the technology and cost path of building automation and smart appliances.

Appendix A: IPAG’s briefs from the Authority

IPAG’s **Equal Access** paper was presented to the Authority board 6 December 2018. IPAG’s brief is set out below.

The Electricity Authority Board requested the Equal Access framework be added to the IPAG’s 2017/2018 work plan in November 2017. Specific focus was requested on:

- Whether the operation of the existing equal access framework for transmission and distribution networks is sufficiently effective at promoting competition, efficiency and reliability for the long-term benefit of consumers. This may involve, for example, establishing the current feasibility for competitive supply of network support services
- Potential options to strengthen the equal access framework to further promote competition, reliability and efficiency in the provision of electricity and electricity related services, including network support services
- The design, costs and benefits of any changes (regulations and/or market facilitation measures) identified to strengthen the equal access framework (including arrangements for exchange of network support services)

IPAG’s draft **Advice on reducing barriers to customer access to multiple electricity services** was discussed at their meeting 4 December 2019. IPAG’s brief for this work is set out below.

The Electricity Authority asked IPAG to consider how to reduce barriers to customers' access to multiple electricity services. Specific focus was requested on how to reduce or remove the barriers associated with:

- access to data to supply services to a consumer
- shared use of the distribution service to supply services to a consumer.

The Authority identified a variety of matters for IPAG to consider:

- arrangements for service providers accessing market and non-market data needed to provide their services, focusing on costs and contractual/regulatory arrangements such as:
    - the need to specify a method for determining the price of metering services when shared between multiple suppliers
    - how a change in MEP at an ICP is managed
    - how metering costs are shared between service providers
    - how a party might obtain and pay for additional metering functionality
    - how to reduce transaction costs associated with contracting for metering services
- the arrangements for managing shared use of the distribution network to supply services to a consumer.

The 13 distinct problems IPAG identified that were inhibiting the emergence of a DER market that would release the potential value of DER are:

4. Key network information is not collected and/or made available to DER providers
5. Providers and procurers of DER can't see DER "market" information
6. Technical specifications are not consistent or in some cases adhered to
7. Transaction costs for facilitating DER trade are high
8. Distribution pricing does not signal the cost of DER to network operation (congestion and voltage excursions for example) or its value to distributors
9. Distributors are not confident that DER can assist with service quality or is viable as a network alternative
10. Part 4 Incentives appear to be poorly understood
11. Distributors' DER investments are treated as regulated capital but the planning and operating services provided are contestable
12. Distributors may misallocate costs and revenues
13. Distributors may favour in-house or related party solutions
14. Distributors may favour network solutions
15. Distributors may restrict technologies or network users
16. Security and reliability at risk if DER use by transmission and distribution in conflict

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