The Role of Customer-Owned Electricity Distribution Businesses in Accelerating Distributed Renewables Uptake – Implications for Policy and Regulation

Report for

Northern Energy Group

Prepared by

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Notice

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Abbreviations

AER	Australian Energy Regulator
APVI	Australian Photovoltaic Institute
DER	Distributed energy resource – e.g. PV, and electrical storage (including batteries, and EVs with vehicle-to-grid (V2G) bi-directional charging)
DG	Distributed generation
DSO	Distribution system operator
EA	Electricity Authority
EDB	Electricity distribution business
EIPC	Electricity industry participation code
EV	Electric vehicle (plug-in)
FIT	Feed-in tariff
G&T	Generation and transmission (cooperative, in the US)
GFC	Global financial crisis
GHG	Greenhouse gas
GW	Gigawatt
ICA	International Co-operative Alliance
ICP	Installation control point
IEA	International Energy Agency
IoT	Internet of things
kWh	Kilowatt hour
LFCT	Low fixed charge tariff
MW	Megawatt
NEG	Northern Energy Group
NZTA	New Zealand Transport Agency
P2P	Peer-to-peer
PPP	Public-private partnership
PV	Photo-voltaic solar panels
REC	Rural electric cooperative (in the US)
SCI	Statement of corporate intent
TSO	Transmission system operator
UFB	Ultra-fast fibre
V2G	Vehicle-to-grid
VPP	Virtual power plant
W	Watt

About the Author

Dr Richard Meade is an economic consultant and researcher based in Auckland, New Zealand. He is Principal Economist at Cognitus Economic Insight, and Senior Research Fellow in both economics, and social sciences and public policy, at Auckland University of Technology. He holds a PhD in Industrial Organisation and Regulation from Toulouse School of Economics, with his doctoral thesis examining the impacts of different ownership forms on firm strategy and behaviour, and industry outcomes, in utility sectors like electricity, and also in banking.

Richard has been active in electricity sector advisory and research roles since 1988. Since 2005 he has also been actively researching the role and significance of cooperative firms in sectors such as electricity, banking and agriculture. More recently his research and advisory work has centred on how regulation needs to be repositioned in anticipation of disruptive new technologies, business models and players, in sectors like electricity and transport. He regularly presents on these themes to regulators and policymakers in New Zealand and Australia, and presents his research at local and international academic conferences.

Executive Summary

New Zealand, like most developed countries, faces an imperative to increase its supply of renewable electricity generation if it is to have any prospect of decarbonising transport and process heat in order to meet its greenhouse gas emissions reduction targets. Even if this were not the case, the falling costs and improving efficiencies of distributed energy resources (DERs) – like photovoltaics (PV) and batteries (including electric vehicles, EVs) – mean they are becoming inherently attractive, and will increasingly be adopted by firms and households – even in New Zealand where generous support measures have not been used to encourage their uptake.

While the uptake of DERs will undoubtedly produce benefits, experience from jurisdictions with high levels of uptake – notably Australia – points to DER uptake causing significant issues.

These are not confined to disruptions to electricity systems due to the power quality and system reliability issues they can cause, though these are significant enough. They also include the inequities that DER uptake can exacerbate, including through free-riding on existing network capacities for accommodating reverse power flows produced when PV owners export their generation rather than self-consume it, and cost-shifting/waterbed effects under which more affluent DER adopters create costs for less-affluent non-adopters.

This points to an urgent need to upgrade regulatory arrangements and system architectures to ensure DERs can be adopted in a way that realises benefits for all electricity system users, not just those adopting them. Electricity network operators like New Zealand's electricity distribution businesses (EDBs) will necessarily play a key role in both designing and implementing such arrangements, given they are at the "coal face" of integrating DERs into national electricity systems.

Customer-owned EDBs bring key distinctives to how DER uptake can be supported while ensuring their benefits are widely shared, and their adverse costs are minimised. This flows from their particular focus on providing consumer benefits, over and above maximising financial returns. As a consequence of this focus, customer-owned EDBs have a key role to play in either facilitating or directly providing services that benefit their customers and associated communities.

Because of their focus being broader than that of other types of firms, this means they often can justify providing services earlier, at higher quality, or at all, when profit-focused providers find it unprofitable to do so. Customer-owned EDBs can point to this being achieved in practice, for example through providing ultra-fast broadband (UFB) in regions that would otherwise be under-served, or encouraging the uptake of EVs through facilitating or providing networks of EV fast

chargers. The very creation of customer-owned distribution businesses in New Zealand and elsewhere (e.g. rural electric cooperatives in the US) points to the key role they play in helping to support development in regions that might otherwise be overlooked by investors.

These considerations point to customer-owned EDBs having a key role to play in accelerating the uptake of distributed renewables and other DERs. They also point to customer-owned EDBs having a role to play in accelerating the uptake of:

- Digital platforms for coordinating DERs and maximising their benefits – which also encourages their uptake; and
- Community renewables schemes – as a means of ensuring the benefits of DERs are enjoyed by all customers, not just those able to afford them, while also minimising adverse DER impacts like wealthier DER adopters avoiding fixed network charges that are then borne by less-wealthy non-adopters (so-called "cost-shifting"/"waterbed effects"), or rushing to tie up under-priced network capacity for exporting DER generation ("network capacity gold rushes").

The increasing penetration of DERs directly challenges the presumptions underlying existing electricity sector regulation. This includes whether and how electricity distribution prices are regulated, and the extent to which traditionally monopoly services like electricity distribution can be involved in competitive activities like generation and retailing (which both characterise DERs).

In many ways DERs provide consumers with means to address traditional regulatory concerns through their own choices. This means there is reason to reassess whether traditional regulatory protections applied to EDBs are still warranted, and if so, how they might need to be revised. To the extent that customer-owned EDBs are naturally focused on delivering benefits to the customers – including through the uptake of DERs – this means they are less likely to give rise to the concerns that existing regulation seeks to address.

Hence, to the extent that rising DER uptake relieves regulatory concerns for all EDBs, it could conceivably do so even more for customer-owned EDBs. This points to a need to consider whether existing regulatory exemptions enjoyed by customer-owned EDBs should be applied more generally, to ensure the benefits of DERs are enjoyed as soon and as widely as possible.

1. Introduction

1.1 Study Context

1. New Zealand, like many other countries and regions (e.g. the EU), has committed itself to a course of reducing its greenhouse gas (GHG) emissions in order to mitigate climate change. Specifically, New Zealand's domestic reduction targets include net zero emissions of all GHGs other than biogenic methane by 2050.[1]

2. Unusually among developed countries, New Zealand's electricity supply is already more than 80% renewable (mainly hydro, but also geothermal and wind in significant amounts). Also, around half the nation's GHG emissions come from agricultural emissions (e.g. methane from ruminant livestock) for which there are currently few technologies for emissions reductions aside from reducing the national herd sizes. This means New Zealand faces greater imperative than many developed nations to reduce emissions from its transport sector, which accounts for around 20% of the nation's total emissions, and over 40% of New Zealand's greenhouse gases from the energy sector.[2]

3. In turn, reducing transport sector emissions hinges on the growing uptake of either fully, or partly (e.g. hybrid), electric vehicles (EVs). Supporting such uptake not only requires increasing renewable electricity sources to supply the low-carbon energy required, many of which sources will increasingly comprise *distributed renewables* – renewable generation sources located very near to the users of their output[3] – like photo-voltaic solar panels (PV) given their falling costs and increasing consumer appeal. It also requires electricity distribution infrastructure to support those growing supplies, and to facilitate EV uptake while coping with the increasing peak demands caused by EV fast charging. Figure 1.1. provides a snapshot of this emerging context.

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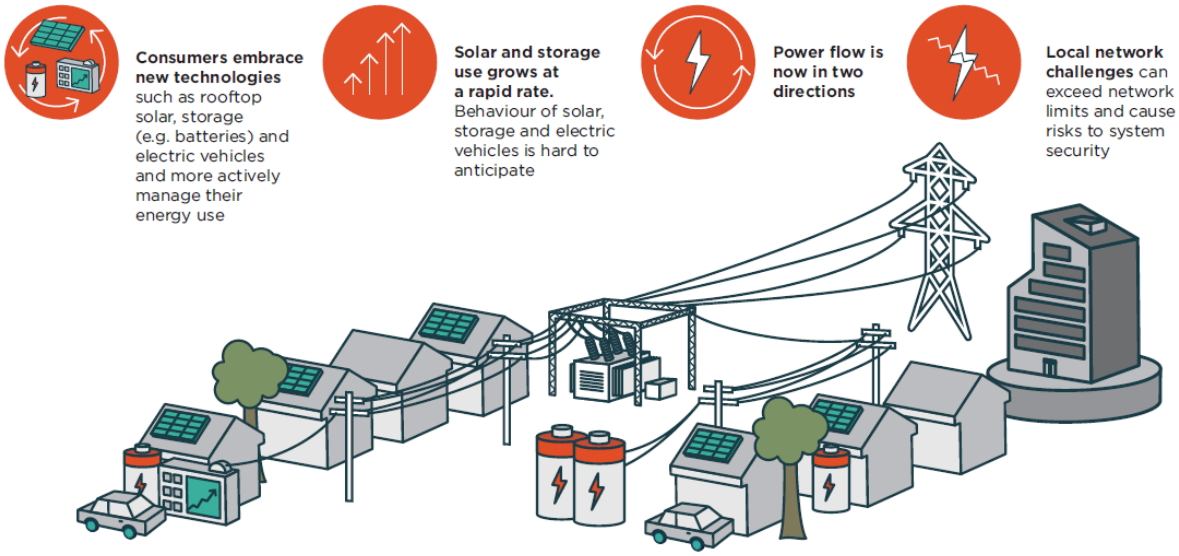
[1] https://www.mfe.govt.nz/climate-change/climate-change-and-government/emissions-reduction-targets/about-our-emissions, accessed 15 October 2015.

[2] https://www.transport.govt.nz/multi-modal/climatechange/, accessed 15 October 2020.

[3] More formally, this study treats distributed renewables as being renewable electricity resources that either direct connect to their users (e.g. home-based generation and consumption) or to local, low-voltage distribution networks (including commercial and industrial renewables systems connecting to such networks). Hence grid-connected renewables are not treated as being distributed renewables.

Figure 1.1 – The Emerging Decentralised Electricity Sector



Source: Energy Networks Australia (2020), Figure 3.

4. New Zealand's electricity distribution businesses (EDBs) can be expected to play an increasingly important role in helping to facilitate the uptake of both distributed renewables like PV, and supporting the uptake of EVs, in New Zealand. They will therefore also play an important role in the achievement of New Zealand's renewable energy and emissions reduction objectives.

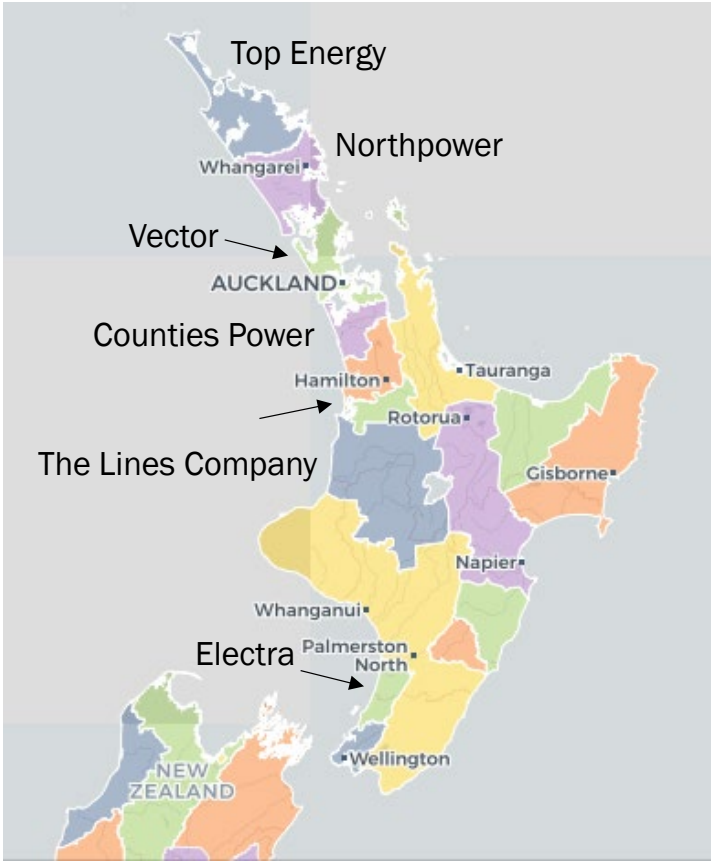
1.2 Study Purpose

5. The purpose of this study is to explore the particular role of customer-owned EDBs in facilitating and accelerating the uptake of distributed renewables like PV, as well as other distributed energy resources (DERs) like grid-scale and residential batteries (including EVs, which represent mobile electricity storage and discharge sources). Unlike investor-owned EDBs, customer-owned EDBs have an explicit focus on delivering benefits to their customers and associated communities.

1.3 Details of NEG Members and their Regulatory Context

6. This study was commissioned by the Northern Energy Group (NEG), a consortium of seven, customer-owned EDBs located predominantly in the northern half of New Zealand's North Island. The largest member of NEG, Vector, has a hybrid ownership model, having just under 25% investor ownership, with a trust (Entrust) representing consumer interests owning just over 75% of the firm.

Figure 1.2 – Northern Energy Group Details



	Total Circuit Length (km)	*Maximum Demand (MW)*	*Total ICPs*	*Price-Quality Regulated*
Top Energy	4,062	71	32,156	Y
Northpower	6,053	176	59,380	N
Vector	18,708	1,821	565,200	Y
Counties Power	3,251	128	42,458	N
Waipa Networks	2,231	74	26,672	N
The Lines Company	4,385	73	23,579	Y
Electra	2,289	102	44,799	N
	40,978		794,244	3/7
All EDBs	154,853	1,821	2,135,309	17/29
NEG as % of all EDBs	26%	100%	37%	3/17

Sources: map adapted from interactive EDB map available at the Energy Network Association website. EDB data based on information disclosure data for the year ending 31 March 2019 as published on the Commerce Commission website, and own analysis.

7. As shown in Figure 1.2, NEG's seven EDBs account for just over a quarter of New Zealand's total distribution lines length, but more than a third of the nation's electricity customers (as

measured by installation control points, or ICPs), largely due to Vector serving around one third of the country's population in Auckland.

8. Under New Zealand's information disclosure and price-quality regulatory regime for EDBs (Part 4 of the Commerce Act 1986, as administered by the Commerce Commission), customer-owned EDBs can be exempted from price-quality regulation if they meet certain customer ownership and control criteria:[4]

    8.1. Of New Zealand's 29 EDBs, 17 are exempt from price-quality regulation, as are four of NEG's seven members.

9. All EDBs, however, are subject to:

    9.1. Price regulations such as New Zealand's low fixed-charge tariff (LFCT);

    9.2. Restrictions on their ability to engage in competitive activities like electricity retailing and generation (Part 3 of the Electricity Industry Act 2010, as administered by the Electricity Authority):

        9.2.1. EDBs can apply for specific exemptions from such restrictions, and certain of NEG's members have successfully done so (e.g. Top Energy); and

    9.3. Regulations affecting all electricity market participants under the Electricity Industry Participation Code – EIPC, or the Code), also administered by the Electricity Authority:

        9.3.1. These include Code rules limiting the distribution charges EDBs can levy on distributed generation such as distributed renewables.

10. How NEG's member firms are owned and regulated is relevant to how they might – or might not – be able to facilitate the uptake of distributed renewables.

[4] See Meade (2018) for an overview of New Zealand electricity sector regulation, and how that regulation needs to be repositioned in anticipation of disruptive new technologies like DERs, and the new business models and players those technologies will give rise to.

1.4 Rationale for Focusing on Customer-Owned EDBs

Explicit Focus on Delivering Customer Benefits

11. Like "cooperative" firms more generally – i.e. firms owned by a particular class of patrons other than investors (such as customer, suppliers, workers) – customer-owned EDBs potentially offer benefits to their patron-owners that would not otherwise be provided by firms focused only on commercial returns. These include either lower cost or higher quality service delivery for potentially unprofitable customers. They also include the possibility of accelerated service delivery relative to that provided by profit-focused firms, and even service delivery where profit-focused firms find it unprofitable to provide any service at all.

Openness to New Models for Delivering Customer Benefits – e.g. DER Platforms

12. The explicit focus of customer-owned EDBs on delivering consumer benefits means such firms might play a key role in accelerating the uptake of distributed renewables and other DERs, relative to the uptake that would arise with supply by only profit-focused firms:

    12.1. In part, this reflects customer-owned EDBs likely being more agnostic than investor-owned firms about how to deliver customer benefits, and hence being more open to traditional network assets being replaced with investments more suited to encouraging consumer-benefitting DER uptake;

    12.2. These include investments in digital platforms of the sort likely to be essential for both unlocking consumer benefits from DERs, and ensuring they can be integrated on distribution networks in ways that benefit all consumers.

Concern about Equity and Access Issues

13. Additionally, their explicit focus on delivering consumer benefits means customer-owned EDBs can be expected to be more attuned to the equity and access issues predicted to arise with the uptake of PV, EVs and other DERs. Specifically, the uptake of such new technologies – typically, by more affluent customers with the necessary financial and other resources (e.g. roof space for residential PV) – can be expected to result in cost-shifting or "waterbed effects" by which network costs fall increasingly on less-affluent non-uptaking customers.

14. This places the spotlight on the possible role of customer-owned EDBs in accelerating the rollout of grid-scale batteries and tailored pricing plans to better integrate distributed

renewables and delay or avoid the costs of network upgrades. It also points to the possible role of customer-owned EDBs in supporting the uptake of community renewables/solar schemes, offering less-affluent customers an opportunity to also participate in distributed renewables by achieving scale economies and lower entry costs.

1.5 Structure of this Report

Snapshot of Growing Importance of Distributed Renewables Worldwide

15. Section 2 briefly surveys the growing importance of distributed renewables and other DERs both globally and in selected jurisdictions, as well as the drivers of uptake:

    15.1. This growing importance has been driven not just by policy initiatives for decarbonising electricity and transport sectors, but more fundamentally by the falling costs and growing consumer appeal of these technologies (especially PV); and

    15.2. A particular focus is on the growth in PV uptake in Australia, which is at the forefront of PV penetration worldwide, and offers lessons about the types of issues this raises for electricity systems and how they might be addressed.

Summary of Challenges Presented by Growth in DERs, and Emerging Responses

16. Section 3 describes the types of challenges presented by emerging high levels of DER penetration in electricity systems around the world, and particularly in Australia. These include increasing security of supply issues caused by both:

    16.1. The inherent intermittency of distributed renewables supply, which rely on variable natural energy sources; and

    16.2. Technical characteristics of distributed renewables systems, affecting how they integrate with wider electricity systems.

17. It goes on to discuss some of the emerging solutions for managing these issues, encompassing:

    17.1. Blunt measures such as outright curtailment of new distributed renewables or how existing such renewables are operated;

17.2. Structural measures such as the creation of renewable energy zones or hubs to ensure their better integration into transmission and distribution infrastructures;

17.3. Pricing and demand management responses intended to better manage where and how distributed renewables affect the electricity systems they form part of;

17.4. The use of grid- or residential-scale batteries to enable the time-shifting of distributed renewables output; and

17.5. The development of digital platforms to maximise the benefits of DERs while also ensuring they can be integrated in distribution and other infrastructures in ways that benefit all consumers (not just those adopting DERs).

Emerging Models of Community Ownership

18. Section 4 provides snapshots of ownership models for distributed renewables, particularly models of community ownership (of which ownership by customer-owned EDBs is a special case):

18.1. While this section discusses customer-owned (i.e. "cooperative") community renewables, a fuller discussion of the role that customer-owned EDBs might play in accelerating distributed renewables uptake is left to Section 7.

Focus on Customer Ownership Rationales and Impacts

19. Section 5 briefly surveys the rationale for certain firms to be customer-owned, and the impacts of such ownership including:

19.1. The level and timing of service delivery in contexts where investor-owned firms may not offer any service at all; and

19.2. The cost and quality of service delivery.

20. The section also includes a brief summary of special features of NEG members' ownership arrangements which can be expected to affect their approaches to encouraging and managing DER uptake.

Survey of NEG Members regarding Experience of DER Uptake, and Issues Anticipated over Decade to 2030 as DER Uptake Accelerates

21. Section 6 presents the results of a survey taken of NEG members by way of structured interview, canvassing:

    21.1. The level of existing DER penetration on each member's network, and the associated drivers and issues; and

    21.2. NEG members' expectations regarding the commercial, regulatory, technical and organisational issues (i.e. challenges, opportunities, etc) they anticipate over the next decade to 2030 as DER uptake continues to grow.

22. The discussion of anticipated organisational issues traverses how NEG members perceive their customer ownership to affect the ways they encourage and respond to DER uptake and associated issues and opportunities.

Role of Customer-Owned EDBs in Accelerating the Uptake of Distributed Renewables and Other DERs

23. Section 7 specifically examines how customer ownership of EDBs is likely to affect the uptake of distributed renewables and other DERs, relative to investor-owned EDBs.

24. This includes discussion of how customer ownership is likely to affect:

    24.1. The development of digital platforms to maximise customer benefits of DERs while ensuring they can be integrated on distribution networks in ways benefitting all customers; and

    24.2. The development of community solar schemes, which offer potential benefits to less-affluent customers both in terms of accessing new technologies, and insulating such customers from cost-shifting/waterbed effects caused by DER adoption by more affluent customers.

Conclusions, and Implications for Policy and Regulation

25. Section 8 ends with a discussion of the study's implications for policy and regulation, and overall conclusions.

26. In short:

26.1. Customer-owned EDBs offer potential advantages in accelerating the uptake of distributed renewables and other DERs;

26.2. They also offer certain natural protections against the types of issues that electricity regulation seeks to address;

26.3. This points to how a more nuanced approach to how customer-owned EDBs are regulated can be justified, with some specific examples offered.

1.6 Contributions of this Study

27. This study provides a snapshot of the issues and opportunities presented by the uptake of distributed renewables and other DERs (including EVs). It highlights how electricity distributors will play an increasingly important role in ensuring that such uptake is not only beneficial to uptakers, but also to non-uptakers (with potential harms managed or avoided).

28. The study further highlights the special role of customer-owned EDBs in achieving such beneficial uptake, and points to what this special role might mean for policy and regulation. This supports more informed discussions and debates about the roles of different types of organisations in supporting New Zealand's wider climate, transport and energy initiatives.

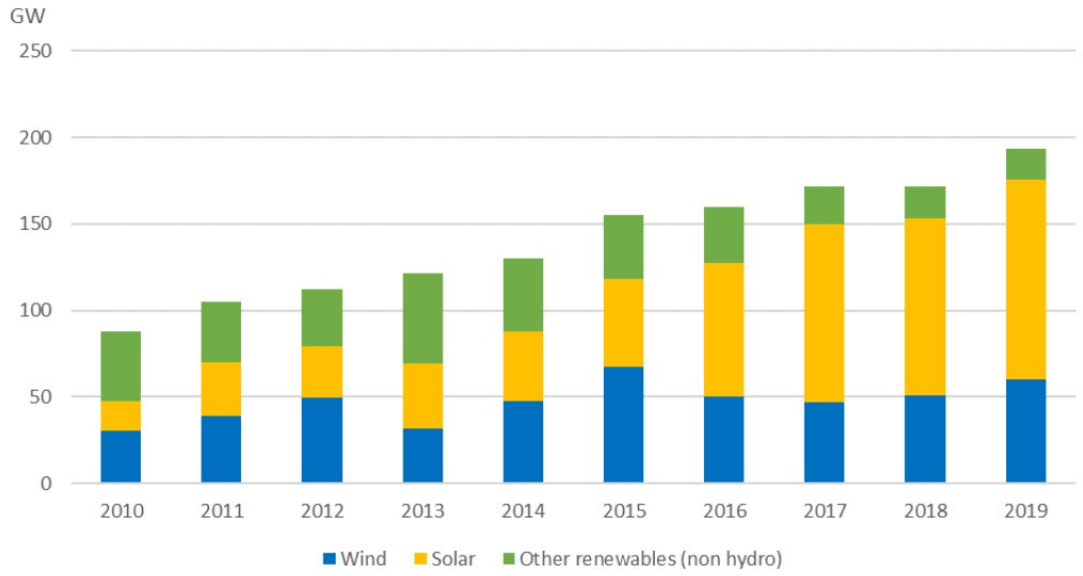
2. Global Growth of Distributed Renewables

2.1 Snapshot of Global DER Uptake

Growing Importance of PV in Renewables Portfolio

29. At a global level, non-hydro renewable electricity generation – i.e. generation using wind, solar and other fuels (e.g. biomass) – remains relatively modest compared to fossil fuel generation. However, its contribution to global electricity supply is growing rapidly, dominated by the growth in PV-based generation in particular as the costs of PV continue to fall, and because of policy measures to encourage PV uptake. Figure 2.1 illustrates the rapidly increasing importance of PV in the mix of non-hydro renewables.

Figure 2.1 – Growing Importance of PV in Global Non-Hydro Renewables Mix



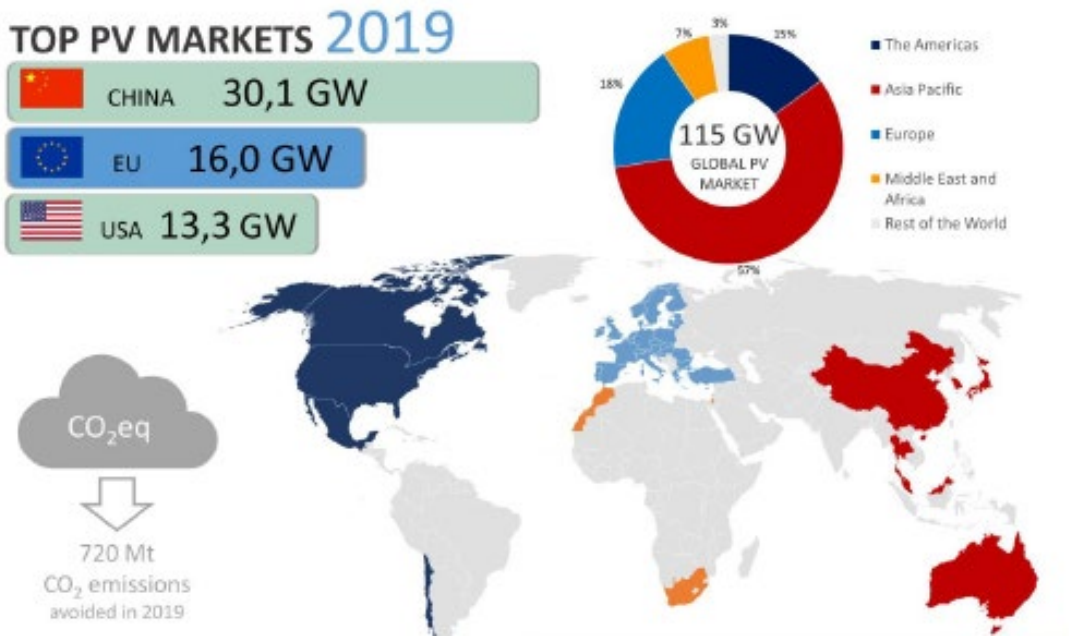
Source: IEA-PVPS (2020), Figure 6.

Global Distribution of PV Capacity and Growth

30. According to the International Energy Agency, 115 GW of PV was installed in 2019, bringing the global installed capacity of PV to 627 GW.[5] As shown in Figure 2.2, China leads the way with 205 GW of cumulative PV capacity, followed by the EU with 132 GW, and the US with 76 GW. Australia ranks seventh in the world by total installed capacity, at 15 GW.

[5] IEA-PVPS (2020).

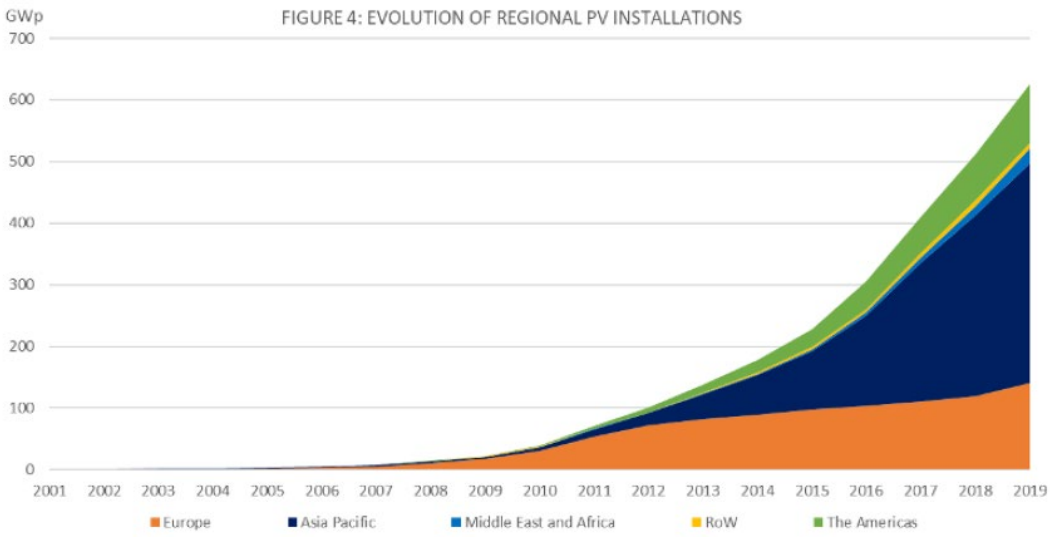
Figure 2.2 – Global Distribution of PV Capacity



Source: Extracted from IEA-PVPS (2020).

31. As shown in Figure 2.3, total PV capacity has grown strongly over the past 20 years, dominated by especially rapid uptake in the Asia-Pacific Region.

Figure 2.3 – Regional Breakdown of Global PV Capacity Growth

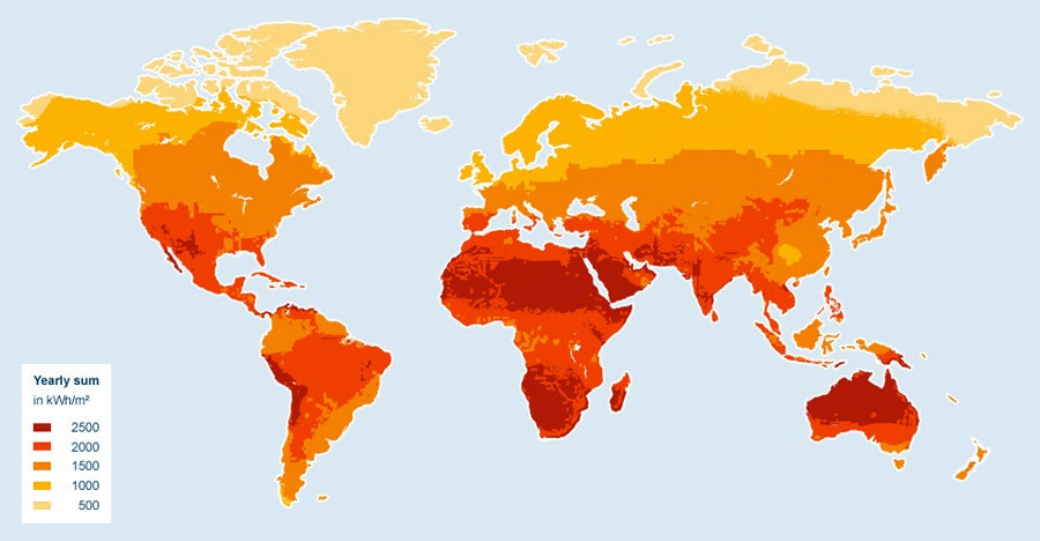


Source: IEA-PVPS (2020), Figure 4.

32. While it might be expected that PV uptake should occur mainly in the sunniest parts of the world, by comparison with Figures 2.2 and 2.3, Figure 2.4 indicates that much of that uptake has occurred in parts of the world without the greatest sunshine resource. Notably for New Zealand, while much of EU's PV uptake has occurred in sunny Spain, a great deal

has also occurred in areas like Germany enjoying similar sunshine resource to that in New Zealand.[6]

Figure 2.4 – Global Annual Sunshine Resource



Source: nz.coop website.[7]

33. Despite its rapid growth, PV accounts for only 3% of global electricity supplied (5% in the EU). Moreover, the market penetration of PV varies markedly by region, with Australia and Germany being the two countries with the highest PV uptake in terms of watts/capita (at 595 and 585 watts/capita respectively), even though they rank fourth and seventh in terms of total installed capacity.

2.2 Drivers of PV and Other DER Uptake

34. A major driver of PV uptake (the globally-dominant class of distributed renewables), has been renewable generation targets complemented by generous policy support measures intended to decarbonise electricity systems dominated by fossil fuel generation. These have included both subsidies to reduce installation costs, and generous feed-in tariffs (FITs) guaranteeing PV adopters significant revenue streams from their generation.[8] Figure

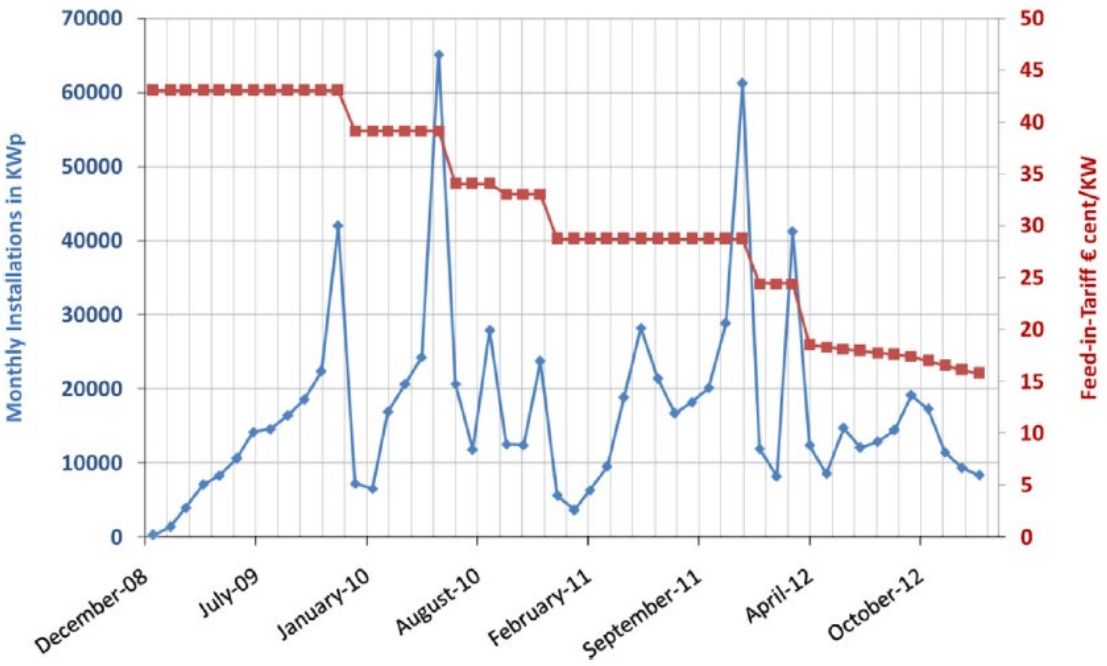
[6] A key difference between Germany and New Zealand is that the latter has not offered the sorts of generous support measures that have strongly contributed to PV uptake in the former. For New Zealand to achieve similar PV penetration rates without support measures it will be necessary for installed PV costs to fall, and/or PV panel efficiencies and electricity prices to rise, enough to make up for the lack of support, all other things being equal.

[7] https://nz.coop/solar-energy-and-opportunity-co-operatives, accessed 15 October 2020.

[8] E.g. see Karakaya et al. (2015), and Best et al. (2019) regarding Australian incentives.

2.5 illustrates how spikes in PV uptake in Germany have often occurred just ahead of pre-announced falls in FITs taking effect.[9]

Figure 2.5 – Importance of Feed-In Tariffs for German PV Uptake



Source: Karakaya et al. (2015), Figure 2.

35. More generally, key drivers identified in studies of DER uptake include:[10]

35.1. Attractive return on investment:

35.1.1. Indeed, while early adopters often cite technical or environmental reasons for adopting PV, later more "mass market" adopters cite financial reasons;[11]

35.2. Installation feasibility (housing type and tenure, etc) – for PV especially, but also for EVs (i.e. chargers);

35.3. Adopters' income, and DER investment costs:

[9] Evidence from Australia points to similar impacts of FIT changes and uptake surges. See https://pv-map.apvi.org.au/analyses.

[10] Cohen et al. (2019).

[11] Simpson and Clifton (2017).

35.3.1. The association between income and PV adoption has been shown for PV adoption in New Zealand,[12] and in another study has been shown to reflect the fact that wealthier households tend to be higher energy users, more frequently own their home, or own houses better suited to PV;[13]

35.4. Attitudes regarding the environment – e.g. preferences for "green electrons";

35.5. Preferences for energy self-sufficiency;

35.6. A desire to engage with new technologies, and to manage energy usage (i.e. consumer "empowerment");

35.7. For EVs – driving range constraints, and the availability of charging infrastructure; and

35.8. Synergies/complementarities between PV and EV ownership – PV owners are more likely to plan to buy an EV than non-owners of PV, and an increasing uptake of EVs also leads to a supply of "second life" batteries that can be a lower-cost means of securing storage for PVs (relative to buying new batteries).[14]

36. A number of other studies also point to the importance for uptake of helping potential DER adopters understand the costs, benefits and risks of new technologies. Key ways of achieving this include:

36.1. Access to local PV companies who can help customers navigate the complexities of DERs;[15]

36.2. Education as to PV costs and benefits;[16]

36.3. Mechanisms to mitigate PV risks – e.g. institutionalised tests of PV systems and labelling schemes,[17] which can help to reduce the risk of being mis-sold systems; and

[12] Heinen and Richards (2020).

[13] De Groote et al. (2016).

[14] Neetzow et al. (2018).

[15] Karakaya et al. (2015).

[16] Simpson and Clifton (2017).

[17] Korcaj et al. (2015).

36.4. Peer effects – i.e. interpersonal contact with other PV owners (versus simply observing PV uptake by others), providing reassurance that PV works as intended and without complications.[18]

37. Early research on PV uptake in New Zealand highlights drivers such as a desire for energy independence (coupled with a lack of trust of power companies), greater control over financial outgoings, and concern for the environment.[19] Conversely, barriers to PV uptake in New Zealand were found to include high up-front costs and lack of financial incentives, uncertainty about investment returns, and expectation of falling PV costs (delaying investment).

2.3 DER Uptake in the US

38. Based on US Solar Energy Industries Association data, California leads the US in terms of total installed PV capacity, with Hawaii and other, mainly southern states also enjoying significant uptake. Residential PV installations exceeded 2,800 MW in 2019, with non-residential installations amounting to just under 2,200 MW.[20]

39. Both of these, however, have been dwarfed by utility-scale PV, which is projected to continue to outstrip smaller-scale installations (see Figure 2.5). In 2019, utility-scale (i.e. non-distributed) installations accounted for 60% of the country's 13 GW of new installations.[21]

40. The following trends have underpinned PV's rapid growth in the US:[22]

40.1. Median residential module sizes have risen 167% over 2000-2018 (from 2.4 kW to 6.4 kW), reflecting both declining costs and rising module efficiency, although these have been partly offset by declining incentives;

40.2. The proportion of PV systems with storage is rising but still relatively modest with typically 5% or less of residential installations including storage in 2019 (although 60% of PV permits issued in Hawaii in 2018 included storage); and

[18] Palm (2017).

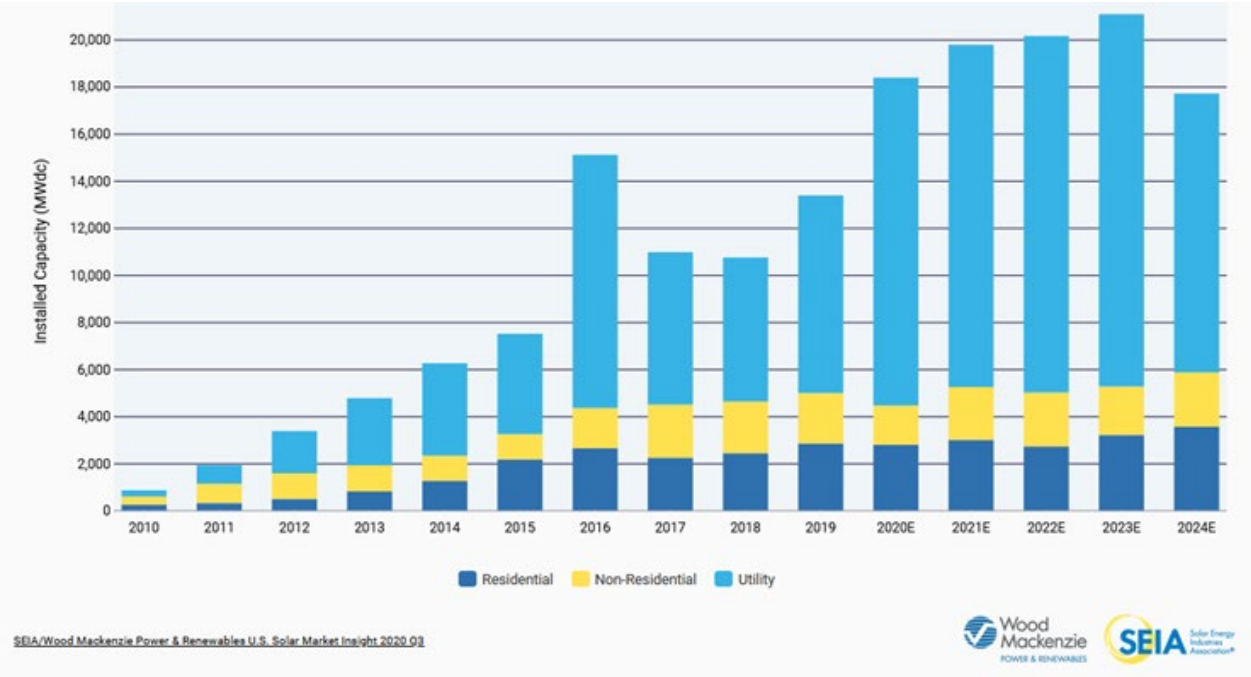
[19] Ford et al. (2014).

[20] https://www.seia.org/solar-industry-research-data, accessed 29 September 2020.

[21] IEA-PVPS (2020).

[22] Barbose and Garghouth (2019).

Figure 2.5 – Current and Projected Dominance of Utility-Scale PV in the US



Source: Solar Energy Industries Association website.[23]

40.3. There are strong economies of scale in both residential and non-residential systems – for residential installations in 2018, median prices were c. US$1/W lower for the largest systems (>12 kW) compared to the smallest (≤2 kW);

40.4. The levelised cost of rooftop solar has been estimated to be US$0.2/kWh, versus US$0.11/kWh for commercial/industrial, and US$0.04/kWh for grid-scale solar.[24]

2.4 DER Uptake in Australia

41. As shown in Figure 2.6, Australia's electricity system remains dominated by fossil fuels, but is undergoing rapid change with strong growth in renewables (both wind and PV, especially rooftop solar), accompanying falls in black and brown coal generation.

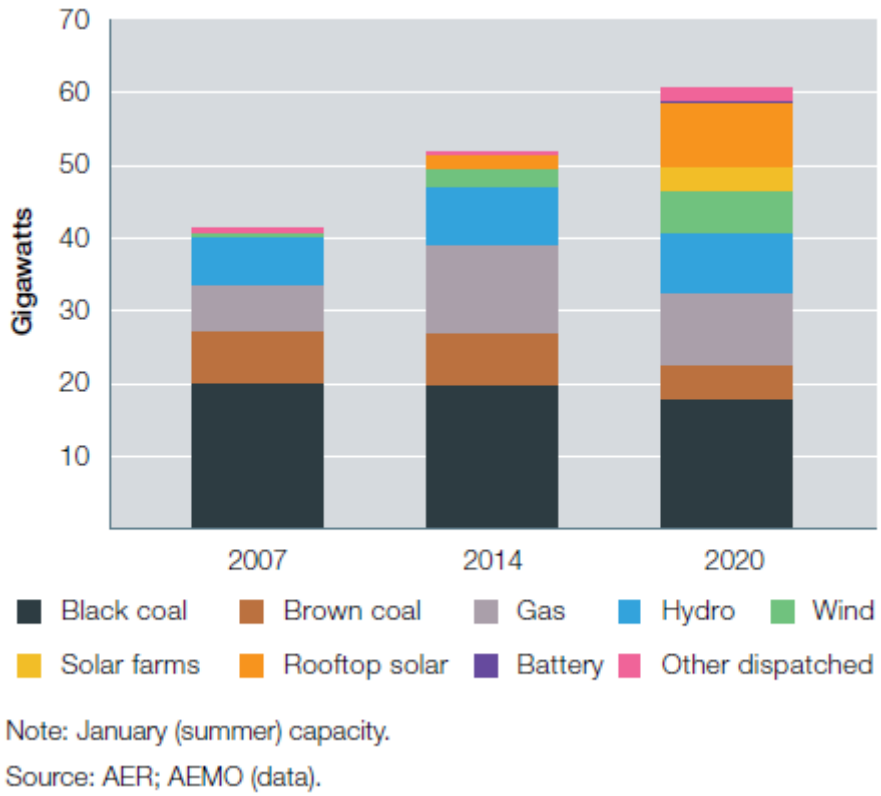
42. While fossil fuels accounted for 77% of generation in 2019, wind accounted for 8%, solar farms for 2.5%, and rooftop solar 5.2%. Renewables are filling much of the supply gap caused by fossil generation closures, with more than 93% of generation investment since 2013 being in wind and solar. Notably, commercial solar farms are only slowly emerging,

[23] https://www.seia.org/solar-industry-research-data, accessed 29 September 2020.

[24] As reported in Borenstein (2020).

although grid-scale solar investment outstripped rooftop solar in 2019 (4,000 MW versus 1,600 MW).[25]

Figure 2.6 – Australia's Changing Electricity Generation Mix



Source: AER (2020), Figure 1.

43. According to the Australian Photovoltaic Institute (APVI), as of June 2020 there were over 2.46m PV installations in Australia, with a combined capacity of over 18 GW:[26]

    43.1. By 2018, 20% of Australian households had installed PV, a total figure comparable to that of the US despite Australia's much smaller population.[27]

44. Figure 2.7 illustrates just how rapid Australia growth in PV total capacity has been, in part driven by increasing average system sizes (rising from around 1.5 kW in 2010 to just under 8 kW in 2020).[28]

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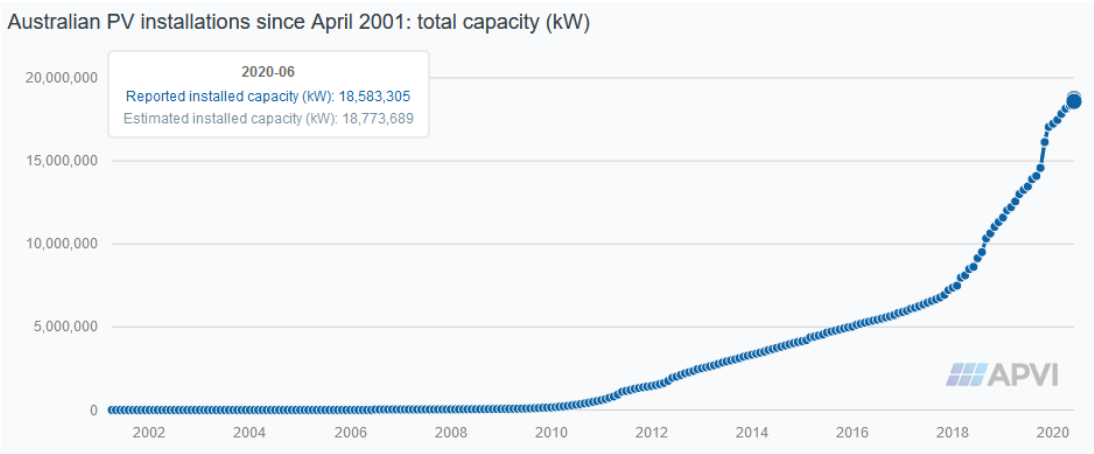
[25] AER (2020).

[26] https://pv-map.apvi.org.au/analyses, accessed 21 October 2020.

[27] Best et al. (2019).

[28] https://pv-map.apvi.org.au/analyses, accessed 21 October 2020.

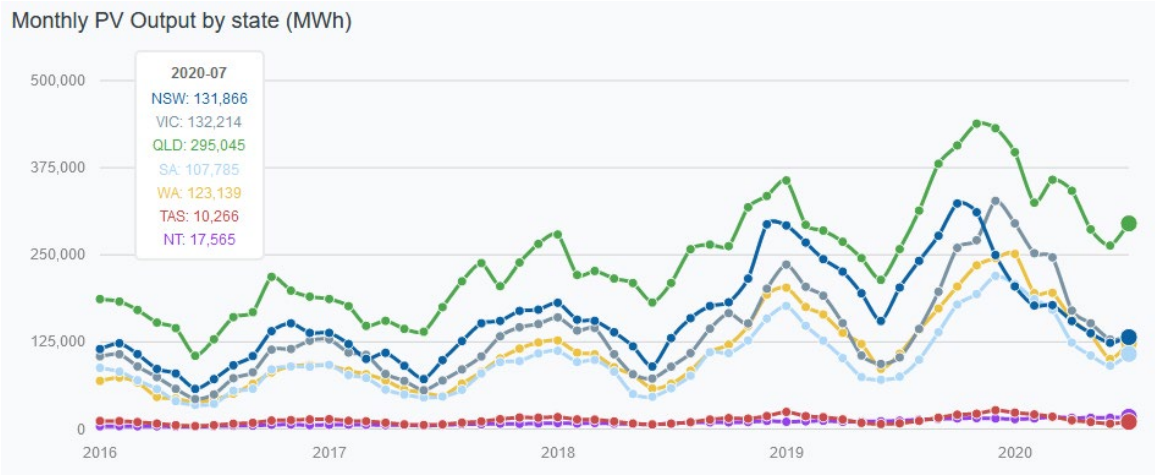
Figure 2.7 – Growth in Australia's Installed PV Capacity



Source: APVI website.[29]

45. Figure 2.8 shows PV generation by state, with Queensland and New South Wales having led the way in terms of total PV output.

Figure 2.8 – Australian PV Generation by State



Source: APVI website.[30]

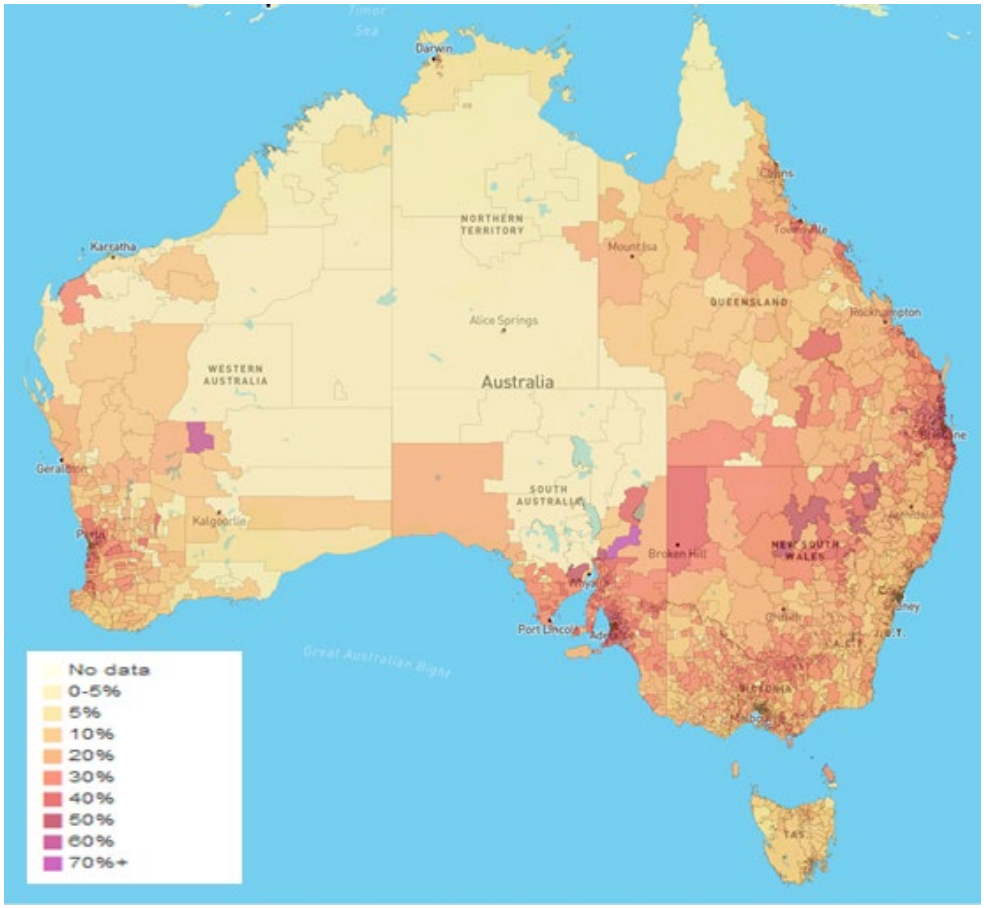
46. PV uptake has varied by postcode in Australia, in part because PV support measures prioritise uptake in postcodes that fall in zones with the greatest sunshine resources.[31] Figure 2.9 illustrates the national variation in PV penetration by postcode, with penetration in some postcodes being 70% or more.

[29] https://pv-map.apvi.org.au/analyses, accessed 21 October 2020.

[30] https://pv-map.apvi.org.au/analyses, accessed 21 October 2020.

[31] Best et al. (2019).

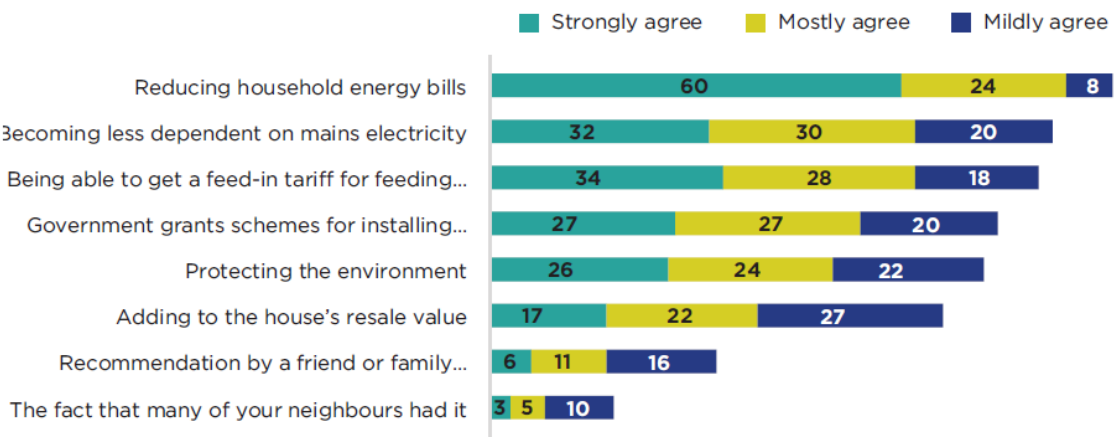
Figure 2.9 – Australian PV Penetration by Postcode



Source: APVI website.[32]

47. Key drivers of PV uptake in Australia are summarised in Figure 2.10.

Figure 2.10 – Key Drivers of PV Uptake in Australia



Source: Energy Networks Australia (2020), Figure 9.

[32] https://pv-map.apvi.org.au/historical#5/-25.404/118.608, accessed 21 October 2020.

3. Emerging DER Challenges and Responses

3.1 DER Challenges

48. Distributed renewables and other DERs (e.g. storage) are increasingly offering zero marginal cost electricity supplies. Among other benefits, this offers the potential of reducing peak electricity demands, deferring the need for costly network upgrades, and reducing consumers' power bills while also reducing GHG emissions.

49. However, in the context of the wider electricity systems in which they typically arise (i.e. excepting independent micro-grids), DERs can give rise to a range of undesirable effects which serve to reduce their benefits. These include:

    49.1. Power quality and system reliability issues;

    49.2. Relatedly, network management issues;

    49.3. Electricity market impacts; and

    49.4. Consumer and equity issues.

50. It is instructive for New Zealand to look to the experience of jurisdictions that are much more advanced in their uptake of distributed renewables (e.g. Australia), to anticipate what issues might arise, and consider how best to manage them.

51. This section briefly surveys some of the issues identified in such jurisdictions, and the types of solutions that are being developed or implemented to resolve them.

Power Quality and System Reliability Issues

52. South Australia's blackout in September 2016 illustrates how electricity systems with high non-hydro renewables penetration can be vulnerable to major outages. While the natural intermittency of renewables generation like wind and solar can be a major contributor to such vulnerability, the Australian Energy Market Operator report on the 2016 event implicated other features of renewables:[33]

[33] AEMO (2017).

52.1. Specifically, PV and wind are "non-synchronous inverter-connected" generation, with active control mechanisms that shut them down automatically – within seconds – when they experience disturbances of sufficient severity or rapidity, which can cause cascading issues for other grid-connected assets;

52.2. This feature is unlike conventional generation, which provides more "inertia" in electricity systems that helps them to ride out disruptions, but which may prove inadequate to ride out future disturbances with rising renewables penetration.

53. Increasing renewables penetration – especially of PV which generates at its maximum during the sunniest hours of each day – can exacerbate such vulnerability due to accelerating the retirement of traditional (e.g. fossil fuel) generation:

53.1. Such penetration depresses daytime wholesale electricity prices, undermining the viability of traditional generation, and reducing the availability of such generation with the ability to provide technical stability services to counter the vulnerabilities arising from renewables.[34]

54. Aside from such potentially catastrophic effects, increasing renewables penetration gives rise to a range of less severe yet still very important power system issues. Based on Australian experience, these include:[35]

54.1. Low "inertia";

54.2. Weak system strength;

54.3. More erratic frequency shifts;

54.4. Voltage instability; and

54.5. Rising costs of procuring market services to maintain system frequency.

55. For example, when PV generation is high (due to strong sunshine) during non-peak demand periods, this can cause network voltages to rise. If they rise sufficiently, then PV systems

[34] AER (2020).

[35] AER (2020), Energy Networks Australia (2020), GridWise and Farrierswier (2020).

(i.e. their "inverters") can automatically shut down the PV generation, causing sudden losses of supply along distribution networks.[36]

Network Management Issues

56. A critical limitation of existing distribution networks in the face of rising distributed renewables penetration is that those networks were designed and built to manage electricity flowing in one direction, from traditional generation to ultimate consumers:

    56.1. With DER's, however, those networks are being required to manage bi-directional flows, as DERs export to networks at times when their generation exceeds the own-consumption of their "prosumer" owners;

    56.2. This causes swings in network voltages that give rise to unreliability, and can require network operators – absent other solutions – to limit new DER connections or existing DER exports as reverse flow capacities are reached.[37]

57. Figure 3.1 indicates when PV penetration is expected to reach 40%, which is considered to be sufficient to cause reverse flows on Australian networks. That threshold penetration rate is expected to be sooner than 2030 in areas shaded red or orange.

58. Other network management issues associated with DER penetration include:[38]

    58.1. A need for significant upgrades (in progress) to standards relating to safe distribution network operation;

    58.2. A need for standards on DER interoperability, complicated by reliance on equipment sourced from overseas manufacturers;

    58.3. A lack of visibility regarding certain DERs (e.g. batteries), and even on DERs like PV for which installations must be disclosed to network operators, in terms of real-time operations;

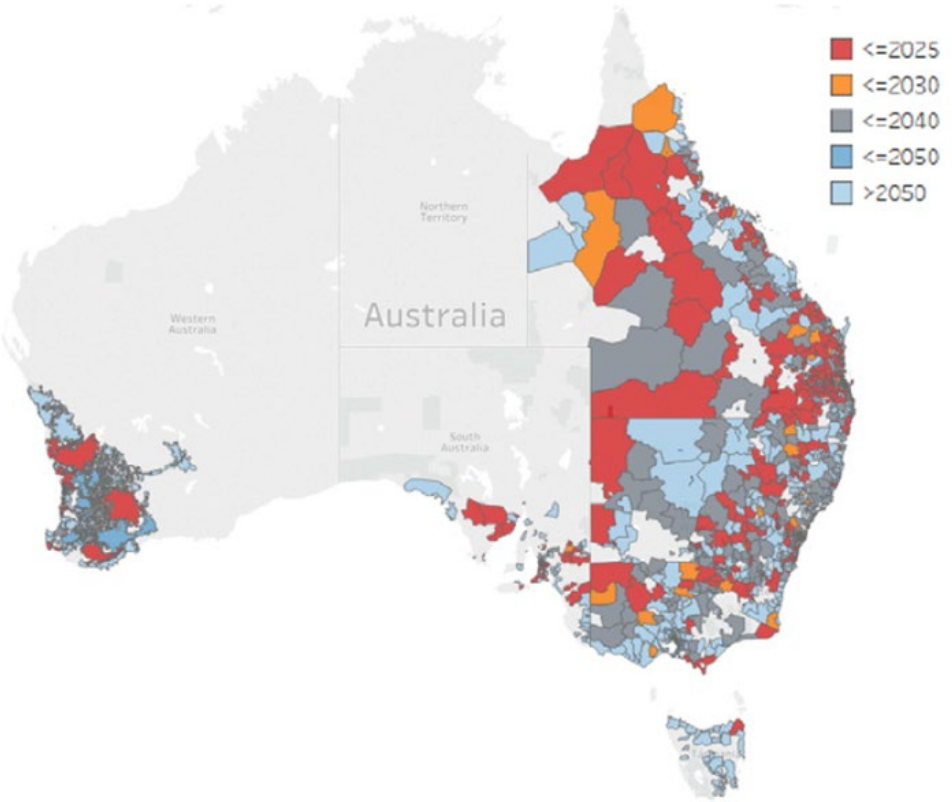
    58.4. An associated lack of standards or industry agreement on what DER data should be shared, and in what format;

[36] For a more in-depth non-technical explanation, see Energy Networks Australia (2020).

[37] Energy Networks Australia (2020), GridWise and Farrierswier (2020).

[38] GridWise and Farrierswier (2020).

Figure 3.1 – Timing of Reverse Flows Reaching Network Threshold Levels in Australia



Source: Adapted from Energy Networks Australia (2020), Figure 5.

58.5. A lack of understanding about the impacts of EVs and EV charging on network requirements and management; and

58.6. Under-developed pricing, demand response, market and technology mechanisms for better integrating DERs into distribution networks (including mechanisms for using DERs to provide network support services).

Electricity Market Impacts

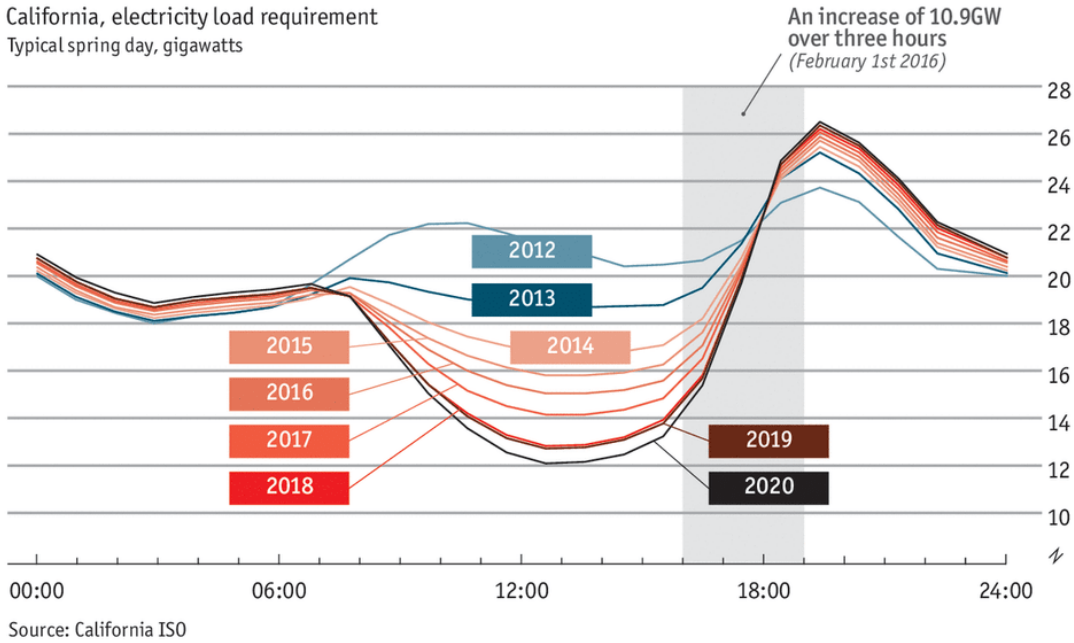
59. As noted earlier, the depression of daytime wholesale electricity prices due to increasing PV generation is accelerating the retirement of fossil fuel generation in Australia:

59.1. Negative wholesale prices have also been occurring more frequently, typically when renewables generation is high and demand is low, intensified due to geographic clustering of renewables (especially in South Australia and Queensland).[39]

[39] AER (2020).

60. Similar effects have been established in California, where high levels of PV generation depress wholesale electricity prices during the day, but also increase shoulder hour wholesale prices (as made famous by the Californian "duck curve", illustrated in Figure 3.2):[40]

Figure 3.2 – California's "Duck Curve" Illustrating the Impact of Increasing Solar Penetration on Net Load



Source: The Economist website.[41]

60.1. While this reduces the profitability of low-cost traditional generation, the profits of higher-cost generators could be increased.

61. In turn, this depression of wholesale prices causes a "cannibalisation effect" for DERs – i.e. increasing DER penetration undermines DER value, with both absolute and relative cannibalisation effects for wind and solar, working in different directions:[42]

61.1. Wind reduces solar value, but solar penetration increases wind value when penetration is high and demand is low;

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[40] Bushnell and Novan (2018). Notably, California – like Australia – has summer-peaking demand due to air conditioning usage (versus New Zealand's winter-peaking demand for heating).

[41] https://www.economist.com/graphic-detail/2018/03/28/what-a-ten-year-old-duck-can-teach-us-about-electricity-demand, accessed 21 October 2020.

[42] Prol et al. (2020).

61.2. Solar competitiveness (and wind) could be jeopardised absent other measures such as storage, demand management or intercontinental connections.

Consumer and Equity Issues

62. Under existing network pricing models, particularly those including variable network charges, DER uptake is expected to increasingly lead to inequities referred to as "cost-shifting" or "waterbed effects":[43]

62.1. Specifically, customers adopting DERs typically consume less electricity from the network, and therefore contribute less towards network cost recovery via variable network charges, requiring those charges to increase for non-adopters;[44]

62.2. Since DERs are more likely to be adopted by more affluent customers, this means less affluent customers could face an increasing burden in paying for networks that DER adopters still use and require (e.g. for exporting), although the increasing penetration of EVs can serve to mitigate this effect.[45]

63. An associated equity issue is that pricing for customers exporting to distribution networks is still in its infancy, meaning that DER adopters who export to distribution networks and exploit existing capacity for bi-directional flows do not appropriately contribute to either the cost of that capacity, or the cost of expanding bi-directional capacity once existing capacity has been exhausted.

64. Other consumer issues sometimes associated with DERs include:[46]

64.1. Consumers being mis-sold DERs that do not meet their needs; and

64.2. Poor quality DER equipment or installations – e.g. PV installations undermining weathertightness of roofs.

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[43] E.g. see Boampong and Brown (2020), Meade (2018).

[44] In turn, this can lead to "grid defection" by both sets of customers, resulting in a "death spiral" in which networks are unable to cover their costs and have to reduce services. E.g. see Meade (2018) and references therein.

[45] Hoarau and Perez (2019).

[46] Simpson and Clifton (2015) refer to Australian DER consumers perceiving a need for better education, and also to a need for certification schemes and independent product/installer information.

3.2 Emerging Reponses to DER Challenges

65. In response to these DER issues, responses such as the following have emerged:

    65.1. Blunt measures such as outright curtailment of new distributed renewables or how existing such renewables are operated;

    65.2. Structural measures such as the creation of renewable energy zones or hubs to ensure their better integration into transmission and distribution infrastructures;

    65.3. Pricing and demand management responses intended to better manage where and how distributed renewables affect the electricity systems they form part of; and

    65.4. The development of digital platforms to maximise the benefits of DERs while also ensuring they can be integrated in distribution and other infrastructures in ways that benefit all consumers (not just those adopting DERs).

66. More generally:

    66.1. Considerable research is being undertaken (and in jurisdictions like Australia, well-funded) to better understand the issues arising with DER penetration, and how best to accommodate new technologies that maximise their benefits and minimise their harms;[47] and

    66.2. Regulatory sand-pits and experimentation are becoming more common, to trial possible solutions.[48]

Curtailment of DERs, and Restrictions on DER Operation

67. Many of the tools required to effectively integrate and manage DERs in existing electricity systems are yet to emerge:

    67.1. Partly because the need for them is only now becoming apparent; and

[47] See, for example, the Australian Renewable Energy Agency (ARENA) website, https://arena.gov.au/, detailing multiple research streams and their funding. GridWise and Farrierswier (2020) provides a comprehensive overview of Australia's major DER research initiatives.

[48] AER (2020).

67.2. Also, because some of the required tools will necessarily be complex to develop and implement.

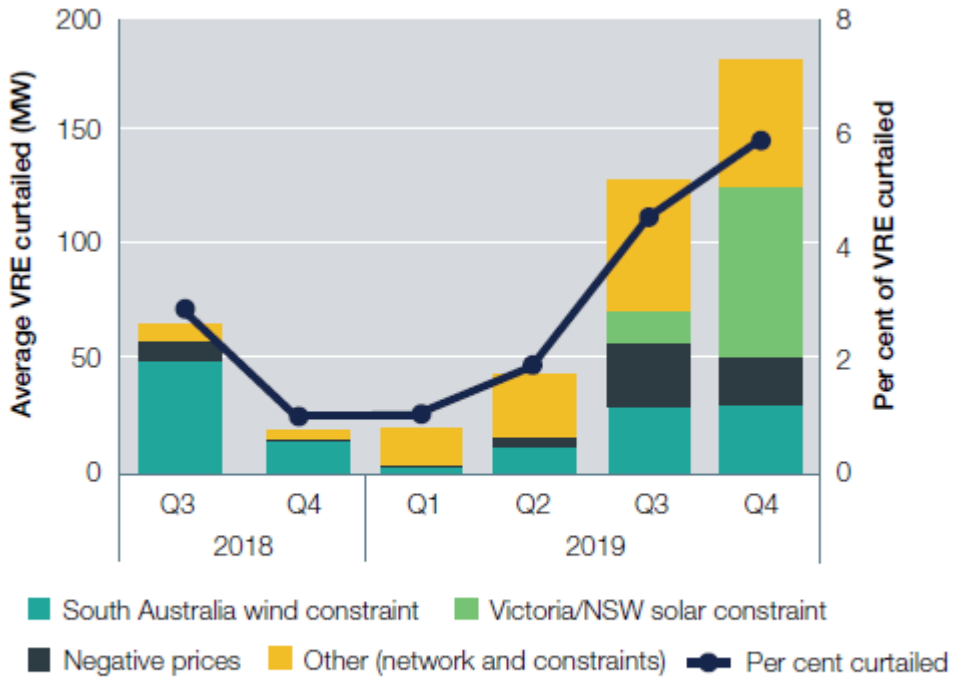
68. When confronted with novel system reliability and network management issues, especially given existing regulatory obligations and financial incentives to maintain network reliability, electricity transmission and distribution network operators' most readily-available tools include blunt instruments such as:

68.1. Prohibiting further DERs to be installed on parts of networks where capacity limits and/or critical power quality and system reliability issues arise with existing DER penetration;

68.2. Limiting how existing DERs can be operated, such as prohibiting export from PV systems during times of high production and low demand:

68.2.1. Recent Australian experience with such measures is illustrated in Figure 3.3, showing that up to 6% of DER generation needed to be curtailed in 2019, with PV and network constraints playing increasing roles.

Figure 3.3 – Curtailment of Renewable Generation in Australia



MW, megawatt; VRE, variable renewable energy.

Source: AEMO, *Quarterly energy dynamics Q4 2019*, February 2020.

Source: AER (2020), Figure 2.

69. Such curtailment not only undermines the economics of DER systems (e.g. reducing export revenues) and discourages DER investment.[49] It also raises further equity issues – early DER adopters enjoy effectively under-priced access to the existing capacity of networks to absorb reverse flows and power quality variability, but:

    69.1. Later DER adopters can find themselves constrained out of the market; and

    69.2. All network customers risk having to bear the costs of network upgrades to accommodate further DER uptake, whether or not they benefit from those upgrades (other than avoiding increasing power quality and system unreliability issues caused by others) or contribute to their need.

70. In order to improve on such blunt responses, one response in Australia has been reform requiring connecting generators to "do no harm" to system strength, including:[50]

    70.1. Generators and batteries being required to provide primary frequency response support when required; and

    70.2. Exploring longer-term security services, such as new markets for inertia, system strength and voltage control.

Structural Measures such as Renewables Hubs/Zones

71. A more structural approach to managing issues related to increasing DER penetration is the designation and creation of zones or hubs/clusters – e.g. where DERs have good production potential and existing infrastructure is better able to accommodate them. Examples include:

    71.1. Renewable energy zones in Australia;[51] and

    71.2. Local energy hubs in the UK.[52]

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[49] Dato et al. (2020).

[50] AER (2020).

[51] https://arena.gov.au/blog/what-are-renewable-energy-zones-and-why-do-they-matter/, accessed 22 October 2020.

[52] https://hub.communityenergyengland.org/resources/BEIS-Local-Energy-Team/, accessed 22 October 2020.

72. By encouraging and supporting DER uptake in such areas the intention is to:

72.1. Ensure that DERs are better able to be integrated into existing infrastructure without significant additional cost or harms; or

72.2. Help to scale up local energy initiatives, encourage innovation and collaboration, etc.

Pricing and Demand Management Responses

73. Better aligning DER production and electricity demand is one of the ways to ensure that DER penetration can better be accommodated in existing network infrastructures, maximising their benefits and minimising their harms:

73.1. Existing network pricing models – e.g. fixed and variable distribution charges without time-of-use or peak-demand components – are potentially exacerbating DER issues, and in any case can only be part of a solution to DER issues given consumers' final prices also include energy components that also need refining; and

73.2. Existing institutions for encouraging smaller-scale consumers to shift their demand in response changing market circumstances are not yet as developed – or cost-effective – as demand response mechanisms already well-established for commercial and industrial customers.

74. Greater use of time-of-use and/or fixed (including peak-demand) charging as components of improving alignment between DER generation and electricity demand are gaining increasing attention:

74.1. Doing so can reduce cost-shifting/waterbed effects;[53]

74.2. They can improve consumer welfare, though introducing time-of-use pricing for commercial and industrial customers ahead of residential customers can cause residential prices to increase (another form of potential waterbed effect);[54]

[53] Boampong and Brown (2020).

[54] Gambardella and Pahle (2018).

74.3. However, they can also give rise to conflicts of interests between PV and EV owners (if they are not one in the same).[55]

75. In Australia, a suite of related measures are being implemented to better manage issues arising with high DER penetration:

75.1. "Cost-reflective" tariffs are being used to encourage users to:

75.1.1. Shift energy use to times of lower demand; and

75.1.2. Operate DERs in ways that minimise network stress; and

75.2. The Australian Energy Regulator (AER) is supporting investments in demand management innovations that reduce the need for network investments, e.g.:

75.2.1. Residential and grid scale battery storage projects;

75.2.2. Device control trials; and

75.2.3. Research into distributed energy platforms.

Development of Digital Platforms

76. There is growing recognition among industry, policymakers and researchers that increasing decentralisation and bi-directional flows in electricity systems with high DER penetration mean that low-voltage distribution networks are becoming much like high-voltage transmission systems in terms of the coordination issues they confront in attempting to maintain system reliability.[56]

77. This has given rise to industry-led initiatives, subject to wider stakeholder and regulatory involvement – notably in the UK (Open Networks Project) and Australia (Open Energy Networks Project) – to assess which electricity system architectures offer the best prospect

[55] Hoarau and Perez (2019).

[56] E.g. see Meade (2018), Newport Consortium (2018), Energy Networks Australia (2020), Energy Networks Australia's *Open Energy Networks Project* (https://www.energynetworks.com.au/projects/open-energy-networks/), or the UK Energy Network Association's *Open Networks Project* (https://www.energynetworks.org/creating-tomorrows-networks).

of accommodating DERs in ways that benefit not only adopters but also other network-connected customers, for example by:

77.1. Mitigating cost-shifting/waterbed effects;

77.2. Maintaining reliability – e.g. via DERs providing network support services; and

77.3. Delaying, rather than increasing, the need for network enhancements.

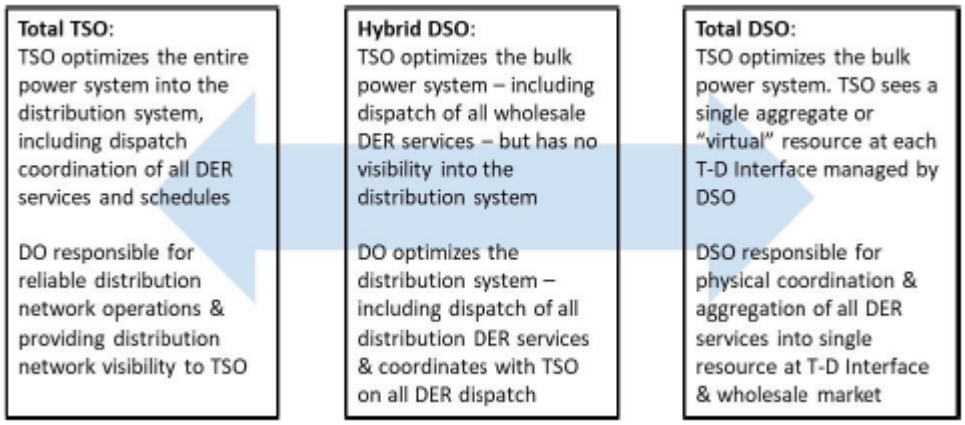
78. Figure 3.4 summarises the three leading candidates for such architectures:[57]

78.1. At one extreme, existing transmission system operators (TSOs) extend their current coordination of real-time grid-connected electricity supply and demand to also coordinate DERs, with distribution network operators assisting TSOs to do so;

78.2. At the other extreme, distribution network operators perform similar functions to TSOs, coordinating real-time supply and demand at the distribution network level including DERs, becoming distribution system operators (DSOs); and

78.3. Probably most realistically, there is a hybrid approach where TSOs and DSOs are jointly responsible for DER coordination at varying levels.

Figure 3.4 – Candidate System Architectures for Accommodating and Coordinating DERs



Source: Newport Consortium (2018), Figure 2.

79. Whichever direction system architectures ultimately take in order to best coordinate DERs, an underlying theme is that the sorts of institutional and technology arrangements that currently exist for grid-connected parties will also be required for generators and

[57] For more detailed discussions, see Newport Consortium (2018), or Energy Networks Australia (2020).

consumers on distribution networks. In addition to improved models for allocating network costs among users, these include:

79.1. Mechanisms for measuring electricity generated and consumed, and determining who is buying/selling to whom, and when, under what prices; and

79.2. Mechanisms for coordinating electricity supply (i.e. DERs) and demand (e.g. household appliances, EVs, etc), in real time, so as to maintain power quality and system reliability – e.g. centralised or decentralised/P2P energy trading, with either:

79.2.1. System security and other constraints embedded in market design (i.e. smart markets); or

79.2.2. Separate mechanisms to simultaneously ensure reliability and power quality (e.g. network services markets, akin to existing ancillary services markets in wholesale electricity markets) and efficient decentralised energy trading.

80. In some shape or form this will necessarily require digital platforms that simultaneously coordinate DER production decisions and consumers' electricity consumption decisions:

80.1. Just as TSOs necessarily play a key role in developing and managing digital platforms in high-voltage electricity grids, it should be expected that DSOs will likewise play a key role in the development and operation digital platforms required for coordinating DERs;

80.2. The particular role of customer-owned EDBs in the development and operation of such platforms is discussed in Section 7.2.

4. Growing Role of Community Ownership in Distributed Renewables

4.1 Dominance of Grid-Scale, Household and Commercial Renewables

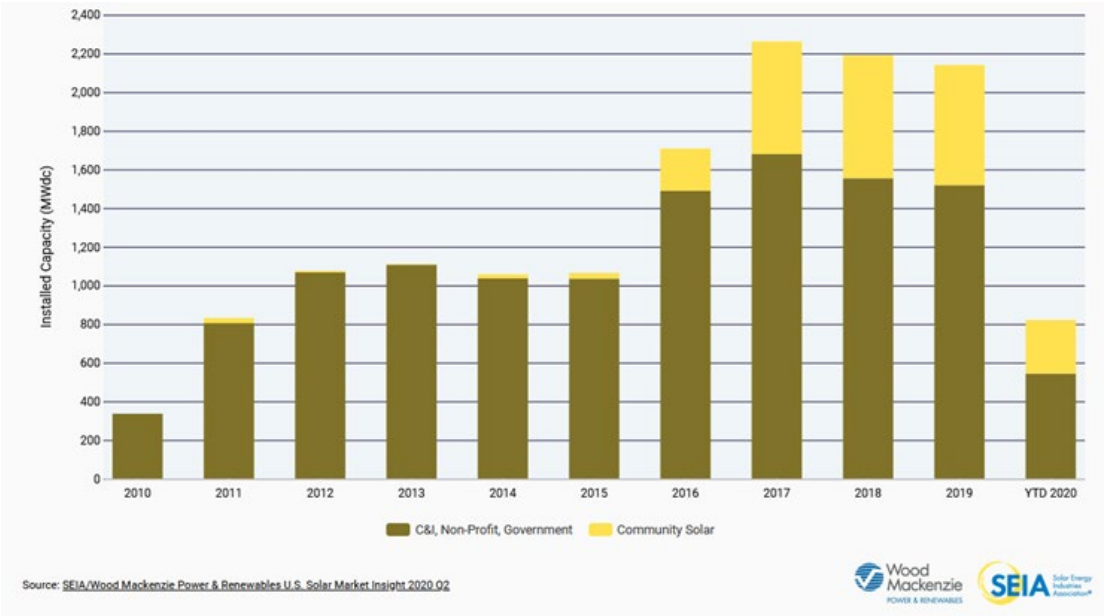
81. Much DER uptake, particularly that of rooftop PV systems, has occurred at the level of individual households, and hence predominantly through private ownership (although leasing models also arise). That said, PV uptake in the US in particular has been dominated by grid-scale or utility-owned (i.e. non-distributed) schemes, while commercial and industrial scale installations are strongly growing both in the US and other jurisdictions (e.g. Australia).

82. This section shows that community ownership of renewables is a small but significant and growing sector worldwide, focusing on the US, Europe, Australia and New Zealand.

4.2 Community Solar in the US

83. Figure 4.1 illustrates the growth of commercial and industrial solar in the US, while highlighting another strongly emerging category of PV ownership, namely community solar:

Figure 4.1 – Commercial and Industrial PV, and Community Solar, in the US



Source: Solar Energy Industries Association website.[58]

[58] https://www.seia.org/solar-industry-research-data, accessed 29 September 2020.

83.1. Community solar schemes enable multiple electricity users to club together and invest in larger-scale PV schemes, helping them to achieve scale economies as well as making storage more affordable;

83.2. Unlike purely commercial energy projects in which a private operator initiates, develops and operates a project by itself and for its own benefit, community energy involves communities developing, delivering and collectively benefitting from an energy project such as a PV installation;[59] and

83.3. They also help to overcome access issues for those who lack the resources to invest in their own installations, or are unable to do so (e.g. because they rent their home, or because their homes are unsuitable for PV installations due to shading, inappropriate roofing, heritage protections, etc).

Role of Rural Electric Cooperatives in US Community Solar Schemes

84. Rural electric cooperatives (RECs) have played an important role in the development of community solar schemes in the US:

84.1. RECs are analogous to customer-owned EDBs in New Zealand, being distribution firms developed and owned by their customers, albeit predominantly in rural areas (where investor-owned firms found it unprofitable to create the distribution networks that rural communities valued highly enough to create themselves).[60]

85. Under RECs' community solar schemes, the REC develops a PV installation scheme that their customers can participate in (e.g. via purchasing power, or leasing panels):

85.1. 227 RECs in 33 states offer such programmes (as illustrated in Figure 4.2), with a combined capacity of 140 MW;[61]

85.2. RECs can participate directly in community solar schemes, or indirectly via schemes developed by generation and transmission (G&T) cooperatives, which in turn are jointly owned by a number of RECs.[62]

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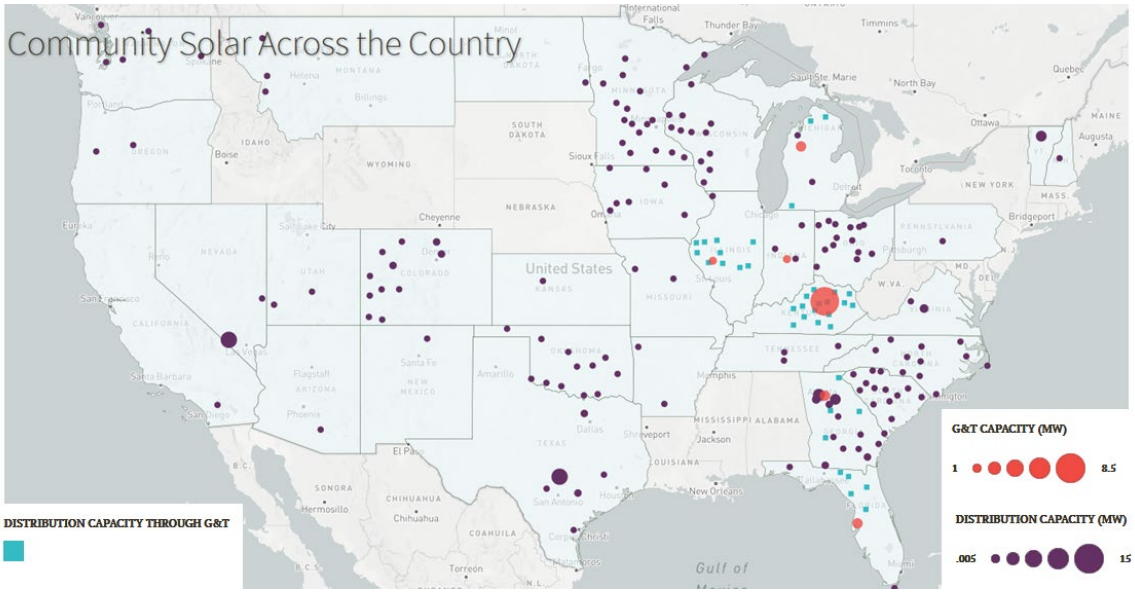
[59] Haines (2020).

[60] Meade (2005), Meade and Söderberg (2017).

[61] https://www.electric.coop/wp-content/Renewables/community-solar.html, accessed 15 October 2020.

[62] Meade (2005).

Figure 4.2 – Community Solar Schemes developed by Rural Electric Cooperatives in the US



Source: Adapted from NRECA website.[63]

Community Renewables in Hawaii – Converting Utility Ownership to Community Ownership and Transitioning to Renewables

86. The Kaua'i Island Electric Cooperative (KIUC, or Kaua'i Electric) in Hawaii, serving 33,000 customers, became a cooperative in 2002 after being bought by a group of local business people:

    86.1. Instead of illustrating how cooperatives often form in situations where investor-owned firms find it unprofitable to offer service, it illustrates the reverse process of "mutualisation", under which an investor-owned electric utility was acquired by a local community.

87. Changing the firm's focus enabled the community to transition the firm's generation from predominantly fossil fuels to renewables (biomass, hydropower and solar):

    87.1. In 2008 the firm set out to meet 50% of its overall demand using renewable energy by 2023. By 2019 it had achieved a 56% renewable generation, and the goal was revised to achieve 70% renewable by 2030.

[63] https://www.electric.coop/wp-content/Renewables/community-solar.html, accessed 21 October 2020.

4.3 Community Renewables in Europe

88. As a matter of policy, the European Commission has recognised that decarbonising the EU's highly centralised, fossil-fuel heavy electricity systems will necessarily require consumers to be active participants in generating from renewable sources like wind and PV.[64] Measures to support the development of community energy have emerged as a consequence.

Denmark's Leading Role

89. In some parts of Europe these measures were pre-empted by local initiatives that encouraged the development of renewables at community level. Denmark in particular is noteworthy for having encouraged this development long before the EU adopted policies to reduce the bloc's GHG emissions:[65]

    89.1. Denmark is credited with having developed the modern wind generation industry in the late 1970s and early 1980s, not because of state support or efforts of large-scale businesses, but due to the efforts of small groups of farmers and communities. At that time villages would commonly form 'wind guilds' to collectively develop local wind turbine schemes.

    89.2. By 2001, 150,000 Danish families were involved in over 2,100 wind co-operatives, collectively supplying 50% of all turbines and supplying 3.5% of national electricity needs.

90. In addition to having a strong tradition in both cooperative enterprise and energy activism (e.g. opposition to nuclear), Denmark has offered generous support measures encouraging distributed wind generation (e.g. tax-exempt income from wind turbines). Other relevant features include:[66]

    90.1. Cooperatives are formally prohibited from owning turbines, but limited partnerships have instead been used to replicate common ownership (illustrating how cooperative ventures can take a variety of legal forms);

[64] Gancheva et al. (2018).

[65] Hicks et al. (2014).

[66] Gancheva et al. (2018).

90.2. Utilities must finance grid expansions, not turbine owners – relieving distributed renewables investors of the costs of any required grid or network capacity expansions;

90.3. NIMBYism is mitigated by requiring developers of turbine schemes to offer 20% of shares to residents within 4.5 km of the project, resulting in many projects being jointly-owned between utilities and communities.

Germany Also Active in Local Energy Initiatives

91. Germany is also notable for playing a leading role in the EU's development of community-based renewables. It has national policy promoting both wind and solar, complemented by both policy (e.g. regional political support for finding and providing space for renewable installations) and public support for community renewables:[67]

91.1. As of 2012, c. 50% of renewables capacity was installed under community ownership, most commonly via limited partnerships between utilities and communities;

91.2. This has been assisted by growing use of virtual power plants (VPPs) and virtual storage – i.e. the aggregation and coordinated use of small-scale DERs to realise extra value from distributed renewables.

92. Other factors supporting the growth of community renewables in Germany include:[68]

92.1. Legal and other developments favouring remunicipalisation of the energy sector – through municipalities acquiring network concession contracts as they renew, resulting in over 70 new municipal power utilities;

92.2. Considerable municipal autonomy;

92.3. Energy communities can partner with local authorities to take advantage of access to preferential financing (including due to strong local authority balance sheets) – highlighting the importance of synergies with other local community organisations;

[67] Gancheva et al. (2018).

[68] Gancheva et al. (2018).

92.4. Germany's drive to retire its fleet of nuclear generation post-Fukushima; and

92.5. Established environmental and alternative energy movements.

Community Renewables in the EU Taking a Variety of Legal Forms

93. EU community energy initiatives involve a variety of legal forms, including:[69]

93.1. Partnerships – including public-private partnerships (PPPs) with local authorities;

93.2. Co-operatives (the most common form), community trusts and foundations, and non-profit customer-owned enterprises;

93.3. Limited liability companies;

93.4. Housing associations – financing community renewables via rent adjustments subject to tenants' decision-making, and addressing social issues such as fuel poverty (as in social housing estates in Denmark); and

93.5. Municipal (i.e. local authority) ownership.

94. They sometimes also take the form of:[70]

94.1. Community trusts and foundations – requiring returns to be applied for specific local or community purposes (i.e. broader community benefit rather than individual profit to members); and

94.2. Non-profit customer-owned enterprises – often being used for independent networks (e.g. micro-grids), being similar to cooperatives, but with special rules to:

94.2.1. Ensure ongoing reliable and affordable service to the community; and

94.2.2. Protect against monopoly abuse – e.g. by requiring all profits to be returned to consumers through savings on bills.

[69] Gancheva et al. (2018).

[70] Roberts et al. (2014).

95. Irrespective of the specific legal forms that local energy communities take, their emergence can be attributed to several key processes that are gaining traction across the EU:[71]

95.1. Remunicipalisation – the process of increasing municipal control over local energy management (as observed in Germany);

95.2. Devolution – the process of increasing the strategic and political role of local authorities in energy policy; and

95.3. Participative governance – the promotion of direct democracy and citizens' influence on energy and climate policies.

Particular Role of Cooperatives in EU Community Renewables

96. Customer-owned – or "cooperative" – schemes are a key feature in Europe's distributed renewables landscape. They represent groups of citizens that have organised themselves to collectively pursue renewable energy or energy efficiency initiatives.

97. While their total contribution to European electricity generation remains relatively modest, there are currently around 3,000 energy cooperatives across Europe.[72] Figure 4.3 illustrates the distribution of wind and PV cooperatives throughout Europe belonging to cooperatives network REScoop.eu:

97.1. Wind cooperatives predominate in more northern parts of Europe where wind resources are plentiful relative to sunshine resources, while solar cooperatives predominate in the more sunny southern parts of Europe.

98. While renewables cooperatives share most of the features of other forms of local energy communities, they are a unique ownership model economically and legally:[73]

98.1. Unlike traditional businesses, they are owned by their members/users on a 'one member – one vote' basis, and aim to maximise local benefits rather than return on capital; and

[71] Gancheva et al. (2018).

[72] Abada et al. (2020).

[73] Gancheva et al. (2018).

Figure 4.3 – European Energy Cooperatives

Source: REScoop.eu website.[74]

98.2. Like other forms of local energy communities, energy cooperatives contribute to a more democratic energy system and local social and economic development by, for example addressing energy poverty, or creating community employment.[75]

Community Energy in the UK

[74] https://www.rescoop.eu/community-energy-map, accessed 24 September 2020.

[75] As such, they can be considered to align with aspects of the wider energy democracy movement – see, for example, Burke and Stephens (2017).

99. As in Europe and the US, community energy initiatives make a modest overall contribution to the UK's electricity system, but have experienced strong growth. In 2019, the community energy sector in England, Wales and Northern Ireland:[76]

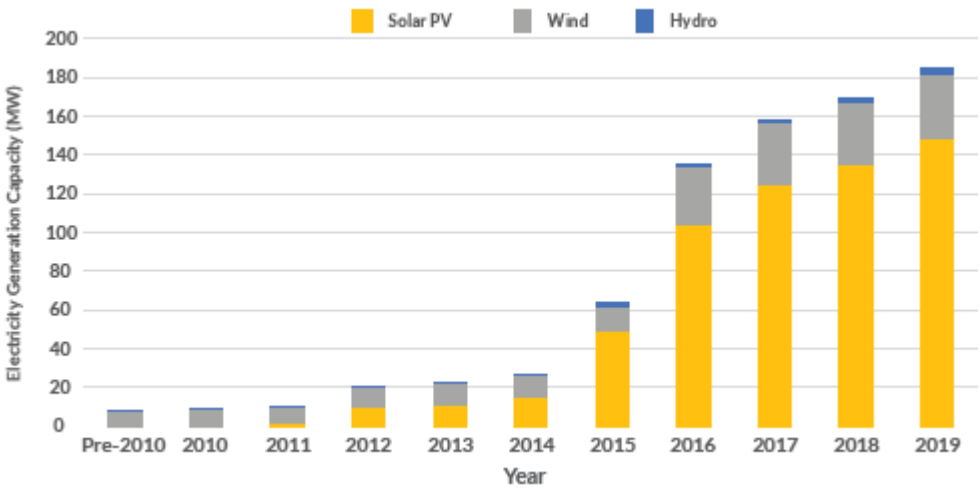
99.1. Comprised over 300 organisations, involved in generation, but also projects in low-carbon transport, energy storage and energy efficiency;

99.2. Mostly took the legal form of Community Benefit Societies (BenComs, 47%), followed by Community Interest Companies (CICs, 11%); and

99.3. Installed 15.4 MW of renewables, taking total community-owned capacity to 265 MW, and generated 222 GWh of low-carbon electricity.

100. Figure 4.4 illustrates the growth in community renewables in England, Wales and Northern Ireland, highlighting the dominance of community PV, reflecting the rapidly-improving economics of PV (and generous support measures) relative to hydro and wind.

Figure 4.4 – Growth in Community Renewables, Especially Community PV, in England, Wales and Northern Ireland



Source: Community Energy England and Community Energy Wales (2020).

4.4 Growing Community Renewables in Australia

101. Community renewables are a new but rapidly growing sector in Australia. In 2009, there were only three known community renewable projects under development. By 2014, there

[76] Community Energy England and Community Energy Wales (2020).

were over 45 communities actively involved in setting up renewables projects,[77] and in 2020 there are now over 100:[78]

101.1. Hepburn Wind, Australia's first community-owned wind farm, started producing electricity in mid-2011;

101.2. Australia's first community-owned solar project – ClearSky Solar also started operating in 2014.

102. Figure 4.5 illustrates the distribution of community energy schemes in Australia, which also include indigenous community schemes.

Figure 4.5 – Community Renewables Schemes in Australia

Source: Community Power website.[79]

[77] Hicks et al. (2014).

[78] Haines (2020).

[79] https://cpagency.org.au/resources/map/, accessed 9 October 2020.

103. The advantages of a community approach to renewable energy development are seen to lie in the potential to:[80]

103.1. Build community resilience and empowerment;

103.2. Build a strong understanding of renewable energy and a practical movement of action on climate change;

103.3. Support regional communities and foster local economic development; and

103.4. Help develop renewable energy industries, technology, jobs and training.

104. Notably, community renewables projects enable groups to act on many values and goals simultaneously, for example addressing concerns about sustainability, educating communities about renewable energy, and generating new income streams for investors and communities:

104.1. In part, some Australian community renewables schemes have arisen due to a perceived lack of federal government leadership in power planning, with communities taking the initiative to decarbonise electricity production into their own hands.[81]

105. In a related vein, wind and solar farms provide farmer-landowners with a way to "drought-proof" their incomes without requiring much of their land, with royalties able to be applied to things like education and farm improvements.[82]

4.5 Examples of Community Renewables in New Zealand

106. A discussion of how customer-owned EDBs might have a particular role to play in accelerating distributed renewables in New Zealand is deferred to Section 6. Ahead of

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[80] Hicks et al. (2014).

[81] *Renewable energy park for Central West NSW community part of 'energy democracy' movement*, https://www.abc.net.au/news/2020-05-15/regional-communities-push-for-own-renewable-energy-parks/12240298, accessed 15 October 2020.

[82] *Small town of Glen Innes to become renewable energy hub scattered with wind turbines*, https://www.abc.net.au/news/2017-10-19/record-investment-in-renewable-power-near-glen-innes/9063854, accessed 15 October 2020.

then, it is worth mentioning other examples of community renewables already emerging based on new technologies like PV:

106.1. Energy Democracy – an organisation that helps to create independent distributed renewables cooperatives, and manages their operation;[83] and

106.2. Raglan Local Energy – a matching scheme of separate, privately-owned DERs, rather than a cooperative scheme like Energy Democracy cooperatives (or a decentralised trading scheme based around peer-to peer (P2P) trading of surplus energy).[84]

107. Energy Democracy Is a management company with Australian origins that takes a fee for managing the assets and energy consumption of community solar (or wind) cooperatives that it helps to set up:

107.1. It is effectively also a community energy cooperative builder, providing templates (i.e. governance, regulatory compliance, etc) and a "platform" for enlisting communities to develop a large-scale jointly-owned PV (or wind) and storage scheme;

107.2. This enables scale economies to be achieved while providing distributed renewables access to those customers without the capital or physical ability to install their own smaller-scale combined PV (or wind) and storage system;

107.3. Generation produces income that is used to offset members' power bills, while also reducing their carbon footprint.

108. In effect, Energy Democracy achieves scale economies in cooperative creation, and DER investment and operation, by rolling out its cooperative ownership model across multiple independent schemes.[85]

109. By contrast, under the Raglan Local Energy scheme, customers who have their own PV installations can share any excess power they generate with the local community – at

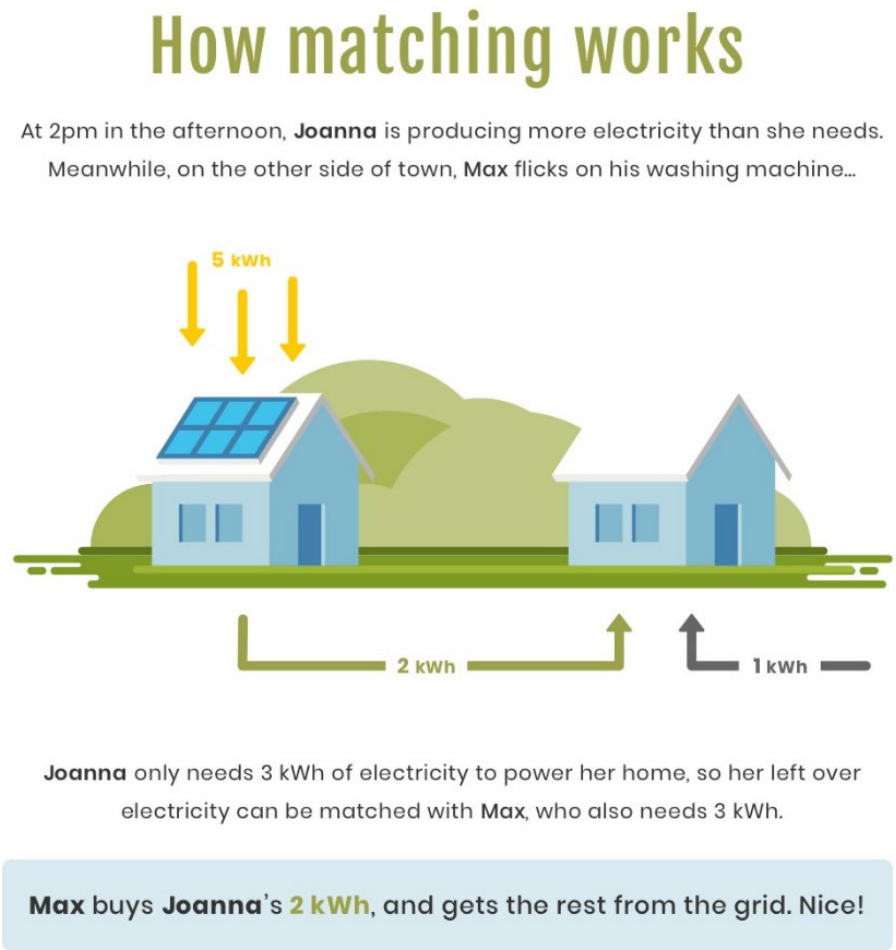
[83] https://www.ed-co-op.com.

[84] https://raglanlocalenergy.co.nz.

[85] For further details, see: https://www.ed-co-op.com/faq/.

cheaper than retail but better than wholesale rates, offering gains to buyers and sellers. Figure 4.6 illustrates how this matching works.[86]

Figure 4.6 – Raglan Local Energy Matching Scheme



Source: Raglan Local Energy website.[87]

Conclusion

110. Community-owned distributed renewable generation schemes, increasingly of PV given its rapidly improving economics, is a relatively small but growing trend in electricity systems around the world. Whichever specific form they take, they can be expected to play an important role in New Zealand's growing uptake of PV and other DERs:

    110.1. The specific role that customer-owned EDBs might play in this uptake is discussed further in Section 7.

[86] Further details available at: https://raglanlocalenergy.co.nz/price.

[87] https://raglanlocalenergy.co.nz/price, accessed 15 October 2020.

5. Customer Ownership – Rationales and Impacts

5.1 Background on Cooperative Ownership

111. Customer-owned firms such as customer-owned EDBs are a special type of "cooperative" enterprise. According to the International Co-operative Alliance (ICA):[88]

> "Cooperatives are people-centred enterprises owned, controlled and run by and for their members to realise their common economic, social, and cultural needs and aspirations."

112. Table 5.1 sets out seven core principles which the ICA regards as guiding cooperative behaviour. Based on these principles:

    112.1. Cooperatives can be regarded as being community-focused self-help organisations, providing services to communities which might not otherwise be available (e.g. due to non-cooperative providers finding it unprofitable to provide service);

    112.2. Democratic member control is an important defining characteristic – each member of the cooperative has as much "voice" in its operations as any other member, irrespective of how much or how little they use the cooperative's services;

    112.3. Likewise, member economic participation is another key characteristic – although members contribute the same (nominal) capital, they benefit from membership in proportion to their transactions with the cooperative:

        112.3.1. I.e. the more they buy from (or sell to) the cooperative, the more they participate in the benefits of cooperative membership; and

    112.4. Cooperatives are not purely profit-focused, instead seeking to deliver economic, social and cultural benefits to the communities they serve.

113. Customer-owned EDBs share in these key features:

    113.1. They often serve customers connected to uneconomic parts of the network which would not be provided by purely profit-focused suppliers;

[88] https://www.ica.coop/en/cooperatives/what-is-a-cooperative, accessed 22 October 2020.

Table 5.1 - International Co-operative Alliance Cooperative Principles

Voluntary and Open Membership	Cooperatives are voluntary organisations, open to all persons able to use their services and willing to accept the responsibilities of membership, without gender, social, racial, political or religious discrimination.
Democratic Member Control	Cooperatives are democratic organisations controlled by their members, who actively participate in setting their policies and making decisions. Men and women serving as elected representatives are accountable to the membership. In primary cooperatives members have equal voting rights (one member, one vote) and cooperatives at other levels are also organised in a democratic manner.
Member Economic Participation	Members contribute equitably to, and democratically control, the capital of their cooperative. At least part of that capital is usually the common property of the cooperative. Members usually receive limited compensation, if any, on capital subscribed as a condition of membership. Members allocate surpluses for any or all of the following purposes: developing their cooperative, possibly by setting up reserves, part of which at least would be indivisible; benefiting members in proportion to their transactions with the cooperative; and supporting other activities approved by the membership.
Autonomy and Independence	Cooperatives are autonomous, self-help organisations controlled by their members. If they enter into agreements with other organisations, including governments, or raise capital from external sources, they do so on terms that ensure democratic control by their members and maintain their cooperative autonomy.
Education, Training, and Information	Cooperatives provide education and training for their members, elected representatives, managers, and employees so they can contribute effectively to the development of their co-operatives. They inform the general public - particularly young people and opinion leaders - about the nature and benefits of co-operation.
Cooperation among Cooperatives	Cooperatives serve their members most effectively and strengthen the cooperative movement by working together through local, national, regional and international structures.
Concern for Community	Cooperatives work for the sustainable development of their communities through policies approved by their members

Source: ICA website.[89]

[89] https://www.ica.coop/en/cooperatives/cooperative-identity?_ga=2.44741410.727350221.1603321465-658592616.1601012521, accessed 22 October 2020.

113.2. Their customers each have a vote to appoint their representatives responsible for overseeing EDB governance;

113.3. Customers benefit from customer ownership via dividends, rebates, or low distribution charges, (broadly) in proportion to their electricity consumption; and

113.4. While customer-owned EDBs are often subject to formal requirements to use their resources commercially (e.g. so as to be a good inter-generational custodian of community-developed resources), they often also have explicit objectives that are more concerned with customer benefits rather than maximising profits.

114. Examples of the latter, in respect of NEG's members, are set out in Table 5.2. Notably:

114.1. Formal provisions in NEG members' governance arrangements returning dividends generated by the EDBs to their customers are distinctive, since investor-owned EDBs instead pay dividends to their investors;

114.2. Two NEG members (Northpower and Waipa) invested in ultra-fast fibre (UFB) to accelerate its uptake and hence the achievement of associated benefits to regions which might otherwise have had to wait longer for provision by investor-owned providers; and

114.3. Two other NEG members (Vector and Electra) already have formal arrangements with their customer owners to facilitate the uptake of innovative technologies that benefit their customers.

115. Customer-owned EDBs are far from being the only cooperatives in New Zealand:

115.1. The nation's first known cooperative was the Nelson building society formed in 1864,[90] with many more formed in a variety of sectors since then; and

115.2. As shown in Table 5.3, the top 30 New Zealand cooperatives ranked by 2015 revenues include some of New Zealand's largest and best-known firms.[91]

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[90] https://nz.coop/co-operatives-in-new-zealand, accessed 22 October 2020.

[91] The authors who compiled this table included Electricity Ashburton which is formally a cooperative, but excluded customer-owned EDBs that are functionally cooperatives if not legally constituted as such. See Evans and Meade (2005) for a functional definition of cooperatives that includes customer-owned EDBs.

Table 5.2 – Examples of NEG Members Pursuing Objectives Benefitting Communities

Top Energy	• Statement of Corporate Intent (SCI) objectives include minimising total delivered cost of electricity to consumers;[92] • Energy efficiency and energy poverty initiatives.
Northpower	• Owner's trust deed objects include using dividends from Northpower for the benefit of consumers[93] – c. $100m returned since 1993.[94] • Investment in ultra-fast fibre to accelerate rollout in otherwise underserved region.

Vector	• Contract with majority owner Entrust requires Vector to spend agreed sums each year on:[95]
	  ○ Undergrounding cables – for visual amenity and safety; and
	  ○ Innovative technologies such as EV chargers, PV and batteries – to increase energy or network efficiency, produce environmental benefits, improve the amenity value of the networks, etc;
	• Entrust distributes annual dividend to certain customers.

Counties Power	• SCI provides that the company seeks to provide a cost-effective electricity supply to its consumers, and endeavours to provide them with an annual discount[96] – company has passed benefits (discounts, dividends, payouts) worth $184m to consumers and its owning trust.[97]
Waipa Networks	• Owner's trust deed objects include using dividends from Waipa for the benefit of consumers;[98] • Investment (with WEL Networks) in ultra-fast fibre, to accelerate uptake.
The Lines Company	• SCI states that "our purpose is to help our community prosper and grow through the provision of reliable, safe energy."[99] • Website states "Being part of the community is at the heart of all that we do. It's more than simply being a big employer. It's about adding value, supporting growth and development and giving back to our communities."[100] • Owner's website states that retaining customer ownership means "security of supply and quality service to customers within the District …" and "benefits including locally-controlled services, jobs and discounts for beneficial customers."[101]
Electra	• Owner's trust deed objects include using dividends from Electra for the benefit of consumers;[102] • SCI states that Electra is "committed to meeting the needs of todays and tomorrows customers …" and "developing new relationships, systems, and tariffs to provide customer choices to benefit from electric vehicles, distributed energy sources or shift load to reduce household cost."[103]

[92] https://topenergy.co.nz/assets/Documents/YE-2020-Statement-of-Corporate-Intent.pdf, accessed 22 October 2020.

[93] https://northpower.com/media/documents/Trust-reports/Trust-Deed.pdf, accessed 22 October 2020.

[94] https://northpower.com/company/about-us/ownership, accessed 22 October 2020.

[95] https://www.entrustnz.co.nz/media/40001/dreor.pdf, accessed 22 October 2020.

[96] https://www.countiespowertrust.org.nz/assets/CP%20Statement%20of%20Corporate%202021-%20Final%20May%202020.pdf, accessed 22 October 2020.

[97] https://www.countiespowertrust.org.nz/about/about-the-trust/, accessed 7 October 2020.

[98] http://www.waipanetworkstrust.co.nz/wp-content/uploads/2015/10/Waipa-Networks-Trust-Deed-including-amendments-of-June-2015.pdf, accessed 22 October 2020.

[99] https://www.wesct.org.nz/wp-content/uploads/2020/08/2020-21-TLC-Statement-of-Corporate_Intent.pdf, accessed 22 October 2020.

[100] https://www.thelinescompany.co.nz/what-we-do/giving-back/, accessed 22 October 2020.

[101] https://www.wesct.org.nz/the-lines-company-to-remain-in-customer-trust-ownership-following-community-vote/, accessed 8 October 2020.

[102] http://www.electratrust.co.nz/trust-deed.aspx, accessed 22 October 2020.

[103] http://www.electratrust.co.nz/reports/statement-of-corporate-intent.aspx, accessed 22 October 2020.

Table 5.3 – Top 30 New Zealand Cooperatives by 2015 Revenues

RANK	CO-OPERATIVE	REVENUE (IN MILLIONS)
1	Fonterra Co-operative Group	18,845.0
2	Foodstuffs - North Island	6,238.8
3	Foodstuffs - South Island	2,721.3
4	Silver Fern Farms	2,434.4
5	Farmlands Co-operative Society	2,210.0
6	Alliance Group	1,501.5
7	Zespri	1,458.6
8	Ballance Agri-Nutrients	892.7
9	Southern Cross Medical Care Society	817.8
10	Ravensdown Fertiliser Co-operative	711.4
11	Mitre 10 (New Zealand)	708.6
12	Westland Co-operative Dairy Co	639.3
13	Independent Timber Merchants Co-operative	398.0
14	Market Gardeners	328.9
15	CDC Pharmaceuticals	293.1
16	Tatua Co-operative Dairy Co	285.7
18	Capricorn Society	261.4
19	Livestock Improvement Corporation	228.4
10	FMG (FMG Insurance Limited)	209.3
20	Southland Building Society (SBS Bank)	183.3
21	NZPM Group	174.8
22	Dairy Goat Cooperative (NZ)	156.7
23	Eastpack	135.2
24	Pharmacy Wholesalers (Bay of Plenty)	132.9
25	Ashburton Trading Society	119.4
26	The Co-operative Bank	110.7
27	Union Medical Benefits Society	52.7
28	Electricity Ashburton	46.8
29	Medical Assurance Society	32.7
30	Co-op Money NZ	24.7
Total Revenue		42,354.10

Source: Garnevska et al. (2017).

116. Other examples of customer-owned utilities include:[104]

116.1. US rural electric cooperatives (RECs) – active in 47 states, operating networks covering 75% of the country, owning 43% of distribution networks, and distributing c. US$600m to customers annually:

116.1.1. Electricity distribution and other energy cooperatives are also active in Finland, Italy, Spain, Chile, Argentina, Bolivia, Brazil, Costa Rica, India, the Philippines, Bangladesh and Kenya;

[104] Meade (2014).

116.2. Rural telecommunications cooperatives in the US – 260 customer-owned firms with networks over 40% of the country; and

116.3. US rural water services – featuring 3,300 customer-owned firms:

116.3.1. Water cooperatives and farmer-owned irrigation schemes also operate in Finland, Australian and New Zealand.

5.2 Rationales for Customer Ownership

117. Cooperatives have their origins in the formation of collective enterprises that developed to provide services to communities which might otherwise:[105]

117.1. Not have received service;

117.2. Receive inadequate service quality; or

117.3. Face delays in receiving service – i.e. having to wait until service becomes sufficiently profitable for investor-owned firms to provide it.

118. In other words, cooperative firms are often considered to be "providers of last resort", and as such are an important vehicle for development in socio-economically disadvantaged areas:

118.1. Indeed, RECs led the post-WWII electrification of rural areas in the US, and electricity cooperatives continue to play a leading role in electrifying less-developed countries; and

118.2. In 2010, the UN General Assembly declared 2012 to be the International Year of Cooperatives, in recognition of the contribution of cooperatives to socioeconomic development.

119. Reasons why communities might not otherwise receive timely or quality service except by way of cooperative provision include:

[105] The leading reference for understanding the economic reasons for cooperative formation remains Hansmann (1996). For a general discussion of the economic rationale for cooperative formation, and an analysis of cooperatives in New Zealand agriculture, see Evans and Meade (2005). Girotti and Meade (2017) discuss the origins of cooperative (i.e. mutual) banking in the US and elsewhere.

119.1. Those communities being too high cost, or too low-value, to be profitably served by investor-owned firms:[106]

119.1.1. A good example is electricity provision in the rural US (where customers are few and service areas large), which arose due to the efforts of RECs – other network industries such as rural telecommunications, internet and water services likewise;[107]

119.2. A group of firm patrons being unduly exposed to the risk of opportunistic behaviour *by the firm* if it was owned by investors:

119.2.1. A common example is dairy processing, since dairy farmers are exposed to the risk that an investor-owned processor might not collect and process their highly-perishable milk in a timely fashion, so they find it beneficial to collectively own their dairy processor – hence the Fonterra and Tatua dairy cooperatives in New Zealand;

119.2.2. Another example is where customers of a firm find it difficult to judge the quality of the firm's product (such as seed or fertiliser quality) – giving rise to seed and fertiliser cooperatives owned by their customers as a means of reducing the risk of being sold poor quality product;

119.2.3. Yet another example is when a firm's customers are exposed to the risk of market power abuse by investor-owned firms that are natural monopolies – yet another rationale for customer-ownership of networks such as in electricity, water and telecommunications – it is for this reason that many RECs do not face the same sort of price regulation that investor-owned electric utilities do in the US;[108] or

119.3. Firms being unduly exposed to opportunistic behaviour *by their customers*:

119.3.1. E.g. in banking and insurance markets, where customers have better information than firms about their borrowing capacity, insurability, or private actions taken to mitigate risks – hence mutual banks and insurers, and credit unions, form so that members have less incentive to deceive

[106] Meade and Söderberg (2017) set out a formal model of such cooperative development.

[107] Meade (2005), Meade (2014).

[108] Meade (2005).

the firm, and have common ties to help monitor and bond other members' conduct.

120. Another rationale for customer-owned firms in particular is to enjoy buyer power by collectively purchasing from suppliers rather than competing with each other for supply and duplicating buying efforts:

    120.1. Customer-owner hardware and supermarket chains are an example, which also benefit from collective marketing efforts.

121. Since the Global Financial Crisis (GFC), there has been increased recognition that cooperatives might be formed in declining areas/sectors where investor-owned firms can no longer afford to provide services of sufficient quality to retain customers:

    121.1. "Mutualising" those firms – i.e. taking them into customer ownership – is a means of ensuring continued service provision when the alternative is for the firms to cease operations altogether.[109]

122. In each case, cooperatives arise – relative to the next best alternative form of organisation – when:

    122.1. The benefits of cooperative ownership sufficiently outweigh the costs of collective decision-making and governance; and

    122.2. The costs of cooperative formation (e.g. identifying and coordinating with other potential owners) are not prohibitive.

5.3 Impacts of Customer Ownership

123. From the discussion above the most obvious impacts of customer ownership include:

    123.1. Customers being served in regions/industries where investor-owners find it unprofitable to offer any service at all, including in declining regions/industries;[110]

[109] See the discussion in Meade and Söderberg (2020).

[110] Meade and Söderberg (2017) present a formal model of cooperative firm entry in situations where investor-owners face unprofitable customers.

123.2. Customers enjoying earlier service than if they had to await entry by profit-focused firms;

123.3. Customers enjoying higher service quality than would be profitable for an investor-owned firm to provide:[111]

123.3.1. This might, for example, include customers being less exposed to poor product and service quality in the choice, provision and installation of DERs; and

123.4. Customers enjoying lower prices than they would if their firm (especially natural monopoly firms such as those operating costly physical networks) was owned by profit-maximising investors.

124. Other benefits include:

124.1. Customer-owned firms can be better at responding to crises – e.g. because they are more conservatively operated or financed, they can be better-placed to weather difficult circumstances or crises:[112]

124.1.1. Indeed, customer-owned firms can also be active in supporting local communities during crises – e.g. community renewables schemes in England, Wales and Northern Ireland provided support for communities affected by COVID-19;[113] and

124.2. Customer-owned firms taking into account a wider range of customer benefits than investor-owned firms.

[111] Meade (2014) provides a formal model of how customer-owned utilities can favour higher quality and lower profit than investor-owned utilities, due to customer-owners being directly affected by service quality (whereas investor owners are only directly affected by profit).

[112] For example, customer-owned banks tend to be more financially stable than their investor-owned rivals – e.g. see Iannotta et al. (2007).

[113] Community Energy England and Community Energy Wales (2020).

125. As to the latter, analyses by this author find that when customer-owned firms are assumed to seek to maximise the sum of firm profits and customer welfare (i.e. consumer surplus), they optimally choose to set output prices so low as to result in break-even profits:[114]

    125.1. That way consumer welfare is maximised while maintaining the firm's financial viability.

126. Empirical studies of the relative performance of customer- and investor-owned utilities provide mixed results:[115]

    126.1. In part this could be because customer- and investor-owned firms serve different customer groups – i.e. with customer-owned firms more likely to be serving lower-value or higher-cost customer cohorts;[116]

    126.2. However, a peer-reviewed empirical study of the relative performance of customer- and investor-owned EDBs in New Zealand finds that customer-owned EDBs have lower costs and prices, and higher quality and overall customer welfare.[117]

127. Additionally, cooperative firms have a commitment to the interests of a particular community of customers, rather than a specific business model or activity per se:

    127.1. This means that they can make better counterparties to (or joint venture partners of) other firms needing to make long-term investments to serve those customers:[118]

        127.1.1. Those other firms can have greater confidence that the cooperative firm will continue to serve those customers even when other investor-owned firms might have found it preferable to cease serving them;

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[114] E.g. see Meade (2014), or Girotti and Meade (2017). For a more sophisticated treatment allowing for endogenous firm entry decisions, see Meade and Söderberg (2017).

[115] Söderberg (2011).

[116] Meade and Söderberg (2017).

[117] Meade and Söderberg (2020).

[118] Relatedly, Seipel and Heffernan (1994) argue that cooperatives are often seen as being highly ethical and trustworthy business partners.

127.1.2. Their long-term commitment to the customers they serve makes them a more reliable counterparty in situations where commitments are required.

128. Foreshadowing the discussion in Section 7, these features of cooperative enterprise suggest that customer-owned EDBs might have a particular role to play in:

128.1. Accelerating the uptake of distributed renewables and other DERs where they offer clear customer benefits even if investor-owned firms might prefer more profitable investments;

128.2. Helping to resolve consumer issues with DERs, such as the complexities and risks of choosing appropriate DER systems and suitable installers; and

128.3. Ensuring DER uptake occurs in a way that benefits all network customers, and not just those adopting the DERs.

6. NEG Members' Experience of DERs, and Issues Anticipated over Decade to 2030 with Accelerating Uptake

6.1 Description of NEG Survey

129. The final two sections of this study discuss how customer-owned EDBs might have a particular role to play in accelerating the uptake of distributed renewables, and what this means for policy and regulation.

130. Before turning to that discussion, this section builds on the preparations laid out in the preceding sections by more closely examining NEG members' experiences with DERs to date, and their expectations of DER issues and opportunities over the decade to 2030.

131. It does so by reporting the results of a survey based around a series of structured interviews with NEG members, organised as follows:

    131.1. A high-level stock-take of DER uptake in each NEG member's network;

    131.2. A discussion of the issues and drivers associated with that uptake; and

    131.3. A scan of the issues and opportunities each firm anticipates with DER uptake over the decade to 2030, based around commercial, regulatory, technical and organisational themes.

132. The NEG members' responses to each area covered by the survey are summarised below:

    132.1. Details are summarised in tables for ease of comparison; and

    132.2. High-level themes and conclusions are drawn out in the text and in Section 6.8.

6.2 Stock-Take of DER Uptake on NEG Members' Networks

133. Table 6.1 summarises the NEG members' understanding of the level of DER penetration on their networks to date. Of note:

    133.1. Penetration rates thus far are low for all DER types, but more so for EVs and especially so for batteries compared with PV; and

    133.2. EDBs have patchy visibility even on DER installations, let alone on DER usage.

Table 6.1 – NEG Members' Understanding of DER Penetration on their Networks

	PV	*Batteries*	*EVs*	*EV Chargers*	*Other*
Top Energy	Highest PV penetration rate in NZ. 5 MW total.	No data. Installers advise batteries installed only very rarely.	420 on network.	Facilitated third-party only, because didn't wish to subsidise uptake where market arising.	
Northpower	c. 1000 installations (1% of ICPs), 4 MW capacity. Two installations (2 MW, and 10 or 17 MW) in process. 30 MW solar farm at Bream Bay on hold pending Refining NZ strategic review outcome.	Unknown. Major installer advises that in past quarter c. 25% of new installations have storage – typically half of PV capacity (e.g. 3 kW for 6 kW PV).	Not disclosed. Can be correlated with network area using NZTA registrations.	Initially seeded network with slow chargers to encourage uptake and then a fast charger. ChargeNet and Tesla now installing own fast chargers. Plugshare shows 20 public chargers on network.	60 MW windfarm proceeding to consent, requiring all capacity of new line. 5 MW hydro (Northpower) and 9 MW diesel (Trustpower) also on network.
Vector	1% of customers (440k residential, 565k total). Projecting 5% by 2030.	20% of PV installations have batteries. Vector deploying grid-scale batteries across network, in high-growth areas to learn about demand growth and to delay network upgrades until requirements better known.	c. 15k on network – mainly affluent rural areas within easy driving range of city.	Installed 28 chargers, and continues to offer free recharges, to encourage uptake, catalyse wider uptake (e.g. by Auckland Transport), and to learn about network impacts of charging.	
Counties Power	Not disclosed.	No data for residential. Installers advise c. 50% of commercial installations have batteries. Counties trialling one grid-scale battery.	Not disclosed. Can be correlated with network area using NZTA registrations.	5 x 50 kW plus 350 kW (Bombay, 4 vehicles). All but one owned by Counties.	Three major non-PV DG: • c. 2.3 MW private wind; • 7 MW landfill gas; • 3 MW gas and 1-2 MW diesel.

	PV	*Batteries*	*EVs*	*EV Chargers*	*Other*
Waipa Networks	c. 700 (1.2% of ICPs). 98% are residential, over half of which are at St Kilda housing development in Cambridge (PV installation compulsory). Two commercial installations: • 60 kW private; • 400 kW Waipa-owned on Lakewood commercial development (as trial, with output sold wholesale). 2.5 MW industrial project in process (mostly for own-use).		Unknown. Waipa converting some of own fleet to EV.	Installed 2 fast chargers with Charge Smart, and installing fast chargers at Cambridge pool and at retail development. District council looking at fast chargers at bus depot as own fleet shifts to EVs and e-buses. Set up EV chargers for branding opportunity, but also because increased network throughput enables lower average lines charges per unit.	
The Lines Company	91 registered DERS (c. 80 PV) out of c. 24k ICPs. Largest is 80 kW, but 830 kW installation proposed.	No data.	Not disclosed. NZTA data skewed by leasing.	Few chargers because large, dispersed territory and EV range anxiety. Installed own fast chargers with EECA funding.	Some private microgrids arising (PV/battery/ diesel) for remote new builds where lines more costly.
Electra	700 out of 45k ICPs. Largest is 200 kW at Otaki school.	Only few (no figures disclosed).	399 on network.	2 in each major centre, co-funded with ChargeNet to accelerate uptake.	Opted not to purchase PV installers due to their non-alignment with Electra's consumer focus.

134. Building on the NEG members' survey responses, Figure 6.1 summarises data from NZTA showing that:

134.1. Total EV uptake is very low nationally – in 2018 only 0.23% of the light vehicle fleet was fully electric, with 0.92% petrol/electric hybrid (total of just 1.15%);[119]

134.2. Most EVs are registered in Auckland; and

134.3. EV penetration rates are higher in Wellington, Otago and Canterbury.

135. Also building on the survey responses, this time using administrative data from the Electricity Authority, Figure 6.2 shows the evolution in PV penetration rates for each NEG member over 2013-2020:

135.1. The penetration rate for all EDBs nationally is a little over 1% of all ICPs;

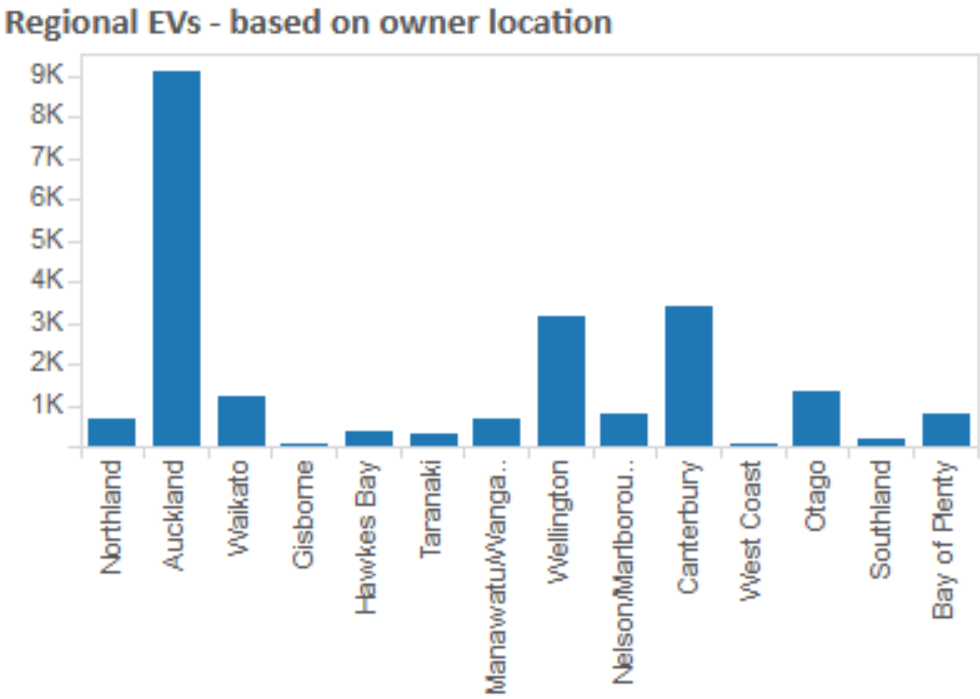
135.2. Vector and The Lines Company have lower PV penetration rates than the national average although, as for EV numbers, Auckland still accounts for the lion's share of total PV capacity; and

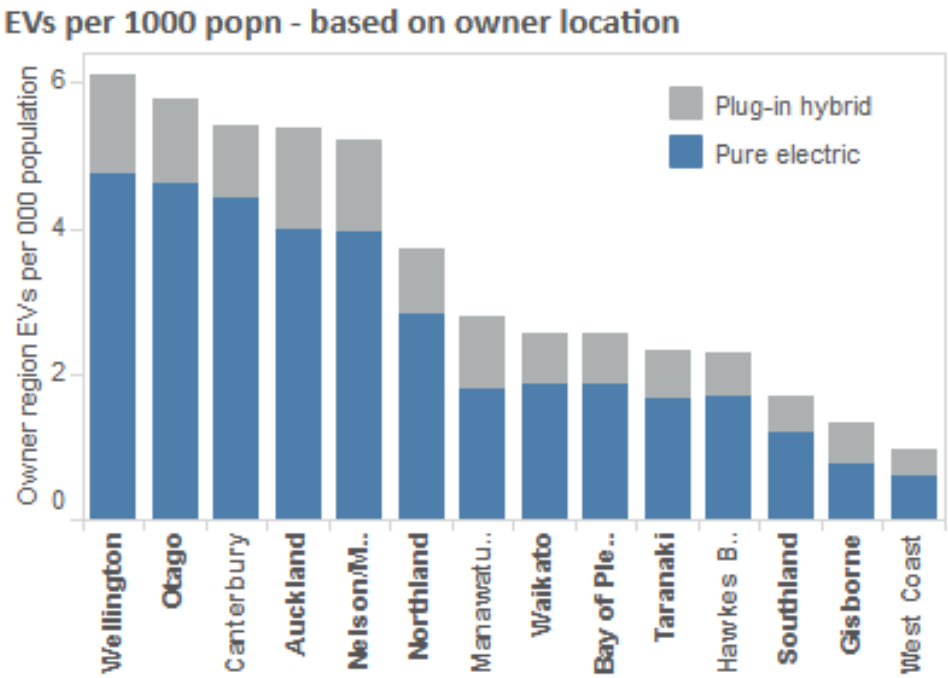
135.3. All other NEG members, especially Top Energy and Waipa, have PV penetration rates above the national average, with Top Energy having more than double the national penetration rate (at just over 3% of ICPs).

136. Finally, Figure 6.3 depicts how much grid-scale batteries have been deployed by Vector, which leads the way nationally with such deployment.

[119] https://www.transport.govt.nz/assets/Import/Uploads/Research/Documents/The-NZ-Vehicle-Fleet-Report-2018-web-v2.pdf, accessed 15 October 2020.

Figure 6.1 – Regional EV Uptake

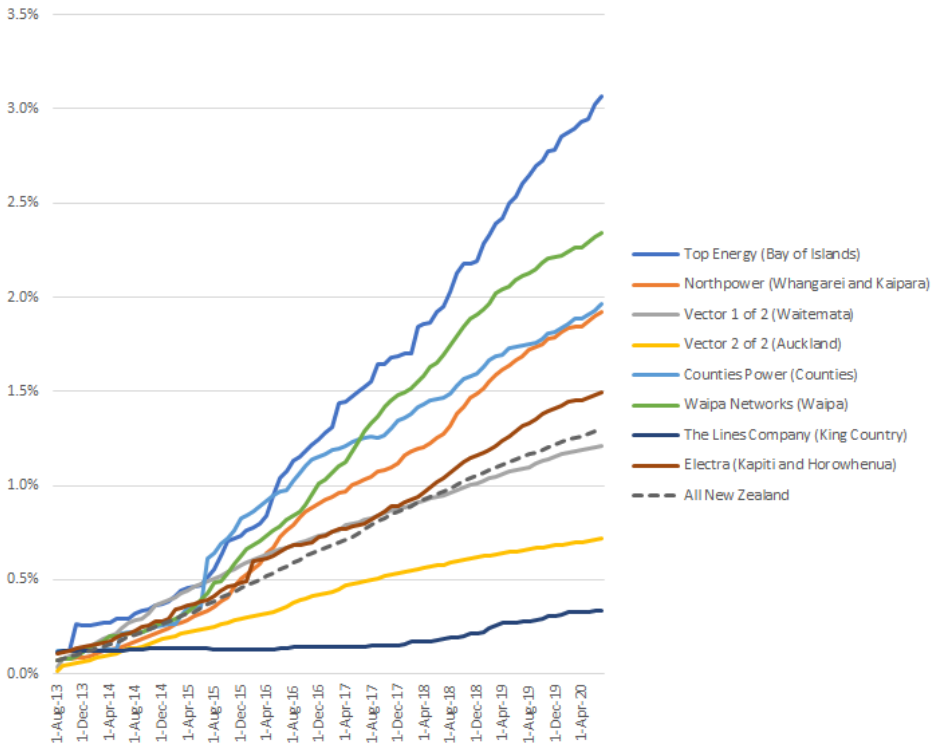




Source: NZTA website.[120]

[120] https://www.transport.govt.nz/mot-resources/vehicle-fleet-statistics/httpswww-transport-govt-nzmot-resourcesvehicle-fleet-statisticshttpswww-transport-govt-nzmot-resourcesvehicle-fleet-statisticsmonthly-electric-and-hybrid-light-vehicle-registrations/, accessed 15 October 2020.

Figure 6.2 – Evolution of PV Penetration Rates: NEG Members versus All New Zealand



Source: data from www.emi.ea.govt.nz.

Figure 6.3 – Vector's Large Batteries and Microgrids

Source: Vector.

6.3 Drivers and Issues Associated with Existing DER Uptake

137. Table 6.2 summarises the issues and drivers associated with existing DER uptake as identified by NEG members.

138. An immediately apparent issue is that EDBs have limited visibility even on DER uptake on their networks, let alone DER usage (a problem shared with Australian networks, as discussed in Section 3.1):

    138.1. While PV systems are officially required to be notified to EDBs, notification is not guaranteed (e.g. Counties Power and Waipa discovered unnotified systems through indirect means);

    138.2. While EV figures can be determined based on NZTA vehicle registrations data, this says nothing about EV through-traffic in each EDB's network area, and the NZTA data can be skewed;

    138.3. EDBs typically rely on working with third party installers to gain any visibility on residential battery uptake;

    138.4. Otherwise EDBs must resort to indirect means of detecting DERs (e.g. monitoring consumption changes) or costly means such as surveys, or direct involvement in DER provision.

139. Other themes emerging from this section of the survey include:

    139.1. Economics, demographics, consumer awareness/preferences, and climate have been key drivers of DER uptake:

        139.1.1. At network level, DERs are not yet clearly more economic than traditional network technologies, though the business case for those technologies is emerging in certain cases (e.g. re-deployable grid-scale batteries as a means of delaying network upgrades while requirements are assessed);

    139.2. Uptake is currently of a sufficiently low level that few interviewees reported network issues arising due to DERs, but they anticipate such issues arising, especially with large/lumpy commercial installations emerging, and in times of low demand (i.e. when PV generation is highest);

Table 6.2 – NEG Members' Issues and Drivers Associated with Current DER Uptake

	DER Uptake Drivers/ Constraints	*DER-Related Network Issues*	*Cost-Shifting/Waterbed Effects/Free-Riding*	*Regulatory Issues*	*Other Issues*
Top Energy	Only 2 industrials (Affco and JNL), and 150 commercials – limited commercial PV potential. Remaining 32k customers range from very affluent (likely uptakers) to very deprived (energy poor). Many ICPs are holiday homes for which DERs uneconomic (though microgrids viable if network connection costlier). Only 140 ICPs suitable for microgrids.	5 MW PV represents 23% of summer peak (versus less than 7% of winter peak), so has potential to cause intermittency issues when demand low. Current DER owners match capacity to own demand, so they are unlikely to cause network issues until they replace their systems in c. 10 years' time with systems capable of greater exports.	Affluent PV adopters able to enjoy advantages of regulated tariffs (e.g. LFCT) while shifting costs to energy poor customers – tariff redesign will attempt to redress.		Grid-scale batteries not yet competitive with diesel generators, since cost c. twice as much and cannot be run for 8 hours (typical planned outage duration) like generators.
Northpower	Good sunshine potential. Whangarei has affluent customers at edges with less affluent customers in centre – uptake occurring at end of feeders. Most customers cannot afford DERs. Ripple control must be removed when installing PV, increasing winter charges and reducing PV savings. Microgrids not yet cheaper than traditional network solutions.	Not facing reliability issues yet, but proposed commercial project (10 or 17 MW) will exhaust export capacity on relevant feeder and raise costs for other users when further growth occurs. Voltage rise occurring on rural installations with long three phase cable runs where customers export back on single phase. Ripple control must be removed when installing PV, increasing winter peak load.	DER clusters emerging in more affluent areas, reducing variable contributions towards network costs, with cost recovery falling more on less affluent customers. Proposed commercial project (10 or 17 MW) will exhaust export capacity on relevant feeder and raise costs for other users when further growth happens. Other possible large-scale installations seeking to reserve existing network capacity, enjoying first-mover advantages.		Region historically struggled to attract investment capital, but seeing growing interest in large-scale DERs. Region well served by PV and other DER installers, with single installer accounting for c. 50% of installations. Skills shortage emerging, as large-scale PV connections require significant internal resources for technical advice and network design/upgrade works.

	DER Uptake Drivers/ Constraints	*DER-Related Network Issues*	*Cost-Shifting/Waterbed Effects/Free-Riding*	*Regulatory Issues*	*Other Issues*
Vector	Key drivers are falling DER costs (though battery costs still an obstacle) and rising environmental awareness. Vector has strategy for DERs but uptake has been much slower than expected – could suddenly take off due to policy change, DER cost declines, improved consumer awareness. Auckland's relatively high proportion of rental properties is an uptake barrier.	Currently DERs are largely dispersed, raising few network issues, but also limiting network services they might provide. EV chargers more critical than EV numbers, as chargers can cause network issues by significantly increasing peak demand (hence Vector installs chargers where there is currently spare network capacity).			Demand response enablers that would improve DER economics (e.g. P2P, aggregation) yet to mature/emerge.
Counties Power	Rising health and safety costs are partially offsetting falls in PV costs. Commercial PV on the rise as it is inherently more economic than residential – feeder constraints and wholesale electricity prices are key considerations.	Networks not designed for bidirectional flows (i.e. DG exports), and too expensive to retrofit capacity. Wind turbine already constraining feeder, limiting further exports from other DG, and raising costs for additional exporters. Major network upgrades required to accommodate-date EV charging. EV chargers also increase network throughput and enable lower average lines charges per unit.	Existing bidirectional capacity of networks is exploited as open access resource, particularly by commercial DG installers, and by regulation they cannot be charged for this. Later installers cannot export as capacity exhausted. As DG owners reduce consumption of network-sourced energy, variable distribution costs are shifted to other (e.g. smaller) users.	EIPC constrains EDBs to charging DG only marginal distribution cost, which is nil while there is existing network capacity to accommodate it. Costs of network upgrades borne by other users, and early exploiters of existing network capacity cannot be charged for external costs imposed on others. Expect regulatory pushback if attempt to mandate storage with new PV installations.	Skills gap, as body of engineering knowledge accumulated over decades is for uni-directional networks. PV not expected to provide network services because: • Peak PV generation does not coincide with peak network demand; and • PV must shut off for safety reasons during network outages. Wealthier PV adopters likely to increase peak demand.

	DER Uptake Drivers/ Constraints	*DER-Related Network Issues*	*Cost-Shifting/Waterbed Effects/Free-Riding*	*Regulatory Issues*	*Other Issues*
Waipa	Waipa's owners exploring how the EDB can influence better consumer outcomes, including via DERs. Undertook HEMS trials revealing four motivations re DER uptake – energy independence, environmental concerns, engaging with technology, and indifference.	Not yet experiencing network issues. Commercial PV installation detected by chance, and had uncertified equipment requiring urgent remediation.		Lakewood commercial PV development required costly and time-consuming (18 month) regulatory approvals due to embedding network on own network.	
The Lines Company	DER uptake issues: • Short-life homes; • 20% of ICPs are holiday homes, and 60% of customers in high deprivation; • Few major centres; • Overcast winters when demand is highest; and • Covid limiting demand for commercial PV from tourist operators.	PV installations dispersed, so network issues not yet arising. Proposed 830 kW project could suddenly change this.			
Electra	Good sunshine, plus many retired people at home during day (so storage less critical for PV viability). Kapiti is easy EV range for Wellington commutes, but Levin is not. Low lines charges deter (induce) PV (EV) uptake.	Fast chargers resolve range anxiety for EV users, but Electra would prefer off-peak charging at home. EV chargers also increase network throughput and enable lower average lines charges per unit.	Customers uptaking new technologies because they can free-ride on existing network capacity, but this is shifting costs to poorer customers.		Many Kapiti customers adopt DERs for philosop-hical reasons, but most can't afford them.

139.3. Early exploitation of open access network capacity by larger/commercial installations is occurring – a form of "network capacity gold rush" – taking advantage of the fact that the EIPC restricts EDBs to charging only marginal cost to distributed generation (DG):

139.3.1. Absent other solutions, this requires prohibitions on further DERs on affected parts of the network and/or that further exports are curtailed (diminishing economics of later/smaller installations), and means costs of network expansions fall on others as demand grows;

139.4. Many interviewees emphasised that DER uptake is occurring among more affluent customers, and could result in significant equity issues as network costs fall increasingly on less-affluent customers, even though DER uptake could lead to increased peak demands and offer few countervailing network service benefits;

139.5. Some EDBs are facing skills gaps/shortages as they increasingly deal with:

139.5.1. Bi-directional network flows;

139.5.2. Network/behind-the-meter demarcation issues when DERs fail or cease to operate for technical reasons; and

139.5.3. Proposals for large-scale PV projects requiring in-depth and specialist assessment; and

139.6. The EDBs interviewed have to varying degrees been active in trialling/exploring the impacts of DERs on their networks, and the opportunities they might offer their consumers in terms of ether reduced lines charges or expanded access to energy services.

6.4 Anticipated Commercial Issues

140. Turning to DER issues and opportunities that NEG members anticipate over the decade to 2030, Table 6.3 summarises their responses in relation to commercial issues and opportunities:

140.1. Their responses in relation to regulatory, technical and organisational issues and opportunities are separately summarised in subsequent tables.

Table 6.3 – Issues and Opportunities Anticipated by NEG Members over Decade to 2030 – Commercial

	PV	*EVs*	*Batteries*	*Other*
Top Energy	Grid-scale solar could be viable alternative to new geothermal generation at Ngāwhā, enhancing Top's strategy of using generation profits to offset lines charges to customers.	Rapid uptake of EVs could cause peak demands for which grid-scale batteries might be an economic solution to manage peaks, but this is probably more than 10 years away given recent network upgrades.	Grid-scale batteries could become economic solution for managing network issues from large-scale PV, or to manage peaks in dry years, but recent network upgrades defer need for such solutions.	Opposed to cross-subsidising DERs from lines business, since business model is to instead use profits from large-scale generation to offset lines charges to customers.
Northpower	Expect PV clusters to appear in growth areas where they add little to new builds and reduce operating expenses, with network upgrade costs socialised to all customers. Expect tariffs to become more fixed for import, and include export charges, to address waterbed effects. Community solar a challenge due to customer demographics (i.e. lack of funds).			Viability of microgrids for EDB being deferred through planning rules that encourage consolidated growth (versus low-density long skinny lines). Remote new customers will find microgrids cheaper than new connections.
Vector				See need for digital platforms to accommodate anticipated DER growth.
Counties Power	Anticipate commercial uptake to accelerate with falling equipment prices – e.g. leasing large roofs for installations.	EVs will increase lines revenues, but only beneficial to EDB if charging off-peak (which can be managed through peak charges).	Grid-scale batteries likely to be cheaper than new substations or substation upgrades within 10 years.	Community solar might be used to address waterbed effects and enhance retail competition, but Part 3 exemptions required.

	PV	*EVs*	*Batteries*	*Other*
Waipa Networks	Commercial PV represents an important business opportunity, with EDB as either a facilitator/enabler or JV partner.			
The Lines Company	Commercial PV is likely to be strong growth area, given scale economies and ability to self-consume during daytime.			Foresee microgrids as economic replacement for uneconomic lines at end of life, for inclusion in RAB given service obligation to existing customers. "Base Power" style units will increasingly be deployed to manage constraints and outages.
Electra	Falling costs will drive uptake, but trying to charge for true costs of PV in order to relieve waterbed effects could result in "death spiral" (i.e. accelerate uptake and worsen waterbed effects).	EVs are a major opportunity to increase network throughput and lower average supply costs. Could offer storage benefits, but risky to develop own system.	Grid-scale batteries likely to be cheaper than new or enhanced feeders within 10 years. Improved communications will enable better network usage and delay need for upgrades.	Acquiring existing installers as entry into DER provision exposes EDB to risk of product and installation (e.g. weathertightness) liabilities.

141. Key themes emerging from these responses are that, over the decade to 2030:

141.1. DERs – particularly grid-scale batteries and microgrids – will become cheaper than replacing or extending/upgrading existing network technologies in an increasing range of applications:

141.1.1. Customer-owned EDBs seeking to provide their customers with quality, low-cost electricity supply face incentives to increasingly substitute DERs for traditional network assets, particularly for end-of-life network assets where they face ongoing service/reliability obligations to existing customers;

141.1.2. The composition of regulatory asset bases should change accordingly, without implying cross-subsidises towards DERs, particularly where DERs are used to replace network assets that are already uneconomic and hence have historically been cross-subsidised (indeed, if DERs are cheaper then any cross-subsidies would be less);

141.2. Commercial PV is likely to be strong growth area given superior and improving economics of large-scale installations where output can be self-consumed during the day:

141.2.1. Conversely, residential DER uptake – especially PV and EVs – will continue to be dominated by more affluent customers;

141.2.2. Such uptake is not necessarily going to provide network services – analysis by Waipa of the St Kilda subdivision shows PV adopters enjoy lower average lines charges, but still had higher peak demands;

141.3. In either case, free-riding on existing network capacity will continue to be an issue:

141.3.1. Respondents are concerned about the associated equity, cross-subsidisation and access issues, but also acknowledge commercial PV opportunities

141.4. Tariff reform will become important for managing peak demands and addressing free-riding and cross-subsidisation issues:

141.4.1. However, pricing the true costs of DERs to relieve capacity free-riding and waterbed effects risks causing a backlash from existing or prospective DER owners;

141.4.2. In any case, retailers are likely to respond to rising DER penetration by rebalancing energy prices to be lower during the day (when PV is generating) and higher at other times, increasing costs for lower-income customers who are not at home during the day;

141.5. Respondents, as firms with strong obligations to serve the interests of their customers, are concerned about the equity, cross-subsidisation and access issues expected to emerge with rising DER penetration.

141.6. Fully realising the benefits of increasing DER penetration, and mitigating their harms, will require the development of solutions such as P2P trading, DER aggregation, DER network support services and community DER models:

141.6.1. Most respondents see it as uneconomic or unduly risky to attempt to develop those solutions for themselves, and hence see a case for either collaborative developments (to achieve scale, and share risks and resources) or awaiting "off the shelf" solutions to be developed elsewhere;

141.6.2. Vector, by contrast, sees itself as playing a leadership role in the development of such solutions (e.g. its joint venture with Amazon Web Services to develop a DER digital platform), given its resources and scale, and also because of its commitment to securing customer benefits from new technologies.

6.5 Anticipated Regulatory Issues

142. Table 6.4 summarises NEG members' responses in relation to DER-related regulatory issues and opportunities they anticipate over the decade to 2030.

143. Key themes emerging include:

143.1. EDBs in general will need better visibility on DERs – both their installation and real-time use – for safety as well as network management reasons;

Table 6.4 – Issues and Opportunities Anticipated by NEG Members over Decade to 2030 – Regulatory

	Pricing	*Network Management*	*DER Solutions*	*Safety*	*Other*
Top Energy	Regulation requiring DG to be charged marginal cost (i.e. nil before network constraints arise) need to be relaxed because it amplifies energy poverty for renters and low-income customers. Regulation is not an obstacle to introducing pricing or other (e.g. curtailment) solutions to manage DER intermittency.	Inadequate standards for DERs mean poor-quality installations could exacerbate intermittency issues.	Costly and time-consuming (12-24 month) Part 3 exemptions required for investment in DERs as alternatives to lines, biasing EDB investments towards: • Existing technologies, even if more costly, in order to meet reliability obligations in a timely way; and • Microgrids (where market impacts don't arise) – opportunities are limited.		Ring-fencing requirements limit ability to optimise across generation and lines, despite possible benefits to customers. Being able to offer generation – as price-taker – to independent retailers should enhance retail competition. Top unable to retail at all due to condition in previous Part 3 generation exemption
Northpower	LFCT and charging DG only marginal cost need to change, and also need export charges, to mitigate capacity gold rushes and waterbed effects. Wary of consumer backlash, which will also arise if later DER adopters charged for capacity expansions or prohibited from exporting if early adopters exhaust existing capacity.		Need Part 3 rules to provide more nuanced general exemptions, vs costly and slow specific exemptions. Networks also need better access to metering information to monitor DER impacts, and hence standards and/or other regulatory arrangements to enable this. Need early standards to avoid stranding non-compliant investments.	Need industry-wide coordination on safety standards (otherwise safety issues can fall between cracks).	Need regulatory acknowledgement of waterbed effects, and need for EDBs to introduce solutions. Fully fixed lines charges likely to be necessary but will take a long time to introduce due to inertia created by existing pricing models.

	Pricing	*Network Management*	*DER Solutions*	*Safety*	*Other*
Vector	Need a shift away from fixed/variable charges towards peak pricing, though price changes alone may be insufficient to change behaviours. LFCT is regressive due to impeding capacity-based pricing.		Regulation rewards investment in traditional network assets, but digital platforms for DERs might bring greater consumer benefits at lower cost. Vector can only implement P2P and other DER-related services via its unregulated businesses.		
Counties Power				Lack of visibility on batteries, and risk of non-compliant inverter systems (e.g. lacking safety shutdowns) create risks for lines crews.	Being able to offer generation, as price-taker, to independent retailers should enhance retail competition.
Waipa Networks	LFCT and incomplete smart meter rollout are impeding necessary tariff changes.		PV adopters enjoy lower average TOU charges, yet still have higher peak demands, and therefore need greater network capacity which should be appropriately priced. EA's processes for regulatory exemptions and rule changes are delaying customer benefits due to taking too long. More streamlined processes are required.		

	Pricing	*Network Management*	*DER Solutions*	*Safety*	*Other*
The Lines Company	Solutions for rationing network capacity will be needed, but not urgently given slow uptake.				
Electra	LFCT is a barrier to required pricing changes to manage DER issues, but wary of consumer backlash if changed. Regulation requiring DG to be charged marginal cost (i.e. nil before network constraints arise) needs to be relaxed. Not being subject to price-quality regulation gives Electra greater flexibility to introduce pricing solutions to DER issues.		See need for nuancing of Part 3 rules and better interface between Part 3 and Part 4 rules (as DERs make lines services more competitive). Need early standards to avoid non-compliant investment stranding.	Sees need for industry-wide standard designs to ensure network compliant DERs, and improved customer communication re managing safety risks during outages, and specifying safe technologies.	Regulation requiring DG to be charged marginal cost also highlights other problems with existing models for charging customers for incremental capacity when other/later customers will also benefit from the new capacity.

143.2. Relatedly, some respondents pointed to the need for better access to smart meter data, and more extensive smart meter rollout, to monitor DERs and manage their impacts;

143.3. More comprehensive and fit-for-purpose standards for DERs would make it easier to accommodate DERs into networks in ways that increase their benefits and reduce their harms;

143.4. Part 3 rules limiting EDB involvement in competitive activities were intended to avoid competitive harms, but were designed long before the costs and benefits of DERs were an issue, and need updating to recognise how better integrating them with networks might in fact address competition concerns while also providing significant other customer benefits:

143.4.1. Many respondents pointed to the process of obtaining exemptions from the Electricity Authority being ad hoc, costly and time-consuming, potentially delaying consumer benefits by years (including by forcing EDBs to meet reliability obligations by replacing failed lines rather than adopting DERs even when cheaper);

143.4.2. They further pointed to the need for more nuanced Part 3 rules and streamlined exemptions, recognising that customer-owned EDBs should be less likely to pose consumer harms given their customer-ownership and consumer focus;

143.5. Many respondents pointed to the need for the LFCT and rules for charging DG only marginal cost to be reconsidered, since they are impeding a shift to more "cost-reflective" tariffs, and encouraging a "network capacity gold rush":

143.5.1. They pointed to the need for new tariff models (e.g. fixed only for import, and marginal export prices) in order to mitigate network capacity gold rushes and free-riding, and waterbed effects – which is necessary to minimise inequities from DER uptake;

143.5.2. However, they are wary of consumer and regulatory backlashes should they attempt to implement such models.

6.6 Anticipated Technical Issues

144. Table 6.5 summarises NEG members' responses in relation to DER-related technical issues and opportunities they anticipate over the decade to 2030.

145. Key themes emerging include:

    145.1. Respondents anticipate increasing network issues as DER uptake gathers pace, especially if DERs are clustered and/or large-scale (e.g. commercial PV), and particularly for EVs.

    145.2. Grid-scale storage could be an important way to delay or manage these issues, although the economics of this varies by network:

        145.2.1. The Western Power model of synergies between networks and residential PV offers a possible model;[121]

    145.3. Vector in particular sees the potential for grid-scale batteries to ease the transition to greater DER uptake and is actively deploying them, and also for platform-based solutions for integrating and managing DERs (e.g. via its tie-up with Amazon Web Services for the development of their New Energy Platform).[122]

    145.4. Pricing and other solutions (e.g. curtailment, and P2P or other platform models) are also anticipated as ways to delay or mitigate DER network issues by providing mechanisms and incentives for mitigating peak demands and addressing other network issues;

    145.5. Inadequate standards and DER visibility (e.g. via smart meters) give rise to possible safety and other network management issues, although they might be managed through changes in training and work practices (e.g. lines crews treating all lines as always being live, better communication with DER owners as to requirements/obligations during outages, etc).

[121] https://westernpower.com.au/community/news-opinion/community-batteries-mutual-attraction/, accessed 29 September 2020.

[122] https://www.vector.co.nz/special-pages/special-pages-nep, accessed 8 October 2020.

Table 6.5 – Issues and Opportunities Anticipated by NEG Members over Decade to 2030 – Technical

	PV	*EVs*	*Batteries*	*Other*
Top Energy	Four 20+ MW commercial PV arrays under application may give rise to network issues. Curtailing further DER output during network events may be less costly than network enhancements. Significant exports unlikely until better returns available (e.g. through P2P trading).			Larger-scale DER installations (e.g. commercial PV) are easier to monitor, and to manage intermittency issues, than dispersed smaller DERs.
Northpower	Anticipating increased network issues – especially during day when demand is low – due to: • Increasing commercial uptake; and • Greater residential uptake due to creative offerings (e.g. pay as you go, fixed price).			Need better DER standards and consumer communication to manage DER safety issues (e.g. during outages).
Vector	Projecting 5% PV penetration by 2030, which will cause network issues if clustered. Anticipate possible use of substations as hubs for supplying local communities using PV (e.g. in conjunction with grid-scale batteries).	Projecting 90-100k EVs by 2030, and even slight clustering of fast chargers will overload feeders. Peak-pricing and other solutions (e.g. smart chargers) required to shift charging to off-peak, and to avoid network upgrade costs that will be partly borne by non-uptakers. Potential for EVs to provide storage services, e.g. via platforms (cf Vector/AWS NEP).	Grid-scale batteries at the outskirts of networks where growth is occurring are an invaluable tool for reducing peak demands while identifying where network expansions will be required. They are also useful for providing resilience to isolated communities, and complementing PV. They can potentially be used as community VPPs to help mitigate waterbed effects.	Inadequate DER standards and variable installation types give rise to safety issues, but these can be accommodated through changes in training and work practices, greater use of monitoring and prediction technologies (e.g. cameras and AI), and customer communication (e.g. regarding outages).

	PV	*EVs*	*Batteries*	*Other*
Counties Power	Anticipate rapid uptake (cf smartphones), with EDBs needing to block installations to manage power flow issues absent more sophisticated solutions. Constraints on PV installation size likely to mean consumers remain on-network.	Anticipate network issues with wealthier customers possibly buying 2-3 EVs each.	Batteries – especially grid-scale – could help to resolve the lack of inertia in PV and wind,[123] as well as mitigate intermittency.	Microgrids are unlikely to become widely viable due to winter-peaking demand.
The Lines Company				Microgrids are unlikely to become widely viable due to winter-peaking demand.
Waipa	PV clusters could result in power quality issues requiring curtailment or other solutions. Negotiated shift timing at industrial plant with large proposed PV output so as to not affect network peaks.			Managing safety risks and DER incompatibility issues by maintaining good relationships with customers and installers.
Electra		Customers likely to want more fast chargers than network can accommodate, so network upgrades are needed unless pricing or other solutions (e.g. fast charger locations) can manage peak demands.	Like Waipa, Electra faces a residential subdivision that mandates PV on each home (without storage). Grid-scale batteries might be used to mitigate network issues, but not yet economic.	EDBs have ability to impose requirements/restrictions on DER system features despite lack of standards and variable installation types, but risk being seen as "bad guy" if they do so.

[123] I.e. PV and wind are "non-synchronous inverter-connected" generation, with active control mechanisms that shut them down automatically (within seconds) when they experience disturbances of sufficient severity or rapidity (as was responsible for South Australia's blackout in September 2016). This is unlike conventional generation, which may prove inadequate to ride out future disturbances with rising renewables penetration.

6.7 Anticipated Organisational Issues

146. Finally, Table 6.6 summarises NEG members' responses in relation to DER-related organisational issues and opportunities they anticipate over the decade to 2030.

147. Key themes emerging include:

    147.1. Many interviewees saw themselves as having a specific role to play in encouraging the uptake of new technologies, particularly where "market" provision (i.e. by investor-owned firms) was perceived to be slow (or non-existent), denying customers and their communities timely access to the benefits of those new technologies, e.g.:

        147.1.1. Rolling out fast-chargers (in Vector's case, with free recharges) to pave the way for subsequent charging infrastructure provision by third-parties, as well as to gauge the network impacts of EV uptake;

        147.1.2. Trialling PV and/or battery installations;

        147.1.3. Trialling grid-scale batteries, as a means of delaying network expansions, but also to assess how they affect other DER uptake;

        147.1.4. In Northpower and Waipa's cases, investing in UFB;

        147.1.5. In Vector's case, purchasing PowerSmart and E-Co Products Group (HRV) in 2017 to be active in DER rollout at both commercial and residential scales, and joint venturing with Amazon Web Services to develop digital platforms for enhancing DER benefits (while also managing associated DER issues, in a way that avoids blunt solutions such as curtailment);

        147.1.6. In TLC's case, owning GoodMeasure which is active in developing commercial/industrial internet-of-things solutions.

    147.2. All interviewees emphasised their focus on delivering customer value (e.g. low-cost access to electricity, reliability, energy efficiency) as opposed to maximising financial returns (e.g. dividends), but that any investments they made still had to stack up commercially:

Table 6.6 – Issues and Opportunities Anticipated by NEG Members over Decade to 2030 – Organisational

	Objectives	*Equity Concerns*	*PV/Batteries*	*EVs/EV Chargers*	*Other*
Top Energy	Seeks to minimise the delivered cost of electricity to its customers, and uses profits from electricity generation (Ngāwhā) to reduce lines charges.	Actively promotes energy efficiency solutions (Healthy Homes initiative). Participating in ERANZ's Energy Mate energy poverty initiative.	Sees a role for itself in advising customers as to DER and installer choices. Prefers to stay on network side of meter because there is existing market supply of PV and batteries behind the meter.	Resisted cross-subsidising charger uptake from lines business, instead facilitating market provision by others (e.g. identifying suitable sites).	Resisted cross-subsidising UFB uptake from lines business, since wants to subsidise lines from other activities (i.e. using generation profits to increase customer dividends and discounts). Inadequate standards and variable installation types mean line crews face complex demarcation issues and skills gaps when faults arise.
Northpower	Focus is on delivering energy at low cost, however that might be achieved. Considering how to rigorously make trade-offs between financial and non-financial customer benefits.				Early UFB investment was to secure early regional benefits in an area typically under-served by private operators. Later UFB investment had stricter return criteria but still accounted for wider regional benefits.

	Objectives	*Equity Concerns*	*PV/Batteries*	*EVs/EV Chargers*	*Other*
Vector	Seeks commercial returns while also generating wider customer benefits. Sees customer focus as being compatible with earning commercial returns, and customers have greater say in company than if it were purely investor-owned. Anticipates investor-owned firms will become more like customer-owned firms (multiple bottom line focus).	Sees leading DER change as being important for managing waterbed effects (and death spirals). Vector's owner is concerned with equity/fairness and affordability.	Sees the development of DER-enhancing platforms as important even if that means customers receive services from third parties rather than from the network.	Took a lead in charger rollout to accelerate uptake, but also to avoid disruptions and cost duplication of competing infrastructures (cf early experience with fibre – multiple trenching, etc).	Vector self-optimises redundant network even though not required to do so, and despite that reducing its RAB and hence financial returns. Skills gaps can be mitigated through greater use of monitoring and prediction technologies (e.g. cameras and AI).
Counties Power	Seek to make savings for customers, including via dividends, discounts and distributions.				
Waipa	Focus is on low tariffs with good service. Considering how to trade-off financial and non-financial customer benefits while generating cash flow required for network maintenance. Prefers peak-absorbing DERs to peak-enhancing DERs, even though latter adds to RAB and hence financial returns.	Community solar might be used to address waterbed effects.	Sees role for itself as trusted consumer adviser re DER and installer choices.		UFB investment was to accelerate regional benefits while earning a commercial return.

	Objectives	*Equity Concerns*	*PV/Batteries*	*EVs/EV Chargers*	*Other*
The Lines Company	Responsibility is to help customers access energy, not to maximise financial returns. All EDBs face same commercial imperatives if DERs included in RAB, but customer-owned EDBs more likely to consider DERs that improve reliability (greater focus on quality).	Community solar might be used to address waterbed effects – had early discussions with local marae having suitable land and opportunity to trade/offset energy with hapū.			
Electra	Focus is on low-cost supply to customers. Investments must be commercially viable, but also considers local economy impacts (e.g. job creation, decarbonisation of transport) and customer impacts (e.g. VOLL during outages, reliability benefits of batteries).	Engaged EV owners in design of tariffs to encourage off-peak charging, deferring network upgrades and mitigating waterbed effects.	Due to inadequate DER standards and variable installation types, sees role for itself as trusted consumer adviser re DER and installer choices. Signalling future lines pricing to support DER investment decisions.	Engaged EV owners in design of tariffs to encourage off-peak charging.	

147.2.1. While they took wider customer/community benefits into account (of the sort that non-customer owned firms would be unlikely to account for), this was generally subject to making a commercial rate of return;

147.2.2. In part this was because they see themselves as stewards of inter-generational community assets;

147.2.3. Some EDBs are also grappling with how they can robustly/efficiently make trade-offs between financial and non-financial customer benefits where this achieves better customer outcomes (e.g. sacrificing network returns in order to achieve greater energy independence).

147.3. Many interviewees also saw a role for themselves in acting as trusted and independent/impartial advisers to consumers as to what sorts of DERs and installers might best suit their situation/needs:

147.3.1. Simultaneously helping to avoid installations that cause network issues while reducing the risk of consumers being sold DER solutions of poor quality or fitness for purpose;

147.4. Some interviewees also clearly took an inter-generational perspective on using their resources, reflecting the fact that those resources were provided by past generations, and needed to be used for the benefit of future as well as current generations:

147.4.1. They contrasted this with investor-owned firms, who face incentives to tailor their asset lives with the cash flow profile required by their investors, which may not coincide with the preferred profile of their customers (who might, for example, prefer a sooner transition to DERs, even if this means shorter lives for existing network assets).

147.5. Many stressed that their explicit customer focus required them to be mindful of equity issues in ways profit-focused organisations might not be:

147.5.1. For some respondents, community solar projects – e.g. in concert with others like Energy Democracy, Housing New Zealand or iwi – could be one means of mitigating free-riding and waterbed effects (i.e. by helping customers unable to invest in their own DERs to still be able to participate through collective schemes).

6.8 Conclusions

148. Some overall conclusions to draw from this survey of NEG members are:

148.1. DER uptake on their networks is low currently, but with improving DER economics it is anticipated to grow – possibly suddenly and strongly (and possibly very lumpily, with growing commercial interest in DERs):

148.1.1. Increasingly it will be more cost-effective for EDBs to replace end-of-life and other network assets with DERs instead of conventional technologies, although this is complicated by legacy regulatory obstacles;

148.2. Despite currently low DER penetration, network issues are arising already, albeit rarely, highlighting the impact of regulation in an emerging "network capacity gold rush", impeding the transition to more "cost-reflective" network pricing:

148.2.1. This is predominantly driven by commercial and affluent residential DER adopters;

148.2.2. Better standards, as well as EDB visibility on DERs and access to smart meter data, will be important elements of ensuring smooth DER integration into networks;

148.2.3. Maximising the benefits of DER uptake will further require solutions like P2P trading, DER aggregation, DER network support services, and community DER models, with most NEG members (notably, excluding Vector which enjoys scale advantages in developing solutions) seeing a need for either collaborative developments or off-the-shelf solutions;

148.3. NEG members regularly expressed concern at likely equity issue accompanying DER uptake, and stressed their obligation to serve the interests of all their customers:

148.3.1. Most see tariff reform as a key means of reducing free-riding and cost-shifting/waterbed effects associated with uneven DER uptake (constrained by possible customer and regulatory backlashes), and a number anticipate that community solar schemes could play a role in also addressing equity issues;

148.3.2. Revisiting Part 3 rules on EDB involvement in competitive activities – especially for customer-owned EDBs – and/or more streamlined exemption processes would help to both address equity issues and enable more efficient DER integration on networks;

148.4. Many NEG members see an important role for themselves in providing education, advice and assurance to their customers regarding what DERs and installers best suit their needs:

148.4.1. Most did not voice concerns about poor equipment or installations, but they widely saw a need for greater customer awareness and assurance in the process of selecting systems and installers; and

148.5. Most NEG members see themselves as playing an important role in accelerating DER uptake, though they differ in terms of how:

148.5.1. Many accept that customer benefits might ultimately be maximised by downgrading existing networks and adopting new technologies;

148.5.2. Some members (e.g. Vector, Electra) even face formal obligations to their owners to pursue such technologies (as mentioned in Table 5.2);

148.5.3. Vector in particular is leading the charge among EDBs for developing platforms to enhance third-party DER uptake and service provision, while also actively trialling new technologies like grid-scale batteries (as are other NEG members).

149. These specific insights from NEG members add to the survey of global DER incidence and issues set out earlier in the report:

149.1. Together, they provide a solid foundation for now turning to how customer-owned EDBs more generally might play an important role in accelerating the uptake of distributed renewables and other DERs, and what that means for policy and regulation.

7. Role of Customer-Owned EDBs in Accelerating DER Uptake

7.1 General Ways in Which Customer-Owned EDBs might Accelerate DER Uptake

150. Based on the discussions in the preceding sections, customer-owned EDBs have a range of distinctive features. Specifically, relative to investor-owned EDBs and other organisations (e.g. local or central government, other electricity sector participants, etc):

150.1. They have a unique commitment to advancing the interests of both current and future electricity consumers in defined areas where they already have substantial assets and established governance arrangements:

150.1.1. That commitment extends to ensuring that consumers are treated fairly;

150.1.2. It also means that, historically, such EDBs have ensured the supply of electricity services even where parts of their service areas might have been inherently uneconomic, and otherwise contributed to their communities receiving services sooner or to a greater degree than would have been made available by profit-focused providers;

150.2. They are governed on a democratic basis, rather than being controlled by profit-focused investors, and hence can better reflect the wider interests and priorities of the communities they serve:

150.2.1. In short, they can maximise a wide range of monetary and non-monetary community benefits – reflecting community preferences – subject to commercial viability;

150.2.2. This contrasts with simply maximising investment value, the dominant focus of investor-owned firms, which does not account for wider community benefits unless they directly produce financial benefits;

150.2.3. Because of these important differences in objectives, customer-owned EDBs are potentially able to make a case for DER investments much sooner than investor-owned firms;

150.3. They have established track records in delivering benefits to consumers (e.g. low prices, price discounts, dividends/distributions) that would not be available under other ownership models.

151. These features, by themselves, point to why customer-owned EDBs might accelerate the uptake of distributed renewables and other DERs – in ways benefitting all consumers equitably – where DERs offer the promise of consumer benefits.

152. Other general ways in which customer-owned EDBs might accelerate distributed renewables uptake include:

152.1. Rather than seeking to maximise the value of their existing assets, customer-owned EDBs are able to change how their inter-generational capital is employed, substituting DERs for conventional lines assets if they should better serve the needs of current and future consumers;

152.2. Being able to offer independent education, advice, assistance and guidance to potential DER adopters, overcoming complexities and risks in selecting which DERs and installers best meet their needs:[124]

152.2.1. This could be particularly important for encouraging uptake when existing uptake levels are low, since in that case the types of "peer effects" found overseas to be important in uptake decisions are unlikely to be effective;

152.2.2. It can also help to overcome incompatibility and other DER-related issues before consumers make their investments, drawing on those EDBs' knowledge of how different DERs integrate with their networks, simplifying and smoothing the integration process;

152.3. By better resolving NIMBYism and other community opposition to renewables where they involve adverse impacts (e.g. visual disturbance for large-scale PV), being both more sympathetic to community concerns by virtue of customer ownership, and returning benefits to communities which can serve to offset any adverse impacts;[125] and

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[124] An example of such an education service being provided by a non-NEG customer-owned EDB is Eastland Network's guide to residential solar PV systems publication, "Spotlight on Solar". See http://www.eastland.nz/eastland-network/home-business/solar-guide/.

[125] Vector's *Urban Forest* scheme – planting two native trees for every tree cut down to protect powerlines – is an illustration of the former. See https://www.vector.co.nz/personal/electricity/what-you-need-to-know/planting-smart.

152.4. Being potentially more receptive to network-side DER investments that create benefits to both networks and customers:

152.4.1. E.g. grid-scale batteries, which are much cheaper per unit of storage than household-level batteries, which could be located near to residential PV clusters (or community renewables schemes) and leased to PV owners in order to improve the economics of their PV investments;

152.4.2. Such batteries simultaneously help the EDB to manage DER-related power quality and system reliability issues and defer more costly network upgrades (which also helps to avoid extra network costs being imposed on other customers);[126]

153. Notably, one type of community preference that customer-owned EDBs might be able to take into account more than other types of organisations is sustainability. Doing so means the relevant communities can achieve their sustainability goals more quickly, as demonstrated by international examples cited in Section 4, such as:

153.1. Community ownership of Kaua'i Electric in Hawaii resulting in a rapid shift towards renewable generation; and

153.2. Community renewables schemes in Australia helping to accelerate renewables uptake where federal government initiatives were perceived to be lacking.

154. While alternative models of community ownership are available, including in New Zealand (e.g. Energy Democracy, Raglan Local Energy), customer-owned EDBs offer certain distinctive advantages:

154.1. Established governance arrangements, management structures and skilled workforces, avoiding the need for community schemes to create these from scratch; and

154.2. Scale advantages, such as:

154.2.1. Access to capital; and

[126] Such a scheme has been trialled by Western Power in Australia. See https://westernpower.com.au/community/news-opinion/community-batteries-mutual-attraction/.

154.2.2. The ability to bulk-buy equipment and installation services and/or deploy grid-scale equipment (especially batteries), at much lower cost – and with greater assurance of network compatibility – than smaller buyers/installers.

155. Finally, given their inter-generational and community focus, customer-owned EDBs might be more prepared and able than other types of organisations to support distributed renewables and other DER uptake despite crises and other shocks such as COVID-19:

155.1. By accounting for wider community benefits, and the interests of future consumers, customer-owned EDBs might be able to advance the case for DER investments in contexts where other providers might regard the uncertainties as too great to support investment during or immediately following crises.

7.2 Role of Customer-Owned EDBs in Development of Digital Platforms for DER Uptake

156. In Section 7.1 a range of reasons are offered for why customer-owned EDBs might lead to the earlier adoption of DERs than other types of organisation. In this section the discussion turns to why customer-owned EDBs might accelerate the creation of digital platforms for integrating DERs.

157. By digital platforms, we mean systems designed to coordinate multiple buyers and sellers of DER services, potentially algorithmically and in real-time, so as to maximise the benefits of those DERs:

157.1. An example is algorithmic P2P trading of PV output when the owners of that output (e.g. household PV owners) are unable to consume it, potentially offering PV owners multiple micro-profit opportunities that "manual" energy trading would be too costly to realise;

157.2. Such trading opportunities might be aggregated by providers of aggregation services, for example to create virtual power plants (VPPs) whose output can be traded on wholesale markets.

158. All EDBs – including customer-owned EDBs – will ultimately have an interest in the operation of such platforms, since:

158.1. They will impact how DERs integrate with networks, affecting network performance, and so EDB-provided platforms could seamlessly integrate things like network

security constraints (as in smart markets used for wholesale electricity pricing, which identify optimal prices while satisfying grid security constraints); and

158.2. Depending on how the platforms are created, they might be able to use DERs to offer new forms of network support services, analogous to ancillary services on the national grid, which integrate DERs into networks without necessarily requiring system security constraints to be imposed.

159. This remains the case even if EDBs are precluded from owning the relevant DERs (e.g. due to Part 3 constraints) – efficiently coordinating even third party DERs and service offerings that maximise their value will remain a key concern of EDBs:

159.1. While EDBs might be permitted to perform such a role for the benefit of all consumers, there is a risk that they might not be perceived to be adequately independent;[127]

159.2. However, customer-owned EDBs might be better-placed than other provider types to assure platform users of their independence, given their commitment to providing customer benefits.

160. Furthermore, cost-benefit analysis of different system architectures commissioned by Energy Networks Australia suggest that slower DER deployment favours DER integration approaches led by networks:[128]

160.1. To the extent that customer-owned EDBs might be better-placed than others to provide independent platform development, this could accelerate the creation of such platforms in New Zealand's low uptake environment.

161. Another reason why customer-owned EDBs might lead to earlier platform development is that profit opportunities for platforms supporting small scale DER integration are currently modest:[129]

161.1. For the same reason that customer-owned EDBs can support the earlier adoption of other technologies than investor-owned providers, if the wider platform benefits

[127] This is a potential shortcoming of the DSO system architecture identified in Energy Networks Australia (2020).

[128] Energy Networks Australia (2020).

[129] GridWise and Farrierswier (2020).

to smaller DER owners and users are sufficient, those EDBs might be able to make the business case for their creation sooner than organisations who value only platform profitability.

162. Relatedly, there is a risk is that if customer-owned EDBs do not create consumer-benefitting platforms, then other providers will do so (eventually), but extract a larger share of consumer benefits as profits in the process (e.g. through charging higher prices to users with higher consumer benefits):

    162.1. Customer-owned EDBs might offer less sophisticated platforms than other providers, but do so sooner – especially in lower-value areas where other firms will delay/avoid entry;

    162.2. In doing so they would leave more consumer benefits on the table for their users, benefitting local communities, and returning any platform profits to customers (ameliorating possible concerns about market power in platform provision).

163. A possible constraint on customer-owned EDBs creating platforms is that often they individually lack the scale and expertise required to create novel technology-based solutions robust enough not to be displaced by later innovators:

    163.1. One possible solution is for customer-owned EDBs to jointly establish platform development initiatives, similar to how RECs in the US form G&T cooperatives to jointly invest in generation and transmission assets which none of them individually could afford or manage.

164. A possibly greater constraint is the culture change required for EDBs and their governors to transition from traditional monopolistic utilities into highly-innovative customer-oriented firms operating in much more uncertain and competitive environments:

    164.1. Vector's joint venture with Amazon Web Services to develop their New Energy Platform provides a possible model for overcoming both sets of constraints;

    164.2. By directly partnering with Amazon, Vector is able to access the innovative technology and capabilities required to produce high-value customer offerings, while Vector's consumer focus helps to shape the platform development so as to prioritise consumer benefits.

165. While investor-owned EDBs are active worldwide in exploring DER solutions like digital platforms, the above discussion points to customer-owned EDBs potentially playing a key role in developing more independent and trusted platforms, and possibly doing so sooner.

7.3 Role of Customer-Owned EDBs in Development of Community Renewables

166. Finally, in this section the possible role of customer-owned EDBs in supporting community renewables is explored.

167. Since community renewables schemes cater to parties who lack the resources or ability to invest in their own DERs, they help to accelerate DER uptake by those parties (and hence overall DER uptake, provided community schemes do not crowd out private schemes):

    167.1. To the extent community schemes offer as lower-cost way to access the benefits of DERs, such schemes might displace private schemes, but result in higher DER uptake regardless (in the same way grid-scale solar schemes are outstripping private and community schemes in the US, although the benefits of those schemes are captured mainly by utilities).

168. Community renewables schemes bear many of the hallmarks of EDB ownership, albeit free of price-quality and Part 3 regulation applying to some or all EDBs:

    168.1. As noted above, however, customer-owned EDBs bring certain distinctive benefits to community DER projects that other community schemes do not share;

    168.2. From a policy and regulatory perspective, a relevant question is whether those benefits are sufficient to warrant exempting customer-owned EDBs from Part 3 and other regulatory constraints if they were to invest directly in DERs on behalf of communities.[130]

169. Even if customer-owned EDBs do not invest directly in community renewables, they may still face greater incentives than other firm types to facilitate community schemes provided by third parties:

[130] Notable here is the trade-off between avoiding potential competitive harms from network owners also investing in competitive activities like generation, and securing the benefits of coordination between network and competitive activities. Meade (2018) surveys studies showing that those benefits can be substantial, casting doubt on the merit of restricting coordination.

169.1. For example, customer-owned EDBs might be able to support the development of community schemes such as those offered by Energy Democracy, or Raglan Local Energy:

169.1.1. Possible types of support include identifying or making available suitable land, identifying where best to locate community schemes on networks to minimise network constraints, co-investing in grid-scale batteries to provide both network and community scheme benefits, providing technical assistance, etc;

169.1.2. Another type of support might be for customer-owned EDBs to reserve existing network capacity for community schemes, helping to mitigate the "network capacity gold rush" by commercial and more affluent DER uptakers that might otherwise occur;

169.2. Alternatively, customer-owned EDBs might be able to partner with agencies such as Housing New Zealand and other social housing providers (including iwi) to assist them with developing community schemes.

170. A prominent reason identified in this study why customer-owned EDBs might do so is their concern about the equity issues arising with DER adoption by more affluent customers, exacerbated by regulatory obstacles to properly pricing the costs of DER uptake:

170.1. Supporting/facilitating community renewables schemes would be a way to help all customers – not just those with the resources – to participate in DERs, consistent with customer-owned EDBs' mission to serve the interests of all their customers;

170.2. Doing so means less affluent customers will be able to "level the playing field" with more affluent customers, reducing cost-shifting/waterbed effects and free-riding on existing network capacity at the same time as they participate in the benefits of DERs.

171. By participating in or facilitating community renewables schemes, customer-owned EDBs are better able to serve the interests of all their customers, while also having a hand in ensuring community renewables better integrate with their networks:

171.1. This simultaneously helps to address equity issues, encourages more efficient larger-scale schemes, and resolves possible power quality and system reliability issues.

8. Implications for Policy and Regulation, and Conclusions

8.1 General Implications for Policy and Regulation

172. This study highlights a number of issues for policymakers and regulators in relation to DERs generally, whether or not they are owned by investor- or customer-owned EDBs:

    172.1. In particular, the rising penetration of DERs has the potential to fundamentally challenge the presumptions underlying existing electricity sector regulation – such as Part 3, Part 4, the LFCT, and constraints on lines charges for DG.[131]

173. For example, as PV and storage/EV penetration rates rise, traditional consumers will instead become "prosumers", in which case they can effectively compete with network services, at least in some circumstances:

    173.1. This contradicts the explicit presumption in Part 4 price-quality regulation that distribution services are not competitive and unlikely to become so, and implicit presumption that consumers are not also producers.

174. Moreover, legacy regulations such as the LFCT, and constraints on lines charges for DG will increasingly be seen to be choices about the nature and pace of DER uptake, but not necessarily in intended or desirable (e.g. equitable) ways:

    174.1. Whatever the aims of those regulations were when they were introduced, it is timely to re-examine whether they achieve – or frustrate – the achievement of those aims with the increasing uptake of DERs.

175. Importantly, Part 3 limits on the extent to which EDBs can be involved in competitive activities like generation or retailing (both of which characterise DERs) require urgent re-evaluation:

    175.1. At their heart they limit EDB involvement in competitive activities to minimise the risk that EDBs will use their market power in lines operations to reduce competition by third parties, inherently making the judgement that protecting the possibility of third party competition is more important than the possible benefits of coordinating lines activities and DERs;

[131] See Meade (2018) for a comprehensive discussion of the issues and required regulatory responses.

175.2. Based on this study, the benefits of coordinating lines activities and DERs are conceivably at least as great as those from combining lines activities and traditional competitive activities like generation or retailing, given DERs are considerably more decentralised, bi-directional and intermittent/asynchronous;

175.3. Moreover, if EDBs were to combine lines activities with DERs in a way that reduced competition and increased prices faced by consumers, that would serve to accelerate those consumers adopting DERs in order to escape such price increases (possibilities that were not open to consumers when the Part 3 limits were devised).

176. The concerns that Part 3 limits were originally devised to address have possibly been addressed by improvements in disclosure rules applying to all EDBs:

176.1. In any case, those limits were devised long before DERs were imminent and their impacts understood;

176.2. There is now a case for Part 3 restrictions to be much more nuanced, with different limits applying depending on the type of DERs, or DER uses, involved:

176.2.1. E.g. allowing EDBs to be involved in DERs to a greater extent than currently provided for if those uses are clearly beneficial to consumers, irrespective of how this affects third-party competition (taking into account the possibility of consumers themselves becoming competitors to lines services, as above);

176.2.2. Additionally, to avoid consumer benefits from DERs that require EDB involvement being delayed by costly and time-consuming exemption processes, consideration should be given to Part 3 providing more general/automatic safe harbours for such involvement.

177. Other general policy and regulatory re-assessments required include:

177.1. Allowing for "cost-reflective" pricing models better suited to the challenges presented by DERs – e.g. allowing pricing experimentation, greater use of fixed/peak and export pricing, and more sophisticated models for allocating network costs to those giving rise to them;

177.2. Greater provision of regulatory safe harbours for EDB involvement in DERs generally, but also in platforms, and community schemes (especially where community schemes address equity issues) specifically, including for sandpitting/trials;

177.3. Reconsidering arrangements for access to, and ownership of, metering data, and adequacy of smart metering technologies (e.g. availability of two-way meters versus one way to enable export charging):

177.3.1. This could be tied to improving static and real-time DER visibility more generally, and paired with greater transparency about network constraints (e.g. real-time network heat maps); and

177.4. Examining the adequacy of standards for DER interoperability, safety, etc, taking a lead from Australia and other jurisdictions already addressing these issues, and making sure standards meet both local requirements and those of major manufacturers.

8.2 Implications for Policy and Regulation Specific to Customer-Owned EDBs

178. The general implications of DER uptake for policy and regulation discussed above apply to investor-owned as well as customer-owned EDBs.

179. What should be clear from this study is that customer-owned EDBs focus on delivering benefits for customers over and above just financial returns. As a consequence, they more naturally protect against many of the harms which existing regulation seeks to address:

179.1. Those harms include misuse of market power, either to over-charge customers for lines services, or to foreclose competition from third parties (with implications for customers); and

179.2. They also include under-providing service quality, and inequities such as energy poverty (or cost-shifting/waterbed effects).

180. This fact is already recognised in electricity regulation both in New Zealand and elsewhere:

180.1. Many customer-owned EDBs in New Zealand are already exempt from Part 4 price-quality regulation; and

180.2. Many RECs in the US are exempt from the type of regulation applied to investor-owned electric utilities.

181. These considerations point to a need for a re-assessment of whether customer-owned EDBs should be subject to the same level of regulation as investor-owned EDBs:

181.1. For example, whatever revised safe harbours might be created under Part 3 rules for EDB involvement in DERs that produce clear consumer benefits (as suggested above), those safe harbours might conceivably be even more lenient for customer-owned EDBs, given their customer focus means they are less likely to be harming consumer interests.

182. More generally, there is cause for policy and regulatory purposes to consider whether customer-owned EDBs should be subject to the same treatments as other firms, and if so, to the same degree, recognising the impact of customer ownership on how customer-owned EDBs are operated and behave (and drawing lessons from customer-owned EDBs' early experience with DERs).

8.3 Conclusions

183. This study shows that customer-owned EDBs:

183.1. Offer potential advantages in accelerating the uptake of distributed renewables and other DERs; and

183.2. Also offer certain natural protections against the types of issues that electricity regulation seeks to address.

184. This points to how a more nuanced approach for regulating customer-owned EDBs can be justified, to ensure the customer benefits of DERs are enjoyed more quickly, fully and equitably:

184.1. In particular, there are grounds to consider whether customer-owned EDBs should be subject to the same level of restrictions as investor-owned EDBs in terms of supporting or making DER investments involving competitive activities like electricity generation or retailing (i.e. a more tailored approach to New Zealand's Part 3 regulation).

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