INNOVATION AND
PARTICIPATION
ADVISORY GROUP

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Energy Markets Policy
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To whom it may concern

Submission on Discussion Document: Accelerating renewable energy and energy efficiency

Thank you for the opportunity to provide input into the policy development process. We applaud the Ministry's efforts to draw together the varied strands of the challenges which face us over the next years and decades. This is an exciting time for the energy sector, and we are enthusiastic that New Zealand will step up to the opportunities ahead.

Yours faithfully

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Introduction to the Innovation and Participation Advisory Group (IPAG)

IPAG is an advisory group, not an advocacy organisation. It is one of two independent groups established by the Electricity Authority (the Authority) and designed to meet its statutory consultation objective. Under the Terms of Reference for advisory groups[1]:

> *The purpose of the IPAG is to provide independent advice to the Authority on issues in the Authority work programme that relate to:*
>
> *(a) evolving technology and business models*
> *(b) competition and consumer choice.*

While established and funded by the Authority, IPAG works independently, providing recommendations to the Authority board to guide the development of their strategy and work programme. Our work explores how new technologies, new business models, and consumer participation can drive transformation of the electricity sector.

Members bring a wide variety of experience from both within and outside the electricity sector, including generation, retail, distribution, technology start-ups, community organisations, and from industries which have already been through similar disruptive change to that facing the energy sector, including telecommunications and media. More information, including the current member list, is available on the Authority's website[2].

Context for our submission

Since IPAG was established in 2017, the group's work has largely dealt with identifying and overcoming the barriers to efficient use of Distributed Energy Resources (DERs). We have completed two projects:

- 'Equal Access'[3] dealt with two oft-conflated subjects:
  - Open access to electricity networks (particularly at the distribution level)
  - Contestability for flexibility services used by network operators (whether provided by batteries, demand response, or other DERs)
- 'Input Services'[4] focused on new market arrangements to unlock effective use of DERs through greater consumer choice of electricity service providers.

Through these projects, we have developed consensus recommendations in several areas addressed by the discussion document. Our response focuses on those areas:

- Section 8.2 – Demand-side participation and demand response
- Section 11 – Local network connections and trading arrangements

Our recommendations and proposals would also support development in other areas, and we touch on those relating to:

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[1] https://www.ea.govt.nz/development/advisory-technical-groups/src/charter-and-terms-of-reference/
[2] https://www.ea.govt.nz/development/advisory-technical-groups/ipag/
[3] https://www.ea.govt.nz/dmsdocument/25026-ipag-final-advice-on-equal-access
[4] Our final advice is not yet published, but a near-final version is available in our December meeting minutes. https://www.ea.govt.nz/dmsdocument/26353-draft-advice-access-to-input-services-04-december-2019

- Section 5 – boosting investment in energy efficiency and renewable energy technologies
- Section 9 – facilitating local and community engagement in renewable energy and energy efficiency

Our Equal Access recommendations were accepted by the Electricity Authority board in February 2019 and form the basis of the Authority's planned Open Networks implementation project. In responding to MBIE's consultation we have not developed any new material but are keen to ensure that all stakeholders working on DER integration in New Zealand are aware of the work and build on it.

Key concepts

Before addressing the specific questions asked in the discussion document, we recap our take on two concepts critical to the problems and solutions, which we refer to in the body of our submission.

Key concept: DERs

The discussion document refers to DERs in several contexts, noting the transition to large quantities of rooftop solar, household batteries and electric vehicles.

DERs will play a major role in New Zealand's transition to zero carbon, and large numbers are projected to be connected to the electricity system over the next three decades:

- The Ministry of Business, Innovation and Employment's own Electricity Demand and Generation Scenarios (EDGS)[5] include cases where in 2050:
    - rooftop PV reaches between 10% and 45% of households
    - 80% of PV installations also have batteries
    - EVs make up between 44% and 74% of the light vehicle fleet
- Transpower's Te Mauri Hiko – Energy Futures[6] included a base scenario where:
    - 1.5 million households have rooftop PV by 2050, making up more than 20% of the new generation installed
    - 6GW of household batteries (enough to meet a full hour of New Zealand's current peak demand with no other supply)
    - 85% EV market share

DERs behave differently to other electricity market resources. They are:

- Small in comparison to traditional resources, often only a few kilowatts
- Widely distributed throughout the country and within each region
- Typically connected to local distribution lines, not the high voltage grid
- Increasingly owned by consumers and communities
- Mostly produce electricity, but also include other energy types such as solar heating or hot water

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[5] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-modelling/electricity-demand-and-generation-scenarios/
[6] https://www.transpower.co.nz/resources/te-mauri-hiko-energy-futures

- Active or passive
    - Passive DERs (such as solar panels) only produce electricity when they have fuel (sun or wind) which may not be when people are using electricity
    - Active DERs (such as batteries or demand response) can be operated when they are needed; people can choose when to use them, which helps match demand, and can complement passive DERs

Achieving an efficient and issue free energy transition will require effective DERs integration and management . Traditional ways of operating may not be able to keep up with the pace of change and will not deliver the most efficient solution. DERs are only useful to assist network operation or any other role to the extent they are coordinated and predictable.

Key concept: Flexibility

The discussion document includes a variety of related concepts for the use of DERs, including distributed generation, demand-side participation, demand response and local network connections and trading.

We have found that the concept of 'flexibility' better captures the range of participation enabled by new technologies and business models than 'Demand Response'.

Flexibility is the ability and preparedness to respond to signals by varying production or consumption of electricity at a specific location.

Signals may be delivered by distribution or energy prices, managed tariffs, "by event" contracts, or long-term agreements.

Responses may be consumer controlled or remotely switched and may be delivered by any DER technology.

Section 8.2 - Demand-side participation and demand response

Effective customer participation is about more than demand response, it is about the effective use of DERs.

Q8.7 Do you consider the development of the demand response (DR) market to be a priority for the energy sector?

Development of flexibility markets is critical to ensure that we get the best value from new distributed technologies. Flexibility markets (together with the planned introduction of real-time wholesale pricing, and changes to transmission and distribution pricing) would unlock the full potential of customer participation in the electricity markets.

Flexibility is broader than demand response, and encompasses response from:

- Load:
  - Traditional demand response – for example where a factory is paid to temporarily cut production to provide a certain MW reduction
  - Dynamic demand – where consumers delay or bring forward their usage in response to expected pricing or other signals, and may or may not be directly compensated
  - Controlled load – such as ripple control hot water, which is centrally triggered
- Storage – such as aggregated distributed batteries charging overnight to flatten the trough
- Generation – for example a small, behind the meter diesel generator generating in a peak period to reduce apparent load at that site

The most important driver for unlocking the benefits of flexibility in New Zealand is the incentive for distribution companies (distributors) to procure services from DER providers in an open and transparent manner[7]. The development of a distribution network flexibility market should be a priority.

Q8.8 Do you think that DR could help to manage existing or potential electricity sector issues?

Flexibility, including traditional demand response, can make a significant contribution to some issues in the sector. It can:

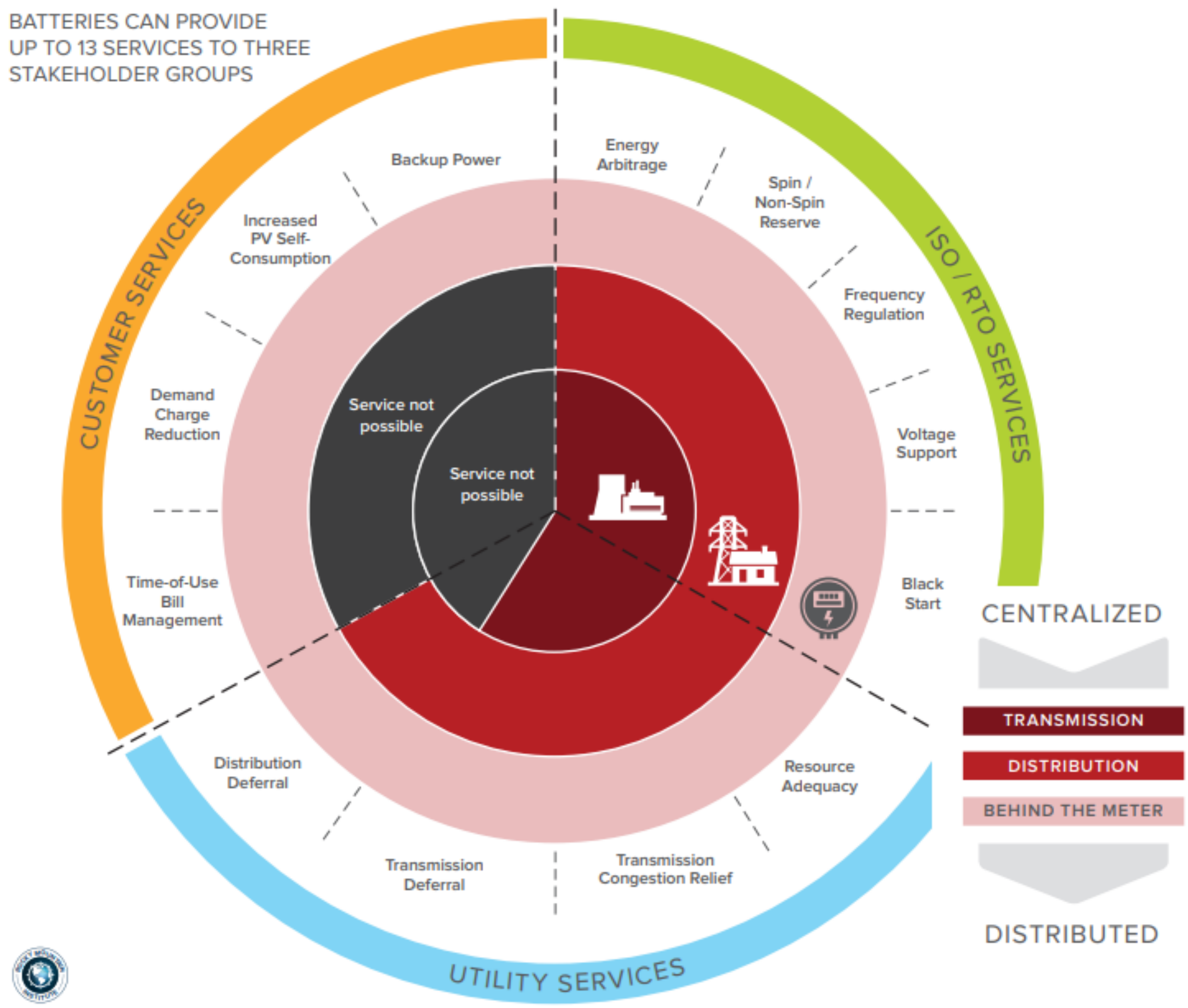
- Allow behind-the-meter owners to manage their costs by reducing network and energy charges
- Support short-term security of supply by participating in ancillary service markets
- Allow retailers to manage volatile electricity prices by responding at times of high or low wholesale prices
- Allow the Transpower and distributors to postpone grid and network investment by reducing peak load

The issues addressed by flexibility services are almost as broad as those for pure battery storage, shown in Figure 1 below. However, flexibility is not a panacea. It cannot address inter-

[7] For example, Transpower's existing demand response platform is a valuable contribution to avoiding transmission investment, but it suffers from many of the issues identified in our response to Q11.1. IPAG is about to begin a 6-month project to identify how to transition this programme to a more open and effective basis for flexibility trading.

seasonal energy storage, and it will not negate the eventual need for network investment to meet underlying demand growth. It helps a lot, but it's only part of the solution.

Figure 1: Potential services provided by batteries and flexibility providers



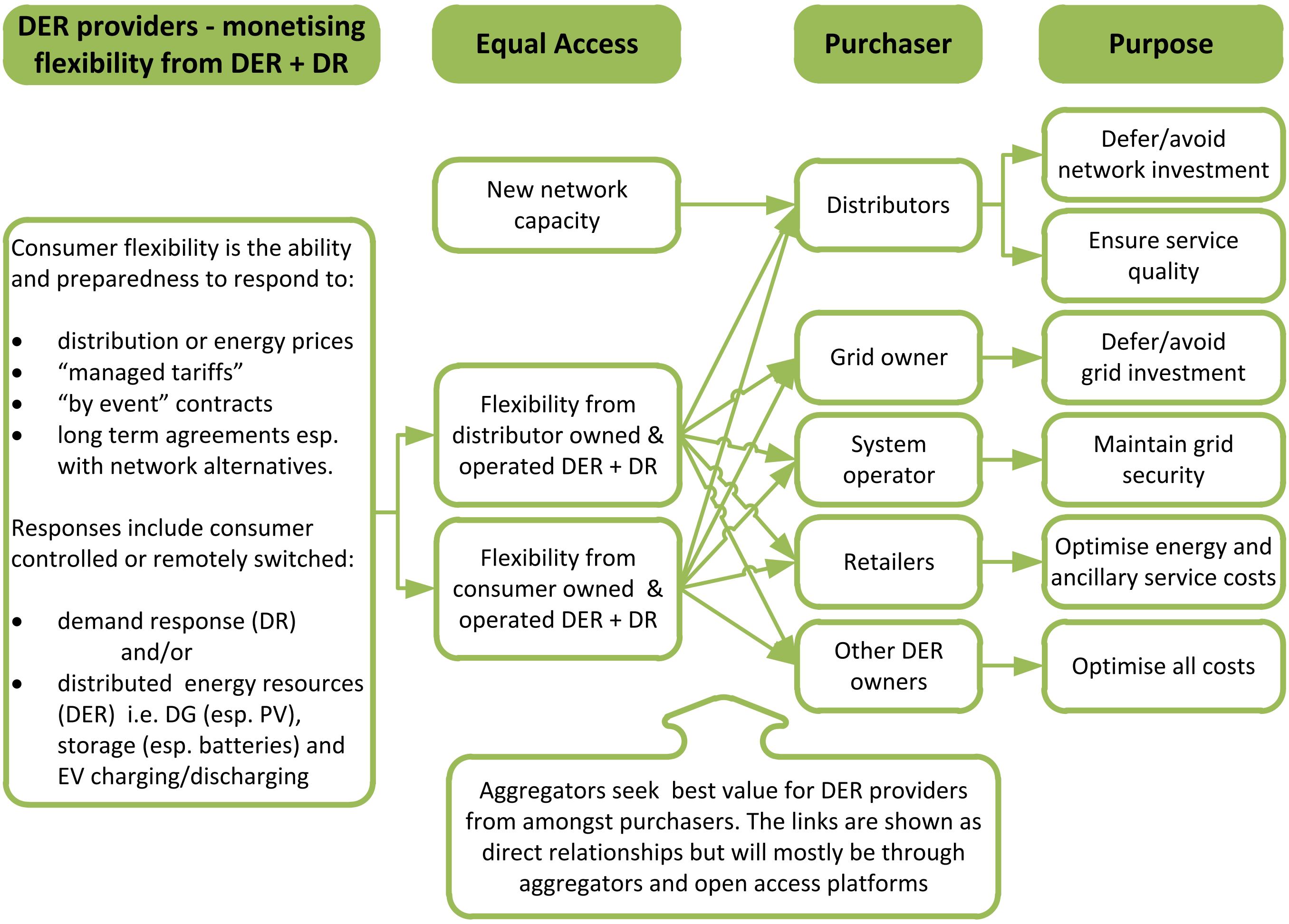
Source: Rocky Mountain Institute, Economics of Battery Storage[8]

[8] https://rmi.org/insight/the-economics-of-battery-energy-storage-how-multi-use-customer-sited-batteries-deliver-the-most-services-and-value-to-customers-and-the-grid-executive-summary/

Q8.9 What are the key features of demand response markets? For instance, which features would enable load reduction or asset use optimisation across the energy system, or the uptake of distributed energy resources?

Figure 2 presents our conception of the actors involved in flexibility markets and the relationships between them.

Figure 2: Components of a market for flexibility



Source: IPAG final advice on equal access

While the ultimate end state may include formally organised platforms for flexibility services, it is reasonable to plan for initial arrangements implemented through direct negotiations or implied via pricing signals. Aggregators will likely interpose themselves between individual DER owners and purchasers, matching the flexibility on offer with the purchasers and the prices they are prepared to pay

Although there is plenty of scope for flexibility services to provide value today to distributors, retailers and others, there is currently limited explicit demand for these services, and as a result the pool of DER providers who can offer flexibility is small. The potential for provision is large, and in our view, increased demand will quickly be met by supply. The key is to make the innate need explicit.

Pricing for flexibility must place different services on an equal footing, not preferring or supressing any option. The Authority's principles for distribution pricing[9] provide a useful guide, and could easily be adapted for flexibility:

(a) Prices are to signal the economic costs of service provision, including by:

- *(i) being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs);*
- *(ii) reflecting the impacts of network use on economic costs;*
- *(iii) reflecting differences in network service provided to (or by) consumers; and*
- *(iv) encouraging efficient network alternatives.*

(b) Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.

(c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:

- *(i) reflect the economic value of services; and*
- *(ii) enable price/quality trade-offs.*

(d) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.

Q8.10 *What types of demand response services should be enabled as a priority? Which services make sense for New Zealand?*

Transpower's 'Battery Storage in New Zealand' discussion document[10] explored the value of the services in a New Zealand context. The highest potential value service is the deferral of distribution network investment. This aligns with our view on the highest value use of flexibility services from DERs and is the reason for our focus on ensuring visibility of distribution network demand.

[9] https://www.ea.govt.nz/dmsdocument/25528-distribution-pricing-practice-note-august-2019

[10] https://www.transpower.co.nz/sites/default/files/publications/resources/Battery Storage in New Zealand.pdf

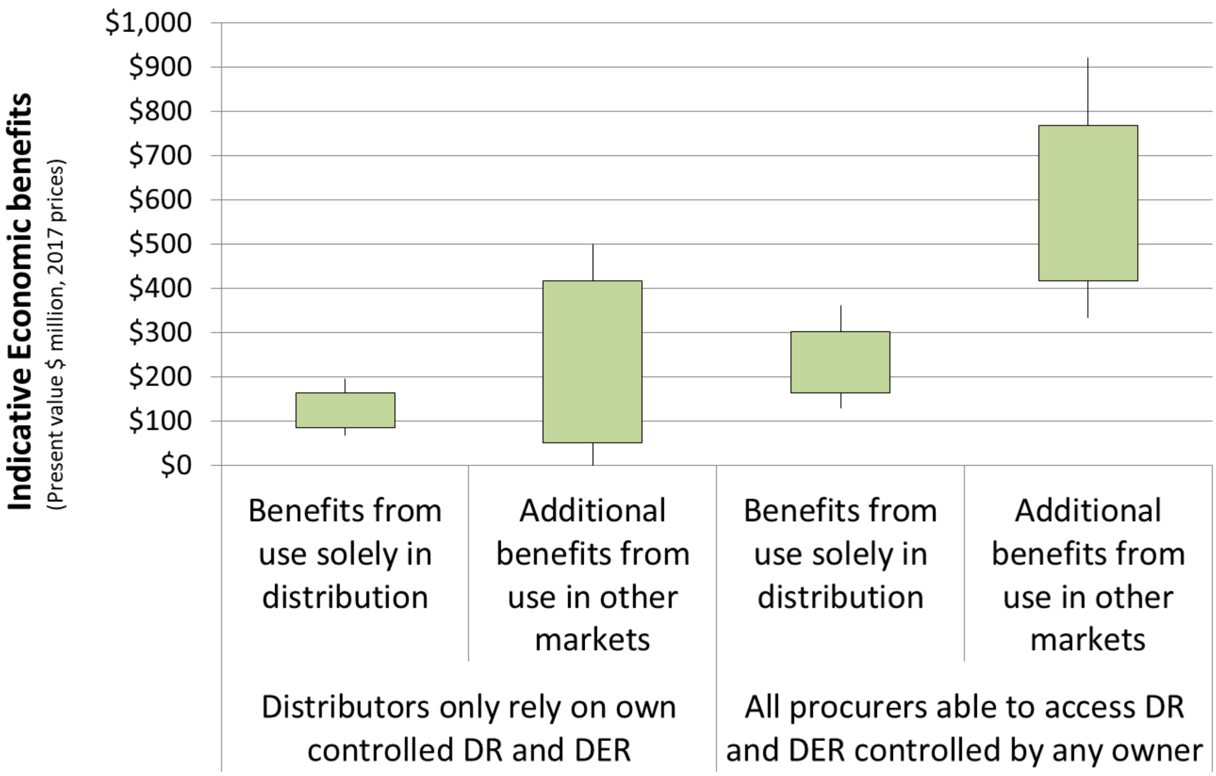
Section 11 – Local network connections and trading arrangements

IPAG considers access arrangements at the distribution level (especially access for consumer owned DERs) will need to evolve radically for DERs to maximise the long-term benefit of consumers. Changes will be needed to terms of network access, approaches to procuring network inputs, and to the availability of network and market information.

***Q11.1** Have you experienced, or are you aware of, significant barriers to connecting? Are there any that will not be addressed by current work programmes outlined above?*

Interested parties can already connect DERs to local networks. However, there are barriers to doing so in a way that unlocks the full benefits that DERs bring to the overall electricity system. A continuation of our current environment will lead to distributor-owned DERs being used to supply only distribution-level flexibility services (Figure 3, leftmost case). This would preclude hundreds of millions of dollars of benefits arising in the case where any party can freely invest in DERs and supply flexibility services to distributors, Transpower and retailers (Figure 3, rightmost case).

Figure 3: Benefits from broader deployment of DER and DR



Source: Modelling completed for the IPAG. For further detail see IPAG July 2018 meeting papers[11].

Our Equal Access recommendations identified thirteen barriers that distort efficient decisions about how customers and distributors use the local network:

[11] https://www.ea.govt.nz/development/advisory-technical-groups/ipag/meeting-papers/2018/17-july-2018/

1. Distributors use what could be described as static approaches to manage the lower voltage parts of their network. They may not have enough network information to effectively coordinate DERs with the distribution network service as the level of DERs on the network increases.
2. Information that would give third-party DER providers a sense of where DER investment and deployment could provide benefits on the distribution networks or how much they would be paid is not accessible.
3. Distributors and third-party owners of DERs require clear and consistent specification to ensure DERs entering the network meet appropriate network code. These do not currently exist.
4. High transaction costs can impede trading between procurers (especially distributors) and suppliers of DER services.
5. Distribution pricing does not signal the cost of DERs to network operation (congestion and voltage excursions for example) or its value to distributors
6. Distributors do not yet have the evidence that coordinated DERs delivered through a contestable framework can provide network reliability or serve as an alternative to network investment.
7. Part 4 Incentives appear to be poorly understood. This may lead distributors to focus on in-house solutions, without using a contestable framework or not use DERs as a network alternative at all.
8. Distributors' DER investments are treated as regulated capital, but the planning and operating services provided are contestable
9. Distributors might not be constrained in allocating costs and revenues between emerging contestable markets and the regulated distribution service
10. Distributors may not be incentivised to explore non-internal or related-party options to deliver the distribution service.
11. Distributors may not be incentivised to explore non-network alternatives to delivering network support.
12. Distributors may place restrictive connection and operation standards for the use of DERs without recourse.
13. Security and reliability of electricity networks could be compromised if DER use by Transpower and distributors is not coordinated.

Proposed activities to address each of the barriers is included in our equal access project advice, and included in the Appendix to this submission.

The Commerce Commission (the Commission), Authority and Electricity Networks Association (ENA) have plans to address each of these barriers and are the right entities to do so.

Q11.2 *Should the section 10 option to produce a users' guide extend to the process for getting an upgraded or new distribution line? Are there other section 10 information options that could be extended to include information about local networks and distributed generation?*

A guide to help those seeking to connect new DERs to the distribution system would be useful. However, currently each distributor has different connection standards and arrangements. Such a guide will only be truly effective if connection arrangements are first standardised across all distributors, for both household level connections (for example, solar, batteries and EV charging infrastructure) and larger community or commercial facilities (distribution connected solar, wind, batteries and charging infrastructure above 10kW).

Q11.3 *Do the work programmes outlined above cover all issues to ensure the settings for connecting to and trading on the local network are fit for purpose into the future? Are there things that should be prioritised, or sped up?*

All the barriers identified above will be addressed by work in Authority and Commission plans, but prioritisation of other important work (e.g. the Authority's response to the Electricity Price Review, and the Commission's DPP3 reset including new quality standards) within those entities has precluded progress on these important but less immediate topics. In our view, the ability to monetise flexibility services is the linchpin of a successful transition to a DER-led future, and activity to progress this must be sped up.

Our work has identified the first steps towards removing barriers, but there is a lot yet to be learned. Activity must start now if New Zealand is to have time to respond. We believe that clear guidance to distributors on management of DER connection, including standards, trials, and advice on best-practice, is an important contribution that the Authority and Commission can make together with the ENA. This would be aimed at removing the barriers identified above, allowing consumers to monetise the flexibility services their DERs may provide, and assisting consumers understand what type of DERs may, or may not, provide the most flexibility. However, such work needs to be prioritised and resourced effectively. We are concerned that:

- there is nothing in the Authority work plan for the coming year which relates to distributors creating opportunities for flexibility providers to be paid for flexibility services as an alternative to network augmentation
- the joint Commission/Authority project on distributor participation in markets for contestable services[12] has been dormant since July 2019.

For exchange to occur, providers of DER services (sellers) and procurers of DER services (buyers) need a platform or forum or exchange where they can identify the opportunities, see the prospective value, meet and trade. While we see the long-term potential for DER flexibility to be rewarded by variable real time locational distribution price, there will need to be a short-term approach/mechanism to incentivise the growth of aggregators offering distribution network alternatives. There is no point in progressing any initiative to facilitate local trading arrangements until there is an avenue for DER owners to monetise their flexibility with distribution networks.

The path ahead is not completely clear, but the immediate next steps are. In our equal access advice, we identified a three-phase, industry-led approach to breaking down the barriers to effective use of DERs in the distribution network:

1. *Information* - Distributors take the first steps by communicating their needs in a simple way

[12] https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/commerce-commissionelectricity-authority-joint-project-spotlight-on-emerging-contestable-services

2. *Standardised Contracts* - Bilateral DER flexibility contracts are commonplace (especially longer-term arrangements providing an alternative to network augmentation)
3. *Control Systems* - Control systems for DERs are integrated into a common approach

Making the best use of DERs requires full engagement by all participants through each phase of designing the market. We advocate the use of market trials and customer engagement to reduce the chance of unintended consequences if aiming for the full solution at the outset. We believe that market structures can deliver the best outcomes, and that the evolution of these structures will require facilitation rather than direct intervention.

The ENA Network Transformation Roadmap[13] is closely aligned to our advice and lays out goals for each action area in three timeframes: 0-2 years, 2-5 years and 5-10 years. Each document contains a comprehensive plan to deliver the outcomes required.

Since those documents were published in 2018 and early 2019, the industry has not been idle, with several distributors running projects to install and use their own DERs on their own networks. Examples include:

- Batteries (Alpine Energy, Counties Power, Vector)
- Electric vehicles (Wellington Electricity, Vector)
- Microgrids (Powerco)
- Virtual Power Plants (Wellington Electricity with Contact)
- Remote Area Power Supplies (PowerNet)

However, almost all effort has been in projects where distributors are expanding their own capability on their own network, rather than projects involving reaching out and working with other parties. This is at least partly because portions of the benefit accrue to others, even though they cannot be obtained without distributor action.

In that light, our input services advice placed greater emphasis on the role of government and regulators to coordinate industry trials, oversee their execution, and report results. That too has proven difficult to get started. It must be sped up.

Q11.4 *What changes, if any, to the current arrangements would ensure distribution networks are fit for purpose into the future?*

The changes needed to support greater volumes of DERs are set out in our advice and the Network Transformation Roadmap, but they are complex and will not be completely understood until we start to get experience. The immediate focus is on exploration and learning, but we must quickly move to understanding and deployment. Delaying action will create significant costs to consumers, particularly from uncoordinated or constrained investment in DERs.

Cost-reflective distribution pricing is a necessary pre-condition for effective trading on distribution networks, but the rollout will change residential electricity bills. Changes to electricity pricing are naturally contentious, and it is important that government entities actively support

[13] https://www.ena.org.nz/dmsdocument/483

distributors as they make changes that have been agreed to be in the best interests of New Zealand as a whole, and particularly those distributors which are the first to introduce new distribution pricing.

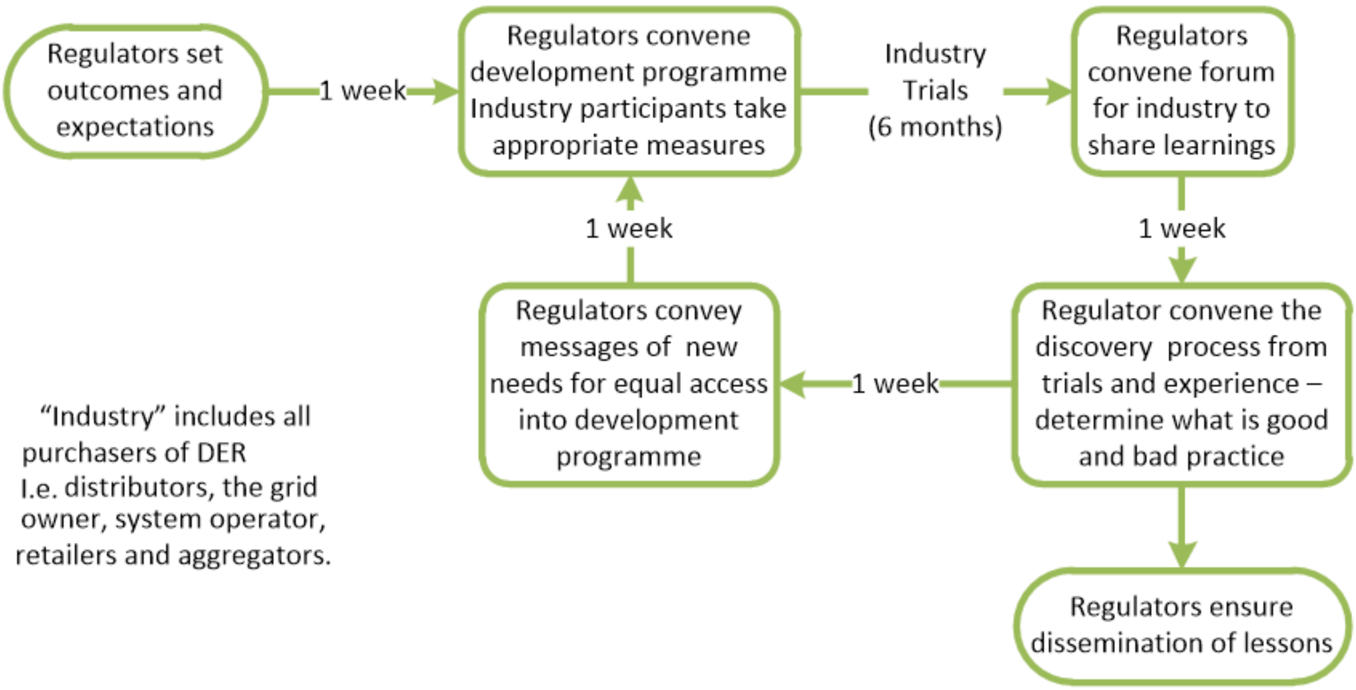
The first steps to the changes required are well understood but are languishing for lack of resources. The first barrier to effective use of DERs connecting to and trading on local networks is the lack of mechanisms to be financially compensated for the benefits they bring to the network. We are no longer convinced that a solely industry-led approach will deliver the change required. We recommend that:

- The Commission be supported to prioritise initiatives that drive distributor innovation.
- The Authority be supported to prioritise coordination of trials (as per Figure 4) in addition to its traditional focus on Code changes.

We recognise that these additional activities may require additional resources.

IPAG has not considered distributor funding for innovation, but may do so in future.

Figure 4: Potential trial process



Other sections

***Q5.5** What measures other than those identified above could be effective at accelerating investment in clean energy technologies?*

Measures to support access to the flexibility provided by DERs will help to accelerate uptake of distributed renewable electricity resources. They would be complementary to the ETS.

***Q9.6** Are the barriers noted above in relation to electricity market arrangements adequately covered by the scope of existing work across the Electricity Authority and electricity distributors?*

As noted in our response to question 11.3, the barriers will be dealt with by planned Authority, Commission and ENA work, but progress has been much slower than we think is necessary.

Appendix

The following are the implementation pathways identified in our Equal Access Advice. Numbering follows the original report, referencing activities and recommendations.

Highest priority implementation pathways

1. The Authority to publish an equal access development programme by June 2019 which sets out the tasks, priorities and milestones, and includes an engagement approach characterised by collaboration between regulators and participants and continuous trial-based evolution

2. The Authority to ensure all distributors to publish a plan of how they will build their network performance data set

5. The Authority to publish guidance for distributors to report on export congestion (s6.3(2)(da)) by June 2019, and report on distributor progress by December 2019

14. The Authority to ensure the distribution pricing principles provide appropriate guidance for providers and procurers of DER by June 2019

24. The Authority and Commission to report annually on the performance of the equal access framework, and progress with implementing the actions required to achieve the desired outcomes.

25. The Authority and Commission to develop a dashboard showing measures of progress towards equal access , including complaints.

Implementation pathways for action Q3 2019

7. The Commission and Authority to encourage distributors to collaborate in finding the most efficient way of capturing and publishing utilisation data. The Authority and Commission to report on progress by September 2019.

8. The Authority to work with distributors and data users to identify what data is required to support a DER market, and make sure accessible data is available to DER suppliers. The Authority should report publicly on progress by September 2019.

10. The Authority to encourage distributors to make available 'standing offer' price information for DER. The Authority to report on its progress by September 2019.

11. The Authority to identify how to establish a register of DER which is available to supply services. The Authority should report on its progress by September 2019.

19. Authority to work with a sample of distributors and DER suppliers to develop options how distributors could contract with DER to support network alternatives. Review progress September 2019. Implement by December 2019.

20. Electricity Authority and Commerce Commission to provide guidance to distributors and DER providers on trialling contestable frameworks. Authority and the Commission to report on progress by September 2019

23. Electricity Authority and Commerce Commission to develop a joint work programme to investigate potential efficiency and competition implications from: DER being treated as regulated capital; risks from misallocation of costs and revenues; risks from favouring in-house, related party or network solutions; and risks from restricting technologies and network users. This will include developing and costing options to mitigate any efficiency and competition harm identified.

Implementation pathways for action end of 2019

4. The Authority to integrate hosting capacity capability into Part 6. Gazette Code amendment in 2019, and report on distributor progress by December 2019.

9. The Authority and Commission to support distributors in providing accessible information on current or expected network investment needs in Asset Management Plans. A preferred option identified by December 2019.

12. The Authority to oversee the Electrical Engineers Association (EEA) and stakeholders to develop common technical codes for deployment and common standards for connection of DER.

13. The Authority to require adoption of the common standards by all distributors. The Authority should report on its progress by September 2019.

15. The Authority to determine how to provide DER installations with standard and default distribution connection and use of system agreements.

16. The Authority to encourage interested procurers (especially distributors) and active DER providers to develop arrangements for trade.

18. The Authority to support ENA to develop systems to signal the presence and cost of congestion within networks. Authority to report progress by December 2019.

21. The Authority to develop a reporting framework for distributors and DER suppliers to report results of trials. The Authority to establish a portal for sharing experience by December 2019.

22. Commerce Commission undertake an information campaign on Part 4 incentives including publicising relevant case studies as part of the DPP reset – late 2019.

Implementation pathways for action in 2020

6. The Authority to enable parties to access data. Develop effective backstop arrangements, subject to advice from the IPAG.

26. The Commission to reinforce its expectations of the treatment of costs and revenues for regulated service under the Commerce Commission Part 4 regime via an annual review of practices and penalties for rule-breakers.

27. The Commission to require distributor Directors to sign an annual declaration to investigate the use of DER for network alternatives. The best opportunities to trial and learn might be small-scale.

29. The Authority to report publicly the results of Transpower's trial Demand-Response programme, including technical details of what worked and what didn't work. Intention of informing future iterations of Transpower's programme ahead of RCP2.

Implementation pathways from 2020

3. The Commerce Commission to ensure distributors report annually on progress in fulfilling action 1.1.

17. The Authority progress towards distribution pricing that will reflect the cost of DER on the network. In 2020, review distribution pricing reforms and explore the use of contracts for DER with long-term appetite for a single schedule of prices.

28. The Commission and Authority to note the merit of aligning equal access at network level with transmission, including a longer term vision for similar principles to apply for both transmission and network companies.