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Targeted Reform of Distribution Pricing – Response to the Electricity Authority's Issues Paper 5 July 2023

1. This is Vector's ('our,' 'we') response to the Electricity Authority's (Authority) Issues Paper on Targeted Reform of Distribution Pricing. No parts of this submission are confidential, and it can be published on the Authority's website.

2. We are disappointed that this consultation coincided with the Commerce Commission's (Commission) consultation on its Input Methodologies (IM) draft decision. We also note that both these consultations coincided with electricity distribution businesses' (EDBs) preparation of annual information disclosures and where applicable price quality compliance statements. We have been led to believe that the Authority and the Commission endeavour to co-ordinate their consultation processes so that substantive submissions do not coincide. This is in recognition that it is usually the same resources within EDBs that prepare submissions for both the Authority and the Commission. Both regulators must do better in this area if they are genuinely interested in quality stakeholder feedback.

3. In this regard we note that our submission reflects the constraints unfortunately placed upon us by the lack of co-ordination of the consultations and regulatory filings referred to above. To try to manage these constraints we have focused primarily on the sections of the Authority's paper covering 'regulatory reform options' and 'connection pricing.' For the remaining sections and questions within those sections, please also refer to the Electricity Networks Aotearoa's (ENA) submission, which we have inputted into.

Executive summary

4. EDBs in Aotearoa New Zealand are facing a number of challenges when it comes to distribution tariff setting:

    a. Decentralised energy system: The rise of distributed energy resources (DERs) is challenging the traditional centralised model of electricity distribution. These DERs can both supply power to the grid and draw power from it, and provide value across a whole 'stack' of different services, complicating tariff structures and revenue models;

b. Affordability: Ensuring that low-income households are not disproportionately burdened by price changes, and EDBs are able to connect consumers quickly and efficiently while still incentivising decarbonisation and innovation remains a complex issue;

c. Peak demand and network capacity: Peak demand periods puts strain on EDB networks. Developing tariffs that encourage consumers to shift their energy consumption away from peak times, with sufficient certainty to alleviate the need for costly network upgrades, is a challenge;

d. Regulatory uncertainty: Changes in regulations and policies can impact pricing approaches and revenue models for EDBs. Uncertainty in regulatory decisions from both the Authority and the Commission can make long-term planning difficult; and

e. Data management: To implement sophisticated pricing reform, accurate and timely metering data is required. Integrating smart meter data into price-setting options requires investment and coordination.

5. As the country's largest electricity distributor, Vector is absolutely confronting these challenges head on as we continue to play our part in enabling electrification and doing it in the most affordable way possible for our consumers.

6. In April 2023 we implemented a range of pricing changes which demonstrates Vector's leading role in innovative and cost-reflective pricing reform, including:

   a. **Peak signal only in winter period** (Apr-Sep) for residential and general time of use tariffs: Peak price signal only targeting actual peak periods where network congestion may occur on our winter peaking low voltage network. The time of use differential is based on an estimate of the long-run investment cost on an electricity network of $98 per kW per annum. This means a retailer (or an agent working on their behalf), shifting one kW of load out of all our peak periods in the winter, can save $98 of variable distribution charges;

   b. **New residential tariff for DERs Installation Control Points (ICPs)**: Incentivise retailers to make ICPs available for future load management, and capable of connecting or responding to Vector's Distributed Energy Resource Management System (DERMS);

   c. **Introduction of a new sub-transmission commercial consumer group**: Vector has introduced a new time of use (TOU)-only commercial price plan, for consumers that have a connection directly to the Vector sub-transmission network and/or have paid for their connection assets to a Vector zone substation. The rationale for adding this consumer group is that it provides a more accurate cost allocation by removing the assets, which are downstream from their point of supply on the sub-transmission network; and

d. **Transmission pass-through pricing**: a grid exit point (GXP) allocation pricing approach was considered best placed to sheet home the new transmission pricing methodology (TPM) charges to the consumers on the individual GXPs for which the charges arose, to stay true to the intent of the design. We considered this would both minimise the revenue risk and be consistent with the pricing principles and guidance, therefore we transitioned to a GXP allocation approach which meant transmission cost recovery pricing was not tied to individual ICPs.

7. Vector has sought expert advice from global consultants to envision a future where the energy system is orchestrated in a way that avoids unnecessary network reinforcements and saves money for consumers. As discussed further below, and in more detail in our February 2023 submission to the Authority's parallel workstream[1], we worked with NERA to conclude that, while the appropriate mechanisms for procuring flexibility (e.g. contracted flexibility, price-response or another method) will take time to develop, implementing dynamic operating envelopes and other tools in the near term will be essential to enabling safe and secure value stacking by DER, regardless of how the future plays out. Maximising security of supply, reliability and stability remains crucial as the market evolves.

8. Meanwhile we continue to work with the Brattle Group (as demonstrated in our 2023 Pricing Roadmap[2]) on envisioning the role distribution pricing plays in our new energy future.

Process and timeframes

9. We were disappointed with the timeline of this consultation on distribution pricing. Either the Authority did not consult with the Commission over its ongoing consultation on the IM review, or it went ahead knowing that there was a clear overlap in consultation periods. The Commission has a strict process to adhere to so were unable to even entertain any extensions, but the Authority could have timed the release of this paper at a more suitable time in the year. This was particularly surprising given the extreme adverse feedback the Authority had received for taking near-identical action the last time the Commission reviewed the IMs, back in 2016. At that time, the Authority consulted on a major TPM issues paper, reform of distributed generation (DG) pricing, and avoided cost of transmission payments (ACOT) at the same time as the Commission consulted on the IMs.

10. In order to get the best input possible from stakeholders, enough time must be provided to respond adequately. This is reflected in our own submission where if we were allocated more

[e] Available online at https://blob-static.vector.co.nz/blob/vector/media/vector-2023/vector-submission-issues-paper-updating-the-regulatory-settings-for-distribution-networks_1.pdf

[2] Vector's 2023 Pricing Roadmap, available here https://blob-static.vector.co.nz/blob/vector/media/vector-2023/2024-pricing-roadmap-april-2023-final.pdf

time, we could have elaborated further on issues. Instead, we are relying heavily on the ENA's submission to represent our views in a number of areas.

11. We were also promised (back in our meeting on 5 May 2023 with the Authority on distribution pricing scorecards) that our draft scorecards would be made available to us towards the end of June. We received our draft scorecard on 8 August, only a week ahead of this consultation's deadline.

12. Similarly, submissions for the 'updating regulatory settings for distribution networks' consultation were only published to the Authority's website on 8 August 2023 (the deadline for this consultation was six months earlier in February 2023). Visibility of other stakeholders' positions could have been useful for stakeholders for this consultation.

13. This raises concerns for Vector and other EDBs over the Authority's consideration of the overall timeline for the following reasons.

    a. The Default Price-Quality Path (DPP) reset – regulatory reform to distribution pricing could impact heavily on revenues sought by suppliers for DPP4. In particular, the Authority must pay attention to section 54V[3] of the Commerce Act and ensure reform options are conveyed to the Commission; and

    b. Timings of EDBs' annual price setting – as relayed to the Authority in their meeting with the ENA on 26 July 2023, EDBs price setting starts 9 months prior to prices being implemented. The Authority will have seen evidence of this in Vector's pricing methodology[4]. This is to set expectations for the Authority around the potential speed of pricing reform for EDBs.

14. And more generally we are concerned that the above workstreams are interlinked and crucial for the energy transition to be successful. Yet there does not appear to be sufficient co-ordination or oversight across our regulatory bodies. For this reason, Vector continues to support the creation of a Ministry of Energy as a first step to get better and aligned policy and regulatory settings across the energy sector. If relatively simple process matters cannot be effectively coordinated across multiple regulatory agencies, we seriously question how more significant matters can be.

Role of retailers

15. It is pleasing to see the Authority is losing patience with retailers who continue to avoid reconciling with smart meter data even when it is available and claim exemptions from being

[3] [Commerce Act 1986 No 5 (as of 10 July 2023), Public Act 54V Impact of certain decisions made under Electricity Industry Act 2010 – New Zealand Legislation]

[4] https://blob-static.vector.co.nz/blob/vector/media/vector-2023/electricity-pricing-methodology-2024.pdf p.22

billed EDBs' evolved pricing. We thoroughly support the actions the Authority proposes taking in this area, including increasing monitoring of retail pricing – which is long overdue.

16. What is strongly implicit throughout the paper is that, in designing and setting our distribution prices, the Authority does not think EDBs need to consider whether or how these prices may find their way through to end consumers. Therefore, this would mean there is no need for us to find a 'sweet spot' between complexity, the ability for retailers to accommodate and respond, and pass-through. This has motivated EDBs' evolution to fixed TOU pricing to date.

17. In many ways the Authority's conclusion follows logically from the direction it is setting. It expects EDBs to increase the granularity of our pricing – more pricing areas, more consumer groups within each area, more scientific, accurate and potentially dynamic signalling – at the same time as not wanting to limit consumers' ability to choose from a range of retail offerings, including a uniform price if that best meets their needs, or to limit retailers' abilities to innovate in order to meet those needs.

18. In practice, it is actually more straightforward for us not to have to consider either how retailers might accommodate our prices, or how to engage end consumers in pricing and demand response. This suggests a more dispassionate focus for EDBs, purely on cost signalling.

19. However, we want to communicate clearly that we, and many other EDBs, firmly view ourselves as consumer-centric organisations, meeting the needs of the consumers in our communities now and into the future. The idea of setting "charges" to retailers, as opposed to "prices" for consumers, runs counter to that ethos. The fact that the pricing principles require us to consider the "transaction costs, consumer impacts and uptake incentives" of price changes, as do our Boards, confuses things further.

20. Further, retailers themselves have a range of views on their role in the system, and the role of our pricing. Every year when we consult with retailers on price changes, we hear from some that they want to be able to reflect our prices faithfully through to end consumers – they believe this is the right thing to do, and a key part of their value proposition. Any complexity we introduce works against them. Other retailers believe the opposite – that our prices are but one of many input costs they face, and they must have full flexibility to design propositions that allow them to attract and retain customers.

21. As we note above, much of this is implicit in the paper. It must be explicitly addressed with the sector. Until there is alignment between the Authority and the sector, and within the sector, on these key issues of philosophy right at the top of the design process, the risk is that we keep talking past each other. It is also relevant that the Commission wishes all networks to engage more with end consumers as part of establishing their forward investment plans. Given the Commission's regime has a price/quality at its heart, it is difficult to undertake such engagement with consumers without also being able to engage on our tariffs – both levels and form. The fact that we are subject to a regime where one regulator is requesting higher levels of end consumer engagement and the other regulator requires us to price only to

retailers – is further evidence of the growing need for a Ministry of Energy to establish coherent and joined-up policy and regulatory thinking in the energy sector.

Structure of this submission

22. Our responses to the specific questions posed in the paper are provided in the remaining sections of this submission. As noted above, due to competing priorities during the consultation period, we have focussed heavily on two sections of the paper (regulatory reform option and connection pricing); our responses to the remaining questions are at a high level only.

Regulatory reform options

Q1. Are there other options that you think the Authority should consider?

23. The Authority could consider introducing minimum requirements for pricing reform i.e. mandatory Time of Use (TOU).

24. The Authority's Distribution Pricing Practice Note (DPPN) is very technical, and changes are introduced on an ad-hoc basis by the Authority. We would recommend more direct engagement (i.e. workshops and other collaborative fora) to run through what the changes (and intentions behind the changes) mean for EDBs.

25. We encourage the Authority to clearly explain to stakeholders how they consider distribution pricing should differ from transmission pricing, if in fact there are any differences. The electricity industry has engaged extensively over the last decade with the Authority's processes to develop the current transmission pricing methodology (TPM). Throughout these processes the Authority has advocated strongly for many of the principles that underpin the TPM. It would be valuable for stakeholders to understand how these TPM principles translate into distribution pricing. A reconciliation of principles across the distribution pricing and transmission pricing, in our view is fundamental to giving confidence on consistency of approach and application.

Q2. Do you have any comments on the options outlined?

Continuation

26. Continuation could work with stronger indications of what pricing is actually preferred in the medium to long-term, then the scorecards could be used to accelerate EDBs towards the preferred pricing outcomes without resorting to the code change processes needed for "control" (which would also require decisions to be made about the specific outcomes sought).

27. At present the scorecards and evaluation methods for establishing the scores are very subjective rather than objective. If decisions were made in advance by the Authority, then the scorecards could become an objective metric related to progress made towards the targets.

28. We were pleased to see more direct feedback in the draft scorecards received on 8 August. This is a step in the right direction, but we would like to see the regulator going further with black and white instructions rather than leaving EDBs to second-guess the Authority's preferred reform options.

Control

29. For this option, the Authority must work in collaboration with the Commission. If a particular pricing approach is mandated this could have significant implications for EDBs' allowed revenues and could be consequential for the DPP4 reset and electrification investment more generally. This would be unchartered territory for the Authority, and we would caution the Authority against jumping to control where the unintended consequences extend well beyond the Authority's own jurisdiction.

Call-in

30. If this option is called upon it needs to be through a joint process between the Authority and the EDB. Collaboration on impact and outcomes is essential for this option to work with the intended circumstances.

Connection pricing

Q19. Do you agree with the assessment of the current situation and context for connection pricing? What if any other significant factors should the Authority be considering?

31. EDBs face the prospect of large new customers (data centres, embedded wind and solar farms, etc.) connecting at times and in places that are difficult to predict.

32. At times this may necessitate reopening an EDB's price-quality path – a costly and time-consuming process that will delay connections considerably and, potentially, the delivery of benefits from electrification/decarbonisation.

33. If connection costs are not met by connecting parties, this also has the undesirable consequence of 'smearing' connection costs caused by one party across others through lines charges, i.e., connection charges cease to be 'cost-reflective,' thereby departing from one of the defining principles of efficient pricing.

34. The paper suggests network companies might be requiring customers to make contributions to investment projects that greatly exceed their own requirements. This is not the case for Vector. Quite the contrary:

a. We guard against precisely this scenario through the application of a standard $/kVA charge to deal with system growth;[5]

b. We also, by mutual agreement allow customers to do their own trenching, civil works, reinstatement and laying of duct, i.e., if they believe they can undertake a project more cheaply themselves;[6] and

c. As a more general point, many of the most significant costs of connection (traffic management, etc.) are imposed by others (local councils) and beyond our control.

35. We cannot attest to what other EDBs are doing in this space, but we have not seen any credible evidence of EDBs levying excessive connection charges on individual parties for investments that benefit others. However, we do see the opposite from some parties: namely, the costs arising from one party's connection being smeared across other network users via lines charges.

36. Capital contributions also have one vital broader implication that bears mentioning: they reduce EDBs' financing requirements. Without those contributions from connecting customers, EDBs would need to finance those works themselves (for recovery via price-quality paths). That additional burden could come at a time when EDBs are already facing profound financing challenges from the substantial investments required to enable electrification.

37. As we stressed in our submission[7] to the Commission's recent IM review draft decision, financeability is a key concern for EDBs and could compromise our ability to maintain satisfactory credit metrics and any move to limit capital contributions would only make those problems worse.

38. The Part 4 purpose requires the Commission to promote the long-term benefit of consumers of regulated services. They must do this by promoting the outcomes consistent with those produced in workably competitive markets – namely, that the suppliers of these services have incentives to innovate and invest, including in replacement, upgraded, and new assets.

39. EDBs do the heavy lifting on annually connecting tens of thousands of consumers. This involves managing a variety of third parties, complex and varied sites to work on (greenfields and brownfields each having their own complications), and high consumer/ developer expectations. For Vector, new connections are generally between 12,000 to 14,000

[5] Vector, Policy for determining capital contributions on Vector's electricity distribution networks, From 1 December 2021, Pursuant to: Electricity Distribution Information Disclosure Determination 2012, p.6.

[6] Op cit., p.8.

[7] Vector, Submission of the IM review draft decisions, 19 July 2023 p.26

connections per year across the greater Auckland area[8]. This is done with nearly no complaints from connecting parties as can be seen by the small number of Utility Disputes Limited (UDL) complaints[9], all while the number of connections faced by EDBs is growing rapidly.

Q20. Do you agree with the problem statement for connection pricing?

40. At Vector we pride ourselves in the work we do to connect customers safely, quickly and cost efficiently and we are of the view that the majority of connecting parties value the connection services provided.

41. Unfortunately for Vector and consumers, EDBs' pass-through costs have increased across all segments (notwithstanding the high inflationary environment we currently face). These costs reflect third-party pass-through costs that Vector and others cannot absorb (examples include traffic management, civil works, and reinstatement costs).

42. To mitigate these costs, Vector issues multiple civil quotes for each connection, strives to continuously improve processes, and implements efficient network designs for long-term resilience. Vector provides options to large customers like data centres and allows them to arrange civil works themselves. From our discussions with international consumers, this practice is common in other parts of the world too.

43. Regarding traffic management, it is important to note we are actively working with Auckland Transport and Waka Kotahi to move it from a rules-based approach to a risk-based approach. A more pragmatic approach will assist in reducing these costs.

44. Vector's disclosed capital contribution's policy adheres to the Electricity Authority's pricing principles. There are also no incentives to inflate costs because assuming the contribution paid is equal to the costs no asset is added to the EDB's regulatory asset base (RAB).

45. Vector believes that there are strong incentives to coordinate connection and associated system growth investments within our current settings. New connecting consumers are aware of the impacts they are causing to the network and the associated costs that they are incurring. We are working to provide options that assist customers in lowering the upfront

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[8] Vector had 12,478 new connections in 2020; 13,854 in 2021; and 13,437 in 2022 - see Vector's Electricity Information Disclosures here https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/financial-and-network-information

[9] In the past 5 years UDL has recorded 102 complaints about delays in setting up new connections New Zealand-wide, 69 are about retailers (0.7% of retailer total), 33 are about EDBs (2.6% of EDB total). See UDL submission to the EDB Targeted ID Review Process and Issues Paper, 20th April 2022, p.3 available here https://comcom.govt.nz/__data/assets/pdf_file/0016/282121/Utilities-Disputes-Limited-Submission-on-EDB-targeted-ID-review-process-and-issues-paper-20-April-2022.pdf

connection costs (DER tariff, reduced system growth charges if capable of responding to a dynamic operating envelope).

46. One example of this is the work we carried out with Aotearoa New Zealand's first electric bus depot. In February 2023 we saw the opening of New Zealand's first fully electric bus depot, in Panmure, Auckland. Our team worked with Auckland Transport (AT), NZ Bus and Kinetic to complete the project.

47. The Panmure bus depot formerly housed 44 diesel buses (and diesel tanks), but now it is home to 35 electric buses – each one able to be charged up to 502kWh each night, via fast DC chargers. If all of them plugged in at peak time, it would require a significant investment in the network. Along with AT we conducted a Grid Impact Study, we assessed the requirements of a high-voltage connection to the depot and the charging infrastructure needed to supply it.

48. Together with NZ Bus we adopted a smart-charging system, which will be connected to our DERMS. This will manage e-bus charging dynamically to avoid increasing peak demand, while guaranteeing full charging overnight and during times of the year when the network is unconstrained. This was achieved through the development of a non-standard DERMS tariff which helped inform our new DER tariff. The system also future proofs the depot for potential development of additional Bus to Grid (B2G) systems (which are being assessed overseas) to transfer surplus energy from bus batteries back to the network.

Q21. Do you agree with the Authority's preferred pricing approach for connection charges?

49. The Authority wants EDBs to reduce allocations to access seekers "where these are overly high" but note that these "allocations should be subsidy free." We should note that anything less than a 100% capital contribution includes some form of subsidy to the access seeker.

50. We also note the direct and significant impact reducing capital contributions would have on capex forecasts in EDBs' Asset Management Plans (AMPs) with subsequent flow on effects for expenditure allowance setting for the Commission resetting of EDB price paths from 1 April 2025. The Authority needs to carefully consider that the Commission makes its final reset decision in November 2024 and the wide-ranging jurisdictional implications of interfering with the process. Therefore, any mandated changes to capital contributions by the Authority would need to occur before the Commission's reset draft decision in May 2024. The Authority should not (and would be acting in error) be so bold as to assume reopener mechanisms in the Commission's regime for so many EDBs can simply alleviate this issue. It is unlikely that reopeners could respond in time to meet the requirements of most access seekers and significant uncertainty would remain over the outcome of any reopener process.

51. The ability to offer flexibility to access seekers where they can balance cost versus quality of service is relatively limited due to the physical nature of the network unless the Authority is envisioning some form of firm right for the management of discretionary load by EDBs where

an access seeker agrees to be "first off" in the case of an EDB needing load management to resolve a network constraint.

Q22. Do you have any thoughts on the complementary measures mentioned above and to what extent work on these issues could lead to more efficient outcomes for access seekers?

Providing information on asset locations and network capacity

52. In its latest AMP[10], Vector published a case study on interactive maps for network headroom and system growth projects.

53. To support customer and stakeholder engagement, Vector publishes key network information on its open data portal where users can not only visualise detailed geospatial information of the network but also conveniently download the raw information for use in their own systems or more detailed analysis in expert tools. The information available includes location of assets (ZSS and 11 kV feeders), the boundary of our coverage area and ongoing and future works for network projects (within the next 2 years).

54. Based on customer and stakeholder feedback, the open data portal now also hosts two new interactive maps for network headroom and all system growth projects covered by this 10-year AMP. The network headroom map indicates the headroom in the 11 kV network for winter and summer peak conditions. The expectation is that this map supports early-stage customer engagement. For system growth projects, the AMP always provides a comprehensive view of expected expenditure, timing and options considered. The new interactive map will complement this information by providing a spatial visualisation, which ensures the stakeholders and customers can easily identify the projects planned in their area of interest.

55. However, if maps with information on asset locations and network capacity allow access seekers to target areas where they expect lower costs, does that imply that costs are not being correctly allocated and are being subsidised by existing users? If there are areas with lower connection costs, it suggests that these maps simply enable access seekers to find places where they have the "first mover advantage," which is something the Authority wishes to minimise.

56. We also note that making this information available (along with many other new information disclosure requirements introduced by the Commission) is not costless. The Commission's current opex and capex allowances limit the ability of EDBs to invest in significant new resources needed to develop the systems needed to make new data requirements available.

[10] AMP 2023, p.85 available here https://blob-static.vector.co.nz/blob/vector/media/vector-2023/vec246-vector-amp-2023-2033_120523_1.pdf

Additional allowances will be needed at the next DPP reset if such investment in new systems is significant.

Allowing access seekers to contract works directly from a large pool of approved providers

57. On the Authority's second complementary measure to allow access seekers to contract works directly from a large pool of approved providers, it must be pointed out that the pool is not limited by EDBs but rather by New Zealand's small pool of contractors willing to build their capacity and certify their workforce to support this type of work across all the regions of New Zealand.

58. The Authority should also be mindful that relative certainty for providers allows those companies to resource up to provide the capacity required. A pool approach might not provide the same level of certainty resulting in inadequate capacity of resource to the detriment of access seekers.

Q23. Are there other options you think the Authority should consider for connection pricing?

59. Ahead of considering other options, the Authority must engage with EDBs on financeability, and subsequently with the Commission on the DPP4 reset to ensure the impacts of any changes are understood and accounted for.

60. The Authority needs to be careful in considering other options that assume EDBs will make a required investment. The Commerce Act Part IV purpose statement is clear that there should be incentives to invest. There is a risk that some options may dampen or even remove those incentives. This may result in EDBs deciding not to make certain investments for a variety of reasons e.g. financeability issues- and all of this at a time when network investment is critical to enabling Aotearoa New Zealand's electrification transition.

Q24. Which if any of the above options do you consider would best support distribution pricing reform in the area of connection pricing?

61. The Authority should start with a review of EDBs' adherence to the pricing principles in relation to capital contributions (see section 11 of our policy[11]). With all policies disclosed on EDBs' websites this could start as a desktop exercise and develop into direct engagement with each EDB on where there are perceived gaps. This then could become a new feature of the pricing scorecards.

Peak period price signals

Q3A. Do you agree that a combination of TOU tariffs and load control (appliance) tariffs would be useful for the smart management of peak demand?

[11] Vector's capital contributions policy https://blob-static.vector.co.nz/blob/vector/media/vector2021/211201-policy-for-determining-capital-contributions-electricity-distribution.pdf

Q3B. Do you consider that TOU pricing could have unintended consequences for congestion on the LV network?

Q3C.Do you consider that use of shoulder pricing as part of the TOU price structure could be an effective way to mitigate this risk? What other ways could be effective?

Q4. Do you agree with the assessment of the current situation and context for peak period pricing signals? What if any other significant factors should the Authority be considering?

Q5. Do you agree with the problem statement for peak period pricing signals?

Q6. Do you have any comments on the Authority's preferred pricing for peak periods?

Q7. Are there other options you think the Authority should consider for improving peak period pricing?

Q8. Which if any of the above options do you consider would best support distribution pricing reform around peak pricing signals and why?

62. As noted above, our comments in the remaining sections of this submission have been left broad, due to a lack of time to fully engage on the content in the paper.

63. Regarding peak signalling, we support the point made in ENA's submission that the Authority needs to be crystal clear in its definition of the ultimate objective of distribution pricing reform:

   a. Some parties view it as providing signals to encourage consumers to shift load, so that future network build can be minimised. The measure of success therefore would be the extent to which peak demand growth is suppressed; and

   b. However, we suspect the Authority views it as providing consumers (and their agents) with information to *inform choices* and encourage *efficient* usage of, and investment in, the network – which may mean peak demand increases and more network is built, based on consumers' choices.

64. Until we are all clear on the intended outcome, it is likely parties in the sector may be talking past each other. This goes to the heart of how EDBs see their role – on the one hand it could be to design tariffs that engage end-consumers and effect load shifting; on the other, it would be simply to send cost-reflective signals to retailers, who will then act in accordance with consumers' preferences. This may or may not effect changes in load, but again that may still meet the objective if the choices are informed. We strongly suggest the Authority leave little room for doubt in what it believes its primary intent actually is so that distribution pricing reform can respond accordingly. As has been recently experienced with significant TPM changes leading to changes in load control activity and capability, there can be significant unintended consequences of not maintaining existing incentives and capability, let alone engaging consumers to build new options. Consumers' expectations and preferences can take a generation to influence, and care needs to be taken in the approach to building a culture of responsiveness.

65. We think there are a range of commercial mechanisms (pricing and other contractual tools) that will be of use for encouraging efficient use of the existing network, in order to stimulate an efficient level of future investment. As we discussed in more detail in our submission to the Authority in February, on its *Updating the Regulatory Settings for Distribution Networks* consultation paper[12], shifting load from peak periods is at the heart of Vector's Symphony strategy, in order to minimise the costs of network expansion and maximise affordability to consumers. We are committed to avoiding the cost of upgrades which may benefit only a few being socialised over many. At a time of heightened awareness of energy affordability, this matter would appear to magnify in importance.

66. While we are also committed to evolving our pricing and increasing its complexity and efficacy over time, to give it the best chance of achieving its intent, we are also far from convinced that pricing alone can provide enough certainty of consumer choice and consumer behaviour to be able to defer significant amounts of investment, especially at the low-voltage (LV) level.

67. As part of our submission in February we provided a report we commissioned from NERA[13], which describes the interaction between commercial mechanisms to inform and encourage consumer behaviour and physical, backstop mechanisms to guarantee it. Device management, by a range of parties including the EDB, will be a key feature of that future.

68. NERA's report highlights that, in a world in which flexible DER are managed by a range of parties across our network, relying on pricing alone to orchestrate specific outcomes at the low-voltage level will be problematic. Or, viewed from another perspective, response to energy and distribution prices will certainly create issues at the LV level. It is hard to come to any other conclusion when wholesale market prices or EDBs' TOU prices (at least currently) do not contain any reflection of specific costs or elements of real-time congestion on the LV network.

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[12] Available online at https://blob-static.vector.co.nz/blob/vector/media/vector-2023/vector-submission-issues-paper-updating-the-regulatory-settings-for-distribution-networks_1.pdf

[13] Submitted with this report and available online at https://blob-static.vector.co.nz/blob/vector/media/vector-regulatory-disclosures/nera-report-for-vector-20230228-v1-0.pdf

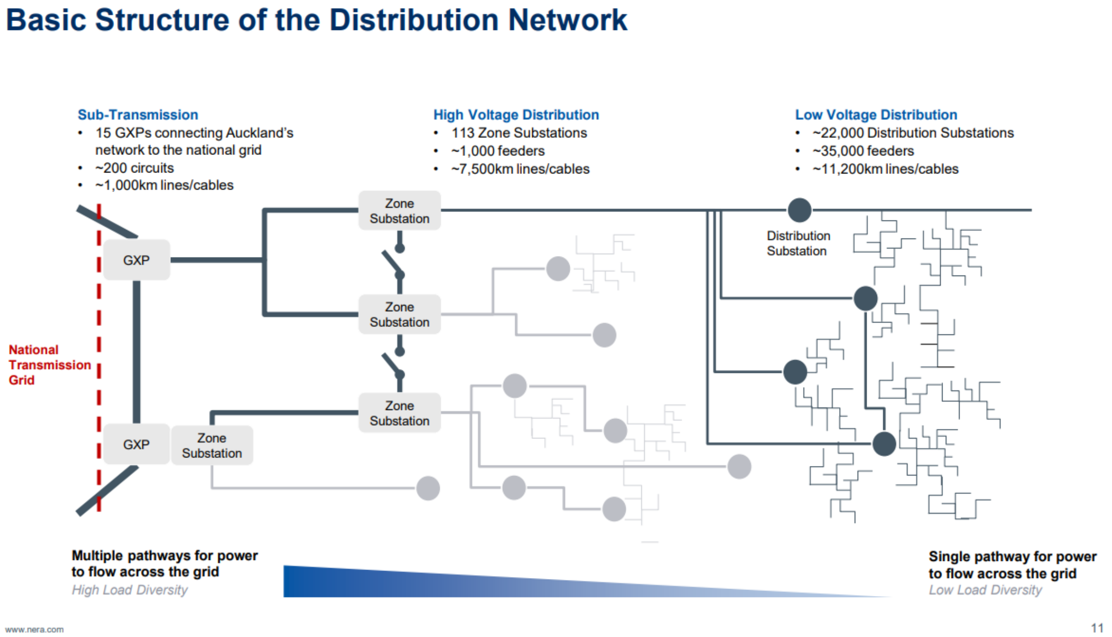
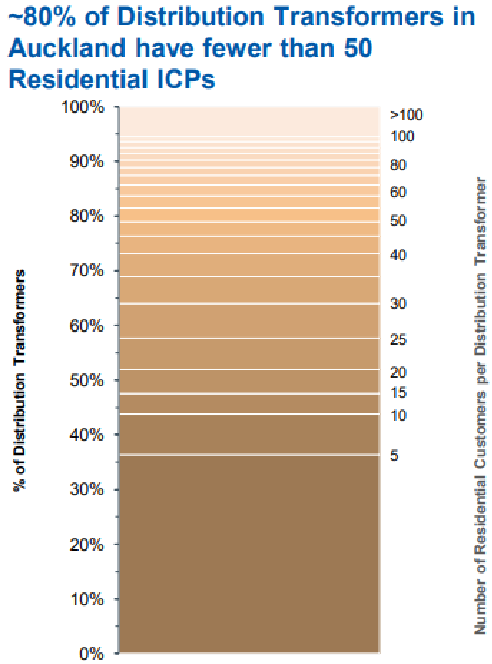


Diagram from NERA's report showing stylised representation of the distribution network

69. As set out in NERA's report, and shown in the diagram on the right, the number of consumers served by a specific LV asset can be very low; e.g. for Vector, a third of our distribution transformers serve just five or fewer residential connections (note some of these transformers also serve one or more commercial consumers). Diversity benefits are much lower at this level, and the chances of a high proportion of consumers ignoring a price signal are higher.



70. Aggregation of consumer devices, and automated response of those devices to wholesale price signals, as intended through the recent introduction of *Dispatch Notification* under real-time pricing, or TOU network prices, will definitely create new challenges for EDBs operating their networks. An aggregator managing a fleet of (for example) hot-water cylinders, or smart EV chargers, may want to dispatch all of those devices 'on' in response to a rapid fall in spot prices, and/or at the end of an EDB's peak TOU pricing period. Without appropriate interaction between the aggregators and the host EDB, coordinating and managing ramp rates and maximum loads, will almost certainly create unplanned outages and significant congestion issues on LV networks. Voltage and thermal limits on specific assets will be at risk.

71. Typically, residential connections can physically allow consumers to consume up to 14 kVA, but design standards plan for much lower levels of coincident, after-diversity maximum demand (ADMD) – in the range of 2.5-5kW per residential connection – resulting in a smaller physical network upstream and reduced costs for all consumers. As a result of these design practices, we do not think any EDB in New Zealand would currently be able to accommodate a large number of 7kW EV chargers and 3kW hot water cylinders turning on at the same time on its LV network, and we suspect no network is planning to build a network capable of doing so – despite the availability of this flexibility being an implicit assumption in the broader wholesale market design. Managing congestion at all levels of the network – LV, HV and sub-transmission – will therefore become a key challenge for EDBs going forward.

72. It is therefore critical that the Authority considers what backstop, physical mechanisms will be required to support any of the commercial mechanisms like pricing designed to inform consumer and aggregator choices.

73. With regard to discussion on different types of cost-reflective pricing, we need to be clear that TOU means "time-varying." There are then different categories of time-varying charges, which may either be static (i.e. fixed and predetermined in advance, irrespective of network conditions) or dynamic, reflecting real-time conditions. Indeed, a uniform, constant price can still be described as "cost-reflective," if it accurately reflects the average cost of using the network.

74. Point 4.19(c) in the consultation paper suggests that TOU tariffs are different to tariffs that reward flexibility. This is not the case – they are one and the same. There are now several instances of retailers publicly trialling smart technology (hot water load and EV management) at least partly in response to EDBs' cost-reflective TOU prices, with their response periods aligned with EDBs' TOU pricing periods. Shifting load out of peak TOU periods provides a clear reward to retailers (and their customers) for being flexible, which is more stable and predictable than rewards from responding to electricity market signals.

75. It is also worth noting that in the future the difference in network loading between "peak" and "off-peak" may become smaller as more consumers are able to shift loads, and overall load profiles flatten. Thus, the incentive an EDB could offer to consumers shifting load from "peak" to "off-peak" would likely be lower to reflect the reduced benefit of shifting loads. However, if the network is highly optimised and loadings are high, the cost of an extra MW in any of those peak periods could be extremely high but will be sustained over a large "peak" time period.

76. Finally, we support the ENA's view that further guidance from the Authority in relation to peak pricing must include consideration of the following factors:

    a. The premium value to EDBs of certainty of response from managed loads, compared with potential response from consumers. EDBs cannot simply "magic up" new capacity if consumers choose to ignore a price signal one evening;

b. The lack of diversity at low voltages, and the greater risk of synchronised behaviour, which can limit the usefulness of price response; and

c. The coincidence of peaks (or lack thereof) on LV and HV networks, and the implications for both TOU time periods, peak/off-peak differentials and LRMC calculations.

Off-peak price signals

Q9. Do you agree with the assessment of the current situation and context for off-peak pricing signals? What if any other significant factors should the Authority be considering? Q10. Do you agree with the problem statement for off-peak pricing signals? Q11. Do you have any comments on the Authority's preferred pricing for off-peak usage? Q12. Are there other options you think the Authority should consider for improving off-peak pricing? Q13. Which if any of the above options do you consider would best support distribution pricing reform around off-peak pricing signals and why?

77. With regard to overall pricing structure, as we understand it, broadly, the Authority's desired approach for EDBs is:

    a. Peak charges – provide a signal of forward-looking LRMC of investment;

    b. Off-peak charges – provide no (or a very low) signal not to consume; and

    c. Residual/fixed charges (recovering costs of previous investment and common costs) – recovered in such a way as to provide no incentive to change behaviour; i.e. broad-based and non-distortionary.

78. The residual/fixed charge approach reflects the Authority's conclusion of TPM reform for residual cost allocation. Again, it would be useful for this structure to be spelt out very explicitly.

79. However, the inability to sheet home post-upgrade costs to consumers whose actions may have caused those upgrades (i.e. an "exacerbators pay" approach) does raise significant equity concerns. This is a reason why we would consider using AMD or banded capacity (nominated) as an allocator for residual costs.

80. Consider the case of a residential suburb where 33% of the houses charge an EV at home in peak periods, 33% of the houses charge an EV at home outside peak periods and the other 34% do not own an EV. Prior to an upgrade, with material peak TOU signals, those charging their cars in peak periods will pay higher network charges than those not doing so, as should be the case. This will reduce residual costs for the rest of the consumers in the suburb.

81. However, if this wilful peak charging eventually precipitates an upgrade, creating significant spare capacity, the EDB's peak charges may reduce and could be removed (depending on the scale of the upgrade and the timeframe over which peak charges are calculated). This will lead to the costs of that upgrade becoming *residual* charges for that pricing area and consumer group. These will be smeared across *all* consumers in that suburb, in a non-distortionary way, regardless of their previous impact on the network.

82. All consumers will still have the same capacity of ~14kVA, so a simple capacity charge will not help. Would the answer be to partition EV owners and non-EV owners into different consumer groups, and then use each group's share of coincident peak demand (rather than each group's AMD) to allocate residual costs between the groups?

83. As noted above, equity and affordability are significant concerns for us as we support the energy transition. Various approaches are being discussed to manage these issues, including active management of EV charging. We would welcome discussion with the Authority on how issues such as this example should be addressed.

84. With regard to the context and problem statement, the Authority correctly notes that the low-fixed charge (LFC) regulations still have significant influence over EDBs' pricing and our ability to strike the right balance between variable and fixed costs. This has meant that EDBs who have attempted to follow the Authority's guidance in relation to TPM charge pass-through have been limited in the extent to which they can pass those costs through as fixed charges. Doing so only means they have to recover more of their own fixed costs through variable charges. We have attempted to avoid doing so by recovering TPM charges separately from our own costs, which has enabled us to introduce a zero off-peak price to standard consumers.

Target revenue allocation

Q14. Do you agree with the assessment of the current situation and context for target revenue allocation? What if any other significant factors should the Authority be considering? Q15. Do you agree with the problem statement for target revenue allocation? Q16. Do you have any comments on the Authority's preferred pricing? Q17. Are there other options you think the Authority should consider for improving target revenue allocation? Q18. Which if any of the above options do you consider would best support distribution pricing reform around targeted revenue allocation?

85. We comment here at a high level due to the time constraints noted earlier in this submission.

86. The Authority has not clearly explained how they consider their objectives for distribution pricing interact with the Commission's regime.

87. The Commission determines allowable revenues (target revenue) for non-exempt EDBs on a building blocks approach. These building blocks are effectively current costs such as operating expenditure, depreciation etc. The building blocks do not reflect future costs. Under the Commission's regime, EDBs set prices to recover building block allowable revenues which are sometimes referred to as BBAR.

88. The Authority has indicated that EDB pricing should however signal future costs. We consider it would be useful if the Authority explained how they consider these future costs should be considered in regard to EDBs setting prices to achieve BBAR.

Retailer response

Q25A. Do you agree with the assessment of the current situation and context for retailer response? What if any other significant factors should the Authority be considering? Q25B. [for retailers]: What plans do you have for responding to distribution price signals as distributors reform their price structures? What barriers do you see to responding efficiently? Q25C. [for distributors]: What plans do you have to increase the proportion of your customers that face time-varying charges (for example, making TOU plans mandatory for retailers whose end-users have an AMI meter installed)? Q26. Do you agree with the problem statement for retailer response? Q27A. Do you have any comments on the Authority's preferred pricing? Q27B. [for retailers]: What use do you make of deemed and residual profiles? Please explain the reasons for this. What barriers do you see to phasing out use of deemed and residual profiles? Q28. Are there other options you think the Authority should consider for retailer response? Q29. Which if any of the above options do you consider would best support distribution pricing reform in the area of retailer response?

89. Our key comments in relation to this section are covered at the top of this submission.

90. As we noted earlier, we are very encouraged by the Authority deciding to act in this space and ensure that the incentives on retailers to respond to reformed distribution pricing are as strong as possible. It is absurd to think that some smart meter data is not being used for reconciliation when it is available; we continue to support a ban on the unnecessary use of profiles, as we have noted in other submissions to the Authority.

91. We also support limitation of exemptions to the extent possible, and greater monitoring of retail pricing and innovation by the Authority. Our TOU prices for mass-market consumers in Auckland are mandatory, and we welcome moves to ensure exemptions from those prices are minimised.

92. As the Authority notes, a retailer faces a wide range of input costs. And, as noted, if EDBs' charges become more complex and cost-reflective, a retailer is incentivised to respond in one or more ways:

   a. by providing information to end consumers to support load shifting;

   b. managing appliances remotely themselves (like EV charging or hot water); and/or

   c. adapting their own retail plans and prices to reflect upstream signals in some way.

93. We are now, finally, seeing at least the latter two approaches happening in the market, with TOU pricing offers becoming much more prevalent.

94. We support the EA's position that placing restrictions on retailers' abilities to innovate or meet consumers' preferences is not warranted, at this point. Some consumers will welcome complexity and transparency, others will prefer simplicity. Our sector has almost finished unwinding the restrictions the LFC Regs placed on both distributors and retailers, which all parties agree has hamstrung innovation in pricing for two decades. With consumers' needs and preferences continuing to evolve, and heterogeneity increasing, we do not want to see any new limitations on consumer choice introduced.

95. However, notwithstanding these comments, more monitoring of the retail market and retailer offerings is definitely required. If progress stalls and we do not see sufficient reaction from retailers to our evolving prices, across all of the potential response set above, further intervention may be warranted. We also do not consider that this monitoring should be solely limited to retailer price innovation.

96. As we have advocated before it is important that changes in the overall *levels* of EDB pricing find their way through to end consumers. In previous EDB Commission price resets we have not seen price reductions passed on to consumers, and the Authority has not transparently monitored or reported on these changes. Likewise, retailers are now receiving settlement residual allocation methodology (SRAM) payments from EDBs which we expect should flow back to end users via retailers' hedging and pricing practices. Increased reporting will give confidence that the competition the Authority relies on to ensure retail pricing is efficient is actually occurring in practice.

97. While the Authority may assume that most retailers will repackage EDBs' prices in line with consumers' preferences, it is clear that some will not. The response to our own price changes each year (level and structure) is remarkably varied. For some retailers (e.g. Ecotricity), passing through distribution prices and structures as faithfully as possible is a key part of their proposition. Other retailers may feel unable to manage the financial risk that complex input pricing creates and may pass this risk on to their customers in full. Others do not change their retail prices at all if their input costs change – at least in the short term.

98. In recent years, we and other EDBs have experienced a wide range of reactions from retailers in conversations about increasing the complexity of our charging. These views can sometimes be disconnected from the views espoused publicly. As part of the increased monitoring, we would encourage the Authority to collect information from EDBs who consult with retailers on their price changes each year. We noted the Authority considers in para 8.15 there is a "'sweet spot' between the benefits of cost-reflectivity versus the benefits of simpler consumer offerings." However, if the Authority thinks that increased complexity of distribution pricing should not be something for EDBs to shy away from on behalf of retailers, or end consumers, it should make this guidance loud and clear.

Yours Sincerely
For and On Behalf of Vector Limited,

Richard Sharp
GM Economic Regulation and Pricing

PROMOTING EFFICIENT AND AFFORDABLE INFRASTRUCTURE TO ENABLE ELECTRIFIED TRANSPORT

PREPARED FOR VECTOR

28 FEBRUARY 2023

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Introduction

- Alongside government programmes to increase EV uptake, the NZ electricity industry, including the market regulator (the Electricity Authority) is considering options for a framework for EVs and EV charging to provide flexibility services. According to a recent study by the Boston Consulting Group (BCG) on behalf of several parties in the NZ energy industry, load flexibility could yield $10 billion in NPV savings to 2050 (across generation, transmission, and distribution). These savings would be passed onto to consumers through market competition and various regulatory mechanisms.[1]

- The EA states that flexibility services "should be procured competitively with all providers competing on a level playing field", and is currently considering the competition impacts of network operators directly controlling DER (including EV charging) through their work programme to update the regulatory settings for distribution networks.[2]

- Flexibility services can provide value to the whole system through (a) avoided dispatch of expensive generators; (b) avoided investment in peaking capacity; and (c) avoided investment in transmission and distribution capacity. This value will be felt by consumers through lower network revenue allowances and lower wholesale energy prices.

- As we demonstrate through these slides, competitive provision of flexibility services may realise the value of **(a)**, but is unlikely to be *immediately* effective in realising **(c)**, particularly the distribution component (or **(b)** but that doesn't have as much to do with distribution networks). While this report focusses on EV charging, the same principles would deliver savings from any DER with a degree of flexibility and dispatchability.

- A framework that provides EDBs with a high degree of certainty over EV charging behaviour and outcomes is the only way to avoid network solutions during the initial stages of the EV rollout in the next few years. The key objective of such a framework should be to provide the certainty EDBs need while not getting in the way of flexibility markets developing.

1. BCG (November 2022), The Future is Electric – A Decarbonisation Roadmap for New Zealand's Electricity Sector
2. EA (July 2021), Updating the Regulatory Settings for Distribution Networks, Improving competition and supporting a low emissions economy, para. 6.3.

Unmanaged EV charging could impose large costs on society

In the absence of managed EV charging, the EV roll-out may exacerbate system peak demand

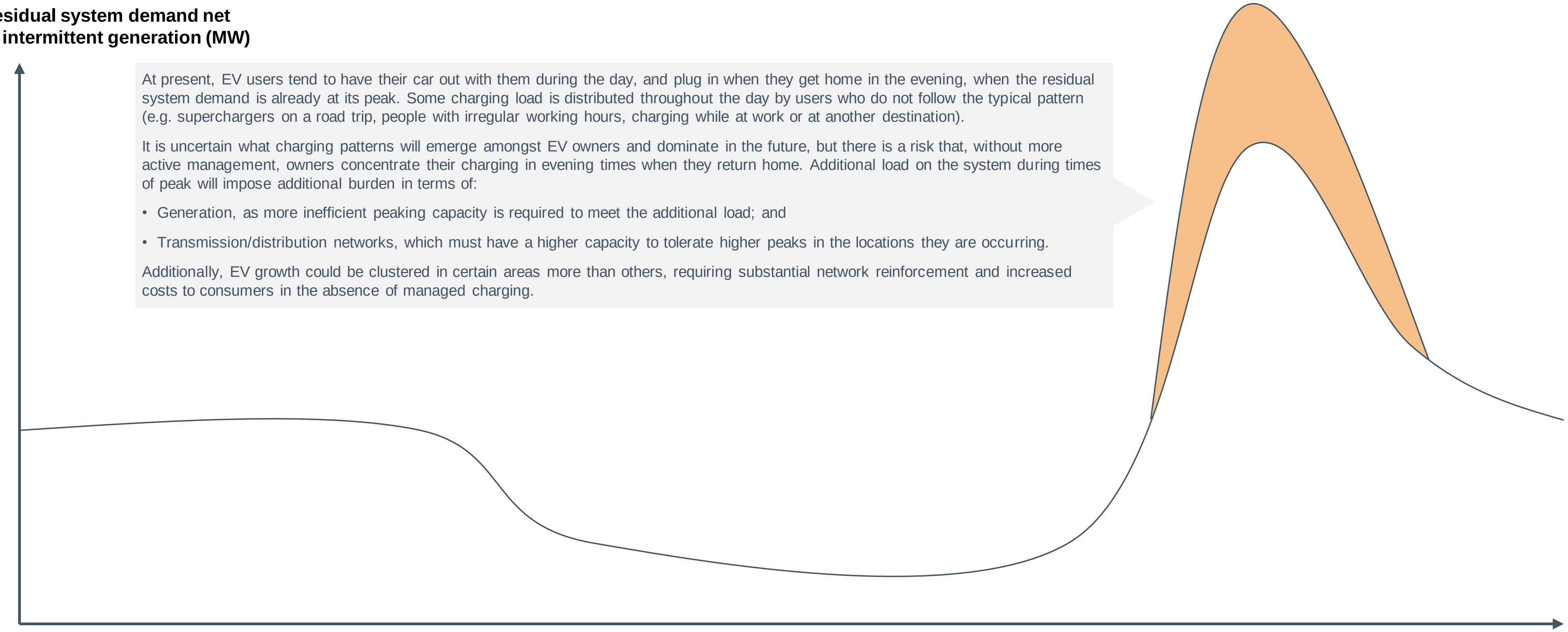
Residual system demand net of intermittent generation (MW)

At present, EV users tend to have their car out with them during the day, and plug in when they get home in the evening, when the residual system demand is already at its peak. Some charging load is distributed throughout the day by users who do not follow the typical pattern (e.g. superchargers on a road trip, people with irregular working hours, charging while at work or at another destination).

It is uncertain what charging patterns will emerge amongst EV owners and dominate in the future, but there is a risk that, without more active management, owners concentrate their charging in evening times when they return home. Additional load on the system during times of peak will impose additional burden in terms of:

- Generation, as more inefficient peaking capacity is required to meet the additional load; and
- Transmission/distribution networks, which must have a higher capacity to tolerate higher peaks in the locations they are occurring.

Additionally, EV growth could be clustered in certain areas more than others, requiring substantial network reinforcement and increased costs to consumers in the absence of managed charging.



Time of day (hours)

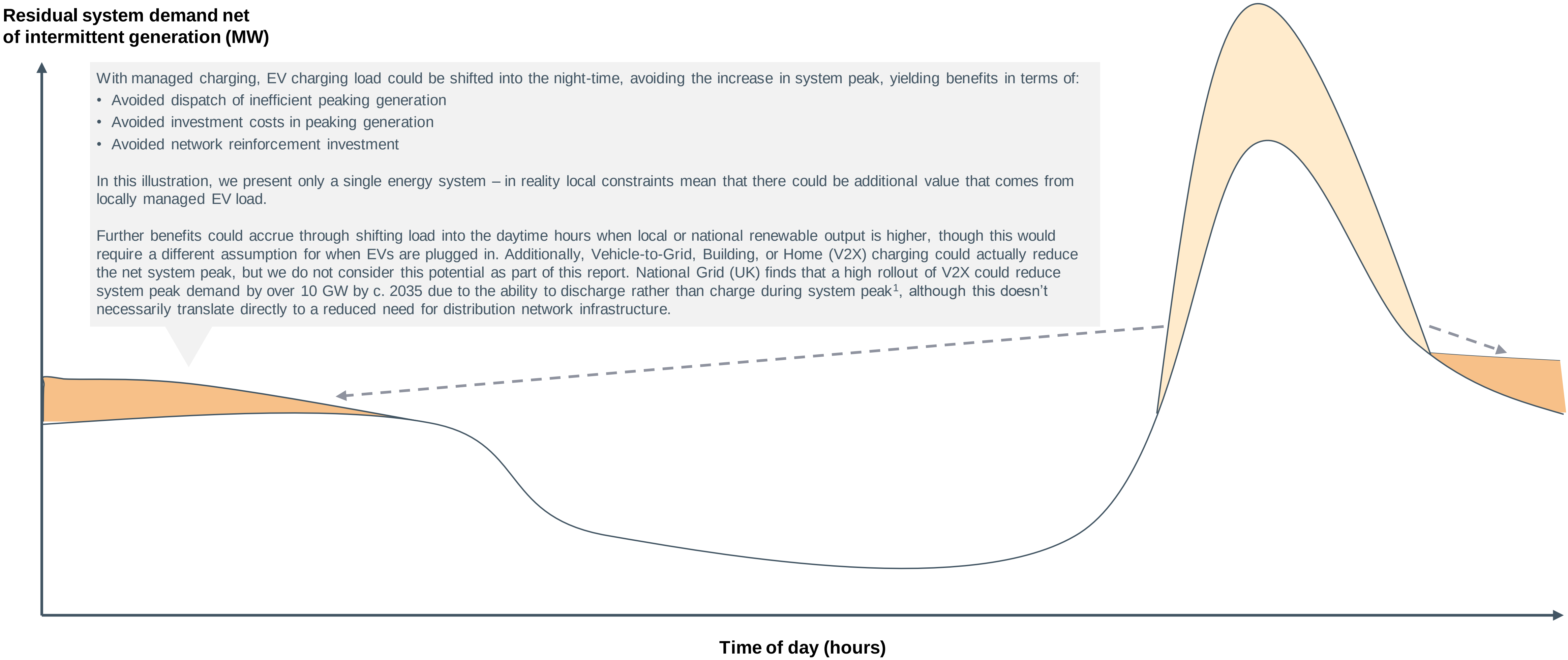
Many social benefits could arise from flexible charging

With managed charging, EV charging load could be shifted into the night-time, avoiding the increase in system peak, yielding benefits in terms of:

- Avoided dispatch of inefficient peaking generation
- Avoided investment costs in peaking generation
- Avoided network reinforcement investment

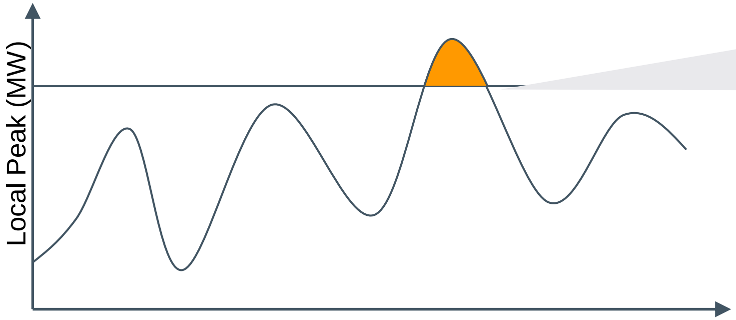
In this illustration, we present only a single energy system – in reality local constraints mean that there could be additional value that comes from locally managed EV load.

Further benefits could accrue through shifting load into the daytime hours when local or national renewable output is higher, though this would require a different assumption for when EVs are plugged in. Additionally, Vehicle-to-Grid, Building, or Home (V2X) charging could actually reduce the net system peak, but we do not consider this potential as part of this report. National Grid (UK) finds that a high rollout of V2X could reduce system peak demand by over 10 GW by c. 2035 due to the ability to discharge rather than charge during system peak[1], although this doesn't necessarily translate directly to a reduced need for distribution network infrastructure.

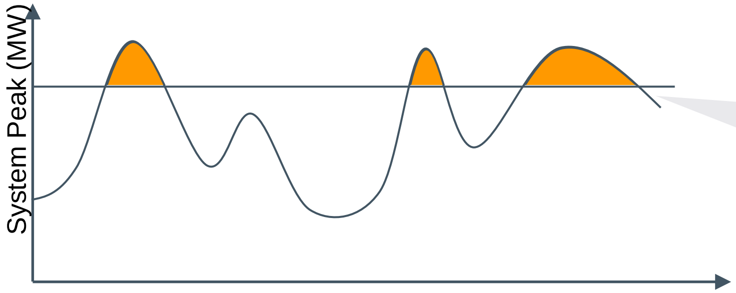


1. National Grid (2021), Future Energy Scenarios, p. 273

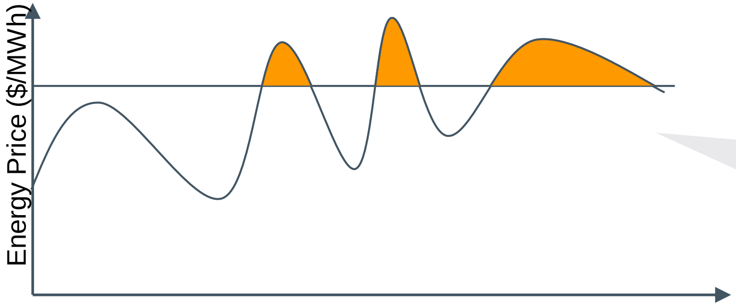
The value to the system from orchestrated EV charging, in terms of generation and network savings, are partially overlapping



Benefits to distribution networks are driven by local peaks, which may be very granular and not visible to anyone but the EDB. Owners of EVs or flexibility traders could access this value by shifting their charging out of periods of congestion, which would mean EDBs avoid the capex required to accommodate higher local peaks. At low voltages, individual EVs may represent a significant portion of a local peak, due to limited diversity on smaller sub-networks.



Benefits to the transmission network and investments in peaking capacity are driven by system peaks. Owners of EVs or flexibility traders could access this value by selling flexibility to Transpower which could avoid the capex required to accommodate higher peaks and impact forecasts of system peak demand.



Benefits to the system from avoided dispatch of expensive generation comes from arbitraging wholesale energy prices and providing ancillary services (i.e. charge when RE output is high and discharge when demand is at its peak, or interrupt charging when system frequency falls). Owners of EVs, or flexibility traders operating on their behalf, could access this value by directly participating in wholesale or ancillary markets.

For the remainder of this report, we focus on the societal benefits which could be provided in terms of avoided investment in distribution networks

System benefits are ultimately passed through as consumer savings

While system cost savings may benefit many parties in the short term, the forces of competition and regulation mean that electricity consumers are the ultimate beneficiary through reduced prices.

Wholesale energy costs

- In the short run, EV owners will tend to arbitrage peak and off-peak wholesale energy prices, reducing price volatility and reducing prices at the system peak.
- In the long run, a less volatile and more flexible total consumption profile means that capacity requirements can be better met through efficient baseload capacity and cheap renewable energy resources.
- EV owners and flexibility traders will bring more competitive discipline to the wholesale market. Further, competitive forces will push energy retailers to procure the cheapest energy they can and pass those savings on to consumers.
- At all times, however, the actions taken by those managing EV charging and other DER to reduce wholesale costs must remain within the physical and power quality limits of the network.

Network costs

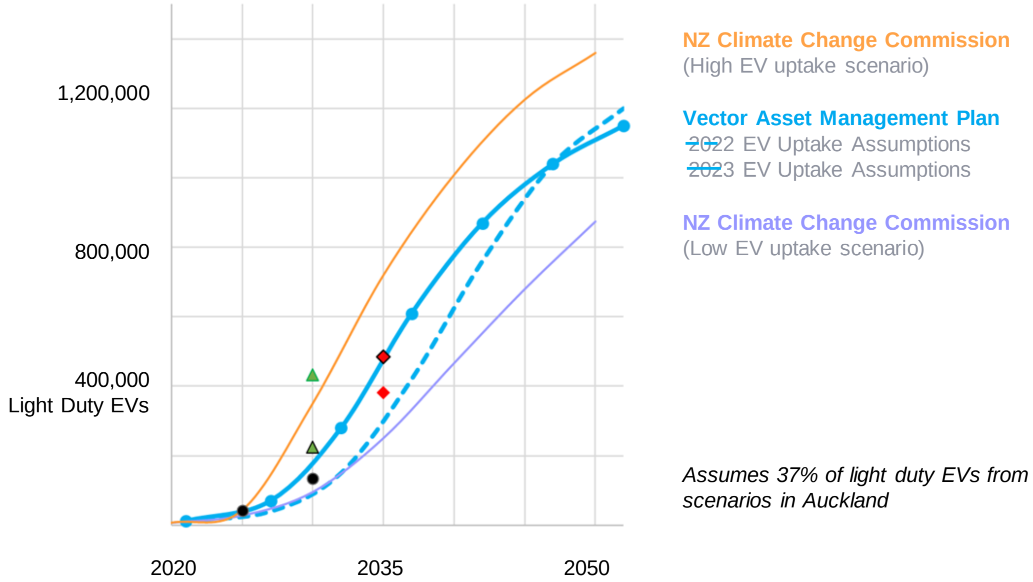
- “Steel in the ground” network investments lock in a specific peak management solution, and a resulting cost, for decades. This increases the potential for assets to be stranded as technology (e.g. V2X) and new solutions develop.
- Additionally, due to the forecast uncertainties for long-lived assets, costs of deployment, and the sizing options for standard equipment, investments may be oversized relative to what is ultimately required. Flexibility delivered from EVs is shorter-term, more adaptable, and better able to meet the precise needs of the system without oversizing.
- This would require the ability to either use short-term opex in place of long-term capex to benefit consumers through reduced regulated revenue for network companies, or to incentivise off-peak charging through sharper TOU signals for distribution charges.

Throughout this document, benefits to the system can be extended to ultimately benefit consumers.

Vector forecasts rapid EV uptake in Auckland

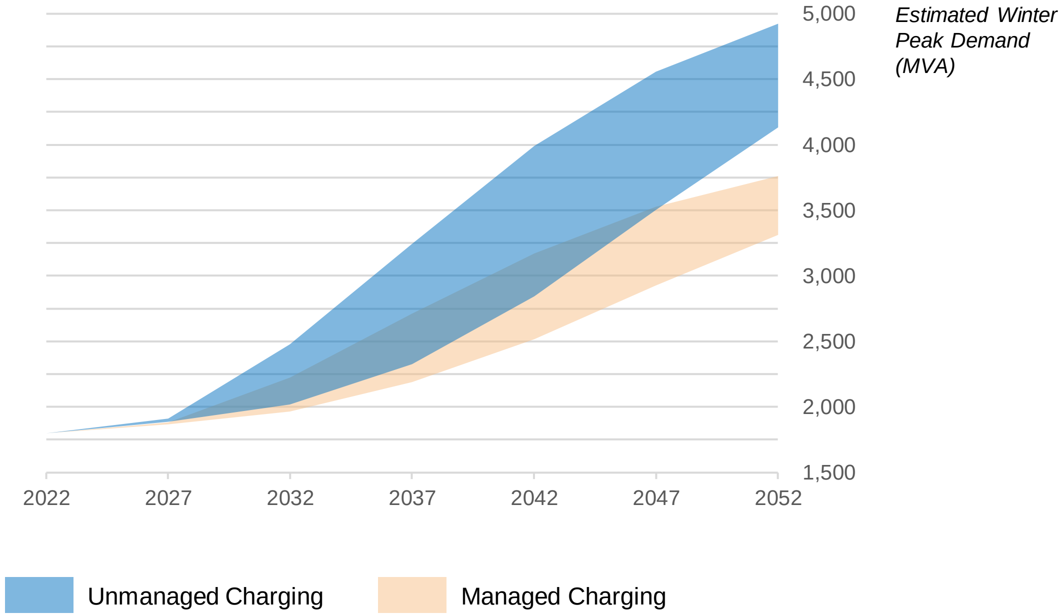
Vector has run scenarios studying the impacts of EVs, finding that unmanaged EV charging results in significantly higher winter peak demands and wider ranges of potential outcomes than with managed EV charging, and this will start impacting network investment planning for the next regulatory cycle.

There could be up to 1.4m Evs in Auckland by 2050



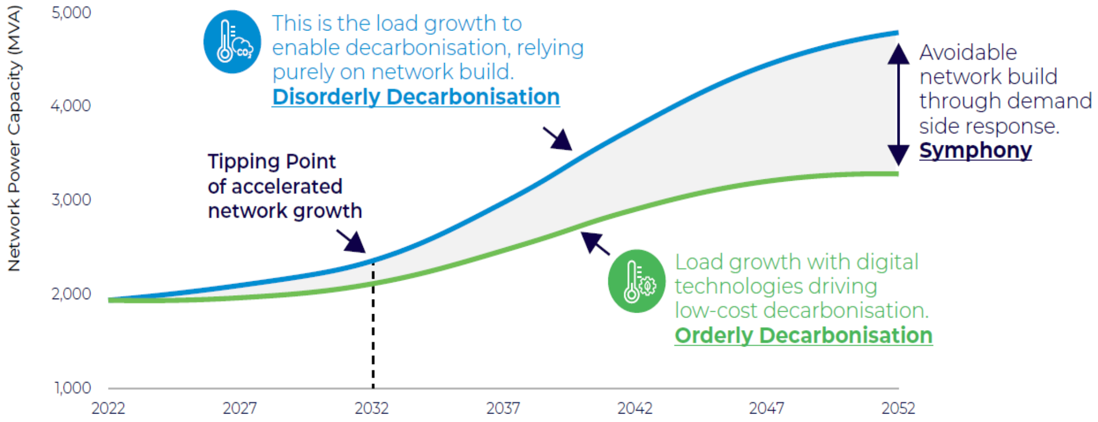
Assumes 37% of light duty EVs from CCC scenarios in Auckland

Vector Winter Peak Demand Estimates with Managed and Unmanaged Residential EV Charging



Rapid EV uptake in Auckland could precipitate the need for significant network reinforcement if charging is unmanaged

If charging is inflexible or unmanaged, Vector's network capacity is expected to more than double to accommodate charging load[1]



Vector's 2022 TCFD Report

Potential consumer savings of ~$150 MM per annum in 2050s

- Investment decisions made during the coming regulatory cycles could make some of the full potential value unavailable in the future
- Based on Sapere's estimated peak cost of $96/kW per annum for distribution.[2]
- BCG estimates total savings from EV smart charging could reach $3 bn by 2035 in aggregate, including generation and transmission savings.[3]

By comparison, the Climate Change Commission finds that EV-driven peak demand growth could increase network costs by $1.7 BN nationally.[4]

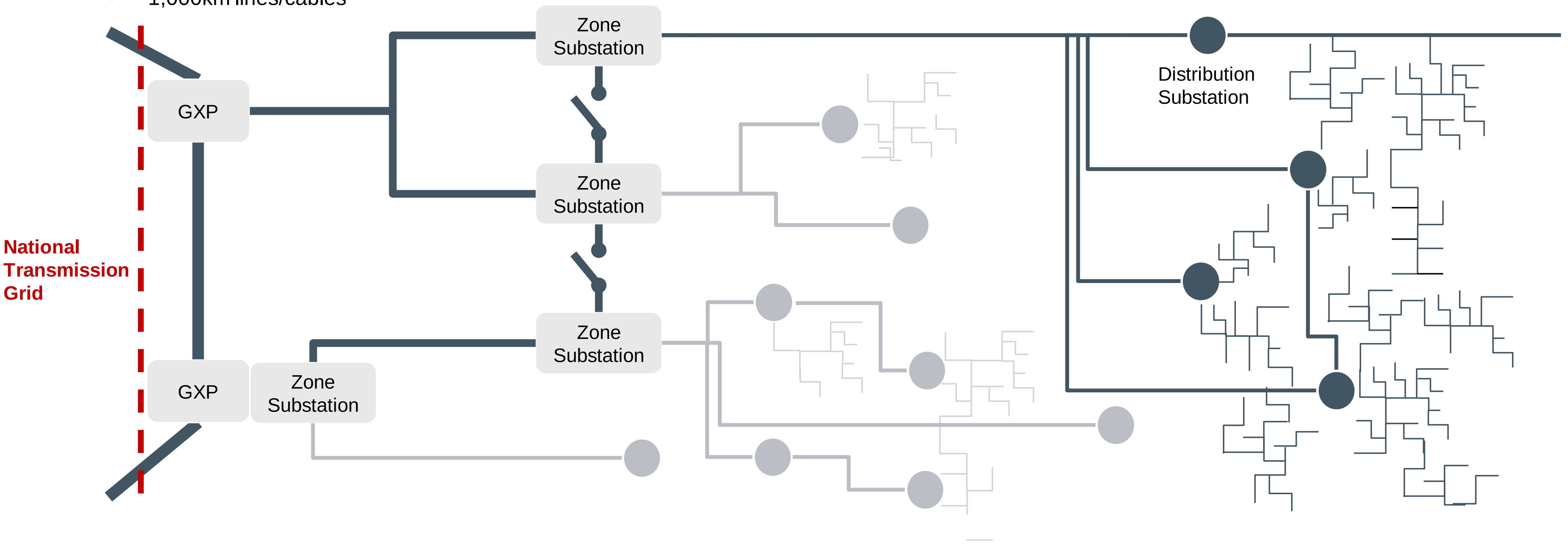
1. Vector (August 2022), 2022 TCFD Report, p.17.
2. Sapere (30 August 2021), Explaining the Cost Benefit Analysis performed on the potential of Distributed Energy Resources, slide 12.
3. BCG (November 2022), The Future is Electric – A Decarbonisation Roadmap for New Zealand's Electricity Sector, p. 92.
4. EECA (8 August 2022), Improving the performance of electric vehicle chargers, p.9.

Basic Structure of the Distribution Network

Sub-Transmission
- 15 GXPs connecting Auckland's network to the national grid
- ~200 circuits
- ~1,000km lines/cables

High Voltage Distribution
- 113 Zone Substations
- ~1,000 feeders
- ~7,500km lines/cables

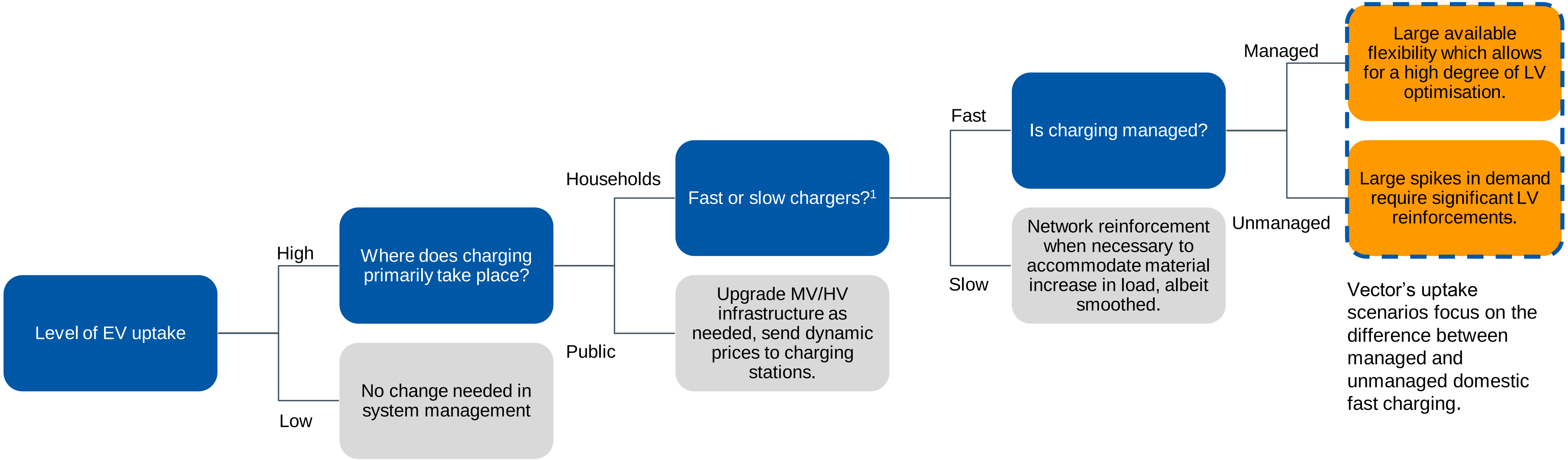
Low Voltage Distribution
- ~22,000 Distribution Substations
- ~35,000 feeders
- ~11,200km lines/cables



Multiple pathways for power to flow across the grid
High Load Diversity

Single pathway for power to flow across the grid
Low Load Diversity

The exact increase in network demand will depend not only on the level of EV uptake, but how they are charged



Vector's uptake scenarios focus on the difference between managed and unmanaged domestic fast charging.

The ultimate value of flexibility on EDB investment depends on (a) level EV uptake; (b) whether charging occurs at home or in public; and (c) whether homes have managed charging

1. Fast charger: Dedicated wall charger for EV; Slow charger: 3-pin outlet.

The challenges presented by, and the solutions for, public charging and private charging differ

Public charging points

- If EV rollout is focussed towards public chargers, the additional load profile will likely be more dispersed, e.g. drivers may time their charging with their lunch break or shopping trips, rather than in the evening.
- Public charging stations are likely to be connected at higher voltages than household charging, which would avoid localised congestion on parts of the low-voltage network.
- Because drivers will actively choose to charge their vehicle at a public charging point, these could be dynamically priced in the same way that a petrol station is.
- Sending dynamic pricing signals to smaller numbers of public charging stations is likely to be more practicable than to a much larger number of individual homeowners, at least in the near term.

VS.

Residential charging points

- If EV rollout is focussed towards private, domestic use, then charging patterns are more likely to be centred on evening peaks and at low voltages.
- In a world with many private chargers, management of charging output is more important, because:
  - Chargers are connected to small, localised LV networks, where just a few chargers could be a substantial burden on the local network.
  - Charging is likely to be concentrated in the evening times, across most users which coincides with historical network peaks on winter evenings.
  - End users are domestic electricity customers with limited active engagement with the energy system, rather than charging businesses that are motivated to receive, manage and pass on price signals in real time.
  - Where reinforcement is required, the benefits are very local but the costs are socialised across many consumers in that EDB pricing zone, introducing affordability and equity concerns.

For the purposes of this presentation, we address the challenges presented by domestic charging points, even in scenarios where public charging is widespread.

In order to achieve most of these potential savings, a high degree of managed charging is required across the localized LV networks

A high degree of coverage is needed to achieve reinforcement benefits

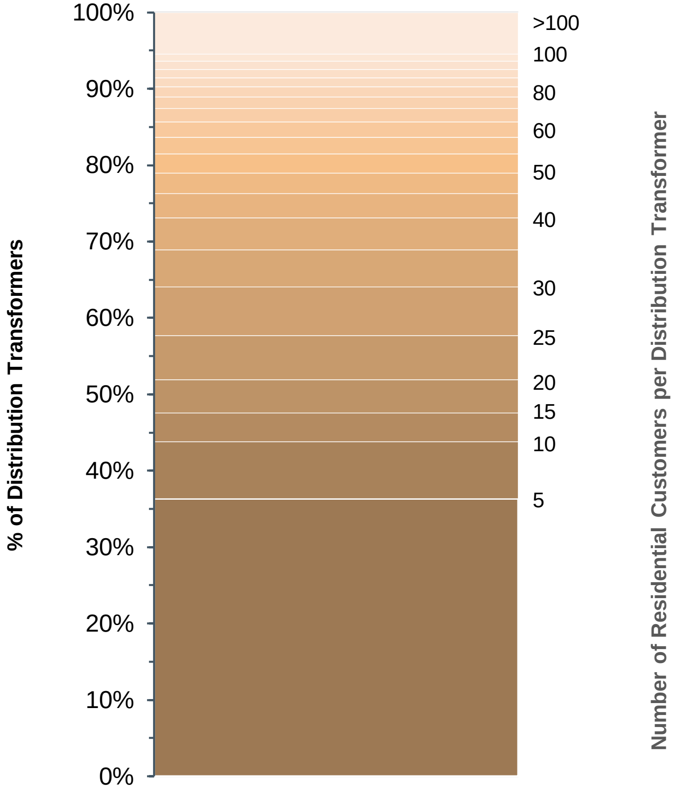
- Distribution reinforcement can be lumpy, and so a large amount of flexible charging capacity could be needed to avoid a particular reinforcement project. Once the reinforcement is made, flexibility in the vicinity becomes less valuable, because it no longer defers investment in localised network capacity.
- Where reinforcements are small/incremental, EDBs must make decisions based on assumptions, in the absence of having visibility of, e.g., exactly which houses on a particular street have a smart charger.
- If EV owners have the option to opt out of managed charging in any given period, some diversification and a degree of overbuild (or over-procurement) is needed to maintain reliability and confidence in sufficient capacity.
- The ability to manage each vehicle may be limited (e.g. at some point the vehicle has to actually charge). Having access to many vehicles provides more options to EDBs to manage a long-duration requirement. However in the early stages of the EV roll-out, geographical concentrations are unlikely to be high enough, or targeted in the right areas, to harness them as specific solutions.

EV managed charging must be available across a wide swathe of area

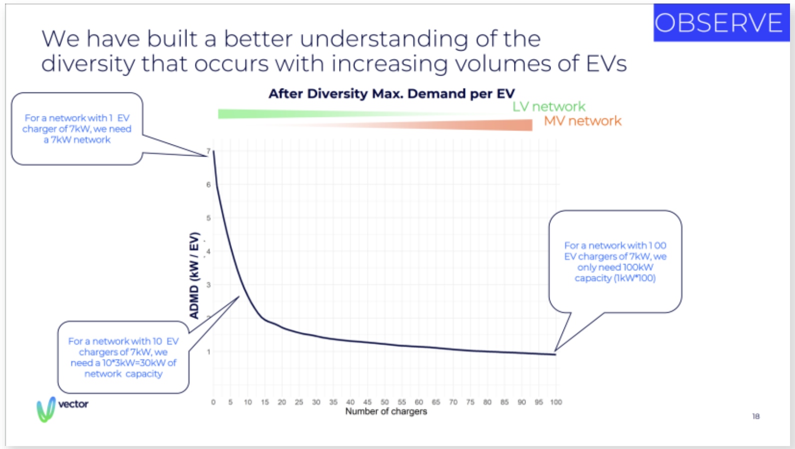
- Vector's network could be viewed as the aggregation of the smaller, localised networks connected to the 22,000 distribution substations across the region.
- Network reinforcement activity is conducted to:
  - ensure that *each of the smaller, localised networks* is capable of meeting local peaks, and
  - ensure the network up to the GXP is capable of meeting the network-wide peaks.
- Thus, EV charging must be visible and available at the connection level which enables an EDB to maximise the opportunities to avoid or defer network reinforcement at all levels of voltage – from LV to sub-transmission.

Due to limited diversification of charging with smaller numbers of consumers, the greatest impacts of rapid EV uptake will be at low voltages[1]

~80% of Distribution Transformers in Auckland have fewer than 50 Residential ICPs



- Many distribution network assets only serve a small number of consumers. With each distribution transformer potentially only **providing power to a handful of EVs**, there is a reasonable probability that most or all of them will at least sometimes charge at the same time. Thus, EDBs will need to consider LV reinforcement needs at a granular scale to accommodate the potential for simultaneous charging.
- However, as the geographical range considered increases, it becomes increasingly unlikely that most or all EV owners will independently charge simultaneously just by chance. **Thus, EDBs can benefit from diversification when considering higher voltage assets.**
- Additionally, limited market depth and liquidity at a local level means that there may be no alternative source when one participant declines to behave optimally, or changes its behaviour at short notice.
- **In order to mitigate extensive and expensive LV reinforcement at a local level, EDBs will require the certainty that peak charging profiles can be managed and guaranteed at a similarly local level.**



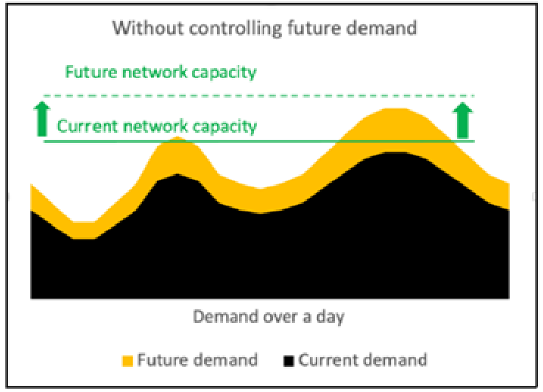
1. See Vector's previous study on diversity effects on its network: https://www.vector.co.nz/articles/ev-smart-charging-trial

Wellington Electricity (WE) has come to similar conclusions in its EV Connect Roadmap

Identified Problems

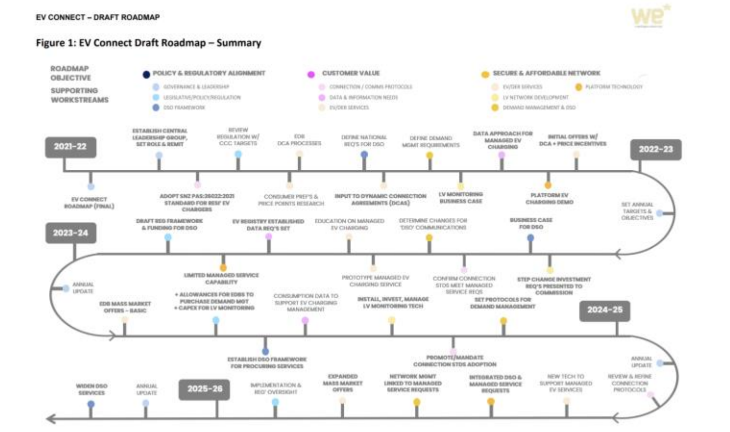
- WE estimates that uncontrolled EV charging could result in an 80% increase in energy use, at a cost to WE of up to $1 billion.
- Just to upgrade 3,000 residential transformers, WE estimates that it would have to double its workforce and it would still take 20 years to do so.

Figure 4: Network capacity without ability to control demand



Proposed Solutions

- WE proposes a detailed 5+ year roadmap for adapting to high EV growth, with focuses on (i) policy & regulatory alignment (e.g. DNO vs DSO arrangements); (ii) customer value; and (iii) secure & affordable network.
- A key component of providing a secure and affordable network is the development of a Dynamic Connection Agreement (DCA), which would provide a "dynamic ability for the network to manage an asset, with owner permissions, during times of network congestion", in return for a payment to the asset owner.
- The DCA is equivalent to the Dynamic Operating Envelope (DOE) we discuss further below.



1. Wellington Electricity (May 2021), EV Connect Consultation, Draft Roadmap

Two main approaches are being considered towards optimal orchestration and management of flexibility

The value from EV flexibility could be achieved with both direct load management and market-based solutions

Managed load	Market-based flexibility
• With ICP-addressable technology an EDB could manage when and where load is reduced in order to avoid the need to build additional peak capacity. • This could either be through a simple rule, e.g. no charging between 4-9 pm, or dynamic charging limits that reflect real-time network conditions. • This system would provide certainty for EDBs to defer investment at all levels of voltage, benefiting consumers through lower distribution charges. • However, it may limit co-optimisation with other sources of value for flexibility, such as wholesale market arbitrage, in some circumstances.	• Parties that manage demand (flex traders) are able to seek out the highest value for that service, optimising across the system over the short-term and creating value to EV owners. • Long-term commitments (e.g. to EDBs) may limit the ability to pursue all short-term market opportunities, and thus will be a part of a portfolio of options to maximise returns from the assets under their control. However, long-term commitments can help to underwrite investment in DER or capability, and may be a necessary part of the overall package. • On the other hand, if flexibility traders target short-term market opportunities, EDBs may be unable to acquire demand reductions at affordable / economical terms to the extent necessary to influence long-term planning, leading to increased infrastructure investments, under sub-optimal timeframes. • Dynamic pricing that balances the benefits of long-term commitments to short-term market opportunities is necessary to ensure co-optimisation on a local level.

If possible, the ideal end state would allow for the dynamic value provided by a market-based solution, while also providing enough certainty to limit unnecessary peak investment in distribution grids. Given this is not yet possible, a framework for smart, managed load in the meantime is necessary.

A Smart EV Charger roll-out underpins all potential solutions

With simple 3-pin chargers in place, managing EV load becomes significantly more challenging, relying on vehicle manufacturer integrations or the owner physically unplugging the car. The Energy Efficiency & Conservation Authority is currently consulting on smart charger roll out.[1]

EECA's approach will seek to strike a balance between the following objectives

- Minimise energy emissions and encourage EV uptake
- Alleviate the costs of decarbonisation on NZ households
- Reduce electricity disruptions for consumers
- Maximise security of supply, reliability and stability
- Minimise network investment using demand management

Smart chargers, connected to smart systems, are critical to unlocking the benefits of demand flexibility to all parts of the electricity system.

1. EECA (8 August 2022), Improving the performance of electric vehicle chargers, p.11.

Flexibility Markets are *Currently* Insufficient to Provide Alternatives for Capex Solutions

Problem: Challenging to determine who should pay for network reinforcement due to EV charging

In the absence of a mechanism to manage load, network reinforcement is likely, but who is it equitable to allocate the costs to?

Reinforcement costs included in EDBs' revenue allowance and charged to generality of customers according to existing distribution charging scheme

This charging mechanism would be the simplest because it would fit within the existing frameworks for revenue allowances and distribution charging.

However, customers that do not own EVs would see an increase in their network-related energy bill, even though they did not do anything to contribute to those additional costs. Presently, EV owners may be more affluent on average than non-EV owners, so it does not seem equitable to require non-EV owners to pay for costs driven by EV owners.

Additional cost-reflective charge by EV owners payable to EDB associated with installing a fast charger, designed to pay for reinforcement costs

This charging mechanism would be more equitable and cost-reflective, but would likely be seen as discouraging EV rollout, contrary to national objectives.

More cost-reflective distribution pricing would help, but in the absence of fully dynamic, locational distribution charging, it would be difficult to send the *right* signal to each fast charge installation point, and so may still not be completely equitable and cost-reflective.

Dynamic, locational distribution charging could resolve this challenge, but would be complex to implement and may further penalise customers who cannot afford the up-front capital required to purchase energy-efficient appliances or choose when to consume electricity.

Additionally, a pricing mechanism should ensure that a single customer that triggers a reinforcement is not responsible for all of the costs.

This problem is solved by introducing mechanisms which prevent the need for EV-related reinforcement

Problem: There is no market price signal to provide granular distribution-level EV response

Wholesale market price signals will not always coincide with when the distribution network benefits from curtailment

Currently the only widespread price signal available to flexibility traders is the wholesale energy spot price, and so benefits can only be delivered to transmission and distribution reinforcement savings if peak congestion on the network coincides with high wholesale prices.

Generally speaking:

- Wholesale prices are high when system-wide demand is **high,** and when renewable output is **low**.
- Wholesale market prices do not account for any distribution-level constraints – the market is blind beyond the GXP
- Distribution capacity constraints are far more complex and localised. They may happen at the same time as system peaks, but not with enough certainty that the wholesale price signal is effective on the distribution level.
- Wholesale prices are likely to be impacted by national renewable output, while distribution costs will continue to be driven by local demand peaks, meaning that wholesale prices will weaken as a proxy for distribution system requirements.

Thus, going forward, wholesale energy prices are **highly unlikely to signal EV response when and where it can help the distribution network defer the need to reinforce** (which would then result in savings for consumers)**.** Even when wholesale and distribution requirements do align, the signal delivered by the wholesale price alone **will fail to adequately reflect the full value that managed EV charging could provide** at that time.

Distribution locational marginal pricing (D-LMP) for distribution charges could signal efficient EV charging, but this is complex to implement

EDBs recover their revenue requirement through a distribution charge, which is levied on retailers and then passed onto customers through retail rates.

In Vector's footprint, customers' distribution charges vary based on whether they are: (i) controlled or uncontrolled load participants; (ii) low or normal users; and (iii) on time-of-use (TOU) or flat tariffs. TOU customers, which are the majority, pay the most granular rates, with a flat daily charge and different volumetric rates for peak (weekdays 7-11 am and 5-9 pm, April-September only) and off-peak (all other periods) consumption. There is now also a separate tariff specifically for manageable DER.

Thus, distribution charges currently only signal reinforcement costs very bluntly in the TOU tariff, **assuming that the need to reinforce the network is driven uniformly by consumption during all peak hours and across the entire network.**

An effective distribution charge for this purpose would need to **dynamically signal the value of congestion on a very short time scale and narrow geographic region**, which would require Vector to move away from charging fixed, published distribution rates, which is likely to be unpopular. Additionally, Sapere (2017) found that D-LMP would be technically very challenging because "the DC approximation of the electrical system [is unlikely to] provide a reliable basis to produce DLMPs".[1]

Even with an effective D-LMP, relying on retailer and/or consumer response to price signals will not necessarily provide long-term certainty that matches the certainty provided by network reinforcement, or the certainty required to defer investment at the local level, where diversity benefits are low.

1. Sapere (2017), An exploration of locational marginal pricing at the distribution level in the New Zealand context, p.ix

Problem: Transaction and coordination costs may be prohibitive for customers and flexibility traders, and will require EDBs to enhance their capability

Customers and flexibility traders must find and coordinate with each other

At present, the only realistic way to sell flexibility services is to the wholesale market (including ancillary services) or to arbitrage the time-of-use distribution charges. While broader flexibility markets will ideally develop, each residential EV customer currently provides only limited value to the flexibility trader. Until deeper, markets exist, the **search and onboarding costs** associated with each additional customer may be a significant proportion of the potential value that a flexibility trader can achieve.

Residential customers generally do not buy EVs with the intention of providing flexibility services, which will be increasingly true as EV ownership spreads to wider populations. In other words, it's an old problem in a new world: disengaged retail customers are now disengaged EV owners. **Thus, in a world where EV owners have to choose to participate, there is a real risk that they do not, and minimum scale is not reached**.

By relying on customers and flexibility traders to seek out and find each other, there is very likely to be inefficiently low participation in selling flexibility services, providing little certainty to EDBs.

Commercial arrangements between EDBs and flexibility traders will require time to establish

In order to engage freely with flexibility traders, EDBs would need to enter into complex contractual arrangements with flexibility traders, where the money paid to the flexibility trader reflects the value delivered to the EDB. This will require more flexibility in the EDBs' funding regime than currently exists – a regime which does not currently incentivise the avoidance of capex in the long run.

While EDBs are well-placed to understand what the requirements of the system are at any given time, they do not generally procure services like these, nor do they have established methods to assess the value received from these types of services.

EDBs will likely need to develop new procurement, contracting and trading capabilities to ensure that the flexibility procured matches the system requirements. **This will entail substantial set-up and ongoing transaction costs, which EDBs are not funded for in the short run.** These capabilities will benefit society in the long run and so should and will be developed by EDBs, but are not readily available unlike capex solutions. This transition will be more challenging for smaller EDBs, for whom network solutions are much simpler and more affordable than engaging in flexibility markets.

Until the necessary relationships between customers, flexibility traders and EDBs are established, direct load management is necessary to ensure efficient use of distribution networks.

Problem: Networks have a long-term commitment to customers and regulators, and thus seek long-term solutions to security of supply

Network reinforcement is a long-term investment, so any non-network solutions must provide the same level of long-term certainty in order to replace it

Where a distribution network is locally constrained, the EDB could reinforce the network to increase its capacity. The reinforcement would last decades with virtual certainty, and would be paid for by consumers over the duration of the asset.

By contrast, flex contracts with EVs would only last for as long as a counterparty is willing to contract for, likely no more than a few years. It would be challenging for flexibility traders to sign a contract for as long as the life of the asset it replaces, and ensure that they will retain that consumer as well its contracted load. A shorter contract would not itself be a problem if each contract could be renewed or replaced (by a different user with a similar profile) upon expiry, but it is difficult for an EDB to have confidence that this will happen.

If a contract ends without replacement and the EDB was insufficiently diversified, it may need to carry out network reinforcement to replace the contract, or risk jeopardising the security of supply. A network solution cannot simply be implemented overnight and cost the same as if it were planned in advance.

Given the lead time required to carry out network reinforcement (e.g. a few years, depending on the project), an EDB may carry out the network reinforcement anyway, to protect against the risk that a contract ends without replacement and the reinforcement is needed. Lead times are even longer for Transpower, which may require up to 10 years to plan an investment.

Network industries tend to prefer capex over opex solutions

In regulatory regimes globally, capex plans tend to receive lighter scrutiny than opex. Additionally, networks can benefit by outperforming not only the expenditure allowance but also the allowed rate of return. Combined, there is a tendency for network companies' commercially-focussed shareholders to prefer building the asset base and earning low risk returns were possible.

Network (capex) solutions are more familiar to the normal operating practices of network industries, in comparison to contracting with flexibility traders, auctioning capacity, etc. Additionally, as discussed on the following slide, at a small scale with only a few participants, there would be limited liquidity which EDBs could use to respond to network constraints.

In jurisdictions with explicit programmes to promote non-network solutions, uptake has been slow even when they do not rely on market dynamics. For example, California's Distribution Investment Deferral Framework had only commissioned 38 MW of non-network capacity in its first three annual solicitation rounds, due in part to the onerous solicitation process.[1]

Until flexibility markets are mature and liquid at a low voltage level, they will not be able to fully substitute or defer capex solutions in the majority of circumstances.

1. California Public Utilities Commission (2 March 2021), Demand-side alternatives to traditional supply-side investments: Updated and new approaches in California

Problem: In planning for very local network requirements, there is effectively no market depth or liquidity

Market dynamics on a national level

In a national market (like the wholesale spot market or transmission networks), there are hundreds or thousands of traditional and non-traditional resources, owned by a large number of individual operators who compete with each other.

These resources are relatively fungible, i.e. they each provide MW of capacity and/or MWh of energy, plus maybe a small number of ancillary attributes.

If one player changes its behaviour or fails to deliver, it can be replaced by any number of alternatives, albeit perhaps at a slightly higher cost to the system. Ultimately, the lights will stay on.

Market dynamics on a local level

On a local level, a resource that can be provided to the distribution network will only provide value to network infrastructure upstream of it, e.g. local LV infrastructure on its street, but not on a neighbouring street.

If the “market” for a particular service consists of just five houses (or five EV chargers) connected to a distribution asset, there is a high correlated risk that multiple resources become unavailable at once. For example, a retailer managing two or three EVs on that street decides today to give its capacity to the wholesale market rather than providing services to the distribution network, or those vehicle owners decide to charge during peak times.

In this case, there is no alternative provider that could step in and fill that gap to that market, even for an increased price, and no short-notice alternative solution to the EDB.

It is unclear whether markets would thus ever be sufficient at an LV level, even once DER are ubiquitous. In the transition to that state, DER deployment is not likely to occur uniformly or in the areas they are most needed.

Even a market-based solution must have a mechanism to ensure that the physical limits of the network are reflected in EV owners’ ability to deploy their flexibility.

Comparator Models from Other Jurisdictions or Industries

The UK 2021 UK Regulation on Smart Charge Points

Regulation parameters[1]

- Each new Smart Charge Point (CP) must have a **smart functionality**.
- The default option of those CP is to **shift EV charge off peak time** (peak time defined as weekdays 8AM-11AM and 4PM-10PM).
- **Charging start randomly delayed** by up to 10 minutes in order to protect the grid stability, avoiding creating a new peak demand and "gradually ramping up the demand."
- Only **private** CP are concerned.
- Leaves the option for the consumer to **override time constraints** and **change default options,** which is especially attractive given general consumer preferences for smart charging.
- Regulation is focused on Smart Chargers only – does not apply to non-smart chargers.

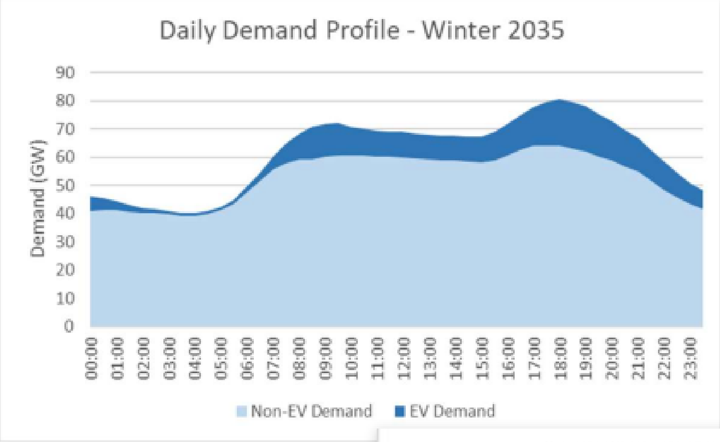
The motivation[2]

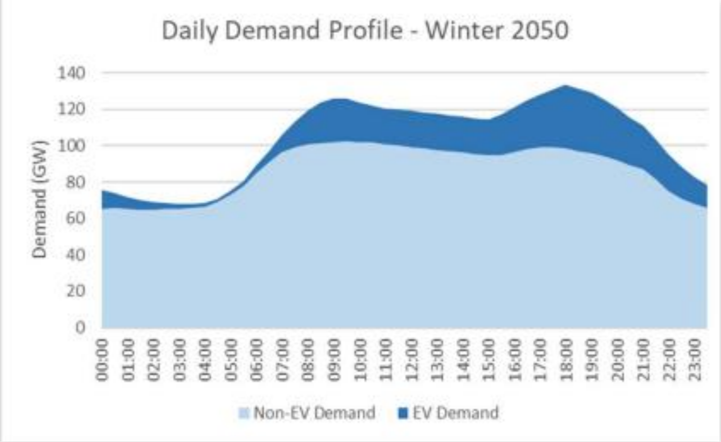
- Shifting EV charging time could **reduce the peak by 11% by 2030 and 9% by 2050** (the impact might be lower if more CP are constructed in workplace, increasing the morning consumption peak).
- **Reducing the risks and costs of instability** due to overcharging the grid if too many EV start charging at the same time.
- Saving from **£300m to £1100m in power system cost** by 2050 at effectively just the of introducing the programme.
- Eventually, could help filling the power gap in the grid using **bidirectional charging** (V2G and V2X).

1. Office for Product Safety and Standards (May 2022), Complying with the Electric Vehicles (Smart Charge Points) Regulations 2021
2. Department for Business Energy and Industrial Strategy (14 July 2021), Impact Assessment: The Electric Vehicles (Smart Charge Points) Regulations 2021

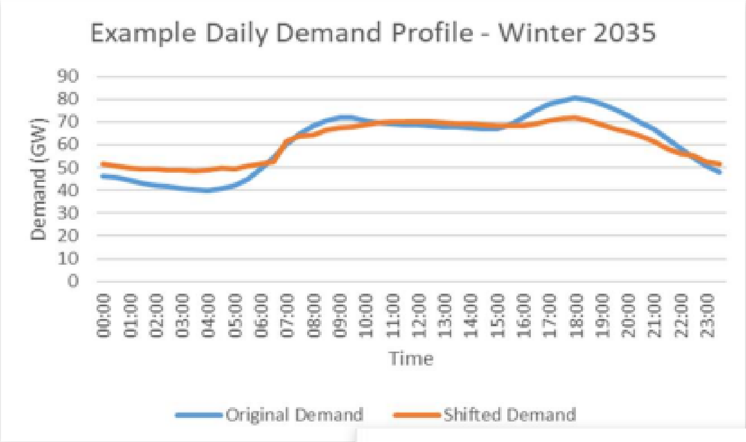
The UK charging regulations are driven particularly by the potential to shift demand away from peaks

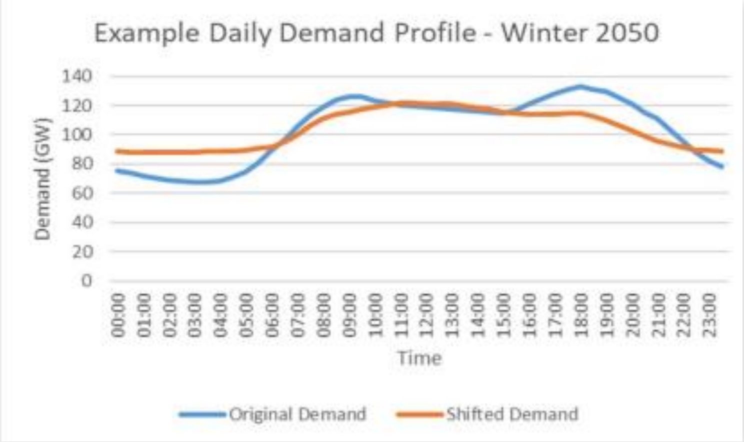
"Unshifted" EV demand is expected to be a significant contributor (20-30%) to system peak demand in coming decades





Peaks can be completely flattened if EVs shift towards off-peak periods





1. Department for Business Energy and Industrial Strategy (14 July 2021), Impact Assessment: The Electric Vehicles (Smart Charge Points) Regulations 2021

Physical limits of the network can be maintained through either a static or dynamic "operating envelope"

An "operating envelope" is a limit on the amount of energy that can be imported from or exported to the network at any time, in order to maintain network stability. This envelope could be either static or dynamic.

Static Operating Envelope

- Traditionally operating envelopes have been set conservatively and statically (by necessity), to ensure that the network can tolerate the "worst case scenario" in terms of import or export. For example, the new UK EV charging rules, for those who don't opt out, are effectively a static operating envelope that reduces to 0 during peak hours.
- A static envelope does not make full use of the network, because it does not account for periods when there *is* spare capacity locally due to underuse of available capacity. Thus it does not enable optimal allocation of capacity and will be unnecessarily restrictive on DER.

Dynamic Operating Envelope (DOE)

- In order to make better use of distributed solar and storage, the Australian Renewable Energy Agency (ARENA) launched Project Evolve, to test the feasibility of a DOE**.** The goal is to maximise the use of DER, while limiting the risk of breaching the physical and operational limits of the network. Different forms of DOE are being trialed and implemented around Australia.
- Under a DOE, the DNSP can release the static operating envelope by computing dynamically upper and lower bounds on the import and export of power in real time for each customer connection point using algorithms. These bounds are computed as function of the network properties, time, weather, customer energy consumption and generation, etc, and can be set on up to a 5-minute basis, forecasted for the next day or so. The bounds can also be used to manage the ramp-up of load after a period of reduced capacity.
- The Australian Energy Regulator has recently released guidance on estimating the Customer Export Curtailment Value (CECV), and on how these values can inform cost benefit analyses to expand the network and allow for wider envelopes (i.e. because the value of curtailed export is potentially greater than the cost of network expansion).[1]
- New Zealand's FlexForum recently released an insights paper introducing DOEs, noting that they will be an essential tool for enabling the safe and secure participation of DER in national wholesale markets.[2] There are already some early applications of DOEs in New Zealand, for example at Auckland Transport's new e-bus charging depot in Panmure.

Under either type of envelope, an investment trigger is necessary to ensure that operating envelopes are not a perpetual tool to avoid network reinforcement where that is the economically efficient choice. A minimum standard envelope could be maintained, or EDBs could estimate an equivalent to CECV which feeds into its reinforcement plans. Alternatively, EDBs could procure load flexibility from those same EVs to keep the DOE wide for EVs which do not participate, with a commensurate cost allocation and payment.

1. AER (June 2022), CECV Final Methodology, Explanatory Statement
2. FlexForum (August 2022), A Flexibility Plan 1.0: what we need to do and how we can do it

Transpower and EDBs have explicit powers in case of an emergency, which could be extended to allow for DER response

The Electricity Industry Participation Code 2010 obligates the SO to take action in a grid emergency[1]

- The SO must ensure in advance that it has the physical ability to disconnect load or generation if it becomes necessary.
- The SO must notify participants if conditions arise where it is likely to take an emergency action.
- If an emergency occurs due to insufficient generation or other mismatches in generation/demand/frequency, the SO may request that generators or demand users adjust their output/demand accordingly to ensure stability.
- If an emergency occurs due to the transmission constraints, the SO may request that generators and/or demand on either side of the transmission constraint increase/decrease their output/demand accordingly to relieve the constraint.

The Default Distributor Agreement gives load management abilities to EDBs[2]

- The DDA covers the relationship between EDBs and energy retailers, but not with non-retailer aggregators, specific consumers, EVs, etc.
- EDBs must provide SO with capability to disconnect load when requested for transmission system capabilities.
- Load shedding, and the restoration of power, by the EDB must follow the following list of priorities:
  - Safety
  - Network stability and security
  - Maintaining power to critical infrastructure
  - Maintaining power to high voltage infrastructure
  - Maintaining power high priority customer groups

While load management powers exist in some circumstances, EDBs do not currently have the power to manage EV charging and other DER in emergency situations. These powers could be broadened, with care to ensure that they do not become so broad as to discourage development of flexibility markets.

1. Electricity Industry Participation Code 2010, Schedule 8.3, Technical Code B
2. Default Distributor Agreement, Schedule 4

Assessment of Potential Interim Solutions

We develop and appraise a range of frameworks which EDBs could follow to manage EV load until flexibility markets are mature

- Given the obstacles which currently exist in relying on market signals and flexibility markets to deliver distribution system benefits at the low-voltage level, a framework is necessary to ensure that EDBs can still manage and avoid local system peaks which would otherwise be imposed by EVs.

- This will minimise the need for network investment to be made to accommodate EV charging in peak periods – investment that could one day be stranded as flexibility markets, or other technologies (e.g. V2X), develop

- Based on precedents which exist in other jurisdictions and contexts, we develop a range of different frameworks which could apply in this context. We assess these against a range of criteria covering each framework's short-term practicality and contribution to the long-term goal of a deep and liquid flexibility market.

- The different options are not mutually exclusive, and could be further sequenced to aid in the progression towards a liquid flexibility market.

Assessment criteria

Provides long-term certainty, enabling EDBs to defer investment

- In order to avoid distribution reinforcement, any solution must reliably reduce EV charging load at local system peaks.
- The solution must be sustainable over a long period of time, such that the EDB can reliably avoid implementing capex solutions.

Provides granular certainty, enabling EDBs to efficiently manage constraints

- Much of distribution network reinforcement happens at LV levels, where each individual end user has a sizeable effect on local network demand and has the potential to exacerbate local network constraints.
- In order to manage peaks and constraints at a very granular LV network level, coverage of the solution must be widespread (i.e. high penetration and certainty of behaviour at very localized level).

Implementable in the near future

- EV uptake is increasing rapidly, and planning for local network solutions will begin soon to accommodate potential load growth. Such investments are likely to be chunky compared to the demand they accommodate.
- Thus, to avoid investment, a framework must emerge shortly, so that it is in place once network reinforcements would be required to accommodate EV-driven load growth.

Consumer centric

- First and foremost, EVs are a mode of transport. Some consumers are likely to feel strongly that they are able to charge their vehicle when they need to, and that their vehicle should be charged in the event of an emergency.
- Solutions should be equitable in that costumers which do not purchase an EV aren't held responsible for the cost of a network or non-network solution.

Allows for transition to full flexibility markets

- The ideal efficient steady state of the market would be to procure flexibility from traders on a local, liquid basis, while allowing traders to identify the revenue sources of greatest value in real time.
- Thus, while the steady state is likely not realistic in the near future, any interim solution should not prevent or slow down the steady state from emerging.
- Not all customers will be engaged in the steady state, so framework should also maximise value provided by disengaged customers.

Options will cover both physical mechanisms for ensuring charging is managed effectively, and contractual mechanisms to ensure that consumers receive value for the flexibility they provide

Some arrangements could be easily implemented in the short term because the tools already exist, but they may impede progress towards a fully liquid end state.

Some arrangements fit more closely with the end state of a fully liquid flexibility market, but may not be possible to implement in the timescales required to avoid network reinforcement.

Physical mgmt. arrangements

Default off-peak charging or static operating envelope

Dynamic operating envelope

Within a DOE widening or narrowing, consumers could receive value either through avoiding high prices, DER payments or the trade of their services with other market participants.

Contractual mgmt. arrangements

Static TOU charge already present in status quo

TOU distribution charges

Managed charging regime via registered DER manager[1]

Tradable charging rights

These options could be treated as a progression, moving from left to right over time as the relationship between EDBs and flexibility traders becomes more formalised

1. The EDB would be the default DER manager, focusing exclusively on use for distribution investment deferral, until customer selects a different DER manager that can access all value sources.

Options vary in terms of the access rights for EDBs and customers

Each model presents a spectrum of rights for EDBs and customers.

Customer generally has full control of charging; EDB can't circumvent this.

EDB can override customer preferences in emergency circumstances.

EDB is able to determine allowable charging levels, in all circumstances.

Default off-peak charging

- Option 1: No penalty for opting out; mechanism acts as simply a nudge to encourage users to think about their use of charging infrastructure.
- Option 2a: Customer is required to be on a cost-reflective time-of-use tariff if they install a fast charger.
- Option 2b: Customers can opt out for a one-off fee every time they charge during peak hours, based on contribution to reinforcement cost. Alternatively, customer foregoes payment/discount for participating in scheme.
- Option 3: Customers simply cannot charge at peak – there is no ability to opt out.

Dynamic operating envelope

- Option 1: Customer can decline to be subject to DOE, but may be subject to emergency control of charging if local distribution capacity is constrained. A high fee may be charged to opt out of DOE in any period, reflecting the narrower DOE which would apply to other customers.
- Option 2a: Customer can decline to be subject to DOE, and instead receive a static, profiled envelope or static limit.
- Option 2b: DOE is fully at the behest of EDB. EDB can decline application to connect a fast charger for a customer which declines DOE.

Managed charging regime via registered DER provider

- Option 1: Customer can opt out of scheme with no penalty or additional charge to do so.
- Option 2a: Customers who participate in scheme have a lower tariff overall.
- Option 2b: Customers who participate in scheme can opt out of individual events, following advance notification by the EDB. A fee is charged for doing so, or incentive payment for participation is forgone.
- Option 3: Mandatory participation in scheme, but customer can switch DER providers, which would be responsible for coordinating charging with the EDB.

Tradeable charging rights

- Option 1: Customers are given the option to charge or not on an event-specific basis, given price signal provided by EDBs. Correct payment is necessary to ensure that customers respond optimally and sufficient response is procured.
- Option 2: EDB can turn down EV charging and determine payment later, based on estimated cost to user of not charging vehicle. Correct payment is necessary to create the conditions for flexibility traders to emerge.

Default off-peak charging for smart EV chargers (static envelope)

Option description	Option assessment
• Inspired by mechanism implemented in the UK, applicable to all smart EV chargers (which we assume will be widespread). • Unless the user opts out of it, charging would occur only during designated off-peak periods, with a random delay of up to 10 minutes to ensure that there is no surge in demand right on the hour. In practice, customers could plug into a 3-pin wall charger to avoid the effects of the mechanism, but they may still not do so if it is inconvenient. • Opt out condition (one-off or sustained) could involve some disincentive so that it is only selected by users who genuinely desire it. In the absence of complex distribution charging, opt-out customers could pay a surcharge for distribution costs, or be required to be on a cost-reflective time of use tariff. However, these signals would likely be too blunt to reflect the true cost of opting out on an unpredictable granular time and geographical basis. This uncertainty would necessitate EDBs building a "buffer" into their load forecasts and investment. • Alternatively, as in the UK, it may simply be a "nudge" to change behaviour and helps disengaged consumers avoid on-peak charging. • If the user opts out, they could engage with a flexibility trader to have their charging managed, participate in other markets, or not participate.	• **Provides long-term certainty to EDBs**: Medium. Depends on the strength of the signal to not opt out (e.g. is there an additional charge or is it just a "nudge"). If many users opt out (and do not engage with other mechanisms), then it may not be effective, particularly at local low-voltage levels of the network. Does not address three-pin charging, which is indistinguishable from other uses of electricity. • **Provides granular certainty to EDBs**: Medium. Strong performance so long as LV-level peaks remain within pre-defined peak hours, but this may not always be the case. • **Implementable in the near future**: Strong. Has already been achieved in the UK. • **Consumer centric**: Medium. Depends on strength of signal to not opt out. If consumers can opt out immediately with no charge, then they retain full flexibility, but other users may have to pay more if an upgrade is required. If a user has to pay extra to opt out in an individual instance, then they lose some flexibility and autonomy. Regime is a 'blunt instrument', managing charging in many periods in which it would not otherwise have been required, effectively "over-controlling" load and unnecessarily restricting flexibility. • **Transition to full flexibility market**: Medium/Poor. Flexibility traders and EDBs would have limited opportunity to develop necessary capabilities, because a customer that only charges off-peak has a reduced opportunity for using flexibility for other reasons, such as arbitraging wholesale prices. Score depends on the counterfactual for customers who don't opt out. If they wouldn't have engaged in flexibility services anyway, then default off-peak does not stand in the way of a flexibility market developing and banks some cost-savings in the near-term; Alternatively, the default option may provide some inertia, preventing some EV owners from engaging with flexibility traders in the first place, when they may have otherwise. • **Other implementation challenges/risks**: Like all options, reliant on a mandate to install smart chargers. Time of local EDB peak need may fall outside of pre-defined peak periods. One-off opt-out charges must be high enough that consumers do not use it systematically. • **Overall assessment: Medium.** Option will almost certainly achieve the near-term objective of avoiding network solutions, but may hinder the development of a full flexibility market.

Dynamic operating envelope

Option description	Option assessment
• Inspired by DOE mechanism being developed and rolled out in Australia. • EDB would send import (and export) limits to each charging point for the day ahead, which would provide bounds around the amount they could charge during intervals through the day that are reflective of the real-time physical limits of the network. Bounds may also reflect maximum allowable rates of change of charging load. • The alternative to a DOE would need to be a static operating limit, set conservatively to ensure that the bounds are never triggered. Thus, **DOE is set based on the physical limits constraining the network**, and it is not possible to opt out, unless a market exists to trade for a share of the DOE of a neighbour (i.e. someone facing the same binding network constraints). These limits would be sent to each charge point in advance. • Customers could engage with flexibility traders, though the traders themselves would have to operate within the bounds of the DOE (unless the customer has opted for a static envelope). Traders could manage the EV owner's charging according to their preferences and ensure charging remains within the DOE at all times. • DOEs also enable the ability to manage export limits, which is increasingly relevant as Vehicle to Grid (V2G) becomes more prominent. • Some reporting by EDBs necessary to demonstrate that DOEs are not being overused to the detriment of customers.	• **Provides long-term certainty to EDBs**: **Strong.** EDBs would retain the ability to curtail demand, if (and only if) physical limits risk being breached, ensuring that their primary objective of security of supply will always be met first. • **Provides granular certainty to EDBs**: **Strong.** A different DOE can be assigned at whichever granularity it is needed. • **Implementable in the near future**: **Medium.** Process is still experimental in Australia, and would need to be translated to NZ context to ensure signals are accurate and feed appropriately into network reinforcement. Early tests are underway in NZ. • **Consumer centricity**: **Medium.** Consumers could only opt out to a static envelope, but a DOE is likely preferable from a consumer's perspective to being given the static envelope as the only alternative. • **Transition to full flexibility market**: **Strong.** Flexibility traders may require more sophistication to forecast and react to changes in the DOE, but this should be feasible. Once flexibility markets are liquid, EDBs could send dynamic *prices* in addition to the envelopes (potentially including D-LMP), allowing traders to include distribution as part of its value stacking. • **Other implementation challenges/risks**: Additional IT investment may be necessary to calculate DOEs and communicate them to end users. Further understanding and monitoring necessary to ensure that efficient reinforcement does still happen (i.e. cost of curtailment vs cost of reinforcement). Further understanding necessary to ensure that efficient reinforcement does happen. Could be complicated and subjected to ensure that available capacity is allocated in a principled fashion. • **Overall assessment**: **Strong.** If it can be rolled out quickly, DOE acts as a good balance between short-term feasibility and ease of transition to full flexibility market, and would remain even with a full flexibility market. DOEs will become increasingly necessary to enable DER participation in wholesale markets.

Note: a DOE is a physical arrangement representing constraints on the network, which could underpin the different contractual arrangements discussed below.

Managed charging regime via registered DER manager

Option description	Option assessment
• Inspired by "ripple control", already in place to manage hot water heaters. Would provide a means for managing the charging of disengaged customers while allowing engaged customers to opt-out and contract with other DER managers. • In the default, EDB would be the DER manager for EV chargers (and other DER), and would deploy flexibility in ways to benefit EDB, and customer would receive a preferred rate for engagement (e.g. a lower distribution charge). The EDB would be able to manage DER in a way that aligns with local network conditions, and manage the return of the load when charging recommences. • If customers opt out of the default arrangement and select a different DER manager (e.g. their retailer), then that DER manager would be given the same incentive or rate for engaging with the EDB (e.g. reduced distribution charges). However, they would also be able to value stack and sell flexibility services into different markets where it is more valuable. By design, the EDB leaving part of the value stack on the table gives flex traders and retailers a competitive advantage against the default EDB DER manager. • In either case, EDB would have the ability to send out a signal to manage the rate at which a customer can charge in order to meet the local requirements of the EDB.	• **Provides long-term certainty to EDBs**: **Strong.** With a sufficient surcharge for opting out of managed charging, most participants would likely only opt out if they are able to offset that surcharge by selling flexibility services through other means, which may also achieve the type of long-term certainty that EDBs require. Additionally, operating limits would still bind. • **Provides granular certainty to EDBs**: **Strong.** With a sufficient surcharge for opting out of managed charging, most participants would likely only opt out if they are able to offset that surcharge by selling flexibility services through other means, and geographic coverage would be near complete. • **Implementable in the near future**: **Strong**. Has already been achieved through hot water ripple control, and alternative providers to the EDB are not immediately necessary. • **Consumer centricity**: **Medium.** Consumers have the ability to opt out or choose a different provider in general, but cannot opt out of the default on a case-by-case basis. • **Transition to full flexibility market**: **Strong.** More opportunity for flexibility traders to engage with engaged customers during peak periods (who have opted out of the default regime). • **Other implementation challenges/risks**: Sticky customers may not wish to switch away from simplicity offered by EDB as default manager, but inability of EDB to value stack creates incentive for other traders to market to the customer. Could be mitigated by having a sunset clause to the arrangement, after which customers on the default option are allocated to a different party. A procedure would need to be developed to ensure that smart EV chargers are enrolled with a DER manager, default or otherwise, e.g. through the terms of connection. • **Overall assessment: Medium/strong**. Effective in the near-term objective. Could hinder but not completely prevent the introduction of a liquid flexibility market.

Flexibility traders are given firm access rights to the charging capacity of the EV

Option description	Option assessment
• Much like access rights a transmission-connected generator could receive, an EV owner (and by extension a flexibility trader it contracts with) would have firm access rights to charge an EV or sell its full charging capacity of an EV to wholesale energy markets, and/or to Transpower/EDBs. • EDBs would have the ability to curtail an EV's charging beyond the level of the DOE if desired (e.g. to widen the DOE for other customers), but would need to reimburse the owner/flexibility trader for having done so. The value to be reimbursed would need to consider (possibly the maximum of): ➢ The opportunity cost of not having a charged vehicle to drive, and the need to charge it at a different time. ➢ The wholesale revenues that the flexibility trader could have earned by selling power from the charged vehicle. • Clear limits or strong disincentives would be necessary to ensure that EDBs do not often curtail load.	• **Provides long-term certainty to EDBs**: **Medium.** EDBs would have a price to pay to avoid network reinforcement, and will continue to pay it as long as it is more cost efficient to do so. However, that price required to change behaviour isn't guaranteed, and could prove to be less economical than network reinforcement. • **Provides granular certainty to EDBs**: **Medium**, as above. • **Implementable in the near future**: **Medium**/**poor**. Challenging to determine what the correct value to pay for curtailment would be, considering the dynamic opportunity cost of selling into the wholesale market. Likely to lead to disputes if cannot easily be measured objectively. • **Consumer centricity**: **Poor**. More challenging to determine the true value of curtailed charging for an EV owner (who values having a car to drive) than for curtailing a generator which operates as a business. Additionally, curtailment costs would ultimately be paid by all customers, including those which do not own an EV. • **Transition to full flexibility market** : **Medium**/**strong.** EDBs paying for flexibility services fits neatly into existing wholesale market framework, making it easy for flexibility traders to enter and eventually sell to EDBs as well as the wholesale energy market. However, an incorrect price signal may shut out the emergence of a flexibility market. • **Other implementation challenges/risks**: Ongoing modelling required to ensure curtailment price is an accurate reflection of the opportunity cost. • **Overall assessment**: **Medium**/**poor.** May not be immediately practical given the sophistication required to price firm access. However, it could be a useful further step near the end state of full flexibility.

Pricing of opt-out mechanisms could be complicated

Free / "nudge"	Simple opt out charge	Dynamic opt out charge
• Customers could opt out of a mechanism (e.g. default off-peak charging) for free, where the benefit of the mechanism is to nudge customers to think about the value that EV charging can provide to the system. Customers could opt out on a long-term or a case-by-case basis. EDB would need to cater for this behaviour, increasing its investment, thereby increasing costs. • However, customers who are indifferent may opt out for no particular reason, limiting the benefits which can be provided to the system and possibly increasing costs borne by all other consumers. • Backstop system could be established which ensures that customers only opt out if they *opt in* to a different system, e.g. they contract with a flexibility trader or enter a different form of arrangement with the EDB.	• Customers could pay a daily fee to opt out (or forego receiving a daily incentive payment), which reflects the long-run marginal cost associated with each unit of capacity which is or is not participating. That fee (or forgone reward) could be an attribute of the commercial proposition offered by retailers to consumers. • However, this LRMC would need to be an average over time and space. In any one instance, a local network which has no network constraints could allow more users to opt out without incurring any additional costs, while another local network may be close to its limit and may value participation more greatly. • A simple signal thus is likely to be inaccurate in many places and times, thus signalling inefficient use or disuse of EV charging.	• Like a DOE, a dynamic opt out charge would reflect the real-time and locally-granular constraints on the network, and would therefore signal the most efficient use of the network. This would end up being equivalent to D-LMP. • It is technically complex to determine and communicate the price that would be charged, and may not be immediately feasible. In addition, the retailer would need to pass this charge on in some form for it to be effective. • Before dynamic pricing can be introduced, a physical limit (like a DOE) must be established and underpin the framework. Dynamic charges would then allow owners to respond within the bounds of that limit.

Assessment against criteria (1/2): Physical arrangements

	Provides long-term certainty to EDBs	Provides granular certainty to EDBs	Implementable in the near future	Consumer centricity	Transition to full flexibility markets	Other implementation challenges/risks	Overall assessment
Default off-peak charging for smart chargers (static envelope)	Medium. Depends on the strength of the signal to not opt out (e.g. is there an additional charge or is it just a "nudge"). Does not address three-pin charging, which is indistinguishable from other uses of electricity.	Medium. Strong performance so long as LV-level peak is always during peak hours, but this may not always be the case.	Strong. Has already been achieved in the UK.	Medium. Depends on strength of signal to not opt out. If consumers can opt out immediately with no charge, then they retain full flexibility, but other users may have to pay more if an upgrade is required. If a user has to pay extra to opt out in an individual instance, then they lose some flexibility and autonomy. Regime is a 'blunt instrument', managing charging in many periods in which it would not otherwise have been required, effectively "over-controlling" load and unnecessarily restricting flexibility.	Medium/Poor. Flexibility traders and EDBs would have limited opportunity to develop necessary capabilities, because a customer that only charges off-peak is effectively unavailable to provide any useful services, or to sell their flexibility when wholesale prices are high. If disengaged customers wouldn't have engaged anyway, then option does not stand in the way of a flexibility market developing; However, option may introduce inertia, preventing some EV owners from engaging with flexibility traders in the first place, when they may have otherwise.	: Like all options, reliant on a mandate to install smart chargers. Time of local EDB peak need may fall outside of pre-defined peak periods. One-off opt-out charges must be high enough that consumers do not use it systematically.	Medium. Option will almost certainly achieve the near-term objective of avoiding network solutions, but will hinder the development of a full flexibility market.
Dynamic operating envelopes	Strong. EDBs would retain the ability to curtail demand, if (and only if) physical limits risk being breached, ensuring that their primary objective of security of supply will always be met first.	Strong. A different DOE can be assigned at whichever granularity it is needed.	Medium. Process is still experimental in Australia, and would need to be translated to NZ context to ensure signals are accurate and feed appropriately into network reinforcement. Early tests are underway in NZ.	Medium. Consumers could only opt out to a static envelope, but this is likely preferable from a consumer's perspective to simply being given the static envelope as the only alternative.	Strong. Flexibility traders may require more sophistication to forecast and react to changes in the DOE, but this should be feasible. Once flexibility markets are liquid, EDBs could send dynamic *prices* in addition to the envelopes (potentially including D-LMP), allowing traders to include distribution as part of its value stacking.	Some investment in IT may be necessary to allow for signalling fully dynamic envelopes. Further understanding and monitoring necessary to ensure that efficient reinforcement does still happen. Could be complicated and subjected to ensure that available capacity is allocated in a principled fashion.	Strong. If it can be rolled out quickly, DOE acts as a good balance between short-term feasibility and ease of transition to full flexibility market, and would remain even with a full flexibility market. DOEs will become increasingly necessary to enable DER participation in wholesale markets.

Assessment against criteria (2/2): Contractual arrangements

	Provides long-term certainty to EDBs	Provides granular certainty to EDBs	Implementable in the near future	Consumer centricity	Transition to full flexibility markets	Other implementation challenges/risks	Overall assessment
Managed charging regime via registered DER manager	Strong. With a sufficient surcharge for opting out of managed charging, most participants would likely only opt out if they are able to offset that surcharge by selling flexibility services through other means, which may also achieve the type of long-term certainty that EDBs require. Additionally, operating limits would still bind.	Strong. With a sufficient surcharge for opting out of managed charging, most participants would likely only opt out if they are able to offset that surcharge by selling flexibility services through other means, and geographic coverage would be near complete.	Strong. Has already been achieved through hot water ripple control, and alternative providers to the EDB are not immediately necessary.	Medium. Consumers have the ability to opt out or choose a different provider in general, but cannot opt out of the default on a case-by-case basis.	Strong. More opportunity for flexibility traders to engage with engaged customers during peak periods (who have opted out of the default regime).	Sticky customers may not wish to switch away from simplicity offered by EDB as default DER manager, but inability of EDB to value stack creates incentive for other traders to market to the customer. Could be mitigated by having a sunset clause to the arrangement, after which customers on the default option are allocated to a different party. A procedure would need to be developed to ensure that smart EV chargers are enrolled with a DER manager, e.g. through the terms of connection.	Medium/Strong. Effective in the near-term objective. Could hinder but not completely prevent the introduction of a liquid flexibility market.
Tradeable charging access rights	Medium. EDBs would have a price to pay to avoid network reinforcement, and will continue to pay it as long as it is more cost efficient to do so. However, that price required to change behaviour isn't guaranteed, and could prove to be less economical than network reinforcement.	Medium. EDBs would have a price to pay to avoid network reinforcement, and will continue to pay it as long as it is more cost efficient to do so. However, that price required to change behaviour isn't guaranteed at a locally-specific level.	Medium/poor. Challenging to determine what the correct value to pay for curtailment would be, considering the dynamic opportunity cost of selling into the wholesale market. Likely to lead to disputes if cannot easily be measured objectively.	Poor. More challenging to determine the true value of curtailed charging for an EV owner (who values having a car to drive) than for curtailing a generator which operates as a business. Additionally, curtailment costs would ultimately be paid by all customers, including those which do not own an EV.	Medium/strong. EDBs paying for flexibility services fits neatly into existing wholesale market framework, making it easy for flexibility traders to enter and eventually sell to EDBs as well as the wholesale energy market. However, an incorrect price signal may shut out the emergence of a flexibility market.	Ongoing modelling required to ensure curtailment price is an accurate reflection of the opportunity cost.	Medium/poor. May not be immediately practical given the sophistication required to price firm access. However, it could be a useful further step near the end state of full flexibility.

Conclusions

- EV rollout in the coming decades will place significant burdens on distribution networks, especially at the low voltage level. The cost of reinforcements, if carried out, will be costly if allocated to EV owners, and unequitable if allocated to all customers.
- However, EVs can also provide significant value to the whole electricity system, if their charging (and battery) capacity is used flexibly.
- In the near term, distribution pricing is unlikely to be as dynamic, locationally-granular or cost-reflective to provide the signals needed to manage EV loads, in a way that enables the EDB to defer investment in the majority of low-voltage assets.
- In the future, flexibility markets *may* be able to signal and coordinate the highly-localised load management necessary to avoid distribution network reinforcement, assuming that sufficient market depth and liquidity emerges at a local level. At present, this is not possible, and future development of market-based solutions to address highly-localised LV constraints, with limited market 'participants', appears challenging.
- As these markets are being developed and tested, various measures should be put in place that allow charging of EVs to be managed to minimise network reinforcement requirements, thereby maximising affordability.
- We have described and evaluated four such options, which are not mutually exclusive.
  - Default off-peak charging and the EDB as default DER manager can be implemented immediately. Users who opt out of off-peak charging could possibly be enrolled with the EDB (if not another DER Manager) to manage charging separately.
  - A dynamic operating envelope and tradeable charging rights will require technical and regulatory development, but are closer to the end state where flexibility traders maximise the value of services that can be provided at any given time, within the physical and power quality limits of the network.
  - In any event, some mechanism for signalling the physical capability of the local network at a given time is necessary to ensure that EVs do not create emergency situations. This can either take the form of a static operating limit or a dynamic operating limit, where the latter would allow EV owners to charge faster when realtime system needs allow it. EDBs may require additional emergency powers that allow them to manage DER during emergency situations.
- A framework should be developed which allows for the progression from the less mature to the more mature operating models.

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