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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

[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.

[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

Basic Structure of the Distribution Network

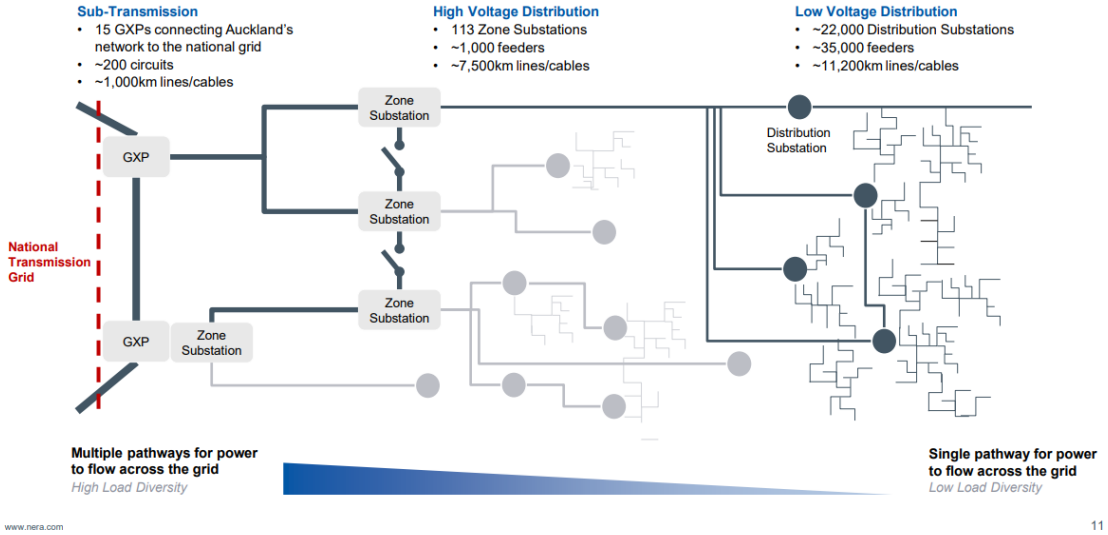
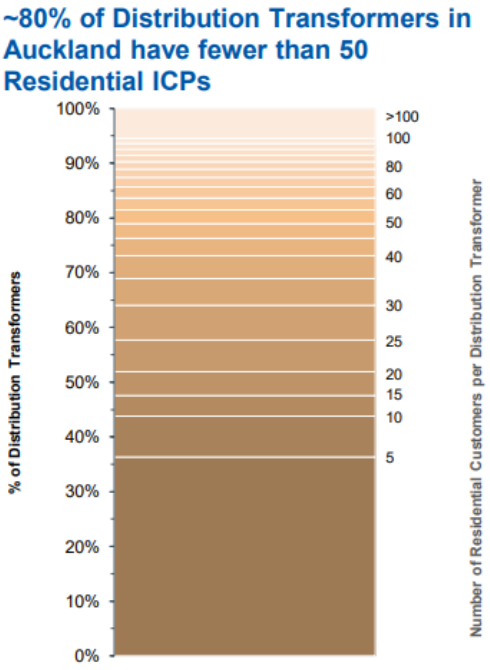


Diagram from NERA's report showing stylised representation of the distribution network

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