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Submission on the Consultation Paper: *Evolving multiple retailing and switching*

Introduction

1. Bluecurrent welcomes the Electricity Authority's consultation paper, *Evolving multiple retailing and switching* (the Consultation Paper), dated 3 June 2025.

2. Bluecurrent broadly supports the changes to the trader, metering equipment provider (MEP), and distributor switching arrangements proposed in the Consultation Paper. We agree that many of these changes will make the switching and electricity registry processes more transparent and efficient, reduce costs for market participants and consumers, and importantly, enhance 'consumer mobility'.

3. In our view, the Authority's integrated approach to switching improvements and multiple trading relationships (MTR) development provides a useful foundation for enhancing consumer mobility. To maximise the success of both initiatives, we suggest the Authority consider whether the switching improvements — many of which were identified in the 2019 *Switch Process Review* — could proceed whilst MTR development benefits from additional design work to consider the frameworks identified through the Wellington MTR trial and international experience.

4. We therefore suggest the Authority consider developing MTR as a focused workstream that can benefit from comprehensive design consideration, whilst allowing the switching improvements to proceed. This approach would enable both initiatives to achieve their full potential in enhancing consumer mobility.

5. Bluecurrent supports an evidence-based approach to MTR development. A comprehensive cost-benefit analysis and structured implementation pathway would ensure MTR delivers meaningful consumer benefits whilst maintaining New Zealand's reputation for effective market design and consumer protection.

Responses to the consultation questions

MTR

Q1. Do you agree that multiple trading relationships and improved switching are key components of consumer mobility? If not, what would you change and why?

Q2. Do you have any comments regarding future stages of multiple trading, whether the proposal provides optionality for the potential future stages, and the options the Authority should consider?

Q3. Do you agree with the proposed solution? If not, what would you change and why?

Q4. Do you agree with the benefits anticipated from the proposed solution? Are there other benefits you can anticipate or improvements to operational effectiveness and efficiency? Can you quantify these benefits?

Q5. Do you anticipate the proposed solution will introduce cost into your organisation, and if so, can you quantify this cost and/or provide a high-level description of the changes that need to be made?

6. Bluecurrent broadly agrees that improved switching processes are a key component of consumer mobility; so is a robust MTR framework that minimises costs for consumers while ensuring arrangements are commercially viable for market participants. The Authority's approach to MTR development recognises that effective implementation extends beyond switching process amendments. The Wellington MTR trial provides valuable insights into the design considerations that will enable MTR to deliver its intended consumer benefits:

> . . .implementing multiple trading into industry will not be without its challenges. Regulatory frameworks, grid and network management, cybersecurity, electricity market integrity and new market design are critical areas that will require careful consideration and strategic planning. Addressing these challenges necessitates collaboration between policymakers, technology providers, electricity market stakeholders and participants, investors and consumers.[1]

7. The Authority has an opportunity to develop a world-leading MTR framework that addresses these implementation considerations whilst delivering superior consumer outcomes. MTR will transform the current one-to-one ICP-retailer relationship that underpins the *Electricity Industry Participation Code* (the Code) into a one-to-many structure. This provides the Authority with an opportunity to design comprehensive Code amendments and supply chain frameworks that optimise this transformation for consumer benefit.

8. The Authority's MTR design process can address three key implementation areas to ensure optimal consumer outcomes: 1) operational framework development, 2) commercial sustainability, and 3) consumer outcomes.

Operational framework development

9. The Wellington MTR trial report for January to June 2024 identifies some of the potential/future Code changes required to make MTR work:

> At this stage, we have identified that a regulatory solution will be required for:
>
> a. Amendments in line with the exemptions granted.
> b. Allocation of meter lease fees.
> c. Provisions that prevent the primary retailer from having a sole contract with the MEP that will prevent a secondary retailing gaining access to the data or meter or reporting functionality.
> d. Provisions that will allow the secondary retailer to be able to request amendments to the metering configuration should it be required.
> e. Amendments to the registry to enable:
>
> i. The network to manage and track ICPs with duplicate ICP identifiers.
> ii. Indication of the ICP identifier that has connection and disconnection rights.
> iii. Capability for the duplicate ICP identifier to be updated at the same time as the consumption ICP identifier.[2]

10. Operational issues requiring consideration in designing an MTR framework that will require Code changes could be in relation to:

    a. *Any new market roles* – The potential entry of new market participants, enabled by MTR, would almost inevitably require changes to the Code. These could have implications for the roles of incumbent participants and their compliance obligations, and how different MTR participants perform their new/amended functions, e.g. intra-trader notification.

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[1] https://kaingaora.govt.nz/assets/About-us/202406-Wellington-MTR-Six-monthly-report-summary-version.pdf, pages 1 - 2

[2] *Ibid.*, page 6

b. *System and process changes across the industry* – These could include further changes to the registry and adoption of the appropriate communications and IT standards/protocols/APIs and privacy and cyber security settings to enable a robust MTR framework. The current lack of standardised formats for the delivery of metering data could be a hurdle for the future evolution of MTR. If there are no agreed standards, MEPs would be required to implement significant system changes, i.e. develop customised data delivery mechanisms with each evolution of MTR.

c. *Flexibility and optionality* – Any initial MTR model will need to have built-in capability to evolve with market and technological developments and rising consumer expectations. While the use of widely agreed industry standards promote efficiency and scalability, this needs to be balanced with ensuring that incentives for innovation that benefits consumers are not dampened.

Commercial sustainability

11. The Wellington trial provides valuable insights that can inform the Authority's MTR framework development:

> . . .there will be real costs to participants if multiple trading were adopted more widely in the market. There would be costs to change individual participants' systems to allow the use of these relationships. It is difficult to quantify what these costs would be without knowing what the final format of these types of arrangements would be within the Code and registry.[3]
>
> Cost structures and cost recovery will need to be addressed with all participants before this concept can be adopted more widely.[4]
>
> The amount of collaboration and coordination necessary to implement a trial involving multiple organisations cannot be underestimated.[5]
>
> . . .More work is required to understand the true costs to participants if this were adopted more widely.[6]

12. The Australian Energy Market Commission's (AEMC) August 2024 decision to implement flexible trading for large customers initially provides useful precedent for the Authority's consideration. The AEMC's staged approach demonstrates how MTR frameworks can be developed to maximise consumer benefits:

> This rule change creates a new framework that enables large customers to separate their flexible and passive resources and engage multiple energy service providers to manage these resources. For these customers, such as manufacturers, other commercial operators, and hospitals, this means the ability to take up different product and service offers for their CER. For industry, it means consumer resources and load can better participate in the wholesale energy and ancillary services markets.[7]
>
> . . .These arrangements will provide large customers and their agents with an easier path to separate their passive and flexible loads using secondary settlement points (SSPs), meter their flexible resources using in-built measurement capability, and derive value from their flexible resources through wholesale and ancillary services markets.[8]

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[3] https://kaingaora.govt.nz/assets/About-us/202406-Wellington-MTR-Six-monthly-report-summary-version.pdf, page 6

[4] *Ibid.*

[5] *Ibid.*, page 7

[6] *Ibid.*, page 8

[7] https://www.aemc.gov.au/sites/default/files/2024-08/Final%20determination%20-%20Unlocking%20CER%20benefits%20through%20flexible%20trading%20-%2015%20Aug%202024.pdf, Summary, page iv

[8] *Ibid.*

> . . .while the Commission is committed to pursuing reforms that encourage innovation, the Commission has determined not to progress the option of multiple Financially Responsible Market Participants (FRMPs) at small customer premises at this time. It considers that further work needs to be done on the National Energy Customer Framework to identify arrangements for future energy services that both protect consumers and enable innovation and competition. The Commission is also aware that enabling multiple FRMPs at this time has the potential to create or exacerbate issues including the scope of the role of Metering Coordinators and implementation of dynamic operating envelopes. These issues need to be considered holistically through other processes. The Commission will continue to work with parties to look at options to trial multiple FRMPs for small customers and is open to a rule change request on this option once other reforms have progressed...[9]
>
> . . .From a cost-benefit perspective, Energeia's analysis indicates that for small customers:
>
> - Benefits will be unlocked for customers who avoid separate metering for their CER devices that are participating in network demand management projects, by using in-built metering.
> - Higher benefits can be achieved when the rule change enables greater participation in dispatch and cost-reflective prices for devices and these benefits will flow to all customers.
> - System costs associated with this rule change are relatively small and for the benefits to match the associated implementation costs, around 16 per cent of CER devices will need to participate at SSPs [*secondary settlement points*].
> - The majority of costs identified would be borne by consumers who choose to take up the arrangements rather than the broader consumer base.[10]
>
> [*Emphasis added.*]

13. The Authority's MTR framework design provides opportunities to establish efficient cost allocation and transparent cost recovery mechanisms that enhance consumer value. Key design considerations include:

    a. *Network line charges* – Who pays for line charges at an ICP where there is more than one trader? Will fixed line charges be split between the traders at the same ICP, and if so, how will cost allocation be determined?

    b. *Metering cost responsibility* – It also needs to be established who pays for metering and how metering costs are recovered under MTR stage 1. Is it the trader for consumption, trader for generation, or a split arrangement?

    c. *Retailer cost at an ICP* – There are costs associated with being the retailer at an ICP under the current one-to-one ICP-customer relationship, e.g. responsibility for providing data for market settlement. How will this cost be allocated as soon as a second trader is added to a metering channel at the same ICP? 'Level playing field' issues between traders at the same ICP could be raised if such costs are not allocated efficiently/fairly.

    d. *Resolving conflict/confusion* -This could require methods for identifying and resolving conflicting instructions, configuration or data management, and data sharing obligations from trader 1 and trader 2 with the MEP and/or the distribution network.

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[9] https://www.aemc.gov.au/sites/default/files/2024-08/Final%20determination%20-%20Unlocking%20CER%20benefits%20through%20flexible%20trading%20-%2015%20Aug%202024.pdf, Summary, page v

[10] *Ibid.*, page 33

Consumer outcomes

14. The Authority's focus on consumer mobility aligns with MTR's core objectives. Early consumer engagement could strengthen MTR framework design by addressing consumer experience considerations, including:

    a. Whether mass market consumers generally prefer receiving/paying two invoices from two traders under MTR, rather than receiving a single power bill which is simpler. We note that C&I customers may not have any issue with having more than a single power bill;

    b. Where and how consumers can raise complaints relating to new traders. This raises the question whether new traders under MTR – like all current retailers – should be required to become members of Utilities Disputes Limited, which would increase their market participation cost; and

    c. How accidental disconnections which could put vulnerable and medically dependent consumers at risk could be avoided.

15. The Wellington MTR trial report for July to December 2024 identifies some of the Code changes that need to be considered in relation to connections and disconnections and consumer care obligations:

> To scale the trial up to the wider electricity market, the following Electricity Code changes would need to be considered:
>
> a) Amendments in line with the exemptions granted for this trial.
> b) Amendments to ensure that the:
>
>   i. Retailer at the consumption ICP identifier
>
>   1. may electrically disconnect or electrically reconnect the generation ICP identifier customer for which it is not the trader in the Registry
>   2. is responsible for consumer care obligations
>   3. change of MEP or meter configuration at an ICP will require agreement of functionality with other retailers dependent on the metering configuration
>
>   ii. Retailer at the generation ICP identifier (or "child" ICP)
>
>   1. does not have electrical disconnection or electrical connection rights
>   2. understands that a credit issue between the customer and consumption retailer may include disconnection of its customer
>   3. cannot change the MEP, and must liaise with the consumption retailer.
>
> c) Ensure that the final solution allocates channels to meters at an ICP identifier that only relate to that ICP identifier
> d) Retailer compliance issues that may otherwise not be visible. There may be audit issues and education or compliance issues with retailers on its back-office system functionality, where retailers may not be managing change notifications from the Registry in a timely manner.[11]

MTR (*continued*)
Q6. Do you agree with the advantages and disadvantages of options 2 and 3? If not, why not or how would you overcome the disadvantages?
Q7. Do you agree that option 1 is the preferred option over options 2 and 3 and the reasons for preferring option 1? If not, why not?

[11] https://cdn.prod.website-files.com/670669f4e6068197aafd0771/68102a40e468ea305595076c_Summary%20version_Six%20monthly%20report%20to%20Dec%202024%20FINAL.pdf, pages 7 - 8

16. Bluecurrent generally agrees with the advantages and disadvantages of options 2 and 3 for MTR identified in the Consultation Paper.

17. We agree that option 1 (MTR stage 1) mitigates the risks and complexities associated with options 2 and 3. There are multiple challenges beyond switching (identified in our response to Q1 – Q5) that need to be better understood and addressed for MTR to be workable, cost-effective, and truly deliver consumer benefits. As such, we suggest that the Authority consider these challenges in conjunction with stakeholders at this early stage.

Suggested next steps for evolving MTR

18. Building on the valuable insights from the Wellington MTR trial and international best practices, the Authority could enhance New Zealand's position as a global leader in energy market innovation through:

    a. Establishing MTR as a strategic workstream that can leverage comprehensive industry expertise and international experience;

    b. Creating an MTR advisory/working group that harnesses collective industry knowledge to develop world-leading framework design;

    c. Commissioning analysis of New Zealand-specific MTR value propositions and optimal implementation pathways; and

    d. Canvassing international best practices whilst developing solutions tailored to New Zealand's unique market characteristics and consumer needs.

Trader switching

Q8. Should the provision of the average daily consumption remain mandatory, or should it be optional? If optional, please explain why?

Q9. Do you agree with the proposal to align timeframes to a maximum of two business days for NT and AN notifications and to reduce timeframes for the CS files?

Q10. Do you agree with the proposed solutions? If not, what would you change and why?

Q11. Do you agree with the benefits anticipated from the proposed solutions? Are there other benefits you can anticipate or improvements to operational effectiveness and efficiency? Can you quantify these benefits?

Q12. Do you anticipate the proposed solutions will introduce cost into your organisation, and if so, can you quantify this cost and/or provide a high-level description of the changes that need to be made?

19. Bluecurrent believes that the provision of the average daily consumption should remain mandatory.

20. We agree with the proposal to align timeframes to a maximum of two business days for NT and AN notifications, and to reduce timeframes for the CS file.

21. We do not have strong objections to the proposed solutions to address the issues identified in the Consultation Paper relating to current trader switching arrangements. We note some of these proposals in Table 1.

Table 1. Bluecurrent's comments on specific trader switching proposals

Trader switching proposal	Description	Bluecurrent's comment
Page 38 of the Consultation Paper Code AD, priority 7 – Physical metering differs	Alerts that the meter installed, or in the process of being installed, differs from that shown in the registry.	We already do this in practice.
Page 39 Code MI – Withdrawn on metering issue	The gaining trader must assess and address the current (existing) metering and MEP capability before sending the NT file.	It would be good if the trader will be doing extra checks in this circumstance.
Page 42 Benefits of the proposed solution for trader switching	(h) increasing standardisation of meter reading provision by requiring MEPs to provide readings where available, and where not available enabling the relevant trader to provide an actual meter reading for the switch event	We already do this in practice.

22. We anticipate some changes to our system and processes should the proposed solutions for trader switching arrangements be pursued. For example, reconfiguring the registry to clarify that a gaining MEP may change a metering installation at an ICP prior to the completion of an ICP switch could require a process change on our part.

23. Retailers/traders are best placed to assess at a high level the costs and benefits of the proposed trader switching solutions.

Trader switching (*continued*)

Q13. Are there any other files that should be added to this list?

24. Bluecurrent does not see the need for any other files to be added to the list of notifications set out under paragraph 5.33 of the Consultation Paper (*Registry manager to provide additional notifications to MEPs*) at this stage.

MEP switching

Q14. Do you agree with the proposed solutions? If not, what would you change and why?

Q15. Do you agree with the benefits anticipated from the proposed solutions? Are there other benefits you can anticipate or improvements to operational effectiveness and efficiency? Can you quantify these benefits?

Q16. Do you anticipate the proposed solutions will introduce cost into your organisation, and if so, can you quantify this cost and/or provide a high-level description of the changes that need to be made?

25. Bluecurrent generally agrees with the proposed solutions for MEP switching set out in the Consultation Paper.

26. We agree with the benefits anticipated from the proposed MEP switching solutions. We agree that benefits will result from more accurate metering records, greater transparency and automation in the

MEP switching process, and enhanced ability for participants to meet their obligations under the Code.

27. The proposed MEP switching solutions will require some changes to our system and processes, i.e. there will be costs to implement these changes. We provide comments on each of the MEP switching proposals in Table 2. Our comments generally refer to mass market metering unless otherwise stated.

Table 2. Bluecurrent's comments on the MEP switching proposals

MEP switching proposal	Bluecurrent's comment
Page 47 of the Consultation Paper – 5.28 (a) Allow both a gaining MEP and a losing MEP to populate a separate meter event for the same day provided each MEP event has a time stamp in addition to the date.	Bluecurrent suggests that this amendment ensure the gaining MEP has the ability / can make the necessary updates without relying on the losing MEP to make those updates.
Page 47 – 5.28 (b) Create new fields with associated business rules to identify specific meter types and communication capability/status, linked to the meter component level, with a business rule driven summary at ICP level.	This would require IT changes/development on our part.
Page 47 – 5.28 (c) Permit a change of MEP participant identifier when both participant identifiers belong to the same MEP, allowing MEPs to manage these changes directly (without trader involvement) and without changing the metering records.	This could potentially require IT changes on our part.
Page 47 – 5.28 (d) Require the registry manager to provide MEPs with additional notifications including gaining trader ICP switch requests (NT file), losing trader switch acknowledgements (AN file), and switch withdrawals (AW file), and ensuring the notifications contain both the losing and gaining trader identifiers.	We expect new required updates from the registry to be automated. As an MEP, we may need to make system changes depending on the new/amended notifications from the registry (i.e. new type of notification).
Page 47 – 5.28 (e) Require MEPs to provide gaining traders with access to the services access interface and meter readings within specific timeframes.	This change could also be commercially driven/desired by one or more of our customers (retailers).
Page 48 – 5.28 (f) Require MEPs to supply both gaining and losing traders with meter readings for the	We would need to set up a process as part of our data services operations to be able to implement this change.

MEP switching proposal	Bluecurrent's comment
switch event date, and then to gaining traders going forward.	
Page 48 – 5.28 (g) Require MEPs to supply relevant traders with revised meter readings or backfilled meter readings (i.e. readings from a metering installation interrogated by the MEP which were not previously delivered to the relevant trader).	This would require changes to our data services operations.
Page 48 – 5.28 (h) Place obligations on traders to notify the registry manager of an MEP nomination and on MEPs to accept the nomination on or before the date the metering is installed or decline the nomination if the metering cannot be installed. This would be supported by a registry enhancement to automatically decline unaccepted MEP nominations in specified timeframes, and a new obligation on traders and MEPs to include this requirement in the trader's and MEP's audits.	We already do this in practice, i.e. we accept a nomination as soon as we get it. Declining nominations could potentially require IT changes on our part. We also need to understand what the timeframe for automatically declining nominations would be as project work can sometimes get a nomination 3 months prior to work being done in the field.
Page 48 – 5.28 (i) Require MEPs to populate new or amended registry metering events for ICPs for 75% within five business days of the metering installation being certified/modified, or from when the ICP's status changes to "active" and 100% within 10 business days. These percentages are to be calculated over any 12-month period. . .Compliance with this requirement will be included in the MEP's audit.	We are already matching these targets – which reflect current expectations – in practice. We therefore do not anticipate a major system change to be able to implement this requirement. In the case of C&I metering, these targets could be challenging to meet for our systems, back office, and field resources due to the complexity of the switching process and the typical desire for this to occur on a specific date rather than as soon as possible.
Page 48 – 5.28 (j) Require MEPs to populate metering component removal events in the registry whether the ICP is decommissioned or not, and ensure the registry can be updated once the status has been changed to decommissioned if the metering components have been removed before decommissioning.	This would require system development. This could also be driven by one or more retailers pushing for this change.
Page 48 – 5.28 (k) Ensure the registry automatically end-dates the metering certification when a distributor	This would be a good change that would involve system development on our part.

MEP switching proposal	Bluecurrent's comment
changes an ICP identifier's status to "decommissioned", and in the event it was decommissioned in error, automatically reinstate the original expiry date of the metering certification. If the metering equipment has been removed the registry will automatically notify the MEP of the reinstatement.	In the case of C&I metering, this would still need a notice from the trader that the ICP will be recommissioned because our system record for the relevant ICP may be marked removed and to reinstate the meter, we would have to create new records.
Page 48 – 5.29 The Code would be amended, and the registry reconfigured to allow both a losing MEP and a gaining MEP to populate a separate meter event for the same day (intra-day operation). Registry functionality would be amended to ensure the removed meter/losing MEP event is inserted before the installed meter/gaining MEP event. Time stamps would also be required for new metering installations, so participants are aware of the start time for meter readings.	We suggest that this amendment ensure the gaining MEP has the ability / can make the necessary updates without relying on the losing MEP to make those updates.
Page 50 – table under 5.33 – NT file Gaining trader makes ICP switch request; notification on receipt of NT file	The NT file, which would be most useful, would require us to make additional system changes. We do not anticipate the same amount of change for the AN and AW files.
Page 51 – table under 5.35 Timeframes for MEPs to provide service access interface and meter readings	We are already matching these service levels in practice.
Page 51 – table under 5.37 Gaining/existing MEP to accept or decline the trader's MEP nomination on or before the date that metering equipment is installed or modified.	We already accept trader MEP nominations. Automatically declining unaccepted trader MEP nominations could require system changes.

Distributor switching

Q17. Do you agree with the proposed solutions? If not, what would you change and why?

Q18. Do you agree with the benefits anticipated from the proposed solutions? Are there other benefits you can anticipate or improvements to operational effectiveness and efficiency? Can you quantify these benefits?

Q19. Do you anticipate the proposed solutions will introduce cost into your organisation, and if so, can you quantify this cost and/or provide a high-level description of the changes that need to be made?

28. Bluecurrent generally agrees with the proposed solutions which will automate the currently manual distributor switching arrangements. Automation is expected to reduce the number of errors associated with manual processing. This will largely improve system and process efficiency and transparency, and reduce compliance costs.

29. Distributors and retailers/traders are best placed to assess at a high level the potential costs and benefits of the above solutions.

Implementation

Q20. Would you prefer a single implementation or a staged implementation? Please give reasons for your preference.

Q21. Do you agree with the suggested implementation timeframes? If not, please state your preferred timeframes and give reasons for your preference.

30. The proposed changes to the various switching processes may be considered together, with the objective of implementing them at the same time. Some of the system changes that will be required will be simpler or more complex, which could inevitably result in the need to implement the changes in a phased manner. For example, some IT system changes could involve iterative testing processes, i.e. may not necessarily progress in a linear manner or will be dependent on activities on the critical path of the system change process. As such, we suggest that sufficient flexibility be embedded in the implementation timeframes for the proposed switching changes.

31. Bluecurrent considers the proposed implementation timeframe for MEP-related switching proposals becoming effective 9 months after the decision is gazetted to be reasonable. However, we suggest that the lead time be extended to 1 year, to provide a grace period (i.e. when no breaches are recorded) that would allow market participants to manage the post-implementation performance of their systems.

32. Retailers/traders and distributors are best placed to assess the reasonability of the timeframes proposed for the changes that will directly affect them.

Regulatory statement for the proposed amendment - MTR

Q22. Do you agree with the objectives of the proposed amendments for MTR? If not, why not?

33. Bluecurrent broadly agrees with the proposed amendments that would help enable MTR, in principle.

34. As indicated in our responses to Q1 – Q7, changes to the switching processes and the registry, on their own, will not be sufficient to make MTR workable. We encourage the Authority to consider the potential MTR-related issues we identify in this submission so the benefits of MTR can be unlocked and optimised for consumers.

Regulatory statement for the proposed amendment - Switching

Q23. Do you agree with the objectives of the proposed amendments to improve switching processes? If not, why not?

35. Bluecurrent generally agrees with the objectives of the proposed Code amendments to improve switching processes.

36. We agree that the proposed changes will improve customer experience and choice, increase transparency and accuracy of information, and reduce compliance costs (including by automating currently manual processes). We agree that the proposed changes would ensure that switching processes are fit for purpose for the current and future electricity market with a metering fleet dominated by smart meters. These changes would align switching processes with modern business

practices and software applications, and accommodate new and innovative technology and traders in an orderly manner.

Regulatory statement for the proposed amendment – Benefits and costs

Q24. Do you agree the benefits of the proposed amendment outweigh its costs?

37. Bluecurrent generally agrees, in principle, that the benefits of the proposed Code amendments described on pages 63 - 64 of the Consultation Paper will eventually outweigh the costs (or will at least be cost neutral in the immediate term) as far as the changes that will directly affect MEPs are concerned.

38. Retailers/traders and distributors are best placed to make a cost-benefit assessment of the changes that will directly affect them.

Regulatory statement for the proposed amendment – Other means for addressing the objective

Q25. Do you have any comments on the preferred and alternative options discussed in the 2019 Issues paper?

39. Bluecurrent generally agrees with the preferred options in the *2019 Switch Process Review – Issues and Options* paper that are captured in the current Consultation Paper, and further expanded or improved by the Switch and Data Formats Group (SDFG).

Regulatory statement for the proposed amendment – Preferred option

Q26. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

40. Bluecurrent generally agrees that the proposed Code amendments are preferable to the other options that were considered to improve switching processes.

41. We note the Authority's statement that "many of the proposed changes are optional, enabling participants to decide whether to proceed with the changes where the cost-benefit of doing so is favourable" (page 65 of the Consultation Paper). We support this approach and suggest that the Authority make it clearer which of these changes are optional.

Regulatory statement for the proposed amendment – Compliance with the Authority's statutory objectives

Q27. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?

42. Bluecurrent agrees that the proposed Code amendments to improve switching processes comply, in principle, with section 32(1) of the Act which sets out the Authority's statutory objectives.

Proposed amendment – Appendix A

Q28. Do you have any comments on the drafting of the proposed amendment?

43. Bluecurrent considers the drafting of the proposed Code amendments to be reflective of the Authority's intended improvements to current switching processes – to ensure they remain fit for purpose for the evolving and future electricity market.

Concluding comments

44. Bluecurrent welcomes the Authority's leadership in advancing consumer mobility through both improved switching and MTR development. To maximise the success of these initiatives, we encourage a comprehensive approach to progressing MTR alongside switching improvements. This will help position New Zealand as a global exemplar in energy market evolution – ensuring robust consumer outcomes and maintaining New Zealand's reputation for effective market design.

45. We would welcome the opportunity to contribute our expertise to any advisory/working group the Authority establishes to support MTR framework development, drawing on our experience in the New Zealand and Australian electricity markets.

46. If you have any questions or require further information, please contact Luz Rose (Senior Regulatory and Policy Partner) at [redacted]

47. No part of this submission is confidential, and we are happy for the Authority to publish it in its entirety.

Yours sincerely

[redacted]

Matt Bostwick
Chief Customer Officer NZ