# Switch Process Review

## Issues with the ICP switching processes and possible options to address these issues

Discussion paper

Submissions close: 5pm, 17 December 2019

# Executive summary

When consumers participate more in markets, suppliers face pressure to compete more vigorously and to innovate. This benefits consumers. Consumer participation in a market is facilitated by making it easier for consumers to choose the goods or services they want to buy in the market. Having an efficient process for consumers to switch electricity retailers is important because it enables consumers to choose their electricity supplier without incurring unnecessary "transaction" costs.

The Electricity Authority (Authority) considers it is timely to review the processes set out in the Electricity Industry Participation Code 2010 (Code) for switching installation control points (ICPs). This is primarily because issues with the current ICP switching processes are causing operational inefficiencies and may be limiting competition and innovation. There are also other drivers for a review, including:

a) the prevalence throughout the country of metering installations with advanced metering infrastructure (AMI)

b) the uptake of evolving technologies in the electricity industry

c) industry participants' back-office systems and processes becoming more technically advanced

d) a general increase in innovation on the part of industry participants and consumers.

Last year we consulted on a draft set of key issues with the ICP switching processes set out in the Code. We sought interested parties' views on:

a) the issues raised in the consultation paper

b) any other issues related to ICP switching that may be hindering competition or introducing operational inefficiencies.[1]

We have used the feedback we received from this consultation, along with our observations of further switching-related issues, to prepare a final draft set of key issues with the ICP switching processes.

Then we have identified possible options to address these issues. Sometimes, there is more than one option to address an issue.

In undertaking these two activities we have sought expert advice from the Switch Technical Group (STG).[2]

The purpose of this paper is to consult with interested parties on the final draft set of key issues with the ICP switching processes set out in the Code, and options for addressing those issues. In particular, we seek interested parties' views on:

a) whether there remain any key issues with ICP switching that are not discussed in this paper

b) the advantages and disadvantages of the possible options for addressing the identified ICP switching issues

---

1 https://www.ea.govt.nz/development/work-programme/operational-efficiencies/review-of-switching-process/

2 The STG comprises individuals that have in-depth knowledge and understanding of one or more of the processes for switching ICPs.

c) what other key options exist to address the identified issues.

We plan to use your feedback to finalise the set of key issues with the ICP switching processes in the Code, and to develop a set of preferred options to address these issues.

We anticipate that some of the preferred options could be included in a “quick wins” Code amendment proposal released for consultation in 2020, while other more complex options are likely to need longer to develop.

# Contents

## Tables

# 1 What you need to know to make a submission

## What this issues paper is about

1.1 The purpose of this paper is to consult with interested parties on a final draft set of key issues with the ICP switching processes set out in the Code, and options for addressing these issues.

1.2 We have identified these issues and options as part of the Switch Process Review project—a project aimed at ensuring the ICP switching processes in the Code are fit for purpose.

1.3 The switch process review aligns with the competition and efficiency limbs of our statutory objective.

1.4 We consulted on a draft set of key issues with the current ICP switching processes in 2018 (from 4 September 2018 to 13 November 2018) (first consultation).[3]

1.5 We have used the feedback we received from this consultation, along with our observations of further switching-related issues, to prepare a final draft set of key issues with the ICP switching processes.

1.6 Next we identified possible options to address these issues. Sometimes, there is more than one option to address an issue.

1.7 This paper (second consultation) contains a final draft set of key issues with the ICP switching processes, and options for addressing these issues. The possible options, and their advantages and disadvantages, are described at a relatively high level. We have not undertaken a detailed assessment of options. We will do this after feedback from interested parties on:

(a) the identified options, and

(b) other plausible options identified by interested parties.

1.8 Following this second consultation, we may group simpler proposed changes to the ICP switching processes into a "quick wins" Code amendment proposal. A "quick win" may:

(a) be a permanent measure addressing an issue that is easily resolved

(b) be a temporary measure to address an issue in a second-best manner, but allowing time for a better, but typically more complex, solution to be implemented.

1.9 Possible changes that are more complex would be subject to further consultation with interested parties on the design of the preferred options, prior to any Code amendment proposal.

1.10 We seek interested parties' views on:

(a) whether there remain any key issues with ICP switching that are not discussed in this paper

(b) how significant the issues discussed in this paper are for the submitter

(c) any plausible options for addressing the identified issues that are not contained in this paper

[3] https://www.ea.govt.nz/development/work-programme/operational-efficiencies/review-of-switching-process/

(d) for each identified issue, the option you consider best addresses the issue

(e) for each option:

(i) any advantages or disadvantages not included in this paper

(ii) any foreseen implementation issues

(iii) your assessment of each option's costs and benefits

(f) those options you believe could be progressed through the Code amendment process relatively quickly, and the reasons for your view.

## How to make a submission

1.11 Our preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix A. Submissions in electronic form should be emailed to SwitchProcessReview.submissions@ea.govt.nz with "Issues and Options Paper—Switch Process Review" in the subject line.

1.12 If you cannot send your submission electronically, post one hard copy to either of the addresses below, or fax it to 04 460 8879.

| Postal address | Physical address |
|---|---|
| Submissions<br>Electricity Authority<br>PO Box 10041<br>Wellington 6143 | Submissions<br>Electricity Authority<br>Level 7, ASB Bank Tower<br>2 Hunter Street<br>Wellington |

1.13 Please note we want to publish all submissions we receive. If you consider that we should not publish any part of your submission, please

(a) indicate which part should not be published

(b) explain why you consider we should not publish that part

(c) provide a version of your submission that we can publish (if we agree not to publish your full submission).

1.14 If you indicate there is part of your submission that should not be published, we will discuss with you before deciding whether to not publish that part of your submission.

1.15 However, please note that all submissions we receive, including any parts that we do not publish, can be requested under the Official Information Act 1982. This means we would be required to release material that we did not publish unless good reason existed under the Official Information Act to withhold it. We would normally consult with you before releasing any material that you said should not be published.

## When to make a submission

1.16 Please deliver your submissions by **5pm** on 17 December 2019.

1.17 We will acknowledge receipt of all submissions electronically. Please contact the Submissions Administrator if you do not receive electronic acknowledgement of your submission within two business days.

# 2 Introduction

## It is timely to review the ICP switching processes

2.1 The Authority wants to ensure the processes set out in the Code for the switching of ICPs are fit for purpose. We consider it is timely to review these processes now. This is because of:

(a) issues within the current ICP switching processes that may be hindering the promotion of our statutory objective

(b) the increased importance of data accuracy and timely data availability to support:

  (i) the ICP switching processes

  (ii) innovation in the retail electricity market

(c) the need for more accurate ICP switching processes to:

  (i) enable new service offerings by electricity retailers

  (ii) enable mass consumer participation in the electricity market

(d) the prevalence throughout the country of metering installations with AMI

(e) the uptake of evolving technologies in the electricity industry

(f) industry participants' back-office systems and processes becoming more technically advanced

(g) a general increase in innovation on the part of industry participants and consumers.

## We believe the current ICP switching processes are causing operational inefficiencies and may be limiting competition

2.2 We consider the issues identified in this paper:

(a) are causing a number of operational inefficiencies in the ICP switching processes, which are imposing unnecessary transaction costs on industry participants and consumers

(b) may be limiting competition and innovation in the retail electricity market, to the detriment of consumers.

2.3 Industry practices are changing, driven in large part by innovation and evolving technologies. Evolving technologies, in particular, are affecting operational efficiency across all aspects of the ICP switching processes—for example:

(a) the use of AMI to record and gather information on electricity conveyed at an ICP

(b) increasingly advanced back-office systems and processes in participants' businesses

(c) the use of innovative technologies in customer service offerings

(d) the increased use of mass market half-hour information for electricity market settlement and customer invoicing purposes.

2.4 The majority of the issues raised in this paper relate to operational inefficiencies. Generally, these inefficiencies are being caused by:

(a) a set of ICP switching processes that were developed some years ago, and which may no longer be fit for purpose

(b) evolving use of the registry as a central source of information

(c) the more prevalent use of AMI

(d) the increasing value of metering information and meter readings to support trader and distributor processes

(e) changing industry practices

(f) innovation and new technology.

## We may move forward at two speeds

2.5 We have reviewed the submissions on our 2018 consultation paper and considered possible options to address the identified ICP switching issues, drawing on the expertise and experience of the Switch Technical Group (STG).

2.6 Some of the possible options are quick fixes that could be put into a Code amendment proposal relatively quickly. Other options would require relatively significant development and evaluation of the design, before being incorporated into a Code amendment proposal.

2.7 Therefore, our current thinking is to progress two workstreams under the Switch Process Review project at different speeds. An indicative process looking forward is as follows:

(a) Issues and options consultation paper (this paper—second consultation): Third quarter of 2019

(b) “Quick wins” Code amendment proposal: Consultation in second quarter of 2020

(c) Design of preferred options for more complex solutions to ICP switching issues: Consultation in third or fourth quarter of 2020

(d) Code amendment proposal for more complex solutions to ICP switching issues: Second or third quarter of 2021.

## This paper raises 29 issues

2.8 This paper raises 29 issues. Table 1 lists them.

**Table 1: ICP switching issues**

| | Issues associated with the trader ICP switching process |
|---|---|
| 1. | The actual trader ICP switch event date is delayed or is not as agreed<br><br>*Associated shortcomings*<br>• The losing trader determining a different switch event date to the gaining trader can cause operational inefficiencies and negatively affect competition and innovation |
| 2. | Replacing/modifying metering installations on the trader ICP switch event date is difficult<br><br>*Associated shortcomings*<br>• An MEP not dealing with a gaining trader causes operational inefficiencies and can negatively affect competition and innovation<br>• Prohibiting modification/replacement of metering installations until an ICP switch completes causes operational inefficiencies and can negatively affect competition and innovation<br>• MEPs being unaware of a trader ICP switch commencing causes operational inefficiencies<br>• Aligning a metering change with an ICP switch event date is operationally inefficient<br>• Forcing a gaining trader to commence trading at an ICP with a metering configuration it does not want is operationally inefficient and can negatively affect competition and innovation<br>• An MEP changing a metering configuration before a trader ICP switch completes can cause operational inefficiencies<br>• A gaining trader amending a proposed switch event date can be operationally inefficient |
| 3. | Gaining traders face difficulties ensuring accurate switch event meter readings for category 1, 2 and 9 metering installations<br><br>*Associated shortcomings*<br>• Operational inefficiencies can arise from different meter readings related to a trader ICP switch<br>• The prohibition on switch event meter readings having decimal places causes operational inefficiencies<br>• Using an estimated reading as the switch event meter reading is operationally inefficient and can negatively affect competition |

| | |
|---|---|
| | • Not providing an accumulating channel read for a trader ICP switch is operationally inefficient and can negatively affect competition<br>• When the losing trader provides a switch event meter reading from a different meter to that being used by the gaining trader, operational inefficiencies and negative effects on competition can arise |
| 4. | A gaining trader may face a delay receiving the first AMI meter reading for the ICP it has gained<br><br>*Associated shortcomings*<br>• A delay in a trader receiving its first meter reading from an MEP is operationally inefficient and can negatively affect competition and innovation |
| 5. | AMI switch event meter readings are not necessarily midnight meter readings<br><br>*Associated shortcomings*<br>• Traders not using available AMI midnight reads is operationally inefficient and can negatively affect competition and innovation<br>• MEPs not providing AMI midnight reads to the gaining trader is operationally inefficient and can negatively affect competition and innovation<br>• Estimating switch event meter readings for future-dated switches can be operationally inefficient and negatively affect competition and innovation |
| 6. | Interpreting trader ICP switching as consumer or embedded generator switching may be misleading<br><br>*Associated shortcomings*<br>• The current approach to determining switching numbers is operationally inefficient |
| 7. | There is no mechanism to identify the sale and transfer of mass consumer or embedded generator accounts between traders<br><br>*Associated shortcomings*<br>• The current approach to determining mass transfers of ICPs between traders is operationally inefficient |
| 8. | The rules for acknowledging trader ICP switch request notifications are not meeting their intended purpose<br><br>*Associated shortcomings*<br>• Mandating only one switch response code in an AN file is operationally inefficient and may dampen retail competition<br>• Not mandating an AN file for a “TR” ICP switch type is operationally inefficient and may dampen retail competition |

| | |
|---|---|
| | • Requiring an AN file for a “HH” ICP switch type is operationally inefficient and may dampen retail competition |
| 9. | Different timeframes for different types of trader ICP switches add complexity to the trader ICP switching process<br><br>*Associated shortcomings*<br>• Different timeframes for different trader type ICP switch processes cause operational inefficiencies |
| 10. | The trader ICP switch withdrawal process has a number of operational inefficiencies<br><br>*Associated shortcomings*<br>• The two-month time limit for switch withdrawals causes operational inefficiencies<br>• The switch withdrawal process is operationally inefficient and prone to error<br>• The unclear switch withdrawal codes in the registry functional specification cause operational inefficiencies<br>• Not mandating an ICP withdrawal acceptance by the losing trader is operationally inefficient<br>• Operational inefficiencies arise when a losing trader does not know of a price category code change made prior to a switch withdrawal |
| 11. | Different timeframes for applying a meter reading to a non half-hour (NHH) ICP switch add complexity to the trader ICP switching process<br><br>*Associated shortcomings*<br>• The current approach to deeming when a NHH switch event meter reading applies causes operational inefficiencies |
| 12. | Sometimes switch event meter readings cannot be obtained despite best endeavours<br><br>*Associated shortcomings*<br>• Operational inefficiencies arise because the Code does not accommodate a losing trader being unable to provide a switch event meter reading despite best endeavours |
| 13. | Registry functionality prevents losing traders from updating an ICP identifier during a switch<br><br>*Associated shortcomings*<br>• A losing trader’s inability to update the registry while an ICP is in the trader ICP switch process causes operational inefficiencies |

| | |
|---|---|
| 14. | The Code is ambiguous as to whether a switch event meter reading is required for certain ICPs with a category 3–5 metering installation<br><br>*Associated shortcomings*<br>• Ambiguity over the provision of NHH and AMI meter readings in the switch completion file for ICP switches carried out using the HH switch type process causes operational inefficiencies |
| 15. | The replacement read process is inefficient<br><br>*Associated shortcomings*<br>• The four month time limit on replacement reads causes operational inefficiencies<br>• The absence of a materiality threshold for replacing AMI switch event readings within five business days causes operational inefficiencies<br>• The inability of losing traders to use RRs (switch event meter read revision) for switches of the HH switch type causes operational inefficiencies<br>• Relying on MEPs to provide AMI meter readings causes operational inefficiencies<br>• Relying on MEPs to provide backdated meter readings causes operational inefficiencies<br>• The absence of clear timelines for resolving erroneous meter readings causes operational inefficiencies<br>• The materiality threshold for non-AMI replacement reads causes operational inefficiencies<br>• The inability of a losing trader to send replacement reads causes operational inefficiencies |
| 16. | Delays updating the registry with the nominated trader at a new ICP may delay meter installation / electrical connection<br><br>*Associated shortcomings*<br>• Prohibiting a trader from assigning a new ICP identifier when it has the "New" status is operationally inefficient |
| 17. | A gaining trader puts obligations on the current trader by electrically connecting an ICP before the trader ICP switch completes<br><br>*Associated shortcomings*<br>• A gaining trader electrically connecting an ICP before or during a trader ICP switch causes operational inefficiencies |
| 18. | A switch withdrawal can cause two trader ICP switches to be withdrawn |

| | |
|---|---|
| | *Associated shortcomings*<br>• Recording the last trader ICP switch where two trader ICP switches have the same event date causes operational inefficiencies |
| 19. | Average daily consumption is not being consistently calculated or is calculated using a different criterion<br><br>*Associated shortcomings*<br>• Calculating average daily consumption over a short period for inclusion in a switch completion (CS[4]) file is a less accurate reflection of average daily consumption over a reasonable period, causing operational inefficiencies |
| | **Issues associated with the distributor ICP switching process** |
| 20. | The process for switching ICPs between distributors is manual<br><br>*Associated shortcomings*<br>• Not recording a pending distributor ICP switch in the registry causes operational inefficiencies<br>• Traders can cause operational inefficiencies when they prevent a proposed distributor ICP switch from completing<br>• A lack of transparency around trader approvals of distributor switches can cause operational inefficiencies<br>• Losing distributors have limited visibility of ICPs that are to be switched to a gaining distributor, which may cause operational inefficiencies |
| 21. | Network extensions are not visible in the registry<br><br>*Associated shortcomings*<br>• A lack of visibility of ICPs connected to a network extension causes operational inefficiencies |
| 22. | Some ICP status changes part-way through a day cannot be accommodated by participants' systems<br><br>*Associated shortcomings*<br>• Moving an ICP's status between 'Active' and 'Inactive' part-way through a day can cause operational inefficiencies<br>• The current approach to moving an ICP's status to 'Decommissioned' causes operational inefficiencies |

[4] "Complete switch".

| | Issues associated with the MEP ICP switching process |
|---|---|
| 23. | The provision of initial metering data to a trader is not always timely<br><br>*Associated shortcomings*<br>• A delay in providing the first meter reading after a trader ICP switch causes operational inefficiencies<br>• MEPs not receiving advance notice of a trader ICP switch causes operational inefficiencies<br>• Delivery of the first meter reading after a trader ICP switch is perceived as being late, which causes operational inefficiencies<br>• The delivery of AMI meter readings five or more business days after a trader ICP switch completes causes operational inefficiencies<br>• MEPs do not always deliver backdated meter readings where meter readings had been missing at the time of regular data delivery |
| 24. | Meter reading file formats are not standardised<br><br>*Associated shortcomings*<br>• Non-standardisation of meter reading formats causes operational inefficiencies |
| 25. | The gaining and losing MEPs cannot use the same MEP event date for an MEP switch<br><br>*Associated shortcomings*<br>• The inability of losing and gaining MEPs to both populate a meter event for the same day creates operational inefficiencies |
| 26. | Registry metering records do not differentiate between different types of metering<br><br>*Associated shortcomings*<br>• Operational inefficiencies arise from the registry metering records not differentiating between metering installation types<br>• An incorrect AMI flag can cause operational inefficiencies and dampen retail competition |

| | |
|---|---|
| 27. | MEPs not updating the registry to record the removal of a metering component can cause safety issues and operational inefficiencies<br><br>*Associated shortcomings*<br>• Safety issues and operational inefficiencies can arise when an MEP does not populate registry metering record removal events when ICPs are decommissioned |
| 28. | The time taken by some MEPs to update registry metering records affects ICP switching<br><br>*Associated shortcomings*<br>• Slow updates of registry metering records causes operational inefficiencies and potentially dampens retail competition |
| 29. | Gaining MEP unable to accept notification and update registry metering records<br><br>*Associated shortcomings*<br>• A trader not notifying the registry manager of an MEP switch causes operational inefficiencies |

Source: Electricity Authority

## This subject matter is technical

2.9 This consultation paper discusses operational aspects of the ICP switching processes in the Code, including registry processes that facilitate ICP switching.[5] These operational aspects are relatively technical and complex in nature. Therefore, this paper's content is relatively technical.

2.10 Submitters reviewing and providing feedback on this paper should:

(a) have a good operational understanding of how the ICP switching and associated data processes operate

(b) understand the implications of the issues raised in this paper and how these relate to other industry processes.

[5] For further information on these registry processes, please refer to the registry functional specification, which is available on our website at https://www.electricityregistry.co.nz/files/FunctionalSpecification.zip.

# 3 Overview of the operation of the ICP switching processes

## There are three different switching processes

3.1 The Code sets out three different ICP switching processes:

*(a) Trader ICP switching*

This is the transfer of a trader's responsibilities in relation to an ICP from:

(i) the trader that had a contractual relationship with the consumer or embedded generator at an ICP (the "losing trader"), to

(ii) the trader that now has a contractual relationship with the consumer or embedded generator (the "gaining trader").

The trader ICP switching process in fact comprises three sub-processes. These are discussed below—refer to paragraph 3.11.

The trader ICP switching process is much the same now, albeit with various "tweaks", as it was in October 2002, when it became an automated registry process.

*(b) Distributor ICP switching*

This is the transfer of a distributor's responsibilities in relation to an ICP from:

(i) the person who formerly operated the network on which the ICP was physically located (the "losing network owner"), to

(ii) the person who now operates that network (the "gaining network owner").

This switching process was implemented on 14 July 2008, and is a manual registry process. No participants, other than the losing network owner and the gaining network owner, have visibility of the process.

*(c) MEP ICP switching*

This is the transfer of an MEP's responsibilities in relation to an ICP from:

(i) the MEP formerly contracted to provide metering services at the ICP (the "losing MEP"), to

(ii) the MEP now contracted to provide metering services at the ICP (the "gaining MEP").

This switching process was implemented on 29 August 2013, and is an automated registry process.

3.2 We consider these ICP switching processes have been working well. However, for the reasons set out in section 2, we believe it is timely to review these processes now.

3.3 The operation of the ICP switching processes are set out in more detail below. Issues with the ICP switching processes are set out in sections 4 to 6.

### Trader ICP switching

3.4 The Code defines a trader to be a retailer or a generator or a (direct) purchaser who:

(a) buys electricity from the clearing manager, or

(b) sells electricity to the clearing manager, or

(c) enters into an arrangement with another retailer or generator or purchaser to buy or sell contracts (or parts of contracts) for electricity for the purposes of the Code.[6]

3.5 Not all retailers are traders. A retailer is not a trader if it buys electricity from another participant instead of from the clearing manager. The Code requires the trader that has an arrangement with a consumer and/or embedded generator at an ICP to be responsible for the ICP identifier for that ICP.

3.6 To record responsibility, the Code requires a trader to record its participant identifier[7] in the registry, against the ICP identifiers for those ICPs for which the trader has an arrangement to:

(a) sell electricity to the consumer at the ICP, or

(b) buy electricity from the embedded generator at the ICP.

3.7 The trader is then responsible for all trader obligations relating to that ICP, as prescribed in the Code, until the ICP is either decommissioned or is switched to another trader. These obligations include:

(a) responsibility for ensuring the electricity conveyed through the point of connection[8] at the ICP is accurately measured, and

(b) responsibility for paying for the electricity conveyed through the point of connection at the ICP.

3.8 A trader ICP switch occurs when:

(a) an ICP is created and the trader enters into an arrangement with the customer at that ICP for the supply of electricity

(b) a trader enters into an arrangement with a customer at an existing ICP for the supply of electricity.

3.9 When a consumer or embedded generator at an ICP switches traders, the trader ICP switch process transfers the ICP identifier in the registry from the losing trader's participant identifier to the gaining trader's participant identifier. This is known as a "switch event".

3.10 The date of a switch event, recorded in the registry, determines the period for which a trader, in relation to an ICP, is responsible for:

(a) the trader Code obligations pertaining to the ICP

(b) selecting an MEP for the ICP

(c) electricity market settlement amounts in relation to electricity consumed and/or generated at the ICP

(d) invoicing distribution charges for the ICP, on behalf of the distributor (for the overwhelming majority of networks in New Zealand).

---

6 Refer to the definition of "trader" in Part 1 of the Code.

7 The participant identifier is a four character code that is unique to each industry participant. It is used to trace all electricity market transactions in the registry.

8 A point of connection is a point at which electricity may flow into or out of a network.

3.11 The Code prescribes three types of processes for switching ICPs between traders. The type of trader switch process to be used for an ICP depends on the ICP's attributes. An identifier is used to denote what type of switch is occurring:

(a) "TR" is used to denote a standard switch, where a consumer or embedded generator has an arrangement with a trader at an ICP, and

(i) decides to change trader, and

(ii) the categories of metering at the ICP are one or more of 0, 1, 2, or 9.

(b) "MI" is used to denote a "switch move", where no trader has an agreement with a consumer or embedded generator to trade electricity at an ICP, and

(i) a consumer or embedded generator enters into an arrangement with a trader, and

(ii) the categories of metering at the ICP are one or more of 0, 1, 2, or 9.

(c) "HH" is used to denote a "gaining trader switch", where a consumer or embedded generator has an arrangement with a trader at an ICP, and

(i) the consumer or embedded generator decides to change trader, and

(ii) either:

(A) the categories of metering at the ICP are 3, 4 or 5, or

(B) at the time of the switch, a metering installation at the ICP:

(1) is being changed from a NHH metering installation to a half-hour (HHR) metering installation that is not AMI; or

(2) is being changed from a HHR metering installation that is not AMI to a NHH metering installation.

## Distributor ICP switching

3.12 The Code adopts the definition of distributor set out in the Electricity Industry Act 2010 (Act). The Act defines a distributor to mean "a business engaged in distribution", where "distribution" means "the conveyance of electricity on lines other than lines that are part of the national grid".[9]

3.13 The Code requires a distributor to, amongst other things, create ICP identifiers in the registry for ICPs connected to the distributor's network. The distributor's participant identifier is recorded in the registry as part of the process of creating the ICP identifier. This enables the network to which the ICP is connected to be easily identified.

3.14 The Code then places various obligations on the distributor in relation to that ICP, until the ICP is either decommissioned or is switched to another distributor. These obligations include maintaining the "distributor attributes" for that ICP identifier (eg, ensuring the registry correctly records the network supply point (NSP) from which electricity is usually supplied to the ICP).

3.15 If an ICP is switched between networks, the distributor-to-distributor switch process transfers the ICP identifier in the registry from the losing distributor's participant identifier to the gaining distributor's participant identifier.

[9] Refer to section 5 of the Act.

3.16 An ICP switches between distributors when:

(a) a network is sold and the network's participant identifier is changed

(b) an embedded network is created or decommissioned. As the ICP is not decommissioned and recreated as part of this process, the ICP identifier is:

(i) transferred from the parent network to the embedded network (when an embedded network is established), or

(ii) transferred to the parent network from the embedded network (when an embedded network is disestablished).

3.17 When an ICP switches between distributors, the Code requires the gaining distributor to obtain the approval of the traders that are responsible for all of the ICPs being transferred, and to advise the Authority of the switch.

### MEP ICP switching

3.18 The Code adopts the Act's definition of metering equipment provider. The Act defines an MEP to mean "a person who, in accordance with the Code,—

(a) assumes responsibility for any metering installation; or

(b) is appointed to be responsible for any metering installation."

3.19 The Code requires an MEP to, amongst other things, record its participant identifier in the registry against those ICP identifiers that pertain to ICPs at which the MEP has agreed to provide a metering installation.

3.20 The MEP is then responsible for all MEP obligations relating to the metering installation at the ICP, until the ICP is either decommissioned or is switched to another MEP.

3.21 If an ICP is switched between MEPs, the MEP-to-MEP switch process transfers the ICP identifier in the registry from the losing MEP's participant identifier to the gaining MEP's participant identifier.

3.22 An MEP switch occurs when:

(a) an ICP is created and the MEP is the first MEP at the ICP

(b) the trader responsible for an existing ICP decides to change the MEP at the ICP

(c) the MEP sells either its entire business, exits the electricity market or its interest in certain metering installations to another MEP.

# 4 Issues with the trader ICP switching process

4.1 The intention of the trader ICP switching process is to transfer responsibility for an ICP under the Code from one trader (the "losing trader") to another trader (the "gaining trader") as quickly as practicable, while meeting the needs of the customer who is switching, the losing trader, and the gaining trader.

4.2 We consider that the following 19 issues with the trader ICP switching process may be introducing operational inefficiencies and/or hindering competition.

4.3 For each issue, we have identified one or more options for addressing the issue.

## Issue 1: The actual trader ICP switch event date is delayed or is not as agreed

4.4 For trader ICP switches that use a switch type of "TR" or "MI", the Code requires the losing trader to complete the switch. The losing trader determines the switch event date in accordance with the requirements set out in Schedule 11.3 of the Code.[10]

4.5 The Code requires a losing trader to establish a switch event date no more than 10 business days after the date on which the losing trader receives a switch initiation notification (NT file)[11] from the registry. The Code requires that 50% of these switch event dates must be within five business days over the last 12 rolling months.

### Shortcoming: The losing trader determining a different switch event date to the gaining trader can cause operational inefficiencies and negatively affect competition and innovation

4.6 Despite the switch initiation notification (NT file) containing the gaining trader's proposed switch event date, the losing trader may determine a different switch event date, if the losing trader:

(a) disagrees with the commencement date of the arrangement between a gaining trader and the consumer or embedded generator at the ICP

(b) disagrees with the gaining trader's arrangement with an MEP to replace or reconfigure a metering installation at the ICP.

4.7 Alternatively, the losing trader may delay completing a switch, for reasons such as:

(a) differences between the trader's metering records and the registry metering records

(b) where the losing trader has insufficient meter readings to create a switch event meter reading

(c) where the losing trader is unwilling to estimate a switch event meter reading—instead wanting to wait for an actual read to be performed

(d) where the losing trader has already invoiced the consumer or embedded generator past the proposed switch event date

(e) where the losing trader may have agreed a contract termination date with the consumer or embedded generator at the ICP that is a later date than the proposed switch event date

10 Refer to clauses 4 and 10 of Schedule 11.3.

11 "Notification of transfer" file.

(f) where a human error, or processing error, has been made

(g) where the ICP has prepay metering with credit remaining.

4.8 Increasingly, we are seeing traders looking to differentiate themselves from their competitors by installing new technology or offering more advanced services. Under the current ICP switching process, it can become difficult for a gaining trader to deliver its service offering to a new customer if the switch event date provided by the losing trader varies from that which the gaining trader wants. The gaining trader will want the switch event date to align with:

(a) the date on which its arrangement with the consumer or embedded generator commences

(b) the metering reconfiguration date, which may include MEP displacement, meter replacement or meter reconfiguration (eg converting the meter or the back office process from pre-pay to post-pay).

4.9 This is an operational inefficiency. It also negatively affects competition and innovation. For example, a trader may be reluctant to enter into an arrangement with a consumer or embedded generator at an ICP if the metering installation at the ICP does not have the capability to provide the services that the trader's offer depends on. Traders, and the trader ICP switching process may lose credibility with consumers and embedded generators, thereby dampening consumers' and embedded generators' propensity to switch traders.

4.10 The Authority's preferred option to mitigate this shortcoming is Option 1.

## Identified options to address Issue 1

4.11 We have identified two options to address Issue 1, and thereby promote competition in, and the efficient operation of, the electricity industry.

### Option 1

4.12 The first option is to amend the Code and make changes to the registry to allow the gaining trader to complete the switch. This would:

(a) require the gaining trader to flag in the NT file who will issue the CS file

(b) if the gaining trader is to complete the switch, require the gaining trader to either read all the NHH meters at the switch event date, or arrange for the MEP to provide meter readings for AMI meters

(c) require the MEP to provide switch event meter readings to a gaining trader where the gaining trader has provided an NT file to the registry

(d) require the registry to copy NT files to the relevant MEP.

#### *Advantages over the status quo*

- Better promotes competition and innovation by—
    - making it easier for a gaining trader to install the technology necessary to provide the services contained in the trader's offer (eg, the gaining trader can co-ordinate the date of the technology change and the switch event date)
    - reducing customer frustration associated with traders being unable to commence supplying services to the customer on the agreed date.

- Better promotes operational efficiency via an automated process that is less prone to error or disagreement between the gaining and losing traders. (The current process requires the use of e-mails and one-on-one discussions between the gaining and losing traders.)
- The gaining trader could give an NT file notification to the registry followed shortly after by a CS file that completes the switch. This would mean that the losing trader would have no warning or control of an impending trader ICP switch. This option would remove NT file notifications as a source of saves but would otherwise not impact on future saves or win-back policy considerations.

***Disadvantages over the status quo***

- Significant system and process changes for traders' back office systems.
- Requires a change to the registry's functionality.
- Requires a change to MEPs' systems and processes
- Requires MEPs to assess a metering installation or configuration change before a switch event date is set by the gaining trader, and stick to that date.

**Option 2**

4.13 The second option is to continue permitting a losing trader to complete a "TR" or "MI", switch, but amend the Code to require:

(a) that if the gaining trader has proposed a switch event date in the NT file, the losing trader must use that proposed switch event date as the actual switch event date

(b) that if the gaining trader has <u>not</u> proposed a switch event date in the NT file, the losing trader must use the date the gaining trader provided the switch initiation notification to the registry manager as the actual switch event date.

***Advantages over the status quo***

- As for option 1.

***Disadvantages over the status quo***

- Requires some system and process changes for traders' back office systems.
- Requires MEPs to assess a metering installation or configuration change before a switch event date is set by the gaining trader, and stick to that date.

Table of options for Issue 1, shortcoming and options

| Shortcoming | Options | |
|---|---|---|
| | Option 1 | Option 2 |
| 1 – losing trader determines a different switch event date | C | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 2: Replacing/modifying metering installations on the trader ICP switch event date is difficult

4.14 Currently, the Code:

(a) requires a trader to have an arrangement with an MEP at the time that a trader ICP switch is initiated. This does not have to be the existing MEP at the switch event date, but must be the MEP from the switch event date[12]

(b) prevents an MEP interfering with a metering installation for which the MEP is not responsible, unless the MEP is the gaining MEP for the metering installation[13]

(c) requires a gaining trader to have an arrangement with an MEP to be responsible for all metering installations at the ICP the gaining trader will be responsible for, before the gaining trader commences switching the ICP. This does not prevent, on the switch event day:

(i) the gaining trader displacing the incumbent MEP at the ICP, or

(ii) the metering installation being reconfigured at the gaining trader's request.

4.15 When a consumer or embedded generator accepts an offer from a trader, the consumer or embedded generator may be agreeing to specific service requirements (eg, weekly invoicing, provision of real time data, etc). This may require a change to the metering at the ICP. Feedback from the first consultation is that this is becoming more prevalent as traders develop new and more innovative services for customers, and metering technology continues to evolve.

4.16 In these situations, the gaining trader may need to displace the existing MEP responsible for the metering installation(s) at the ICP, if the existing MEP cannot, or will not, deliver the necessary metering services at the ICP. However, the Authority understands that in some instances, the gaining trader may be unable to displace the current MEP.

4.17 For example, the Authority understands that in some cases, if the metering at the ICP is owned by the distributor, the distributor's use-of-system agreement may require the gaining trader to use the MEP nominated by the distributor, despite the Code enabling the trader to determine the MEP. If the gaining trader does not want to use the distributor's metering and MEP (eg, because of cost or because the trader's required level of service cannot be delivered by the MEP), the gaining trader would have to install separate metering. However, the gaining trader may find that:

(a) no other MEP is willing to install additional metering at the ICP

(b) metering cannot be installed due to safety concerns (eg, the metering installation is near gas)

---

12 Refer to clause 11.16.

13 Refer to clause 10.12.

(c) there is insufficient space at the ICP to install additional metering (eg, a new meter box is required).

4.18 The most efficient approach is for MEP displacement to be considered and decided prior to a trader ICP switch commencing, with the MEP displacement occurring on the day of the trader ICP switch. This aligns the MEP's service provision with the services required by the trader at the ICP. It also:

(a) benefits the gaining trader and losing trader by reducing operational inefficiencies:

(i) the gaining trader does not need to provide an interim service, until the metering installation is reconfigured, which differs from the service the consumer or embedded generator has contracted for

(ii) the losing trader does not need to reconfigure its invoicing to the consumer or embedded generator at the ICP, as would occur if the metering installation were to be changed before the switch event date

(b) benefits the consumer or embedded generator at the ICP because:

(i) the trader ICP switch event date is not delayed or withdrawn

(ii) they will receive the service they have contracted for, as at the switch event date

(iii) they do not receive confusing invoices from the losing or gaining trader.

4.19 However, it is difficult to align the replacement of an MEP, or the replacement/ modification of a metering installation, with the trader ICP switch event date. This is because most trader ICP switches are backdated, and the gaining trader currently has no control over the exact day of the switch event. In addition, the process is manual and inefficient. It relies on the goodwill of the losing trader and a number of discussions between the losing and gaining trader.

4.20 The concept of replacing/modifying metering installations was not considered in the development of the switching processes, because at that time

(a) a range of services was not available from metering installations and the concept of MEPs had not been adopted within electricity market rules

(b) the prevailing view at the time was that there was sufficient competitive pressure on MEPs to incentivise them to offer the services required by traders.

4.21 As a result, the Code does not provide for shortcomings pertaining to the replacement or modification of a metering installation on the trader ICP switch event date.

4.22 A gaining trader's inability to effectively coordinate meter modification, replacement or reprogramming to coincide with a trader ICP switch reduces the efficient operation of the electricity industry. It may also constrain competition, since traders may elect to not compete at ICPs that do not have the metering configuration to support their service offering. The Authority expects this issue will continue to grow in magnitude, as service offerings and technology continue to evolve.

### Shortcoming 1: An MEP not dealing with a gaining trader causes operational inefficiencies and can negatively affect competition and innovation

4.23 An MEP at an ICP may refuse to deal with a gaining trader at that ICP, because the gaining trader is not yet recorded in the registry as being responsible for the ICP.

4.24 This adversely affects the efficiency of the process for replacing/modifying a metering installation by delaying discussions, investigation and reconfiguration until after the switch event date. The gaining trader would need to complete the switch before being able to replace the metering. This can result in the gaining trader deciding not to proceed with the ICP switch, because it considers that it cannot offer its services to the customer from the outset. This dampens competition.

4.25 The Authority's preferred option to mitigate this shortcoming is Option 1.

### Shortcoming 2: Prohibiting modification/replacement of metering installations until an ICP switch completes causes operational inefficiencies and can negatively affect competition and innovation

4.26 An MEP may be prohibited from modifying, replacing or reprogramming a metering installation until after a trader ICP switch is completed because:

(a) the Code prohibits the gaining MEP doing so without authority of the losing MEP or trader under 10.12

(b) the contract between the losing trader and the existing MEP at the ICP prohibits the existing MEP from doing so.

4.27 This adversely affects the efficiency of the process for replacing/modifying a metering installation. The gaining trader would need to complete the switch before being able to replace the metering. This can result in the gaining trader deciding not to proceed with the ICP switch, or subsequently attempting to withdraw the switch because it cannot offer its services to the customer. This dampens competition.

4.28 The Authority's preferred option to mitigate this shortcoming is Option 2.

### Shortcoming 3: MEPs being unaware of a trader ICP switch commencing causes operational inefficiencies

4.29 The existing MEP at an ICP may be unaware of a trader ICP switch commencing, because the Code does not require the registry to notify the MEP when a trader ICP switch is initiated. The MEP is notified by the registry only when the switch completes.

4.30 This adversely affects the efficiency of the trader ICP switch process. The MEP does not have the opportunity to prepare its systems for an impending trader ICP switch, and may have to make hurried arrangements once it receives notification of a completed or backdated switch.

4.31 The Authority's preferred option to mitigate this shortcoming is Option 1.

### Shortcoming 4: Aligning a metering change with an ICP switch event date is operationally inefficient

4.32 Currently, if the losing trader determines the switch event date for an ICP,[14] the gaining trader faces a manual, inefficient, and at times inaccurate, process to coordinate the switch event date with the losing trader and the MEP.

4.33 MEPs may be reluctant to enter into an arrangement with a gaining trader to change the metering at an ICP to coincide with a switch event date, unless the MEP is assured that

(a) the switch event date will not change

[14] This occurs for switch types "TR" and "MI".

(b) the MEP will not be held in breach of the Code for interfering with a metering installation for which it is not the MEP[15]

(c) the switch will not be withdrawn

4.34 The Authority's preferred option to mitigate this shortcoming is Option 2.

### Shortcoming 5: Forcing a gaining trader to commence trading at an ICP with a metering configuration it does not want is operationally inefficient and can negatively affect competition and innovation

4.35 A trader, in order to gain responsibility for an ICP, may have to commence trading at the ICP using:

(a) a meter type it does not want, and/or

(b) an MEP that it does not have an arrangement with, or does not want to have an arrangement with.

4.36 If a losing trader backdates a switch event date, the gaining trader has no opportunity to replace the existing MEP. To comply with clause 11.16 of the Code, the gaining trader must contract with the existing MEP. This contract may preclude the gaining trader from displacing the existing MEP.

4.37 This adversely affects the efficiency of the process for replacing/modifying a metering installation. The gaining trader would need to complete the switch before being able to replace the metering. This can result in the gaining trader deciding not to proceed with the ICP switch, because it cannot offer its services to the customer from the outset. This dampens competition.

4.38 The Authority's preferred option to mitigate this shortcoming is Option 2.

### Shortcoming 6: An MEP changing a metering configuration before a trader ICP switch completes can cause operational inefficiencies

4.39 If an MEP replaces or modifies a metering installation before a trader ICP switch is completed, the following operational inefficiencies arise:

(a) The losing trader must update its back office system, customer invoicing and electricity market settlement by finalising the old meter readings, and starting new meter readings for a very short period of time

(b) The losing trader may be unaware of the metering change and final meter readings when the customer switches, because the registry metering records cannot be updated until after the switch is completed. If estimated readings are used for the displaced metering installation, the gaining trader will need to determine how the estimated meter readings relate to readings from the new metering installation, as the Code requires both traders to use the same meter reading.[16]

(c) If the switch is subsequently withdrawn, the losing trader may be unaware of the changed metering installation(s) at the ICP if the registry has not been updated with this information. The losing trader may be unable to meet its service

[15] Refer to clause 10.12.

[16] Refer to clauses 6 and 12 of Schedule 11.3.

obligations to the consumer or embedded generator at the ICP it is receiving back, and may not have an arrangement with the new MEP.[17]

4.40 Shortcoming 6 is exacerbated by:

(a) traders being reluctant to contract with the existing MEP at an ICP, because the contract may include notice periods or exclusivity arrangements

(b) MEPs being reluctant to modify a metering installation until after a gaining trader is recorded in the registry as being responsible for the ICP where the metering installation is located

(c) MEPs being unwilling to reprogram AMI meters to enable traders or distributors to provide new services based on accumulating meter register reads.

4.41 The Authority's preferred option to mitigate this shortcoming is Option 2.

### Shortcoming 7: A gaining trader amending a proposed switch event date can be operationally inefficient

4.42 A gaining trader may need to change the MEP and/or metering installation or configuration at an ICP that it intends to switch. The change in MEP or metering installation/configuration may not coincide with the proposed switch event date, if:

(a) insufficient investigation has been carried out prior to determining the switch event date, or there is a change in circumstances

(b) an MEP or metering configuration change depends on other factors, such as weather, plant availability, and outages.

4.43 Completion of the switch on the proposed date may then be very inconvenient for the losing trader, gaining trader and the customer.

4.44 The Authority's preferred option to mitigate this shortcoming is Option 3.

## Identified options to address Issue 2

4.45 We have identified three options to address Issue 2, and thereby promote competition in, and the efficient operation of, the electricity industry.

### Option 1

4.46 An option to address all the shortcomings under Issue 2, except for shortcoming 2, is to amend the Code:

(a) to require that, if a losing trader is completing a switch, and the gaining trader has proposed a switch event date in the NT file, then the losing trader must use that proposed date as the actual switch event date

(b) to clarify that a gaining MEP may replace or modify a metering installation at an ICP prior to the completion of an ICP switch, provided the replacement/ modification date coincides with the switch event date.

#### *Advantages over the status quo*

- Better promotes competition and innovation by:
    - providing gaining traders with much greater certainty that the services it has offered can be provided to the customer

[17] We note that, in this instance, the gaining MEP has breached the Code by installing the new metering installation. Refer to clause 10.12

- permitting the gaining trader to specify the actual switch event date (if it wants to) for all switch types, enabling alignment with contract dates or metering replacement/modification dates
- making it easier for a gaining trader to install the technology necessary to provide the services contained in the trader's offer (eg, the gaining trader can co-ordinate the date of the technology change and the switch event date).

- Better promotes operational efficiency via an automated switch process that is less prone to error.

***Disadvantages over the status quo***

- Requires some system and process changes for MEPs' back office systems.

**Option 2**

4.47 An option to address shortcomings 2, 4, 5 and 6 under Issue 2 is to amend the Code and the registry to allow a gaining trader to complete an ICP switch if it wishes to. This would require the gaining trader to:

(a) flag in the NT file who will issue the CS file

(b) populate in the NT file with the proposed switch event date for all switch types

(c) if the gaining trader is to complete the switch, either read all the NHH meters at the ICP on the switch event date, or arrange for the existing MEP to provide meter readings for AMI meters

(d) require the existing MEP at an ICP to provide switch event meter readings to the gaining trader, if the gaining trader has provided an NT file to the registry

(e) require the registry to copy NT files to the relevant MEP.

***Advantages over the status quo***

- As for option 1.

***Disadvantages over the status quo***

- Significant system and process changes for traders' back office systems.
- Requires a change to the registry's functionality.
- Requires a change to MEPs' systems and processes.

**Option 3**

4.48 An option to address shortcoming 7 is to amend the Code to allow the losing and gaining traders to agree an alternative switch event date without requiring manual workarounds, such as a full switch withdrawal.

4.49 If the losing trader's proposed switch event date in the AN file needs to change because it does not meet the gaining trader's requirement, then:

(a) the gaining trader re-issues the NT file with the revised switch event date and the losing trader must use that date

(b) the gaining trader includes a reason in the re-issued NT file, describing the reason for the change

(c) the losing trader responds with either another AN response, or a CS switch completion.

***Advantages over the status quo***

- As for option 1, plus:
    - a losing trader does not have to set up its systems for a change of MEP or metering installation or configuration for a short period of time prior to the trader ICP switch
    - a gaining trader does not have to set up its systems for a change of MEP or metering installation or configuration for a short period of time after the trader ICP switch.

***Disadvantages over the status quo***

- Requires some system and process changes for traders' back office systems.
- Requires MEPs to assess a metering installation or configuration change before a switch event date is set by the gaining trader, and stick to that date.

Table of options for Issue 2, shortcoming and options. The greyed cells indicate the Authority's preferred option.

| **Shortcoming** | **Options** | | |
|---|---|---|---|
| | Option 1 | Option 2 | Option 3 |
| 1 – gaining MEP will not deal with a trader that is not recorded against the ICP in the registry | CO | | |
| 2 – existing MEP will not deal with a trader that is not recorded against the ICP in the registry | | CO | |
| 3 – MEPs are not aware when a trader ICP switch commences | CO | | |
| 4 – aligning a metering change with an ICP switch event date | CO | CO | CO |
| 5 – gaining trader forced to commence trading at an ICP with a metering configuration it does not want | CO | CO | CO |
| 6 – impact of an MEP changing a metering configuration before a trader ICP switch completes | CO | CO | CO |
| 7 – the gaining trader needs to amend a proposed switch event date | | | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

Issue 3: Gaining traders face difficulties ensuring accurate switch event meter readings for category 1, 2 and 9 metering installations

4.50 If a losing trader is completing an ICP switch, the losing trader must provide the switch event meter reading,[18] but only if a metering installation at the ICP contains a channel recorded in the registry with:

(a) an accumulator type of "C", and

(b) a settlement indicator of "Y".

### Shortcoming 1: Operational inefficiencies can arise from different meter readings related to a trader ICP switch

4.51 At times, the switch event meter reading provided by the losing trader does not match the gaining trader's meter reading for the ICP at the date of the switch. This can result in:

(a) the consumer or embedded generator at the ICP being invoiced/paid based on electricity quantities that differ from those used for wholesale market settlement

(b) UFE in wholesale market settlement, which will be allocated to all purchasers within the ICP's balancing area.[19]

4.52 The Authority's preferred option to mitigate this shortcoming is Option 3.

### Shortcoming 2: The prohibition on switch event meter readings having decimal places causes operational inefficiencies

4.53 Actual meter readings may include several decimal places. However, switch event meter readings with decimal places are not permitted in a CS file. Also, the Code does not set out a process for truncating or rounding switch event meter readings to the nearest whole number.

4.54 The Authority understands industry participants use various practices to handle decimal places on switch event meter readings. Some traders round up, some traders round down, and some traders truncate the decimal places. The result is that a losing and gaining trader may have a mismatch of +/-1 kWh on a switch event meter reading. This mismatch, while small, may prompt the gaining trader to issue a read revision request to the losing trader.

4.55 If an ICP with a category 1 metering installation does not have an external multiplier to convert meter readings to volume information,[20] then truncating or rounding a switch event meter reading for the ICP causes negligible error (ie, <1 kWh).

4.56 For some category 2 metering installations,[21] there may be a multiplier of up to 100 that must be applied to the switch event meter reading. The significance of no decimal places to such a meter reading may mean an inaccuracy of between 50 kWh to 100 kWh, depending on the rounding methodology used.

4.57 Where a losing or gaining trader trades the ICP identifier as HHR, but receives or provides a switch event meter reading with no decimal places, there may be a mismatch

---

18 Within the CS file.

19 A balancing area is a connected area of network, where an ICP can be supplied from one or more GXPs.

20 Most category 1 metering installations and some category 2 to 5 metering installations.

21 Metering installations that are category 2, 3, 4 or 5 may require an external multiplier to convert meter readings to volume information. However, these metering installations may be subject to the shortcomings described under Issue 3, if the metering installations contain category 1 or category 2 meters.

between the switch event meter reading and where the HHR volumes start or end. The consequence is that the HHR volume information may need to be manually adjusted.

4.58 The Authority's preferred option to mitigate this shortcoming is Option 5.

### Shortcoming 3: Using an estimated reading as the switch event meter reading is operationally inefficient and can negatively affect competition

4.59 Despite the availability of actual daily AMI meter readings for about 80% of the AMI metering installations in New Zealand, some losing traders elect to provide an estimated reading as the switch event meter reading.

4.60 A losing trader may use an estimated reading because:

(a) it does not have an arrangement with the MEP to receive daily AMI meter readings

(b) its back office system cannot put daily AMI meter readings into switch completion notifications

(c) the MEP cannot provide a meter reading for the switch event date within an acceptable time period

(d) it completes the switch on the day of receipt of the NT switch request, so does not have the AMI data (as the AMI meter reading is not received until the following day)

(e) the MEP has detected a customer switch and stops providing meter readings to the losing trader.

4.61 However, estimated readings are often inaccurate compared to actual meter readings. An inaccurate switch event meter reading may penalise the gaining trader, or the consumer or embedded generator at the ICP. Therefore, gaining traders often use the replacement read process for ICPs with an estimated switch event meter reading—particularly if the settlement method for the ICP is being moved from NHH to HHR on the switch event date. In this case, absolute accuracy of the switch event meter reading is necessary to comply with the Code.[22]

4.62 Gaining traders face difficulties ensuring that switch event meter readings are accurate. A gaining trader may:

(a) be unable to obtain an actual AMI meter reading for 00:00 hours on the day of the ICP switch without incurring charges from the MEP, particularly in the case of a backdated switch

(b) be unable to obtain an actual AMI meter reading for 00:00 hours on the day of the ICP switch because the MEP will not provide it

(c) be able to obtain an actual AMI meter reading for 00:00 hours on the day of the ICP switch, but only after a delay. If the delay is greater than five business days, the losing trader may refuse to agree to the replacement read.[23] This may impose costs on the gaining trader and the consumer or embedded generator at the ICP.

4.63 These difficulties represent operational inefficiencies. These difficulties can also dampen competitive pressure in the retail electricity market if:

---

22 Refer to clauses 6 and 12 of Schedule 11.3.

23 Refer to clauses 6(3) and 12(2B) of Schedule 11.3.

(a) traders face inefficient costs when switching a consumer or embedded generator—for example:

(i) if a gaining trader requests to amend the switch event meter reading for a significant percentage of ICP switches

(ii) if a gaining trader has to absorb some or all of the cost of energy, lines and other charges relating to an ICP, for the period during which it did not have an arrangement with the consumer or embedded generator)

(b) consumers or embedded generators have a bad first experience of a gaining trader's services—for example:

(i) the gaining trader's service provision may be delayed, while meter reading issues are resolved

(ii) the consumer or embedded generator may have electricity over- or under-billed, if the losing trader reconciles and invoices electricity using NHH meter readings and the gaining trader reconciles electricity using HHR meter readings.[24]

4.64 The Authority's preferred option to mitigate this shortcoming is Option 3.

**Shortcoming 4 – Not providing an accumulating channel read for a trader ICP switch is operationally inefficient and can negatively affect competition**

4.65 Gaining traders that intend to use the HHR reconciliation process need to determine when they start their HHR reconciliation submissions to the reconciliation manager.

4.66 The Authority understands that some MEPs will not provide an initial accumulating channel read to a gaining trader with the first data delivery after a trader ICP switch for 00:00 hours on the switch event day. This is despite the gaining trader having a contract with the customer at the ICP, and therefore being entitled to this information.[25]

4.67 This means that where a gaining trader wants to determine the switch event meter reading from an AMI meter reading, the gaining trader must calculate the meter reading from the AMI data, by subtracting HHR values from a known actual AMI accumulating channel meter reading. For a gaining trader, this process may be manual, and there is the potential for error.

4.68 These difficulties represent operational inefficiencies. These difficulties can also dampen competitive pressure in the retail electricity market:

(a) because they represent inefficient costs for traders switching a consumer or embedded generator

(b) if consumers or embedded generators have a bad first experience of a gaining trader's services—for example, the gaining trader's service provision may be delayed, while meter reading issues are resolved.

4.69 The Authority's preferred option to mitigate this shortcoming is Option 3.

[24] The electricity market may be over reconciled, or under reconciled in this instance as well.

[25] Refer to clause 1(1) of Schedule 10.6.

### Shortcoming 5 – When the losing trader provides a switch event meter reading from a different meter to that being used by the gaining trader, operational inefficiencies and negative effects on competition can arise

4.70 Some ICPs have two meters (eg, ICPs on the distribution network owned and operated by WEL networks). If a gaining trader uses a different metering installation to that used by the losing trader, the gaining trader will need to know the time of the losing trader's switch event meter reading. This is to enable the gaining trader to determine what the coincident read is for the meter that the gaining trader is using.[26] If the losing trader does not tell the gaining trader the time of the switch event meter reading, the gaining trader must estimate the coincident read.

4.71 This can result in the same operational inefficiencies and negative effects on competition described under shortcomings 3 and 4.

4.72 The Authority's preferred option to mitigate this shortcoming is Option 3.

## Identified options to address Issue 3

4.73 We have identified six options to address Issue 3, and thereby promote competition in, and the efficient operation of, the electricity industry.

### Option 1

4.74 An option to address shortcomings 1 and 5 under Issue 3 is to amend the Code to require the MEP at the ICP subject to a trader ICP switch, to provide the switch event meter reading to both (the losing and gaining) traders.

#### *Advantages over the status quo*

- Better promotes operational efficiency, with less effort required of gaining and losing traders during the trader ICP switching process.
- Actual meter readings are always used for the switch event meter readings, regardless of the contract between the losing retailer and the MEP.
- Accurate and co-ordinated switch event meter readings, ensuring accurate settlement and customer invoicing.

#### *Disadvantages over the status quo*

- Requires (losing) traders and MEPs to make some system and process changes.
- Requires traders and MEPs to amend their contracts with each other.

### Option 2

4.75 An option to address shortcomings 3 and 4 under Issue 3 is to amend the Code to require a losing trader to:

(a) provide the gaining trader with a validated actual meter reading for a switch event meter reading, where an actual meter reading is available

(b) provide a revised validated actual meter reading if updated metering information becomes available (eg, a metering error is discovered).

#### *Advantages over the status quo*

- Better promotes operational efficiency, with less effort required of gaining and losing traders during the trader ICP switching process.

[26] Because the meters would have been installed at different times, the meter registers will not be identical.

***Disadvantages over the status quo***

- Requires (losing) traders to make some system and process changes.
- May require traders and MEPs to amend their contracts with each other.

**Option 3**

4.76 An option to address shortcomings 3 and 4 under Issue 3 is to amend the Code to require the MEP at an ICP being switched to provide one or more switch event meter readings to the registry manager, if a metering installation at the ICP is category 1 or 2, and contains a channel recorded in the registry with:

(a) AMI flag = "Y"

(b) at least one channel with an accumulator type = "C".

4.77 Upon receipt of a CS file from the trader that is required to provide it, the registry manager would request the MEP to provide one or more switch event meter readings for 00:00 hours on the switch event date. The registry would hold the CS file until it received the MEP's switch event meter reading(s). The registry would then replace any switch event meter readings in the switch completion file with the switch event meter readings provided by the MEP, and send the revised CS file to both the losing trader and the gaining trader.

4.78 The MEP would be required to provide the registry manager with an actual meter midnight reading for each cumulative meter register recorded in the registry. If the MEP was unable to provide one or more switch event meter readings within a prescribed timeframe, the MEP would respond to the registry manager's request with a "no read available" flag. The registry manager would then send the CS file it was holding to the losing trader and gaining trader. The registry manager would automatically report the unavailability of an actual meter reading to the Authority.

***Advantages over the status quo***

- Better promotes operational efficiency by:
    - making all switch event meter readings midnight readings, other than in exceptional circumstances, which reduces the amount of time and effort a gaining trader must invest in backward calculating what time of day a switch event meter reading is for
    - removing the need for "switch event meter read revision" (RR) files
    - enabling the Authority to monitor MEPs' delivery of switch event meter readings, so that we can identify operational inefficiencies and seek resolutions
    - If the switch is forward dated, the registry would hold the CS file until either the switch event meter reading or a "no read available" notification was received from the MEP. This would benefit the gaining and losing traders because switch events would not need to be delayed in their systems.

***Disadvantages over the status quo***

- Requires traders to amend their systems and processes (to use actual switch event meter readings).
- Requires material changes to MEPs' back office systems, to provide switch event meter readings to the registry manager.

- Should MEPs experience delays obtaining switch event meter readings, then there may be minor delays to the switch completing. However, this should not impact the switch event date—just the date on which the switch completes.
- Requires material changes to the registry (eg, notifying the MEP of the requirement to provide switch event meter readings; holding the CS file and replacing any meter readings in it with those provided by the MEP; issuing an amended CS file to both the losing and gaining traders).

### Option 4

4.79 An option to address the shortcomings 3 and 4 under Issue 3 is to amend the Code, so that for a trader ICP switch involving AMI meters, the MEP must provide the losing and gaining traders with an accumulating channel meter reading as the switch event meter reading, regardless of the arrangement that exists between the traders and the MEP.

#### *Advantages over the status quo*

- Better promotes operational efficiency by:
    - enabling gaining traders to more quickly check the accuracy of switch event meter readings and respond more quickly with a replacement read request where there is an inaccuracy
    - resulting in a gaining trader not needing to backward calculate what time of day a switch event meter reading is for, in order to determine when the trader must start sending submission information for the ICP to the reconciliation manager
    - reducing the likelihood that an MEP detects a trader ICP switch is in progress and stops sending metering information to the losing trader before the switch completes
    - reducing overcharging or undercharging of consumers and embedded generators, and subsequent revision invoices.
    - reducing over or under settlement.

#### *Disadvantages over the status quo*

- MEPs may need to change systems and processes.

### Option 5

4.80 An option to address shortcoming 2 under Issue 3 is to amend the Code and the registry to standardise switch event meter readings to be the actual read, up to 2 decimal places.

4.81 This option would apply if the compensation factor recorded in the registry was greater than 1:

(a) is significant (eg, 50–100 kWh), and

(b) should not become part of UFE.

#### *Advantages over the status quo*

- Better promotes operational efficiency by:
    - reducing the number of RR files
    - reducing the number of trader breaches of the Code.

### *Disadvantages over the status quo*

- Requires a change to the format of the CS file.
- Traders may need to modify their systems and processes.

### Option 6

4.82 An option to address shortcoming 1 under Issue 3 is to amend the Code to standardise the rounding of switch event meter readings:

(a) to 0 decimal places, and

(b) so that if the digit to the right of the first decimal place is greater than or equal to 5, the whole digit is rounded up, and if the digit to the right of the first decimal place is less than 5, the whole digit is unchanged.

4.83 This option would apply if the compensation factor recorded in the registry equalled 1:

(a) is insignificant (eg, <1 kWh), and

(b) is acceptable to become UFE.

### *Advantages over the status quo*

- Better promotes operational efficiency by:
    - reducing the number of RR files
    - reducing the number of trader breaches of the Code.

### *Disadvantages over the status quo*

- Traders may need to modify their systems and processes.
- There will be an increase in UFE.

Table of options for Issue 3, shortcoming and options. The greyed cells indicate the Authority's preferred option.

| Shortcoming | Options | | | | | |
|---|---|---|---|---|---|---|
| | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 | Option 6 |
| 1 – The gaining and losing traders have different meter readings related to a trader ICP switch | C | CO | C | C | | |
| 2 – Switch event meter readings cannot have decimal places | | | | | CO | CO |
| 3 – AMI meter readings are not used for switch event meter readings | C | C | C | CO | | |
| 4 – The gaining trader cannot access AMI meter readings for the switch event from the MEP | C | C | C | CO | | |
| 5 – The losing trader provides a switch event meter reading from a different meter to that used by the gaining trader | C | C | C | C | | |

Key

(c) Blank = addresses none of the issue

(d) P = partly addresses the issue

(e) C = addresses the issue on its own

(f) CO = addresses the issue but requires another option to fully address the issue

## Issue 4: A gaining trader may face a delay receiving the first AMI meter reading for the ICP it has gained

4.84 We understand some traders experience a delay obtaining the first AMI meter reading from an MEP for an ICP that the trader has become responsible for.

4.85 If a trader has an arrangement with an MEP to access raw meter data from a metering installation, the Code requires:

(a) the MEP to provide the trader with access to the MEP's services access interface to collect, obtain, and use raw meter data from the metering installation

(b) the MEP to do this within 10 business days of receiving a request from the trader.[27]

4.86 As with other timeframes specified in the Code, the 10 business day period is a maximum period. It is not a target.

4.87 We have identified shortcomings in the process where MEPs provide initial meter readings to trader, which are resulting in operational inefficiencies and are described as shortcomings as follows.

### Shortcoming: A delay in a trader receiving its first meter reading from an MEP is operationally inefficient and can negatively affect competition and innovation

4.88 At times there are valid reasons for delays in the provision of AMI meter readings. However, such delays may cause problems for a gaining trader at an ICP—for example:

(a) The ICP switch may be delayed, which:

(i) may delay the gaining trader's service provision (eg, weekly invoicing, paying for demand response)

(ii) gives the consumer or embedded generator a bad first experience with the gaining trader.

(b) If the delay is more than five business days after receipt of the switch completion file, the gaining trader will be unable to require the losing trader to accept a revised switch event meter reading.[28] This may cause issues for the gaining trader if the switch event meter reading provided by the losing trader is inaccurate. For example, the gaining trader may end up paying for electricity and line charges that should have been allocated to the losing trader.

(c) Inaccuracies in wholesale electricity market settlement, the settlement of distribution charges, and customer billing can be caused by either backdated switches, or an AMI meter not communicating with the MEP's back office system. The losing trader may not accurately back out quantities submitted for reconciliation, and used for customer invoicing. The gaining trader may not accurately include these quantities in submission information provided to the reconciliation manager, and in customer invoices.

4.89 These problems represent operational inefficiencies. In addition, competitive pressure in the retail electricity market may be dampened if customers have a bad first experience of a gaining trader's services.

4.90 The Authority's preferred option to mitigate this shortcoming is Option 1.

---

27 Refer to clause 1 of Schedule 10.6.

28 Refer to clause 6(2) of Schedule 11.3. Note that this clause applies only when, at the time of the switch, the submission type is changed from NHH to HHR and the metering installation is AMI.

4.91

## Identified options to address Issue 4

### Option 1

4.92 We have identified an option to address Issue 4, and thereby promote competition in, and the efficient operation of, the electricity industry. The option is to amend the Code:

(a) to require the registry manager to provide MEPs with a copy of the switch initiation file

(b) to require MEPs to provide the gaining trader with access to the services access interface and meter readings as soon as practicable, but no later than:

(i) 4 (calendar) days from the date the registry manager sends the switch completion notification to the MEP, for 95% of switch event meter readings

(ii) 6 (calendar) days from the date the registry manager sends the switch completion notification to the MEP, for 95% – 98% of switch event meter readings

(iii) 10 (calendar) days from the date the registry manager sends the switch completion notification to the MEP, for 99% – 100% of switch event meter readings.

The proposed use of percentages is to allow for AMI metering communication difficulties.

#### *Advantages over the status quo*

- Better promotes competition and innovation by providing for traders to receive at least 95% of switch event meter readings within a period that should not result in gaining traders' customers having a negative switching experience.
- Better promotes operational efficiency by increasing the likelihood that the gaining and losing traders are allocated the correct amount of electricity at the switched ICP.

#### *Disadvantages over the status quo*

- MEPs may need to amend meter reading and data delivery processes.

Table of options for Issue 4, shortcoming and options. The greyed cell indicates the Authority's preferred option.

| **Shortcoming** | **Options** |
|---|---|
| | Option 1 |
| 1 – delay in a trader receiving its first meter reading from an MEP | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 5: AMI switch event meter readings are not necessarily midnight meter readings

4.93 When an ICP switches between traders, the switch occurs at 00.00 hours. Ideally then, any meter reading(s) for the switch will also be at 00.00 hours on the day the switch occurs. Meter readings at 00:00 on the day of a switch event are termed a midnight reading.

4.94 We have identified several shortcomings with the current trader ICP switching process, which relate to AMI switch event meter readings that are not midnight meter readings.

### Shortcoming 1: Traders not using available AMI midnight reads is operationally inefficient and can negatively affect competition and innovation

4.95 AMI meters can provide meter readings at specific times (eg, 00.00 hours), provided this is programmed into the meter and/or back office system.

4.96 We understand some losing traders do not use AMI midnight meter readings for switch event meter readings, despite having these reads available to use within 1-3 days of the read occurring.

4.97 We also understand some traders continue to either estimate a switch event meter reading, or use a previous meter reading for the switch event meter reading, despite having AMI midnight meter readings available to them.

4.98 A failure to align a switch event meter reading with the date and time the gaining trader becomes responsible for an ICP causes at least the following inefficient outcomes:

(a) over- or under-invoicing of consumers

(b) either

(i) a good first experience of the gaining trader for the customer at the ICP, if the losing trader overstates the switch event meter reading, or

(ii) a bad first experience of the gaining trader for the customer if the switch event meter reading is understated, and the gaining trader tries to recoup from the customer the value of the electricity and the line charges

(c) over- or under-recovery of network charges

(d) over- or under-settlement of electricity volumes with the clearing manager. The surplus or deficit will become unaccounted for electricity (UFE) and will be paid for (or received) by all other traders on the network

(e) excessive use of the replacement read registry process by losing traders.

4.99 The Authority's preferred option to mitigate this shortcoming is Option 1.

### Shortcoming 2: MEPs not providing AMI midnight reads to the gaining trader is operationally inefficient and can negatively affect competition and innovation

4.100 We understand some MEPs:

(a) do not provide a midnight switch event meter reading to a gaining trader, despite the gaining trader becoming responsible for the ICP at 00:00 hours on the day of the read (ie, at the time of the meter reading)

(b) in some instances, do not provide access to the services access interface to a gaining trader for up to 10 days after a switch has been completed, which is the maximum time period allowed under the Code.

4.101 The Code requires that the switch event meter reading:

(a) must be used by both the gaining trader and the losing trader in determining reconciliation manager submission information

(b) must be on the day of the switch event

(c) may be for any time during the day of the switch event.

4.102 Where an ICP identifier is being switched from a losing trader to a gaining trader, the switch event meter reading provides the demarcation between the losing trader and the gaining trader for settlement and invoicing purposes. The effect of any inaccuracy in the switch event meter reading depends on:

(a) the size of the inaccuracy (which also includes the application of the compensation factor)

(b) how the gaining trader intends to settle electricity in the wholesale market

(c) how the consumer or embedded generator at the ICP is invoiced.

4.103 For example:

(a) If the gaining trader and the losing trader both use a submission type of NHH, the same switch event meter reading must be used by both participants. All electricity conveyed through the ICP is settled, but possibly not with the correct trader, and depending on the switch event date, possibly not into the correct month. If the switch event meter reading is:

(i) lower than a midnight meter reading would have been, the gaining trader's settlement process will account for the increased electricity volume that the losing trader did not account for. If this volume is substantial, the services provided by the gaining trader are distorted, and the consumer or embedded generator at the ICP may have a quite negative first experience with the gaining trader.

(ii) higher than a midnight meter reading would have been, the gaining trader's settlement process will account for the reduced electricity volume that the losing trader has already accounted for. If this volume is substantial, the services provided by the gaining trader are distorted, and the consumer or embedded generator may have a quite positive first experience with the gaining trader.

(b) If the losing trader uses a submission type of NHH and the gaining trader uses a submission type of HHR, all electricity conveyed at the ICP may not be settled, leading to inaccuracies in the market settlement quantities for the ICP. In this case, the losing trader uses a NHH switch event meter reading, while the gaining trader uses a HHR meter reading to start customer invoicing and market settlement. However, the gaining trader may have difficulty determining what time of day it must start HHR submissions for the ICP. If the switch event meter reading is:

(i) lower than a midnight meter reading would have been, the Code requires the gaining trader to account for the electricity volume that the losing trader did not account for.[29] The gaining trader should not submit electricity volumes for an ICP to the reconciliation manager prior to becoming the trader responsible

[29] Refer to clauses 6, 12(2) and 12(3)(b) of Schedule 11.3.

for the ICP. So, the gaining trader must estimate its first HHR meter reading for the ICP. This is to add to the gaining trader's midnight meter reading the difference in consumption between the losing trader's NHH switch event meter reading the midnight meter reading.[30] If this electricity volume is substantial:

(A) the gaining trader may breach the obligations in clause 15.2 of the Code, which require the provision of complete and accurate information

(B) the services provided by the gaining trader are distorted

(C) the consumer or embedded generator at the ICP may have a quite negative first experience with the gaining trader (eg, from a higher-than-expected first invoice).

(ii) higher than what a midnight meter reading would have been, the gaining trader still has the problem of determining what day and what time of day its HHR settlements should start

(c) If the losing and gaining traders both use a submission type of HHR, neither trader is required to use the switch event meter reading in market settlement. Instead, the traders use actual HHR meter readings. Consequently, there will be no inaccuracies in the market settlement.

4.104 The Authority's preferred option to mitigate this shortcoming is Option 1.

### Shortcoming 3: Estimating switch event meter readings for future-dated switches can be operationally inefficient and negatively affect competition and innovation

4.105 Currently, the Code permits a gaining trader to forward date a trader ICP switch that is for a move in (MI switch type).

4.106 The Code requires the losing trader to provide the ICP switch event meter reading for the MI switch type within five business days of receiving the switch initiation notification (the NT file). If the switch event date is beyond this five-day window, the losing trader has no option but to estimate the switch event meter reading. However, if the switch completion were to be delayed to the switch event date, the losing trader may have been able to access an actual AMI midnight switch event meter reading for the switch event date.

4.107 This scenario results in the same potential operational inefficiencies and negative effects on competition and innovation as described above under the first two shortcomings associated with Issue 5.

4.108 The Authority's preferred option to mitigate this shortcoming is Option 2.

## Identified options to address Issue 5

4.109 We have identified five options to address Issue 5, and thereby promote competition in, and the efficient operation of, the electricity industry.

[30] Otherwise, if the gaining trader's first HHR meter reading for the ICP were to use the midnight reading, the difference in consumption would appear as UFE in the market settlement process. This UFE would then be added to the invoiced quantities of all purchasers within the balancing area to which the ICP is connected.

### Option 1

4.110 An option to address shortcomings 1 and 2 under Issue 5 is to amend the Code to require the MEP at an ICP being switched to provide one or more switch event meter readings to the registry manager, if a metering installation at the ICP is category 1 or 2, and contains a channel recorded in the registry with:

(a) AMI flag = "Y"

(b) at least one channel with an accumulator type = "C".

4.111 Upon receipt of a CS file from the trader that is required to provide it, the registry manager would request the MEP to provide one or more switch event meter readings for 00:00 hours on the switch event date. The registry would hold the CS file until it received the MEP's switch event meter reading(s). The registry would then replace any switch event meter readings in the switch completion file with the switch event meter reading(s) provided by the MEP, and send the revised CS file to both the losing trader and the gaining trader.

4.112 The MEP would be required to provide the registry manager with one or more actual meter reading(s). If the MEP was unable to provide one or more switch event meter readings within a prescribed timeframe, the MEP would respond to the registry manager's request with a "no read available" flag. The registry manager would then send the CS file it was holding to the losing trader and gaining trader. The registry manager would automatically report the unavailability of an actual meter reading to the Authority.

#### *Advantages over the status quo*

- Better promotes operational efficiency by:
    - making all switch event meter readings midnight readings, other than in exceptional circumstances, which reduces the amount of time and effort a gaining trader must invest in backward calculating what time of day a switch event meter reading is for
    - removing the need for RR files
    - enabling the Authority to monitor MEPs' delivery of switch event meter readings, so that we can identify operational inefficiencies and seek resolutions
    - if the switch is forward dated, the registry would hold the CS file until either the switch event meter reading or a "no read available" notification was received from the MEP. This would benefit the gaining and losing traders because switch events would not need to be delayed in their systems.

#### *Disadvantages over the status quo*

- Requires traders to amend their systems and processes (to use actual switch event meter readings).
- Requires material changes to the registry (eg, notifying the MEP of the requirement to provide switch event meter readings; holding the CS file and replacing any meter readings in it with those provided by the MEP; issuing an amended CS file to both the losing and gaining traders).

### Option 2

4.113 An option to address shortcoming 3 under Issue 5 is to amend the Code to require that the delivery of a switch completion file, complete with switch event meter readings, is initiated by the later of:

(a) the receipt of the NT file from the registry

(b) the switch event date.

#### *Advantages over the status quo*

- Better promotes operational efficiency by:
    - not requiring a CS file to be provided before the switch event for a future-dated switch event is completed—all CS files will only become due after a switch completes
    - enabling all losing traders to provide an actual meter reading for the switch event.

#### *Disadvantages over the status quo*

- None identified.

### Option 3

4.114 An option to address shortcoming 2 under Issue 5 is to amend the Code to require switch completion files to contain both the date and the time of an actual switch event meter reading.

#### *Advantages over the status quo*

- Better promotes operational efficiency by:
    - enabling gaining traders to have the information they need to accurately start customer invoicing and electricity market settlement
    - reducing over- or undercharging of consumers and embedded generators
    - reducing over or under settlement
    - reducing the amount of time and effort a gaining trader must invest in backward calculating what time of day a switch event meter reading is for.

#### *Disadvantages over the status quo*

- Requires the CS file to be changed and corresponding changes for traders' back office systems.

### Option 4

4.115 An option to address shortcoming 2 under Issue 5 is to amend the Code, so that for a trader ICP switch involving AMI meters, the MEP must provide the losing and gaining traders with an accumulating channel meter reading as the switch event meter reading, regardless of the arrangement that exists between the traders and the MEP.

#### *Advantages over the status quo*

- Better promotes operational efficiency by:
    - enabling gaining traders to more quickly check the accuracy of switch event meter readings and respond more quickly with a replacement read request where there is an inaccuracy

- resulting in a gaining trader not needing to backward calculate what time of day a switch event meter reading is for, in order to determine when the trader must start sending submission information for the ICP to the reconciliation manager
- reducing the likelihood that an MEP detects a trader ICP switch is in progress and stops sending metering information to the losing trader before the switch completes.
- reducing over- or undercharging of consumers and embedded generators
- reducing over- or under-settlement.

***Disadvantages over the status quo***

- MEPs may need to change systems and processes.

**Option 5**

4.116 The fifth option is to amend the Code to require a losing trader to delay releasing a CS file for up to five business days, provided the switch event date is not delayed, if this would enable the MEP to provide the losing trader with an AMI midnight meter reading. If the losing trader receives the midnight meter reading within five business days, the meter reading must be used as the switch event meter reading. If the losing trader does not receive the midnight meter reading within five business days, the losing trader must estimate the switch event meter reading.

***Advantages over the status quo***

- Better promotes operational efficiency by:
  - enabling gaining traders to have the information they need to accurately start customer invoicing and electricity market settlement
  - reducing the number of RR files
  - reducing over- or undercharging of consumers and embedded generators
  - reducing over or under settlement
  - reducing the amount of time and effort a gaining trader must invest in backward calculating what time of day a switch event meter reading is for.

***Disadvantages over the status quo***

- MEPs may need to change systems and processes.
- A delay to switches completing, although not to the effective date of a switch.
- Some traders' systems and processes may need to be changed to accommodate a delay in switch completions while awaiting MEP meter readings (some traders commence providing services to new customers on the switch event date).

4.117 Option 5 would address shortcoming 1 under Issue 5.

Table of options for Issue 5, shortcoming and options. The greyed cells indicate the Authority's preferred option.

| Shortcoming | Options | | | | |
|---|---|---|---|---|---|
| | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 |
| 1 – some traders are not using AMI midnight reads when they are available | CO | | | | CO |
| 2 – some MEPs are not providing AMI midnight reads to the gaining trader | C | | CO | C | |
| 3 – switch event meter readings must be estimated for future dated switches | | C | | | |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 6: Interpreting trader ICP switching as consumer or embedded generator switching may be misleading

4.118 The Authority needs to accurately determine the number of customers and embedded generators switching between traders in order to:

(a) determine the state of retail competition in the New Zealand electricity industry

(b) develop, and report on, the effectiveness of policy

(c) benchmark the New Zealand electricity industry with other competitive jurisdictions

(d) report to the Government and to government agencies.

4.119 We also publish the number of trader ICP switches on our "EMI" website.[31] We are aware that this information is used for a variety of purposes. For example, we know it is used by:

(a) local and international research organisations, when comparing policy and market structures

(b) traders in New Zealand, to determine how their competitive position compares with other traders' positions.

### Shortcoming: The current approach to determining switching numbers is operationally inefficient

4.120 The registry process for switching ICPs between traders involves transferring responsibility for an ICP from a losing trader to a gaining trader. However, this does not necessarily equate to a trader entering into, or exiting from, an arrangement with a customer or embedded generator at an ICP.

4.121 Interpreting a trader ICP switch as a customer or embedded generator switching between traders may be misleading. For example, a customer or embedded generator may:

(a) move into premises and enter into an arrangement with the incumbent trader at the premises. In this situation, there is no switch of ICP between traders, and therefore no trader ICP switch is recorded in the registry, but a customer or embedded generator has switched.

(b) move into premises and decide not to enter into an arrangement with the incumbent trader at the premises, but remain with the trader it had at its previous premises. In this situation, there is a switch of ICP between traders, which will be recorded in the registry, but there has been no switching of a customer or embedded generator between traders.

4.122 Such inaccuracies distort the view of customer/embedded generator switching in New Zealand's electricity sector.

4.123 The current approach to determining the number of customers and embedded generators switching between traders is causing operational inefficiencies for the Authority, and most likely others. We have to spend unnecessary time and effort validating the accuracy of the information on ICP switching.

4.124 The Authority's preferred option to mitigate this shortcoming is Option 1.

[31] https://www.emi.ea.govt.nz/Retail/Reports.

### Identified options to address Issue 6

4.125 We have identified five options to address Issue 5, and thereby promote competition in, and the efficient operation of, the electricity industry.

#### Option 1

4.126 Modify the registry to include:

(a) an additional field in the switch initiation file, that indicates whether the ICP trader switch:

(i) is the gaining of a customer, or

(ii) the result of an existing customer moving premises

(b) an additional maintenance file that indicates a trader has acquired a new customer at an ICP for which it was already the responsible trader

***Advantages over the status quo***

- Better promotes operational efficiency by removing the expenditure of unnecessary time and effort validating the accuracy of ICP switching information.

***Disadvantages over the status quo***

- Requires a significant change to the registry and to traders' systems and processes that interface with the registry.

#### Option 2

4.127 Amend the Code to require each trader to provide a standardised monthly return to the Authority that identifies:

(i) the number and location of ICPs where the trader acquired a new customer

(ii) the number and location of ICPs where the trader lost an existing customer.

***Advantages over the status quo***

- Better promotes operational efficiency by removing the expenditure of unnecessary time and effort validating the accuracy of ICP switching information.

***Disadvantages over the status quo***

- Requires traders to amend their systems and processes to use a standardised format to report trader ICP switching information.
- Requires the Authority to develop a system to collect, store and manage this information.

Table of options for Issue 6, shortcoming and options. The greyed cell indicates the Authority's preferred option.

| Shortcoming | Options | |
|---|---|---|
| | Option 1 | Option 2 |
| 1 – Authority requires accurate trader ICP switch | C | C |

| | | |
|---|---|---|
| information | | |

Key

(b) Blank = addresses none of the issue

(c) P = partly addresses the issue

(d) C = addresses the issue on its own

(e) CO = addresses the issue but requires another option to fully address the issue

## Issue 7: There is no mechanism to identify the sale and transfer of mass customer or embedded generator accounts between traders

4.128 The mass transfer of ICPs between traders from acquisitions and rationalisation of back-office functions is part of a workably competitive retail market. The Authority needs to remove mass transfers of ICPs between traders when looking at the number of consumers and embedded generators switching between traders. This is in order to:

(a) determine the state of retail competition in the New Zealand electricity industry

(b) develop, and report on, the effectiveness of policy

(c) benchmark the New Zealand electricity industry with other competitive jurisdictions

(d) report to the Government and to government agencies.

4.129 We also publish the number of trader ICP switches on our "EMI" website.[32] We are aware that this information is used for a variety of purposes. For example, we know it is used by:

(a) local and international research organisations, when comparing policy and market structures

(b) traders in New Zealand, to determine how their competitive position compares with other traders' positions.

### Shortcoming: The current approach to determining mass transfers of ICPs between traders is operationally inefficient

4.130 Currently the registry does not always record:

(a) the transfer, between traders, of responsibility for an ICP that results from one trader acquiring the other trader's account with the customer or embedded generator at the ICP (eg, through takeovers)

(b) a trader's consolidation of the participant identifiers it uses in the electricity market.

4.131 The registry will record these types of activities as a trader ICP switch when the participant identifier recorded against the ICP identifier is updated.

4.132 At times we are unable to determine whether a trader ICP switch is due to this type of activity. Our current approach is a manual process that relies on:

(a) knowing the activities in paragraph 4.130 are occurring

(b) observing a spike in trader ICP switching and querying traders

(c) manual reporting by traders.

4.133 Identifying the activities in paragraph 4.130 and manually compensating for them in our switching statistics is inefficient and prone to error.

4.134 The Authority's preferred option to mitigate this shortcoming is Option 1.

### Identified options to address Issue 7

4.135 We have identified three options to address Issue 7, and thereby promote competition in, and the efficient operation of, the electricity industry.

[32] https://www.emi.ea.govt.nz/Retail/Reports.

### Option 1

4.136 The first option is to modify the registry to include an additional field in the switch initiation file that indicates the ICP trader switch is the result of a mass customer acquisition.

#### *Advantages over the status quo*

- Better promotes operational efficiency by removing unnecessary effort validating the accuracy of ICP switching information.

#### *Disadvantages over the status quo*

- Requires a change to the registry and to traders' systems and processes that interface with the registry.

### Option 2

4.137 The second option is to amend the Code to require traders to provide a monthly return to the Authority when the trader carries out mass ICP transfers in the registry.

#### *Advantages over the status quo*

- Better promotes operational efficiency by removing the expenditure of unnecessary time and effort validating the accuracy of ICP switching information.

#### *Disadvantages over the status quo*

- Requires traders to amend their systems and processes to use a standardised format to report trader ICP switching information.
- Requires the Authority to develop a system to collect, store and manage this information.

### Option 3

4.138 The third option is to amend the Code to require traders to use a distinct mass transfer switch type when carrying out mass ICP transfers in the registry.

#### *Advantages over the status quo*

- Better promotes operational efficiency by removing the expenditure of unnecessary time and effort validating the accuracy of ICP switching information.

#### *Disadvantages over the status quo*

- May require changes to trader processes and systems.

Table of options for Issue 7, shortcoming and options. The greyed cell indicates the Authority's preferred option.

| Shortcoming | Options | | |
|---|---|---|---|
| | Option 1 | Option 2 | Option 3 |
| 1 – Authority needs to distinguish between trader ICP switches and mass transfers of ICPs where a trader either exits the market or is merged with another trader | C | C | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 8: The rules for acknowledging trader ICP switch request notifications are not meeting their intended purpose

4.139 A losing trader at an ICP sends the gaining trader an acknowledgment of a trader ICP switch request notice (AN file),[33] upon receiving a trader ICP switch initiation notification (NT file). The AN file:

(a) indicates to the gaining trader that the trader ICP switch is being processed, and

(b) provides:

(i) confirmation of the intended switch event date

(ii) additional information that the gaining trader will be unaware of, via response codes such as "contracted customer" or "premises de-energised".[34]

4.140 A losing trader may provide an AN file for trader ICP switches that have the "TR" switch type code, but must provide an AN file for trader ICP switches that have:

(a) the "MI" switch type code

(b) the "HH" switch type code. A switch using this switch type code cannot be completed without an AN file first being issued.

4.141 The difference in requirements for the issue of an AN file between switch types can be confusing for traders. The Authority understands that some traders have adopted a standardised approach of returning an AN file for all switch initiation requests.

4.142 Switch response codes are intended to prevent asymmetry of information between losing and gaining traders in relation to a trader ICP switch. Although ICP information in the registry usefully informs a trader ICP switch, an information asymmetry between a gaining and losing trader arises in respect of:

(a) ICP information not recorded in the registry (eg, whether the losing trader's customer is under contract; that the losing retailer has issued a service request for the MEP to change the metering installation at the ICP)

(b) out-of-date ICP information recorded in the registry (eg, during the switch process period, the ICP has been electrically disconnected, but the registry does not show this because of the prohibition on losing traders updating registry information for an ICP in the switch process).

4.143 The Code is not specific on the use of switch response codes, including not setting a priority order for the use of response codes. Currently, the Code requires only that a switch response code must be used.[35] This raises several issues.

### Shortcoming 1: Mandating only one switch response code in an AN file is operationally inefficient and may dampen retail competition

4.144 Currently, the AN file must contain only one response code. This means the gaining trader at an ICP will receive a subset of relevant information via the AN file in circumstances where multiple response codes are relevant to the ICP switch. For example, the consumer or embedded generator at an ICP subject to a switch request may still be under contract to the losing trader, and the premises at the ICP may be

33 "Acknowledgement of notice" file.

34 A complete list of response codes is contained in the registry functional specification, under SD-020, which is available on our website at https://www.electricityregistry.co.nz/files/FunctionalSpecification.zip.

35 Refer to clauses 1 and 6 of Schedule 11.3.

disconnected. The AN file will inform the gaining trader of only one of these valuable pieces of information.

4.145 Unavailability of relevant information at the time of a switch initiation often imposes inefficient costs on the gaining trader (eg, the switch must be reversed because the potential customer is under contract to the current trader; the gaining trader unnecessarily sends a technician to change the ICP's metering installation).

4.146 In addition, competitive pressure in the retail electricity market may be dampened if ICP switches are delayed due to incomplete ICP information.

4.147 The Authority's preferred option to mitigate this shortcoming is Options 3 and 4 combined.

#### Shortcoming 2 – Not mandating an AN file for a "TR" ICP switch type is operationally inefficient and may dampen retail competition

4.148 As noted above, a losing trader does not have to provide an AN file for trader ICP switches that have the TR switch type code.

4.149 However, this means that gaining traders:

(a) will not receive information related to the ICP that may change their view on proceeding with the trader ICP switch

(b) may need to configure their systems to receive and respond to AN files they will receive from some retailers, but not from other retailers. This adds complexity to their systems, and may lead to some gaining traders ignoring all AN responses for TR switches, when those AN responses may contain important information.

4.150 This raises the same issues around operational inefficiencies and the dampening of retail competition described under the first shortcoming.

4.151 The Authority's preferred option to mitigate this shortcoming is Options 1 and 4 combined

#### Shortcoming 3: Requiring an AN file for a "HH" ICP switch type is operationally inefficient and may dampen retail competition

4.152 Currently, the Code does not permit a trader ICP switch with an "HH" switch type code to be completed unless the losing trader has provided an AN file to the registry manager. The registry's functionality ensures this Code requirement is complied with.

4.153 The AN file provides no benefit if the ICP switch has an "HH" switch type code, because these switches are for large customers. These customers switch traders after a change of a negotiated contract. The losing trader will be aware of the impending switch and in the event of an incorrect switch request, the switch withdrawal process should be used.

4.154 Therefore, the current Code requirement is operationally inefficient and if the losing trader does not issue an AN file within a reasonable period of time, can delay the completion of some ICP switches, for no benefit to the parties involved.

4.155 The Authority's preferred option to mitigate this shortcoming is Option 5.

### We have identified five options to address Issue 8

4.156 We have identified five options to address Issue 8, and thereby promote competition in, and the efficient operation of, the electricity industry.

### Option 1

4.157 An option to address shortcoming 1 under Issue 8 is to amend the Code to set the relative priorities of the response codes. A suggested priority order is as follows (the table is a marked up version of that in the registry functional specification.

| Code | Description | Explanation of use |
|---|---|---|
| AA | Acknowledge and accept | Switch is accepted; there are no relevant issues. |
| CO | Contracted customer | Alerts that this customer has a fixed-term contract at the ICP. The current ~~T~~trader may be contacting this customer, relative to a switch. |
| MP | Metering is pre-paid | Alerts that a meter installed at the ICP is configured as pre-paid. Note that this includes legacy prepaid metering (which will be flagged on the registry) as well as AMI prepaid metering (which will not be flagged on the registry). |
| MU | Unmetered supply | Alerts supply is unmetered. |
| OC | Occupied premises | Advises that the existing customer has not yet advised the losing trader that they are moving out. The premises are occupied. |
| PD | Premises electrically disconnected~~de-energised (disconnected)~~ | Alerts that the status of the ICP is electrically disconnected while the registry has recorded that the ICP is electrically connected~~this site is de-energised (disconnected)~~. |
| AD | Advanced Metering Infrastructure | Alerts that the meter either installed, or in the process of being installed, is different to that shown in the registry~~an advanced meter~~. |

#### *Advantages over the status quo*

- Better promotes operational efficiency and retail competition, by providing more information to the gaining trader in relation to ICP switches.

#### *Disadvantages over the status quo*

- Requires a change to traders' switching systems and processes that interface with the registry.

### Option 2

4.158 Another option to address shortcoming 1 under Issue 8 is to expand the list of response codes to cover situations where more than one response code applies. Suggested additional response codes are as follows.

| Code | Description | Explanation of use |
|---|---|---|
| CM | Contracted customer and metering is prepaid | Alerts that:<br>a) this customer has a fixed-term contract at the ICP. The current Trader may be contacting this customer, relative to a switch, and<br>b) that a meter installed at the ICP is configured as pre-paid. Note that this includes legacy prepaid metering (which will be flagged on the registry) as well as AMI prepaid metering (which will not be flagged on the |

| Code | Description | Explanation of use |
|---|---|---|
| | | registry). |
| CA | Contracted customer and metering is Advanced Metering Infrastructure | Alerts that:<br>a) this customer has a fixed-term contract at the ICP. The current Trader may be contacting this customer, relative to a switch, and<br>b) the meter either installed, or in the process of being installed, is different to that shown in the registry |
| CP | Contracted customer and premises electrically disconnected | Alerts that:<br>a) this customer has a fixed-term contract at the ICP. The current Trader may be contacting this customer, relative to a switch, and<br>b) the status of the ICP is electrically disconnected while the registry has recorded that the ICP is electrically connected |

***Advantages over the status quo***

- Better promotes operational efficiency and retail competition, by providing more information to the gaining trader in relation to ICP switches.

***Disadvantages over the status quo***

- Requires a change to traders' switching systems and processes that interface with the registry.

**Option 3**

4.159 A third option to address shortcoming 1 under Issue 8 is to modify the AN file so that it contains up to four response codes.

***Advantages over the status quo***

- Better promotes operational efficiency and retail competition, by providing more information to the gaining trader in relation to ICP switches.

***Disadvantages over the status quo***

- Requires a change to traders' switching systems and processes that interface with the registry.

**Option 4**

4.160 An option to address shortcoming 2 under Issue 8 is to amend the Code to make an AN file mandatory for trader ICP switches that have the TR switch type code.

***Advantages over the status quo***

- Better promotes operational efficiency and retail competition, by providing more information to the gaining trader in relation to ICP switches that have the TR switch type code.

***Disadvantages over the status quo***

- May require system and process changes for participants that do not provide AN files for TR switch types.

**Option 5**

4.161 An option to address shortcoming 3 under Issue 8 is to amend the Code to make an AN file optional for trader ICP switches that have the HH switch type code.

***Advantages over the status quo***

- Better promotes operational efficiency by removing the need for the losing trader to provide the gaining trader with an AN file that provides no benefit to either trader, and which may delay a trader ICP switch, to the detriment of the customer at the ICP.

***Disadvantages over the status quo***

- The losing trader may have access to information about the point of connection or the customer that the gaining trader does not have access to, and this information may not be conveyed by the losing trader to the gaining trader.
- There will be a change to traders' systems and processes for HH switch types.

Table of options for Issue 8, shortcoming and options. The greyed cells indicate the Authority's preferred option.

| Shortcoming | Options | | | | |
|---|---|---|---|---|---|
| | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 |
| 1 – Mandating only one switch response code in an AN file is operationally inefficient and may dampen retail competition | | | CO | C | C |
| 2 – Not mandating an AN file for a "TR" ICP switch type is operationally inefficient and may dampen retail competition | CO | | | CO | |
| 3 – Requiring an AN file for a "HH" ICP switch type is operationally inefficient and may dampen retail competition | | | | | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

Issue 9: Different timeframes for different types of ICP switches add complexity to the trader ICP switching process

4.162 Currently, the time within which a gaining trader or losing trader must provide a notification as part of a trader ICP switch varies by switch type.

**Shortcoming: Different timeframes for similar trader ICP switch processes cause operational inefficiencies**

4.163 Table 2 shows the current times mandated in the Code.

4.164 The different timeframes for similar trader ICP switching processes:

(a) causes confusion amongst participants, resulting in participants not correctly understanding their obligations and switching-related timeframes, which can

(i) cause traders to set incorrect expectations with their customers

(ii) can cause traders to inadvertently breach the Code

(b) restricts the automation of processes

(c) limits the ability of participants' systems to generate the correct files at the correct times, because of contradictory rules for switching ICPs.

**Table 2: Times for different switch types**

| Switch notice | Standard switch process ("TR" switch type) | | Move-in switch process ("MI" switch type) | | Gaining trader switch process ("HH" switch type) | |
|---|---|---|---|---|---|---|
| | *Status* | *Time* | *Status* | *Time* | *Status* | *Time* |
| Gaining trader notifies registry manager of the switch (NT) | Mandatory | ≤ 2 BD after arrangement becomes effective | Mandatory | ≤ 2 BD after arrangement becomes effective | Mandatory | ≤ 3 BD after arrangement becomes effective |
| Trader acknowledges switch (AN) | Optional | ≤ 3 BD after receipt of NT | Mandatory | ≤ 5 BD after receipt of NT | Mandatory | ≤ 3 BD after receipt of NT |
| Losing trader completes switch (CS) | Mandatory | ≤ 5 BD after the switch event date | Mandatory | ≤ 5 BD after receipt of the NT if the losing trader accepts the gaining trader's proposed switch event date | Not applicable | Not applicable |

| Switch notice | Standard switch process ("TR" switch type) | | Move-in switch process ("MI" switch type) | | Gaining trader switch process ("HH" switch type) | |
|---|---|---|---|---|---|---|
| | *Status* | *Time* | *Status* | *Time* | *Status* | *Time* |
| | | | | No time limit if the losing trader proposes alternate switch event date | | |
| Gaining trader completes switch (CS) | Not applicable | Not applicable | Not applicable | Not applicable | Mandatory | ≤ 3 BD after receipt of AN |

Source: Electricity Authority

4.165 The Authority's preferred option to mitigate this shortcoming is Option 1.

## Identified options to address Issue 9

4.166 We have identified an option to address Issue 9, and thereby promote competition in, and the efficient operation of, the electricity industry.

4.167 The option is to amend the Code to align the timeframes across switching activity (ie, the far left hand column in Table 2), instead of switch type.

### *Advantages over the status quo*

- Better promotes operational efficiency, competition and innovation by, for example:
  - reducing the cost associated with automating ICP switching processes
  - understanding and complying with Code obligations
  - reducing incidences of disputes between participants over switching timeframes.

### *Disadvantages over the status quo*

- Requires some change to traders' processes and systems.

Table of options for Issue 9, shortcoming and options. The greyed cell indicates the Authority's preferred option.

| Shortcoming | Options |
|---|---|
| | Option 1 |
| 1 – there are different time frames for similar switch processes response code | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 10: The trader ICP switch withdrawal process has a number of operational inefficiencies

4.168 The Code permits the gaining trader or the losing trader to withdraw an ICP switch (using the appropriate registry process) up to two months after the switch event date, for one of the following reasons:

(a) the customer or embedded generator at the ICP is cancelling the switch

(b) the ICP is being decommissioned

(c) the account holder did not authorise the switch request

(d) there is a metering issue at the ICP

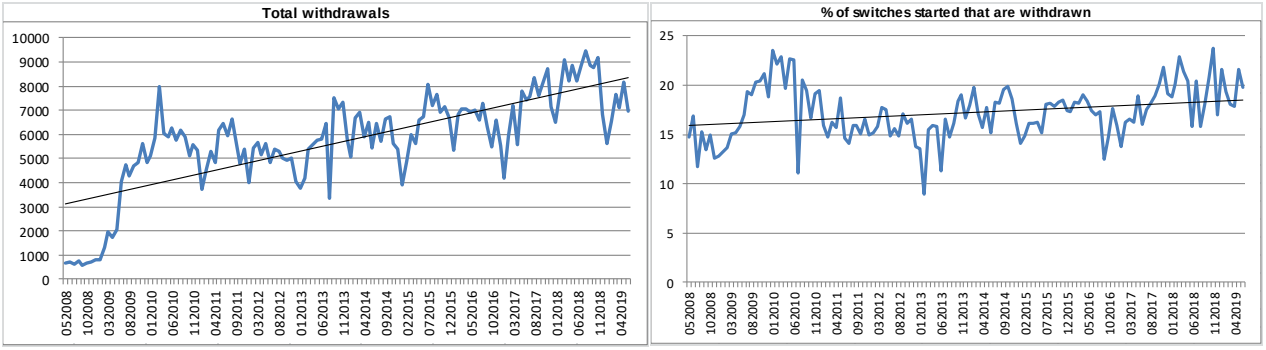
(e) the wrong premises have been, or are being, switched (due to an error by the gaining trader)

(f) the requested ICP transfer date is more than 10 business days into the future

(g) the losing trader is not the responsible trader at the ICP—the ICP has been switched to another trader, and the registry has not been updated to reflect that switch

(h) the gaining trader is in a trader default situation.[36]

4.169 Approximately 17% of switches initiated or completed are subsequently withdrawn. Over the past 12 months, there have been approximately 93,952 trader ICP switch withdrawals. The two graphs below show the total number of trader ICP switch withdrawals since 1 May 2008, and the trend in trader ICP switch withdrawals, expressed as a percentage of total trader ICP switches over this period. As can be seen, the number of withdrawals is increasing steadily.




4.170 A switch withdrawal can only occur if both the gaining trader and the losing trader agree to it, and must be carried out via the registry. If both traders agree to the switch withdrawal, the registry unwinds the ICP switch and the losing trader remains responsible under the Code for the ICP.[37]

4.171 We have identified four shortcomings with this process.

---

36 The trader uses a reason code within the "withdraw request" file to identify which of the reasons listed applies in the circumstances.

37 Refer to clause 18 of Schedule 11.3. Registry reports do not show the switch as ever occurring, although the registry history tables do record it.

### Shortcoming 1: The two-month time limit for switch withdrawals causes operational inefficiencies

4.172 The Code requires that, if a trader ICP switch is to be withdrawn, then it must be withdrawn no more than two months after the switch event date (if it has not been withdrawn prior to the switch being completed).[38]

4.173 This means that if a trader ICP switch is backdated more than two months,[39] the switch withdrawal process may not be used should the switch subsequently need to be withdrawn, regardless of the reason for the withdrawal. (A trader ICP switch may be backdated more than two months for reasons that include customer contracts or errors.)

4.174 Separately, a switch withdrawal can fall outside the two-month window because of delays in receiving information from third parties, such as MEPs or field services agents.

4.175 The two-month limit on using a switch withdrawal causes operational inefficiencies for the gaining and losing traders. This is because electricity market settlement, network settlement, and customer invoicing may, in relation to the ICP, need to be:

(a) delayed, or

(b) reversed by the gaining trader.

4.176 The inability to use the switch withdrawal process more than two months after the switch event date requires off-market settlements. These require more effort from the relevant parties involved than market settlements.

4.177 The Authority's preferred option to mitigate this shortcoming is Option 2.

### Shortcoming 2: The switch withdrawal process is operationally inefficient and prone to error

4.178 Although a switch withdrawal must be undertaken via the registry, often some information must be exchanged directly between the gaining trader and the losing trader, to support the withdrawal. This information may be exchanged in various forms, including JPGs, PDFs and emails. This exchange process is manual, unique to each trader, and can be delayed if the process is directed to a person within an organisation.

4.179 Given the increasing number of switch withdrawals, considerable effort is spent by traders in this process, making the switch withdrawal process inefficient and prone to error.

4.180 The Authority's preferred option to mitigate this shortcoming is Option 3.

### Shortcoming 3: The unclear switch withdrawal codes in the registry functional specification cause operational inefficiencies

4.181 The registry functional specification's definition of each switch withdrawal code does not clearly state:

(a) how the withdrawal code should be used

(b) under what circumstances the withdrawal code should be used.

---

38 Refer to clause 17 of Schedule 11.3.

39 In some cases it can take many months for a gaining trader to determine that the wrong ICP has been switched. The gaining trader may be unable to read or disconnect the ICP because there may be no known customer at the ICP.

4.182 For example, the switch withdrawal codes 'NWWP'[40] and 'NWDF'[41] could be used interchangeably by a losing trader to explain the rejection of a trader ICP switch because both codes apply. Alternatively, these codes could be used when, in fact, another code would have been more relevant.

4.183 Ambiguity in the definitions of the switch withdrawal codes leads to operational inefficiencies, for reasons that include:

(a) time spent by the losing trader clarifying with the gaining trader the reason(s) for a switch withdrawal

(b) time spent by staff from the Authority and traders clarifying the correct interpretation of the switch withdrawal codes in the registry functional specification.

4.184 The Authority's preferred option to mitigate this shortcoming is Option 4.

#### Shortcoming 4: Not mandating an ICP withdrawal acceptance by the losing trader is operationally inefficient

4.185 The response code in an AN file may indicate to the gaining trader that it is switching an incorrect ICP. This type of error can occur when a potential customer provides the gaining trader with inaccurate information (eg, the incorrect physical address for the ICP).

4.186 Currently, when this situation arises, the gaining trader may not be able to withdraw the ICP switch. This situation would arise if the losing trader refused the switch withdrawal request (eg, because the losing trader did not want the consumer or embedded generator at the ICP as a customer).

4.187 Any subsequent effort by the gaining and losing traders to resolve the incorrect switch of the ICP request is an inefficient use of resources.

4.188 The Authority's preferred option to mitigate this shortcoming is Option 5.

#### Shortcoming 5: Operational inefficiencies arise when a losing trader does not know of a price category code change made prior to a switch withdrawal

4.189 The distributor price category code can be changed after a trader ICP switch, which is subsequently withdrawn. In these situations, the losing trader that receives the ICP back is not notified of the change to the price category code.

4.190 The losing trader will then apply the wrong distribution charges to the customer's invoice, typically resulting in a negative customer experience and the need for the trader to correct the customer's invoice.

4.191 The Authority's preferred option to mitigate this shortcoming is Option 6.

### Identified options to address Issue 10

4.192 We have identified five options to address Issue 10, and thereby promote competition in, and the efficient operation of, the electricity industry.

#### Option 1

4.193 An option to address the first shortcoming associated with Issue 10 is to amend the Code, to allow a trader ICP switch to be withdrawn up to two months from the date of the

---

40 "Notice of Withdrawal Wrong Premises"—no customer to bill.

41 "Notice of Withdrawal Date Failed"—no CS file received.

switch completion. (As noted above, currently the two month timeframe is measured from the switch event date.)

***Advantages over the status quo***

- Better promotes operational efficiency by reducing the need for off-market settlements to correct erroneous trader ICP switches.

***Disadvantages over the status quo***

- None identified.

**Option 2**

4.194 Another option to address the first shortcoming associated with Issue 10 is to amend the Code, to allow a trader ICP switch to be withdrawn any time up to the 14 month reconciliation revision cycle for the month in which the switch event date falls.

4.195 Note that both the losing and gaining trader must agree to a withdrawal for the withdrawal to proceed.

***Advantages over the status quo***

- Better promotes operational efficiency by reducing the need for off-market settlements to correct erroneous trader ICP switches.

***Disadvantages over the status quo***

- None identified.

**Option 3**

4.196 An option to address the second shortcoming associated with Issue 10 is to amend the Code to require all communications between traders, in relation to trader ICP switches, to be recorded in the registry. This would include

(a) creating additional text fields (of say 1,000 characters) in the switch withdrawal notification and acceptance files

(b) giving the gaining trader the ability to provide multiple switch withdrawal notifications and acceptance files, where the gaining trader is responding to queries and requests for information from the losing trader.

***Advantages over the status quo***

- Better promotes operational efficiency by:
    - replacing several manual and inefficient file exchange processes with a single, semi-automated process
    - reducing the risk of a switch withdrawal request being missed by the losing trader, since registry files are always delivered (compared with the alternative of an email to a staff member who may be unavailable).

***Disadvantages over the status quo***

- Requires changes to the Code, the registry, and participants' processes and systems.

**Option 4**

4.197 An option to address the third shortcoming associated with Issue 10 is to amend the Code, and the registry functional specification, to clarify the use of withdrawal codes.

***Advantages over the status quo***

- Better promotes operational efficiency by removing confusion around the appropriate use of the withdrawal codes, which
    - increases the likelihood of correct information being conveyed
    - reduces the likelihood of Code compliance issues.

***Disadvantages over the status quo***

- Any traders that are using withdrawal codes inappropriately will most likely need to change their systems and processes.

**Option 5**

4.198 An option to address the fourth shortcoming under Issue 10 is to amend the Code to require a losing trader to accept a switch withdrawal request received within one business day of the gaining trader receiving the AN file from the registry manager, but only for the reason set out in the AN file. This ensures that trader ICP switches initiated in error by a gaining trader (eg, vacant premises; contracted customer), can be corrected quickly and efficiently.

***Advantages over the status quo***

- Better promotes operational efficiency by reducing the inefficient use of resources by gaining and losing traders resolving incorrect ICP switches.

***Disadvantages over the status quo***

- May require some traders to change their systems and processes that interface with the registry.

**Option 6**

4.199 An option to address the fifth shortcoming of Issue 10, is to change the registry so that it generates a notification to a losing trader when a trader ICP switch is withdrawn and the registry's information for the ICP differs to the registry's information for the ICP at the time the switch withdrawal request is made.

***Advantages over the status quo***

- Better promotes operational efficiency by reducing the likelihood of a trader applying the wrong distribution charges to the customers' invoices, thereby avoiding a negative customer experience and the need for the trader to correct the customer's invoice.

***Disadvantages over the status quo***

- Requires a change to traders' systems and processes, and to the registry.

Table of options for Issue 10, shortcoming and options. The greyed cells indicate the Authority's preferred option.

| Shortcoming | Options | | | | | |
|---|---|---|---|---|---|---|
| | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 | Option 6 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 – The two-month time limit for switch withdrawals causes operational inefficiencies | CO | C | | | | |
| 2 – The switch withdrawal process is operationally inefficient and prone to error | | | C | | CO | |
| 3 – The unclear switch withdrawal codes in the registry functional specification cause operational inefficiencies | | | | C | | |
| 4 – Not mandating an ICP withdrawal acceptance by the losing trader is operationally inefficient | | | | | C | |
| 5 – Operational inefficiencies arise when a losing trader does not know of a price category code change made prior to a switch withdrawal | | | | | | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 11: Different timeframes for applying a meter reading to a NHH ICP switch add complexity to the trader ICP switching process

4.200 Under the Code, NHH meter readings are deemed to apply from 00:00 hours on the day after the last meter reading up to and including 24:00 hours on the day of the meter reading. This is unless the NHH meter reading is a switch event meter reading for a NHH-metered ICP that is being switched. In this case, the NHH switch event meter reading is deemed to apply:

(a) for the gaining trader, from 00:00 hours on the day of the switch

(b) for the losing trader, at 24:00 hours at the end of the day before the switch.[42]

### Shortcoming: The current approach to deeming when a NHH switch event meter reading applies causes operational inefficiencies

4.201 The Code's current approach to deeming when a NHH switch event meter reading applies is confusing and leads to complexity in traders' systems. For example, it is difficult to align the relevant events in the registry with the final meter reading for a meter that has been replaced as part of the ICP switch. The meter reading date recorded in the registry metering records will be one day earlier than the date the meter reading is applied in the gaining trader's reconciliation system.

4.202 This can cause inaccurate counts of ICP days, which result in the reconciliation manager scaling reconciled electricity quantities unnecessarily.[43] This creates a small settlement risk for traders.

4.203 The Authority's preferred option to mitigate this shortcoming is Option 1.

### Identified options to address Issue 11

#### Option 1

4.204 We have identified an option to address Issue 11, and thereby promote competition in, and the efficient operation of, the electricity industry.

4.205 The option is to amend the Code to require all NHH meter readings to be applied:

(a) at 00:00 hours on the day of the meter reading, or

(b) at 24:00 hours on the day before the meter reading.

#### *Advantages over the status quo*

- Better promotes operational efficiency by:
    - aligning meter readings with registry events, thereby removing a source of confusion and potential for error
    - removing a manual intervention from the trader ICP switch process.

#### *Disadvantages over the status quo*

- May require some traders to make system changes.

---

42 Refer to clause 6 of Schedule 15.2.

43 Refer to clause 8 of Schedule 15.4.

Table of options for Issue 11, shortcoming and options. The greyed cell indicates the Authority's preferred option.

| Shortcoming | Options |
|---|---|
| | Option 1 |
| 1 – The current approach to deeming when a NHH switch event meter reading applies causes operational inefficiencies | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 12: Sometimes switch event meter readings cannot be obtained despite best endeavours

4.206 Currently, the Code requires the losing trader in a trader ICP switch to provide a switch event meter reading that is either:

(a) a validated meter reading[44] or, if that is not available

(b) a permanent estimate.[45]

### Shortcoming: Operational inefficiencies arise because the Code does not accommodate a losing trader being unable to provide a switch event meter reading despite best endeavours

4.207 In rare instances, a losing trader may be unable to obtain a validated meter reading, or have sufficient information to produce a permanent estimate for an ICP that is being switched to another trader. Examples of when these instances occur include when the metering installation:

(a) is destroyed by fire or other disaster

(b) is tampered with or goes missing

(c) fails catastrophically

(d) cannot be accessed.

4.208 In these instances, the losing trader is in breach of the Code. However, it is impossible for the losing trader to comply with the Code. This results in unnecessary compliance costs for the losing trader and the Authority. These compliance costs represent an operational inefficiency.

4.209 The Authority's preferred option to mitigate this shortcoming is Options 1 and 2 combined.

### We have identified two options to address Issue 12

4.210 We have identified two options to address Issue 12, and thereby promote competition in, and the efficient operation of, the electricity industry.

### Option 1

4.211 The first option is to amend the Code to allow a losing trader to provide a switch event meter reading that is an estimate, when despite best endeavours:

(a) a validated meter reading cannot be obtained, or

(b) a permanent estimate cannot be created.

#### *Advantages over the status quo*

- Better promotes operational efficiency by:
    - removing inefficient compliance activities and associated costs for the Authority and participants
    - reducing participant confusion about appropriate actions when a switch event meter reading cannot be provided.

---

44 A validated meter reading is a meter reading that has passed the trader's validation process.

45 A permanent estimate is an estimated meter reading that has passed a validation process, including a comparison with two validated meter readings.

***Disadvantages over the status quo***

- May require a change to some participants' systems and processes.

**Option 2**

4.212 The second option is for the Authority to develop guidelines around the requirements for meter readings, including what constitutes "reasonable endeavours".

***Advantages over the status quo***

- Better promotes operational efficiency by reducing participant confusion about appropriate actions when a switch event meter reading cannot be provided.

***Disadvantages over the status quo***

- None identified.

Table of options for Issue 12, shortcoming and options. The greyed cells indicate the Authority's preferred option.

| Shortcoming | Options | |
|---|---|---|
| | Option 1 | Option 2 |
| 1 – losing trader may be unable to obtain a validated meter reading | CO | CO |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 13: Registry functionality prevents losing traders from updating an ICP identifier during a switch

4.213 Currently, the registry locks the trader records for an ICP identifier as soon as the registry receives a switch initiation notification. This means the losing trader cannot then update any of the ICP's attributes in the registry, unless the switch is withdrawn.

### Shortcoming: A losing trader's inability to update the registry while an ICP is in the trader ICP switch process causes operational inefficiencies

4.214 Preventing a losing trader from updating an ICP's attributes during a switch is problematic, if the losing trader has electrically disconnected the ICP immediately before, or after, the registry receives the switch initiation notification. Since the losing trader cannot update the registry, the gaining trader will be unaware the ICP is electrically disconnected, unless the losing retailer records this in the AN file. However, provision of an AN file is voluntary for the standard ICP switch process (switch type "TR").

4.215 This may result in a negative customer experience and impose a relatively material cost on the gaining trader, particularly if a manual reconnection of the ICP is required outside normal working hours.

4.216 This is an operational inefficiency. Competitive pressure in the retail electricity market may be dampened if customers have a bad first experience of a gaining trader's services. Traders have informed us of an increase in the number of switched ICPs that are recorded in the registry as being electrically connected, but which are without power when the switch completes.

4.217 The Authority's preferred option to mitigate this shortcoming is Option 1.

### Identified options to address Issue 13

4.218 We have identified two options to address Issue 13, and thereby promote competition in, and the efficient operation of, the electricity industry.

#### Option 1

4.219 The first option is to amend the Code so that, if there is a change to the attributes of an ICP in a trader ICP switch process, the losing trader must advise the registry manager of the change. The registry manager would be required to notify the gaining trader of the change, as well as the other participants that ordinarily receive such a notice (ie, the losing trader, MEP and distributor).

##### *Advantages over the status quo*

- Better promotes operational efficiency by:
    - reduces participants' compliance costs
    - provides more information to the gaining trader in the trader ICP switch process.

##### *Disadvantages over the status quo*

- Requires a change to the registry and to traders' systems and processes.

#### Option 2

4.220 The second option is to amend the Code to require the losing trader to provide an appropriate AN response to the gaining trader, if:

(a) the ICP is subject to a trader ICP switch, and

(b) the registry records show the status of the ICP as:

(i) "active", when in fact the ICP is "inactive", or

(ii) "inactive", when in fact the ICP is "active".

4.221 Refer also to the discussion on Issue 8.

***Advantages over the status quo***

- Better promotes operational efficiency by:
  - reducing participants' compliance costs
  - providing more information to the gaining trader in the trader ICP switch process
  - reducing the need for urgent after hours call outs to electrically connect an ICP
  - reducing customer inconvenience and delay in the case of a move-in switch where the ICP has been electrically disconnected.

***Disadvantages over the status quo***

- Requires a change to the registry and to traders' systems and processes.

4.222 A disadvantage of this second option relative to the first option is that an AN response is issued only once at the commencement of the switching process. If an electrical disconnection occurs after an AN response from the losing trader, the gaining trader will not be informed.

Table of options for Issue 13, shortcoming and options. The greyed cell indicates the Authority's preferred option

| **Shortcoming** | **Options** | |
|---|---|---|
| | Option 1 | Option 2 |
| 1 – A losing trader's inability to update the registry while an ICP is in the trader ICP switch process causes operational inefficiencies | C | CO |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 14: The Code is ambiguous as to whether a switch event meter reading is required for certain ICPs with a category 3–5 metering installation

4.223 Under the "Gaining trader switch process" set out in the Code,[46] the gaining trader has an arrangement with a customer or embedded generator to trade electricity through:

(a) a non-AMI category 3–5 HHR metering installation, at an ICP at which the losing trader also trades electricity through a non-AMI HHR metering installation; or

(b) a non-AMI HHR metering installation, at an ICP at which the losing trader trades electricity through a NHH metering installation; or

(c) a NHH metering installation, at an ICP at which the losing trader trades electricity through a non-AMI HHR metering installation.

4.224 In rare circumstances, an ICP with a category 3–5 metering installation may also have:

(a) a category 1 or 2 metering installation, or

(b) a NHH or AMI metering installation, or

(c) a metering installation with NHH or AMI metering components.

### Shortcoming: Ambiguity over the provision of NHH and AMI meter readings in the switch completion file for ICP switches carried out using the HH switch type process causes operational inefficiencies

4.225 If the type of ICP described in paragraph 4.224 is switched between traders, the current functionality of the registry means the gaining trader will have to provide a switch event meter reading for the ICP, if the registry metering records for the ICP show the meter has a channel with:

(a) accumulator type of "C", and

(b) settlement indicator of "Y".

4.226 If the gaining trader does not provide a switch event meter reading for these channels, the ICP switch will not be completed.

4.227 However, the Code does not explicitly require the gaining trader to provide a switch event meter reading in this circumstance. The Code does not require accumulating channels for category 3–5 HHR-only metering installations, which are the metering installations to which the "gaining trader switch process" is intended to apply. This is because the Code requires category 3–5 metering installations to be settled in the electricity market using half-hour information.

4.228 This ambiguity in the Code can cause operational inefficiencies for new traders, who are initially unaware of the registry's validation on switches involving this type of ICP. In addition, competitive pressure in the retail electricity market may be dampened if ICP switches are delayed.

4.229 The Authority's preferred option to mitigate this shortcoming is Option 1.

[46] Refer to clauses 13 to 16 of Schedule 11.3.

## We have identified an option to address Issue 14

### Option 1

4.230 We have identified one option to address Issue 14, and thereby promote competition in, and the efficient operation of, the electricity industry.

4.231 The option is to amend the Code requirements pertaining to the HH switch type process to require:

(a) the gaining trader to provide switch event meter readings in the CS file, if the registry metering records include a channel with accumulator type = "C" and settlement indicator = "Y"

(b) the MEP not to populate channels with accumulator type = "C" and settlement indicator = "Y" for metering components that are non-AMI HHR only, (ie commercial and industrial HHR metering installations).

#### *Advantages over the status quo*

- Better promotes operational efficiency by:
    - reducing participant confusion over the need to provide a switch event meter read for an ICP with category 3–5 HHR-only metering components
    - reducing the need for manual workarounds
    - reducing the likelihood of Code compliance issues.

#### *Disadvantages over the status quo*

- Requires a change to traders' systems and processes
- Will require establishing a disputes process in the Code for NHH switch event meter readings.

Table of options for Issue 14, shortcoming and options. The greyed cell indicates the Authority's preferred option.

| Shortcoming | Options |
|---|---|
| | Option 1 |
| 1 – Ambiguity over the provision of NHH and AMI meter readings in the switch completion file for HH ICP switches causes operational inefficiencies | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

Issue 15: The replacement read process is inefficient

4.232 The Code requires participants to take all practicable steps to ensure they provide complete and accurate information under the ICP switching processes. A participant must, as soon as practicable, correct any information it has provided, if the participant becomes aware that the information is not complete and accurate.[47]

4.233 Inaccurate switch event readings can, and do, occur for a variety of reasons, including:

(a) unaccounted-for consumption at the ICP while the losing trader was responsible for it (eg, repairs and maintenance were undertaken while the premises were vacant prior to being sold or re-let, or hot water cylinders were left connected while the premises was vacant)

(b) a meter error, discovered after the switch event date

(c) the losing trader does not use a switch event meter reading taken on / determined for the day of the switch (eg, the losing trader uses the last actual read instead)

(d) the losing trader's preference to use an estimated meter reading, rather than an actual reading taken on the day of the switch—for example, because the losing trader does not wish to:

(i) source an AMI meter reading (even if the MEP has one available)

(ii) validate an AMI meter reading it has received.

4.234 The Code provides for a gaining trader in a trader ICP switch to advise the losing trader of an inaccurate switch event meter reading, and for the gaining trader and losing trader to agree a revised reading. This is known as the replacement read process. This process is very heavily used by traders.

### How the replacement read process works

4.235 If the gaining trader in a trader ICP switch considers the switch event meter reading provided by the losing trader is inaccurate, the gaining trader may dispute the meter reading and provide a replacement reading, for the following switch types:

(a) a standard ICP switch (switch type "TR")[48]

(b) a move-in ICP switch (switch type "MI").[49]

4.236 The current Code requirements for replacement readings are quite complex. They may be summarised as follows:

(a) Only the gaining trader may initiate the process for obtaining and using a replacement read.

(b) The gaining trader must initiate the replacement read process within four months of the switch event date.

(c) For a standard switch ("TR" switch type) or a move-in switch ("MI" switch type), the replacement read process can only be used if the switch event meter reading provided by the losing trader differs by more than 200 kWh from the switch event

47 Refer to clause 11.2 of the Code.

48 Refer to clauses 6 and 6A of Schedule 11.3.

49 Refer to clause 12 of Schedule 11.3.

meter reading determined by the gaining trader. (Note the 200 kWh is per meter channel, which is a sizable quantity of electricity over several channels.)

(d) The gaining trader and the losing trader must agree on any replacement reading for an ICP switch. If the losing trader disagrees, the gaining trader must:

(i) use the original switch event meter reading, or

(ii) use the disputes procedure in clause 15.29 of the Code.[50]

(e) Despite (c) and (d) above, the losing trader must accept the gaining trader's replacement read for the ICP switch, if:

(i) the ICP's metering installation is AMI, and

(ii) the ICP's submission type is changing from NHH to HHR at the time of the ICP switch, and

(iii) the switch event meter reading provided by the losing trader was not an actual AMI meter reading, and

(iv) the gaining trader determines a revised switch event meter reading from AMI information, and

(v) the replacement read process occurs within five business days of the gaining trader receiving the switch completion file.

### We have identified eight shortcomings with the replacement read process

4.237 We have identified eight shortcomings with the replacement read process, which are resulting in the replacement read process causing operational inefficiencies.

#### Shortcoming 1: The four month time limit on replacement reads causes operational inefficiencies

4.238 The four month time limit on using a replacement read is proving too short in the case of some backdated ICP switches. For example, a move-in switch completed on 12 Dec 2017, but backdated to 13 Aug 2017, falls just inside the four month window, but only by a day. Consequently, the gaining trader has one day to determine whether the switch event meter reading is inaccurate, before it is too late to use the replacement read process.

4.239 The gaining trader must instead undertake an off-market settlement with the losing trader to correct for the error in the meter reading, with the possibility that the losing trader may not agree to the settlement. This manual process is inefficient compared with the process prescribed under the Code.

4.240 The Authority's preferred option to mitigate this shortcoming is Option 3.

#### Shortcoming 2: The absence of a materiality threshold for replacing AMI switch event readings within five business days causes operational inefficiencies

4.241 Currently, there is no materiality threshold for the process described in paragraph 4.236(e). If a gaining trader adopts this process, the losing trader must accept any minor revision, (eg, less than 1 or 2 kWh). Such relatively small differences may be due to rounding of the switch event meter reading(s).

[50] Refer to clauses 7 and 12 of Schedule 11.3.

4.242 Revising meter readings for small rounding changes in electricity volumes is inefficient, labour intensive, and time consuming.

4.243 The Authority's preferred option to mitigate this shortcoming is Option 2.

### Shortcoming 3: The inability of losing traders to use RRs for switches of the HH switch type causes operational inefficiencies

4.244 A losing trader cannot use the replacement read process in relation to an ICP, if the gaining trader at the ICP:

(a) adopts the process described in paragraph 4.236(e), and

(b) provides in the switch completion file (switch type "HH"—gaining trader completes switch):

(i) a switch event meter reading, or

(ii) a replacement read.

4.245 The losing trader must instead undertake an off-market settlement with the gaining trader to correct for the error in the meter reading, with the possibility that the gaining trader may not agree to the settlement. This manual process is inefficient compared with the process prescribed under the Code.

4.246 The Authority's preferred option to mitigate this shortcoming is Option 1.

### Shortcoming 4: Relying on MEPs to provide AMI meter readings causes operational inefficiencies

4.247 In order to use the process described in paragraph 4.236(e), the gaining trader must rely on an MEP delivering the first AMI meter readings within five business days of the switch event date. However, an MEP may take longer than this because of:

(a) communication issues between the MEP back office systems and the gaining trader's back office systems

(b) a switch occurring where the trader has not made an arrangement with an MEP (noting the gaining trader would have breached the Code by initiating the switch)

(c) the MEP taking a relatively long time to start providing meter reading information to:

(i) a new retailer using the MEP's services, or

(ii) an existing retailer for a new ICP.

4.248 If the MEP takes longer than five business days to deliver the ICP's AMI metering data for the first time, the gaining trader:

(a) cannot require the losing trader to accept an actual AMI meter reading, and

(b) must use the standard replacement read process, which is less efficient.[51]

4.249 The Authority's preferred option to mitigate this shortcoming is Option 4.

### Shortcoming 5: Relying on MEPs to provide backdated meter readings causes operational inefficiencies

4.250 The gaining trader will require HHR information for a period before the switch event date in order to use the switch event meter reading:

[51] Refer to clause 6 of Schedule 11.3.

(a) if the gaining trader intends to use HHR submission information, and

(b) if the losing trader has been using NHH submission information for the ICP, and

(c) if the losing trader estimated the switch event meter reading.

4.251 For contractual or privacy reasons, the MEP may refuse to supply the gaining trader with meter readings before the switch effective date. This means the gaining trader may not be able to use the switch event meter reading, unless the gaining trader estimates the missing HHR information it requires. Any missing HHR information will appear in the reconciliation and settlement processes as UFE on the network.

4.252 The Authority's preferred option to mitigate this shortcoming is Option 4.

### Shortcoming 6: The absence of clear timelines for resolving erroneous meter readings causes operational inefficiencies

4.253 The replacement read process set out in the Code does not prescribe clear timelines for resolving the erroneous meter reading. This results in:

(a) unnecessary confusion amongst participants, and

(b) unnecessary interaction between participants clarifying or agreeing when an erroneous meter reading is to be resolved.

4.254 In addition, the disputes process is unwieldy.

4.255 The Authority's preferred option to mitigate this shortcoming is Option 6.

### Shortcoming 7: The materiality threshold for non-AMI replacement reads causes operational inefficiencies

4.256 As noted above, the replacement read process can only be used if the switch event meter reading provided by the losing trader differs by more than 200 kWh per meter channel from the switch event meter reading determined by the gaining trader. This threshold was set prior to the widespread use of AMI in New Zealand, when meters typically had one meter channel.

4.257 Smart meters may have three, or more, meter channels. This means an error of 200 kWh per meter channel represents a material inaccuracy for the sum of the meter readings for the meter.

4.258 To address this error, the gaining trader and losing trader must instead undertake an off-market settlement with each other to correct for the error(s) in the meter reading(s). These errors can be large. The trader benefiting from the settlement faces the possibility that the other trader may not agree to the correction. This manual process is inefficient compared with the process prescribed under the Code.

4.259 The Authority's preferred option to mitigate this shortcoming is Option 4.

### Shortcoming 8: The inability of a losing trader to send replacement reads causes operational inefficiencies

4.260 Losing traders may need to amend a switch event meter reading in instances where:

(a) the switch event meter reading was based on an estimate, and more accurate data has become available

(b) the metering installations(s) at the ICP were found to be inaccurate

(c) a change to a previously agreed switch event meter reading was later found to be inaccurate.

4.261 Currently, in such instances, a losing trader has the option of:

(a) absorbing the cost

(b) carrying out a bilateral settlement with the gaining trader

(c) asking the gaining trader to provide a revised read via the replacement read process.

4.262 A losing trader cannot provide a revised read to the gaining trader via the replacement read process. This results in:

(a) unnecessary confusion amongst participants, and

(b) unnecessary interaction between participants clarifying or agreeing when an erroneous meter reading is to be resolved.

4.263 The Authority's preferred option to mitigate this shortcoming is Option 1.

## Identified options to address Issue 15

4.264 We have identified eight options to address Issue 15, and thereby promote competition in, and the efficient operation of, the electricity industry.

### Option 1

4.265 An option to address shortcoming 3 and 8 under Issue 15 is to amend the Code:

(a) to permit a losing trader to use the replacement read process

(b) to permit multiple replacement reads for an ICP.

#### *Advantages over the status quo*

- Better promotes operational efficiency by reducing confusion and manual workarounds in relation to replacement reads.

#### *Disadvantages over the status quo*

- Requires a change to the registry and to traders' systems and processes (so that gaining traders are able to receive an RR file and action it).

### Option 2

4.266 An option to address shortcoming 2 under Issue 15 is to amend the Code to include a threshold of +/-1kWh for the process set out in paragraph 4.236(e).

#### *Advantages over the status quo*

- Better promotes operational efficiency by removing transaction costs associated with correcting switch event meter readings that exceed the benefit of making the correction.

#### *Disadvantages over the status quo*

- Requires a change to traders' systems and processes, and possibly a change to the registry.

### Option 3

4.267 An option that helps to address Issues 1 and 7 generally is to amend the Code to require the use of midnight switch event meter readings for ICPs with AMI—ie, the switch event meter reading is at 24:00 on the day before the switch event or 00:00 hours on the day of the switch event.

***Advantages over the status quo***

- Better promotes operational efficiency by reducing the need for RR files to be issued by gaining traders.

***Disadvantages over the status quo***

- Requires a change to traders' systems and processes, and possibly a change to the registry.
- May require MEPs to programme AMI meters to provide midnight readings if the MEP currently does not provide this functionality.

**Option 4**

4.268 An option that helps address shortcomings 4, 5 and 7 under Issue 15 is to amend the Code:

(a) to require the registry manager to provide MEPs with a copy of the switch initiation file

(b) to require MEPs to provide the gaining trader with access to the services access interface and meter readings as soon as practicable, but no later than:

(i) 4 (calendar) days from the date the registry manager sends the switch completion notification to the MEP, for 95% of switch event meter readings

(ii) 6 (calendar) days from the date the registry manager sends the switch completion notification to the MEP, for 95% – 98% of switch event meter readings

(iii) 10 (calendar) days from the date the registry manager sends the switch completion notification to the MEP, for 99% – 100% of switch event meter readings.

The proposed use of percentages is to allow for communication difficulties.

***Advantages over the status quo***

- Better promotes competition and innovation by providing for traders to receive at least 90% of switch event meter readings within a period that should not result in gaining traders' customers having a negative switching experience.
- Better promotes operational efficiency by increasing the likelihood that the gaining and losing traders are allocated the correct amount of electricity at the switched ICP.

***Disadvantages over the status quo***

- Requires a change to traders' systems and processes.
- MEPs will need to amend meter reading and data delivery processes.

**Option 5**

4.269 An option to address shortcoming 7 and to partially address shortcoming 4 under Issue 15 is to amend the Code to increase, from five business days to 10 business days, the maximum time period during which the losing trader must accept the gaining trader's replacement read for an ICP switch (refer to paragraph 4.236(e)).

***Advantages over the status quo***

- Better promotes competition and innovation by improving the trader ICP switching experience for consumers and embedded generators, thereby improving the propensity for customers to switch to another trader.
- Better promotes operational efficiency by increasing the likelihood of the most accurate switch event meter reading being obtained.

***Disadvantages over the status quo***

- The completion of an ICP switch may be delayed, or need to be backdated, if a losing trader faces a delay obtaining an actual switch event meter reading.
- Requires a change to traders' systems and processes.

**Option 6**

4.270 An option to address shortcoming 6 under Issue 15 is to amend the Code to require a trader to respond, within a certain timeframe, to the trader that has requested a replacement read.

***Advantages over the status quo***

- Better promotes operational efficiency by removing the need for traders that have requested a replacement read to manually follow up with the other trader when the other trader does not respond.

***Disadvantages over the status quo***

- Requires a change to traders' systems and processes.

**Option 7**

4.271 An option to address shortcoming 6 under Issue 15 is to amend the Code to establish a workable disputes process for replacement reads.

***Advantages over the status quo***

- Better promotes operational efficiency by introducing a standardised and streamlined dispute resolution process.

***Disadvantages over the status quo***

- None identified.

**Option 8**

4.272 An option to address shortcomings 1, 4 and 5 under Issue 15 is to amend the Code to permit a replacement read to be requested up to 10 months after the date that a trader ICP switch is completed in the registry.

***Advantages over the status quo***

- Better promotes operational efficiency by reducing instances of the following occurring under the replacement read process:
    - disputes between traders over switch event meter readings for back-dated ICP trader switches
    - manual off-market settlements
    - UFE.

***Disadvantages over the status quo***

- None identified.

Table of options for Issue 15, shortcoming and options. The greyed cells indicate the Authority's preferred option.

| Shortcoming | Options | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Option 1 | Option 2 | Option 3 | Option 4 | Option 5 | Option 6 | Option 7 | Option 8 |
| 1 – The four month time limit on replacement reads causes operational inefficiencies | | | CO | | | | | CO |
| 2 – The absence of a materiality threshold for AMI RRs within five business days causes operational inefficiencies | | C | | | | | | |
| 3 – The inability of losing traders to use RRs for switches of the HH switch type causes operational inefficiencies | C | | | | | | | |
| 4 – Relying on MEPs to provide AMI meter readings causes operational inefficiencies | | | | CO | CO | | | CO |
| 5 – Relying on MEPs to provide backdated meter readings causes operational inefficiencies | | | | CO | | | | CO |
| 6 – The absence of clear timelines for resolving erroneous meter readings causes operational inefficiencies | | | | | | C | CO | |
| 7 – The materiality threshold for non-AMI replacement reads causes operational inefficiencies | | | C | CO | C | | | |
| 8 – Losing traders cannot send replacement reads | C | | | | | | | |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 16: Delays updating the registry with the nominated trader at a new ICP may delay meter installation / electrical connection

4.273 When a distributor first records an ICP identifier in the registry, the distributor assigns the ICP identifier a status of "New". There is little information recorded in the registry against an ICP with this status. The registry changes an ICP's status from "New" to "Ready" once the distributor has completed populating the registry with distributor information for the ICP.

4.274 The Code requires this information to be populated as soon as practicable and before electricity is traded.[52] We understand ICP identifiers sometimes retain the status of "New" for considerable periods of time, before transitioning to the "Ready" status. This is often the result of distributors' field processes not aligning directly with Code requirements.

4.275 Traders may also be slow to, or fail to:

(a) claim new ICP identifiers on the distributor's network, or

(b) assign new ICP identifiers, which the registry has notified to them as being "ready", to the appropriate responsible trader.

4.276 This may create delays and uncertainties for MEPs. As a result, some MEPs are insisting the responsible trader claims the ICP identifier in the registry before the MEP agrees to be responsible for the metering installations at a new ICP, and issues the request to install the metering installation(s) at the ICP. This requires a trader to assign the ICP identifier for a new ICP to itself and then notify the MEP, via the registry, that the trader has claimed the ICP identifier.

4.277 Currently, a trader may only become responsible for an ICP when the distributor on whose network the ICP is connected has given the ICP the status of "Ready" in the registry. Some distributors hold the ICP at the "New status" in order to ensure that the trader does not electrically connect the ICP without the distributor's consent. The ICP may remain in the "New" status for a considerable time, only moving to "Ready" when the ICP is due to be electrically connected.

4.278 The consequence of this is that a trader cannot notify an MEP to become responsible for providing the metering installation(s) at an ICP until the trader is responsible for the ICP. This leaves little time for an MEP to:

(a) gain confidence the registry notification process has been complied with, prior to planning to install, or installing, metering equipment, or

(b) determine if another MEP has been notified by the trader to be the MEP at the ICP.

### Shortcoming 1: Prohibiting a trader from assigning a new ICP identifier when it has the "New" status is operationally inefficient

4.279 If an ICP identifier is moved from the "New" status to the "Ready" status on the date the ICP is ready for electrical connection, the ICP may not be electrically connected on that date. This is because:

(a) the responsible trader has insufficient time to organise for a metering installation to be installed at the ICP, or

[52] Clause 7(2) of Schedule 11.1

(b) the MEP has insufficient time to install metering equipment.

4.280 Such a delay is operationally inefficient and unnecessary.

4.281 Some distributors may believe that holding the ICP in the "New" status prevents a trader electrically connecting the ICP until the distributor is certain the ICP can be considered "ready". However, clause 10.33A of the Code prevents a trader (as a reconciliation participant) from electrically connecting an ICP that has not been electrically connected before, until the distributor has given written approval.

4.282 The Authority's preferred option to mitigate this shortcoming is Option 1.

## Identified options to address Issue 16

### Option 1

4.283 We have identified an option to address Issue 16, and thereby promote competition in, and the efficient operation of, the electricity industry.

4.284 The option is to amend the Code to allow a trader to carry out the initial assignment of an ICP identifier that is in the "New" status. In carrying out this assignment, the trader would be required to move the ICP status from "New" to "Inactive" with a status reason code of "New connection in progress".

#### *Advantages over the status quo*

- Better promotes operational efficiency by:
    - enabling traders to notify an MEP at an earlier stage than is possible now, allowing the MEP time to:
        - prepare to install, and install, the metering installation(s) at a new ICP sooner than they otherwise would
        - populate registry metering records once the metering installation(s) is/are in place, which may be before the metering installation is electrically connected
    - enabling traders to set up in their back-office system the ICP identifier for the new ICP, prior to the ICP being electrically connected.

#### *Disadvantages over the status quo*

- Requires a change to the registry and may require minor changes to traders' systems and processes.

Table of options for Issue 16, shortcoming and options. The greyed cell indicates the Authority's preferred option.

| Shortcoming | Options |
|---|---|
| | Option 1 |
| 1 – Prohibiting a trader from assigning a new ICP identifier when it has the "New" status is operationally inefficient | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 17: A gaining trader puts obligations on the current trader by electrically connecting an ICP before the trader ICP switch completes

4.285 The Authority understands that some gaining traders are electrically connecting existing ICPs that have been electrically disconnected by the losing trader, prior to the trader ICP switch process completing (and the gaining trader becoming responsible for the ICP).

### Shortcoming: A gaining trader electrically connecting an ICP before or during a trader ICP switch causes operational inefficiencies

4.286 A gaining trader may become aware, either through the registry or from its new customer, that the new customer's ICP is electrically disconnected. The new customer may ask the gaining trader to electrically connect the ICP before the ICP switch process completes.[53]

4.287 A gaining trader breaches clause 10.33A(4) of the Code if the trader arranges for the ICP to be electrically connected prior to the trader ICP switch being completed.

4.288 If the switch event date is not backdated to the date of the electrical connection, then the losing trader is responsible for:

(a) paying the clearing manager for the electricity used between the date of the electrical connection and the switch event date, and

(b) paying distribution network charges and MEP charges over the same period.

4.289 The losing trader may incur these costs unwittingly—not even knowing the ICP has been electrically connected.

4.290 Should the losing trader know the electrical connection has occurred, the losing trader may incur unnecessary costs—either:

(a) absorbing the energy, lines and MEP charges, or

(b) incurring higher-than-normal transaction costs trying to recover these charges from a customer that refuses to pay the losing trader, because the customer believes it is buying electricity from the gaining trader.

4.291 If the switch does not proceed, the losing trader may also have to incur the cost of another electrical disconnection.

4.292 The Authority's preferred option to mitigate this shortcoming is Option 1.

### Identified options to address Issue 17

#### Option 1

4.293 We have identified an option to address Issue 17, and thereby promote competition in, and the efficient operation of, the electricity industry.

4.294 The option is to amend the Code to allow a gaining trader to electrically connect an ICP that the losing trader has electrically disconnected. To comply with this requirement, the gaining trader:

(a) must have initiated a trader ICP switch by providing an NT file to the registry

[53] The average time for the trader ICP switch process to complete is three business days.

(b) must accept “ownership” of the ICP identifier from the date of the electrical connection

(c) must, if the ICP was electrically connected in error or the trader ICP switch is later withdrawn, electrically disconnect the ICP and pay the losing trader for any costs the losing trader has incurred in relation to the electrical connection of the ICP

(d) must notify the losing trader—

(i) of the electrical connection of the ICP

(ii) of the date of the electrical connection

(iii) of the reasons for the electrical connection.

***Advantages over the status quo***

- Better promotes operational efficiency by:
    - ensuring the trader shown in the registry as the current trader will not incur a financial liability without its knowledge
    - providing a financial incentive for a trader that is authorising the electrical connection of an ICP that is subject to a trader ICP switch to ensure they are authorising the electrical connection of the correct ICP.

***Disadvantages over the status quo***

- Requires a change to the registry.

Table of options for Issue 17, shortcoming and options. The greyed cell indicates the Authority’s preferred option.

| **Shortcoming** | **Options** |
|---|---|
| | Option 1 |
| 1 – gaining trader either in error, or in a trader ICP switch, electrically connects an ICP and a trader ICP switch does not proceed placing obligations on the current trader recorded in the registry | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 18: A switch withdrawal can cause two trader ICP switches to be withdrawn

4.295 Currently, the registry can record only one event per day:

(a) for an event type (eg, trader ICP switch), and

(b) for each ICP identifier.

4.296 Where two updates occur for the same event type, on the same day, the registry will only show the latest event—earlier events are shown as replaced by later events. Although the registry holds the information on both updates, the first update is not visible and is treated by the registry as if it had not occurred.

### Shortcoming: Recording the last trader ICP switch where two trader ICP switches have the same event date causes operational inefficiencies

4.297 Customers sometimes:

(a) agree to switch from their current trader (trader 1) to a new trader (trader 2), and then

(b) subsequently agree to switch to another trader (trader 3).

4.298 Sometimes these switches end up occurring on the same day.

4.299 If the customer did not intend to switch to trader 3, then trader 2 may request a switch withdrawal. If trader 3 agrees with the switch withdrawal the registry will notify trader 1 of the switch withdrawal, because the registry treats the switch to trader 1 as not occurring.

4.300 If trader 1 agrees to the switch withdrawal, the withdrawal will effectively withdraw both switch 1 and switch 2. Responsibility for the ICP will revert from trader 3 to trader 1, missing trader 2. Notifications to that effect will be issued to the distributor and MEP.

4.301 In order for the customer to be supplied by its intended trader, trader 2, the process of switching responsibility for the ICP from trader 1 to trader 2 must start again.

4.302 This is a confusing process for traders to be involved with. The investigation and correction of this type of switching error are time consuming and very inefficient.

4.303 The Authority's preferred option to mitigate this shortcoming is Option 1.

### Identified options to address Issue 18

#### Option 1

4.304 We have identified an option to address Issue 18, and thereby promote competition in, and the efficient operation of, the electricity industry.

4.305 The option is to change the registry so that, if two trader ICP switches occur on the same day, and the second switch is subsequently withdrawn, the first (prior) switch on that day is reinstated as the current trader ICP switch.

#### *Advantages over the status quo*

- Better promotes operational efficiency by replacing a manual process with an automated process that ensures the correct trader is recorded in the registry.

#### *Disadvantages over the status quo*

- Requires a change to the registry.

Table of options for Issue 18, shortcoming and options. The greyed cell indicates the Authority's preferred option.

| Shortcoming | Options |
|---|---|
| | Option 1 |
| 1 – the registry records the last trader ICP switch where two trader ICP switches have the same event date | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 19: Average daily consumption is not being consistently calculated or is calculated using a different criterion

4.306 The registry's functionality requires the losing trader in a trader ICP switch to provide the "average daily consumption" as part of the switch completion notice (CS file).

4.307 The average daily consumption was intended to be the average daily kWh over the last read period (ie, the consumption between the last two NHH actual reads divided by the days between the two reads). This requirement has worked well with manually read NHH meters. However, it does not work well where traders use only HHR information.

4.308 If the losing trader does not have two actual NHH reads or actual HHR meter reads for a minimum period of 30 days, the average daily consumption value should be the average daily consumption value provided by the trader previously responsible for the ICP, in the previous CS file.

4.309 The requirement to provide the average daily consumption as part of the switch completion file is intended to ensure that gaining traders in a trader ICP switch:

(a) apply the correct multipliers to meter readings

(b) have access to information that enables them to estimate settlement and invoice volumes of electricity, until actual meter readings can be obtained.

4.310 Some gaining traders use the average daily consumption as a guide to:

(a) estimating initial submission files and initial estimated invoice in the absence of meter readings

(b) ensuring that compensation factors and all meter channels are taken into account when preparing initial submission fields and initial estimated invoice.

### Shortcoming: Calculating average daily consumption over a short period for inclusion in a CS file is a less accurate reflection of average daily consumption over a reasonable period, causing operational inefficiencies

4.311 With the high market penetration of more frequently read AMI meters (particularly those read daily), this requirement has become less effective. An average daily consumption value based on one day's consumption is a less reliable indicator of someone's electricity usage than is an average daily value based on one month's consumption.

4.312 This is resulting in gaining traders preparing less accurate consumption estimates, which results in less accurate customer invoices and market settlement.[54]

4.313 The Authority's preferred option to mitigate this shortcoming is Option 1.

### Identified options to address Issue 19

4.314 We have identified two options to address Issue 19, and thereby promote competition in, and the efficient operation of, the electricity industry.

#### Option 1

4.315 The first option is to amend the Code to require traders to:

---

[54] Noting that:

a) the market settlement revisions process should eventually correct any market settlement errors

b) the next customer invoice based on an actual read should correct any customer invoicing errors, provided the switch event meter reading is accurate.

(a) provide the average daily consumption value for all NHH and HHR accumulating register reads, if the registry metering records include a channel with accumulator type = “C” and settlement indicator = “Y”

(b) determine the average daily consumption value for—

(i) a NHH accumulating register read using two actual NHH meter reads that are a minimum of 30 days apart

(ii) aggregated HHR meter readings over a 30 day period

(c) provide the average daily consumption value provided in the previous switch completion file, if the trader—

(i) has been responsible for the ICP for less than 30 days, or

(ii) has failed to be able to obtain meter readings twice during the trader’s time being responsible for the ICP.

***Advantages over the status quo***

- Better promotes operational efficiency by ensuring a gaining trader receives a consumption value that is the average of consumption over 30 days or more, thereby enabling the gaining trader to use more accurate consumption estimates, if needed, in consumer invoicing and submission information provided to the reconciliation manager.

***Disadvantages over the status quo***

- Requires a change to the registry.
- Requires a change to traders’ systems and processes.

**Option 2**

4.316 The second option is to amend the Code:

(a) to make the provision of an average daily consumption value in the switch completion (CS) file optional, and

(b) to require that if an average daily consumption value is provided in the CS file, it must be accurate.

***Advantages over the status quo***

- Better promotes operational efficiency by ensuring a gaining trader receives an average daily consumption value in the CS file that is correct, thereby enabling the gaining trader to use more accurate consumption estimates, if needed, in consumer invoicing and submission information provided to the reconciliation manager.

***Disadvantages over the status quo***

- Requires a change to traders’ systems and processes, and to the registry.

Table of options for Issue 19, shortcoming and options. The greyed cell indicates the Authority's preferred option.

| Shortcoming | Options | |
|---|---|---|
| | Option 1 | Option 2 |
| 1 – Average daily consumption is not being correctly consistently calculated or is calculated using a different criterion | C | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

# 5 Issues with the distributor ICP switching process

5.1 We consider that the following issues with the distributor ICP switching process may be introducing operational inefficiencies and/or hindering competition.

## Issue 20: The process for switching ICPs between distributors is manual

5.2 The Code requires a distributor to create an ICP identifier for each ICP on its network.[55] The Code also requires that an ICP identifier, once created for an ICP, cannot be changed.[56]

5.3 Because of this, if an ICP is transferred from one distributor to another, so too is responsibility for the ICP identifier. Schedule 11.2 of the Code sets out the process that must be followed.

### How the process works for switching ICPs between distributors

5.4 As noted in paragraph 3.12, an ICP will be switched between distributors when:

(a) a local network or embedded network is sold, and the network's participant identifier is changed

(b) an embedded network is created or decommissioned—since the ICP is not decommissioned and recreated as part of this process, the ICP identifier is:

(i) transferred from the parent network to the embedded network (when an embedded network is established), or

(ii) transferred to the parent network from the embedded network (when an embedded network is disestablished).

5.5 The Code sets out the following process for this to occur: [57]

(a) The gaining distributor must obtain, from the trader at each ICP to be switched, that trader's consent to the switch. The Code requires this consent because:

(i) the gaining distributor may have a different distribution price plan and loss factors to the losing distributor, which may require a change to the price plan agreed between the trader and the customer or embedded generator

(ii) the trader may not have a use-of-system agreement with the gaining distributor

(iii) the trader may not wish to trade on the gaining distributor's network (eg, the cost-to-serve may be too high).

(b) The gaining distributor must notify the Authority of the ICPs to be switched, in the required format,[58] if and when the distributor receives the consent to the ICPs being switched from all affected traders.

(c) The Authority uploads the distributor notification into the registry, and the registry processes the notification and:

---

55 Refer to clause 1 of Schedule 11.1 of the Code.

56 Refer to clause 11.4(3) of Part 11 of the Code.

57 Refer to Schedule 11.2 of the Code.

58 Refer to DS-010 of the registry functional specification.

(i) updates the distributor participant identifier for each of the ICP identifiers contained in the notification; and

(ii) notifies each trader and MEP recorded against the relevant ICPs.

## We have identified four shortcomings with the process for switching ICPs between distributors

5.6 We have identified four shortcomings with the distributor ICP switching process, which are resulting in the distributor ICP switching process causing operational inefficiencies.

5.7 We expect these operational inefficiencies will grow in significance over time. In New Zealand, there are currently 44 embedded network operators, with 251 associated NSPs. However, as Table 3 shows, these numbers are increasing steadily.

5.8 There is also the possibility of micro grids being operated as embedded networks in the future, placing further upward pressure on distributor switching requests, and compounding the current issues.

5.9 The Code, the registry, and registry processes were never intended to handle:

(a) the number of embedded networks we have today, and

(b) the quantity of ICP identifiers switching between networks.

**Table 3: Number of embedded network NSPs at year end**

| Year | Number of embedded network NSPs |
|---|---|
| 2010 | 100 |
| 2011 | 105 |
| 2012 | 116 |
| 2013 | 134 |
| 2014 | 150 |
| 2015 | 168 |
| 2016 | 200 |
| 2017 | 226 |
| 2018 | 246 |
| 2019 | ~252 |

Source: Electricity Authority

### Shortcoming 1: Not recording a pending distributor ICP switch in the registry causes operational inefficiencies

5.10 The gaining trader in a trader ICP switch may be unaware that the ICP is subject to a distributor switch.[59] If a distributor switch is pending, and a gaining trader switches an ICP, the gaining trader may find itself in breach of the Code. This would happen if the gaining trader did not have an arrangement with the gaining distributor for line function services in relation to the ICP.[60] The gaining trader may also end up having contractual issues with its customer, as the gaining trader would not have agreed network pricing for the ICP with the gaining distributor.

5.11 This situation introduces inefficiencies into both the trader and distributor ICP switching processes, because manual corrective actions are required. Furthermore, there is the possibility that the customer's bad switching experience may discourage the customer from searching out the best electricity deal in the future, which dampens competitive pressure in the retail electricity market.

5.12 The Authority's preferred option to mitigate this shortcoming is Option 1.

### Shortcoming 2: Traders can cause operational inefficiencies when they prevent a proposed distributor ICP switch from completing

5.13 The Code requires a gaining distributor to obtain the consent of the traders responsible for the ICPs that are subject to a proposed distributor ICP switch. Operational inefficiencies arise when:

(a) all relevant traders consent to a distributor ICP switch

(b) the distributor ICP switch process begins

(c) during the distributor ICP switch process, at least one ICP is subject to a trader ICP switch

(d) the gaining trader refuses to:

(i) consent to the distributor ICP switch,[61] which is underway but not yet completed[62]

(ii) communicate with the gaining distributor, which has the same practical effect on the distributor ICP switch process as not consenting.

5.14 Reversing the pending distributor ICP switch is a manual process, which is very inefficient.

5.15 The Authority's preferred option to mitigate this shortcoming is Option 1.

### Shortcoming 3: A lack of transparency around trader approvals of distributor switches can cause operational inefficiencies

5.16 The Authority is responsible for updating the registry in relation to distributor ICP switches. Currently, there is no easily accessible audit trail for us to use that confirms all relevant traders have consented to a proposed distributor ICP switch. We must rely on

---

59 The gaining distributor has obtained the necessary consents but the ICP has not yet been switched between distributors.

60 Under clause 11.16 of the Code, a trader must ensure that it, or its customer, has made any necessary arrangements for the provision of line function services in relation to the ICP.

61 Because, for example, the gaining trader has no use-of-system agreement with the gaining distributor.

62 Distributor ICP switches can take many weeks to complete.

documentation provided by gaining distributors. At times, this documentation has proven incorrect—wrongly showing that all trader approvals have been received.

5.17 This has resulted in:

(a) the Authority incurring inefficient costs in relation to whether trader consent will be granted

(b) the pending distributor ICP switch being reversed, which is an inefficient manual process.

5.18 The Authority's preferred option to mitigate this shortcoming is Option 1.

#### Shortcoming 4: Losing distributors have limited visibility of ICPs that are to be switched to a gaining distributor, which may cause operational inefficiencies

5.19 Losing distributors have limited visibility of ICPs that are to be switched to another distributor (the gaining distributor). A losing distributor may be unaware of

(a) which ICPs are proposed to be switched

(b) changes made to proposed switch dates.

5.20 A gaining distributor may incorrectly identify which ICPs are to be switched. This may leave the losing distributor with the responsibility, under the Code, to maintain an ICP identifier in the registry for an ICP that is no longer connected to the losing distributor's network. The trader responsible for that ICP may also be unaware the ICP should have been switched to another network, and on finding out about this, faces the issues set out in paragraph 5.10 above.

5.21 The Authority's preferred option to mitigate this shortcoming is Option 1.

### Identified options to address Issue 20

#### Option 1

5.22 We have identified an option to address Issue 20, and thereby promote competition in, and the efficient operation of, the electricity industry.

5.23 The option is to amend the Code to include a new distributor ICP switching process that uses the registry as a central hub for transactions between parties involved in a distributor ICP switch. Key obligations on distributors and traders would include:

(a) The gaining distributor notifies the registry manager of a proposed distributor ICP switch, by submitting a distributor ICP switch notification,[63] at least 70 (calendar) days in advance of the proposed switch event date.

(b) The notification under (a) must contain a list of the ICP identifiers for all ICPs that are to be switched. Additionally, the notification must contain the planned distributor-only fields and pricing fields, so traders know what the state of the ICP will be once the transfer is complete.

(c) The registry would validate the file, and then send notifications to the relevant traders asking them to accept or reject the proposed distributor ICP switch. Relevant MEPs will also be notified of the proposed distributor ICP switch.[64]

---

63 Using either an automated file or the registry's web browser interface.

64 The registry would be modified so that "distributor switch" was flagged on each ICP identifier proposed to be switched:

(d) The distributor will be able to provide a further notification to the registry manager that changes the proposed fields and event dates, but only if the final event date is no more than 60 days after the proposed event date in the original notification to the registry manager (i.e. the event date is no more than 130 days after the original distributor ICP switch notification).

(e) If a gaining distributor provides a further notification to the registry manager that:

(i) changes only the event date, any existing trader consent status will be retained

(ii) changes any of the ICP fields other than the event date, any existing trader consent status will automatically be changed back to "awaiting consent", for all ICP identifiers in the distributor ICP switch. Traders will be notified by the registry of this change.

(f) A trader responsible for an ICP identifier subject to a proposed distributor ICP switch must accept or reject the distributor ICP switch at least 30 (calendar) days prior to the proposed switch event date. If a trader:

(i) fails to accept or reject the proposed distributor ICP switch, the trader will be deemed to have consented to the switch

(ii) rejects the proposed distributor ICP switch, the trader may, at any time up to 14 days prior to the proposed switch event date, consent to the switch.

(g) If a trader ICP switch occurs after a distributor ICP switch is proposed, then:

(i) if the losing trader has consented to the distributor ICP switch, the gaining trader is deemed to have accepted the proposed distributor ICP switch

(ii) if the gaining trader consents to the distributor ICP switch but a switch withdrawal subsequently occurs, the losing trader is deemed to have consented to the distributor ICP switch.

(h) At 14 days prior to the switch event date, if any trader has rejected the distributor ICP switch, and the distributor has not (or cannot) extended the switch event date, the registry manager will cancel the distributor ICP switch and notify the relevant distributors, traders, and MEPs.

(i) If all traders accept the proposed distributor ICP switch, the registry manager will transfer the ICP identifiers from the losing distributor to the gaining distributor on the agreed date. Then the registry manager will notify the relevant distributors, traders and MEPs.

***Advantages***

- Better promotes operational efficiency by:
    - providing participants affected by a distributor ICP switch with greater transparency of information about the switch
    - automating more of the distributor ICP switch process
    - providing an easily accessible audit trail for each distributor ICP switch

---

a) on the web browser summary screen

b) on extracts from the web services interface

c) in the PR-010 and PR-030 report files.

- streamlining the process for traders to consent to a distributor switch request.

***Disadvantages***

- Requires a change to the registry and its reports, and to distributors', traders' and MEPs' systems and processes.

Table of options for Issue 20, shortcoming and options. The greyed cells indicate the Authority's preferred option.

| Shortcoming | Options |
|---|---|
| | Option 1 |
| 1 – Not recording a pending distributor ICP switch in the registry causes operational inefficiencies | C |
| 2 – Traders can cause operational inefficiencies when they prevent a distributor ICP switch that has started, from completing | C |
| 3 – A lack of transparency around trader approvals of distributor switches can cause operational inefficiencies | C |
| 4 - Losing distributors have limited visibility of ICPs that are to be switched to another distributor, which may cause operational inefficiencies | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 21: Network extensions are not visible in the registry

5.24 A network extension is a type of secondary network. Secondary networks are electricity networks that are connected indirectly to the national grid. There are generally considered to be three types of secondary network:

(a) customer networks

(b) embedded networks

(c) network extensions.

5.25 A network extension comprises electricity lines, or an electrical installation, owned by someone other than the distributor for the parent network to which the network extension is connected. A network extension has ICPs on it. The distributor for the parent network allocates and manages the ICP identifiers for the ICPs on a network extension. Electricity traded across a network extension is reconciled at the relevant NSP on the parent network.

5.26 An example of a network extension is a shopping mall owned by someone who does not want to be involved in electricity trading or retailing. The mall owner owns the electrical wiring within the mall and is responsible for ensuring the wiring is maintained and safe. Each point of connection in the mall is an ICP, with ICP identifiers assigned, and maintained in the registry, by the distributor for the parent network.

5.27 Network pricing and losses applied to an ICP on the network extension are the same as for an ICP on the parent network with the same type/class of demand.

5.28 Each customer at an ICP on the network extension has a choice of retailer/trader, with the standard trader ICP switching process used for customer switching.

### Shortcoming: A lack of visibility of ICPs connected to a network extension causes operational inefficiencies

5.29 While the distributor for the parent network allocates ICP identifiers to a network extension, the distributor for the parent network may not manage the processes relating to new connections and faults/outages.

5.30 Traders may be unaware that a customer is connected to a network extension, as the registry does not contain this information. ICP identifiers on embedded networks are identified in the registry, while customer networks have only one ICP identifier—for the point of connection between the customer network and the network to which it is connected.

5.31 A trader may attempt to respond to a fault or outage query from a customer, or to a new connection request from a potential customer, by referring the matter to the distributor for the local network. However, the correct process would be different if the customer / potential customer was on a network extension. Should this be the case, the trader should respond to the customer / potential customer by advising the network extension owner of the query/request.

5.32 The distributor for the parent network of a network extension should be aware that a proposed new point of connection, or a change to a point of connection, is on a network extension. The distributor for the parent network may consent to a new point of connection without the consent of the actual owner of the lines or electrical installation.

5.33 These processes surrounding network extensions are inefficient, prone to error, and may under extreme circumstances cause an electrical safety issue.

5.34 The Authority's preferred option to mitigate this shortcoming is Option 1.

## Identified options to address Issue 21

### Option 1

5.35 We have identified an option to address Issue 21, and thereby promote competition in, and the efficient operation of, the electricity industry.

5.36 The option is to amend the Code to require distributors to allocate, in the registry, a reconciliation type (eg, XN) to ICP identifiers for ICPs connected to network extensions.

5.37 The Authority expects all distributors should know which ICP identifiers they have allocated to ICPs on lines or electrical installations that the distributors do not own.

#### *Advantages*

- Better promotes operational efficiency by:
    - providing traders with transparency of an ICP identifier that is connected to a network extension, to enable the trader to send fault or outage queries, or new connection requests, to the correct person for actioning
    - enabling traders to develop systems to automate processes to manage fault or outage queries from customers on network extensions.

#### *Disadvantages*

- Requires distributors to ensure they know where network extensions are connected to their network(s)
- Requires distributors to update the registry with a new connection type.

Table of options for Issue 21, shortcoming and options. The greyed cell indicates the Authority's preferred option.

| Shortcoming | Options |
|---|---|
| | Option 1 |
| 1 – Traders have no visibility that an ICP is connected to a network extension | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 22: Some ICP status changes part-way through a day cannot be accommodated by participants' systems

### The lifecycle of an ICP comprises several "statuses"

5.38 The Code provides for an ICP to have several "statuses" over the ICP's life. These are based on the status of the ICP's physical connection to the network.

5.39 When a distributor first creates the ICP and populates its ICP identifier in the registry, the ICP is recorded as having a status of "New". The ICP retains this status until the distributor populates the registry with certain information about the ICP. At this point, the registry automatically updates the status, to change the ICP's status to "Ready".

5.40 Once a trader is responsible for the ICP, the trader moves the ICP's status in the registry from "Ready" to either "Inactive" or "Active". If the ICP has a status of "Active", the ICP is electrically connected. If the ICP has a status of "Inactive", the ICP is physically, but not electrically, connected. A trader changes the status of an ICP between "Active" and "Inactive" as needed to manage trading activities.

5.41 When an ICP is decommissioned, its status in the registry becomes "Decommissioned".

### Shortcoming 1: Moving an ICP's status between 'Active' and 'Inactive' part-way through a day can cause operational inefficiencies

5.42 The electrical connection and disconnection of ICPs typically occurs at a time other than 00:00 hours. So, if an ICP's status in the registry changes from "Active" to "Inactive", there is likely to be electricity flowing at the ICP on the day ICP's status is recorded as changing.

5.43 If the ICP's status has moved:

(a) from "Inactive" to "Active", the registry will record the ICP as "Active" for the whole day

(b) from "Active" to "Inactive", the registry will record the ICP as "Inactive" for the whole day.

5.44 However, some traders do not adopt the same convention, resulting in:

(a) a trader's count of ICP days not matching what is recorded in the registry (the trader's total will differ by plus or minus one day)

(b) the potential for the volume of electricity recorded at the ICP on the day of the electrical connection/disconnection to be incorrectly accounted for in the settlement of:

(i) the wholesale electricity market (eg, ICPdays[65] scaling could allocate more electricity to the trader than the trader was due, if the trader's ICPdays count was too low)

(ii) lines charges.

5.45 The Authority's preferred option to mitigate this shortcoming is Option 1.

[65] ICPdays is a count of the number of days in a month that a trader holds its total number of ICPs.

### Shortcoming 2: – The current approach to moving an ICP's status to 'Decommissioned' causes operational inefficiencies

5.46 Currently, when a distributor updates the registry to record that an ICP has been decommissioned, the registry prevents any updates to the information for that ICP from the time the distributor status update is made.

5.47 This prevents an MEP updating the registry metering records for the ICP, to show the removal of metering equipment occurred on the day the ICP was decommissioned.

5.48 If the MEP is using the registry to convey a removal meter reading to the trader that was responsible for the ICP, the MEP must backdate the metering event by one day for:

(a) the removal of the metering components from the ICP

(b) the removal meter reading.

5.49 This inaccuracy of one day has a consequence on some trader settlement and invoicing systems, as well as the count of ICPdays. Updating the registry to show the removal of metering components from an ICP before a trader has updated the registry, to say an ICP is inactive, may also raise a number of alerts about the removal in a trader's system. These alerts are sent to the relevant trader, and must be manually handled. This is inefficient and prone to error.

5.50 The Authority's preferred option to mitigate this shortcoming is Option 2.

## Identified options to address Issue 22

5.51 We have identified two options to address Issue 22, and thereby promote competition in, and the efficient operation of, the electricity industry.

### Option 1

5.52 An option to address the first shortcoming associated with Issue 22 is to amend the Code to require that an ICP which moves between the "Active" status and the "Inactive" status is to be treated as follows:

(i) "Inactive" to "Active"—use the date of the day on which the ICP became "Active"

(ii) "Active" to "Inactive"—use the date of the day after which the ICP was changed from "Active" to "Inactive".

#### *Advantages over the status quo*

- Ensuring consistent interpretation of when an ICP's status moves between "Active" and "Inactive" better promotes operational efficiency by reducing the potential for errors in the settlement of:
    - the wholesale electricity market
    - lines charges.

#### *Disadvantages over the status quo*

- Traders may need to change their systems, and will need to change their processes.
- Where an "inactive" status occurs for less than a day, the registry will not record the status change (ie, from "Active" to "Inactive" to "Active").

### Option 2

5.53 An option to address the second shortcoming associated with Issue 22 is to amend the Code to require distributors to use, as the date an ICP is decommissioned, the date of the first full day that the ICP is decommissioned (ie the day after the ICP is actually decommissioned).

#### *Advantages over the status quo*

- Better promotes operational efficiency by removing the need to manually resolve misaligned changes to ICP information in the registry.

#### *Disadvantages over the status quo*

- Distributors may need to change their systems, and will need to change their processes.

Table of options for Issue 22, shortcoming and options. The greyed cells indicate the Authority's preferred option.

| Shortcoming | Options | |
|---|---|---|
| | Option 1 | Option 2 |
| 1 – transition between 'active' and 'inactive' occurs part way through a day | C | |
| 2 – transition from 'inactive' to 'decommissioned' occurs part way through a day | | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

# 6 Issues with the MEP ICP switching process

6.1 We consider that the following issues with the MEP ICP switching process may be introducing operational inefficiencies and/or hindering competition.

## Issue 23: The provision of initial metering data to a trader is not always timely

6.2 In certain circumstances, raw meter data from an AMI meter can be accessed electronically only via an MEP's back office system.[66] The Code regulates the process for accessing and reading raw meter data, in situations where only an MEP can read the metering data from an AMI metering installation.[67] This is because of data encryption and back-office system requirements.

### We have identified five shortcomings with the process for an MEP to provide initial metering data

6.3 We have identified five shortcomings with the process for an MEP to provide initial metering data to a trader. These shortcomings are resulting in operational inefficiencies and may reduce competition in the retail electricity market.

#### Shortcoming 1: A delay in providing the first meter reading after a trader ICP switch causes operational inefficiencies

6.4 We have been advised by some traders that, when a gaining trader takes responsibility for an ICP:

(a) the MEP can take some time to provide the first meter reading

(b) the MEP delivers metering data that is from when the MEP last updated its records of who the trader is that should be supplied with meter readings, and not from the switch event date. For example,, where a switch completes on 4 June 2019, but with a switch event date of 1 June 2019, the first meter read supplied to the gaining trader is then for 4 June.

6.5 This creates significant issues for a gaining trader, who requires the meter readings (in the example above, the meter readings for 1 to 3 June 2019) for the purposes of:

(a) wholesale market settlement

(b) settlement of lines charges

(c) the gaining trader's contract with its customer at the ICP.

6.6 The Code requires an MEP to give a trader access to raw meter data within 10 business days.[68] This 10 business day period is a maximum, not a target.

6.7 An MEP has provided us with analysis showing the average time for that MEP to deliver the first meter reading to a gaining trader is:

(a) 5–8 days, based on the actual switch date ranges recorded in the registry (because trader ICP switch event dates are backdated)

(b) 2–4 days, based on the actual date of the registry switch completion notification.

---

66 Clause 8 of Schedule 10.6 of the Code describes the instances when only the MEP can electronically interrogate a metering installation.

67 Refer to clauses 1 and 8 of Schedule 10.6.

68 Refer to clause 1(1) of Schedule 10.6.

6.8 Despite this, we understand this is still too slow for some gaining traders, who:

(a) offer services such as daily cost or consumption information, or weekly invoicing

(b) wish to dispute an estimated switch event meter reading.[69]

**The Authority's preferred option to mitigate this shortcoming is Option 3.Shortcoming 2: MEPs not receiving advance notice of a trader ICP switch causes operational inefficiencies**

6.9 Under the current ICP switching processes, an MEP only receives a switch completion notification. The MEP does not receive a switch initiation notification. As a result, the MEP may have insufficient time to prepare its systems for a change in trader at the ICP.

6.10 The Authority's preferred option to mitigate this shortcoming is Option 1.

### 6.11 Shortcoming 3: Delivery of the first meter reading after a trader ICP switch is perceived as being late, which causes operational inefficiencies

6.12 Trader ICP switches are often backdated by either the gaining or losing trader. If a trader ICP switch is backdated, then by definition, the MEP will always be perceived as late in providing the meter reading(s) for that switch.

6.13 This "late" delivery creates inefficiencies in the trader ICP switch process, that require inefficient and error prone manual intervention. It is a significant issue for a gaining trader as the trader requires this information for market settlement, use of network settlement, and the trader's contract with its customer.

6.14 The Authority's preferred option to mitigate this shortcoming is Option 3.

**Shortcoming 4: The delivery of AMI meter readings five or more business days after a trader ICP switch completes causes operational inefficiencies**

6.15 A gaining trader may need the switch event meter reading to be an AMI meter reading, in order to provide its service offering to the customer at the ICP.

6.16 A gaining trader can ensure this occurs if it receives and processes a meter reading for an AMI meter within five business days of the trader ICP switch event date. This is because the gaining trader can, if necessary, use the replacement read process to require an AMI meter reading to be used as the switch event meter reading (refer to paragraph 4.235).

6.17 However, a gaining trader cannot rely on the replacement read process in this way if the gaining trader receives a meter reading for an AMI meter five or more business days after the trader ICP switch event date.

6.18 The gaining trader may be unable to provide the level of service to the customer or embedded generator that it has agreed to provide, which:

(a) may give the customer or embedded generator a bad first impression of the gaining trader's service

(b) may place the trader in breach of its agreement with the customer or embedded generator (eg, where the trader and the customer / embedded generator have agreed services such as real time or daily consumption reporting, weekly invoicing, weekly payments).

6.19 To try to meet its service obligation to the customer, the gaining trader will need to either

[69] Under subclauses 6(3) or 12(2B) of Schedule 11.1 of the Code.

(a) pay the MEP for access to backdated metering data

(b) estimate missing metering data.

6.20 The Authority's preferred option to mitigate this shortcoming is Option 2.

#### Shortcoming 5: MEPs do not always deliver backdated meter readings where meter readings had been missing at the time of regular data delivery

6.21 Sometimes an MEP will be unable to provide a trader with complete meter readings—there will be some missing data. The trader must estimate these meter readings.

6.22 Subsequently, the MEP may be able to collect the missing metering data from the metering installation. The Authority understands some MEPs do not deliver metering data to traders that was previously missing, but which the MEP has subsequently been able to collect.

6.23 Traders have a Code obligation to use accurate and complete meter readings in the submission information they provide to the reconciliation manager.[70] If actual meter readings are available, traders should be using these in their revised submissions to the reconciliation manager.[71] Traders also have a contractual obligation to provide accurate and complete information to distributors.[72]

6.24 If MEPs do not provide missing metering data to traders, there is an unnecessary level of inaccuracy in wholesale market settlement, the settlement of lines charges, and customer invoicing.

6.25 The Authority's preferred option to mitigate this shortcoming is Option 4.

### Identified options to address Issue 23

6.26 We have identified four options to address Issue 23, and thereby promote competition in, and the efficient operation of, the electricity industry.

#### Option 1

6.27 An option to address shortcoming 2 under Issue 23 is to amend the Code to require the registry manager to provide MEPs with the following additional notifications:

(a) NT file: gaining trader makes ICP switch request

(b) AN file: losing trader acknowledges ICP switch request

(c) AW file: switch withdrawal is accepted.

6.28 Upon receipt of an NT file, or AN file, an MEP could begin preparing for a new trader at the ICP being switched. The MEP's processes would need to accommodate the potential for the trader ICP switch to be withdrawn.

##### *Advantages over the status quo*

- Better promotes operational efficiency by enabling MEPs to more quickly deliver initial meter readings to gaining traders after a trader ICP switch.

##### *Disadvantages over the status quo*

- Requires MEPs to make changes to their systems and processes.

---

70 Refer to clause 15.2 of the Code.

71 Refer to clause 15.4(2) of the Code.

72 These requirements are set out in the distribution use of system agreement

### Option 2

6.29 An option that helps address shortcomings 1 and 3 under Issue 23 is to amend the Code:

(a) to require the registry manager to provide MEPs with a copy of the switch initiation file

(b) to require MEPs to provide the gaining trader with access to the services access interface and meter readings as soon as practicable, but no later than:

(i) 4 (calendar) days from the date the registry manager sends the switch completion notification to the MEP, for 95% of switch event meter readings

(ii) 6 (calendar) days from the date the registry manager sends the switch completion notification to the MEP, for 95% – 98% of switch event meter readings

(iii) 10 (calendar) days from the date the registry manager sends the switch completion notification to the MEP, for 99% – 100% of switch event meter readings.

The proposed use of percentages is to allow for communication difficulties.

#### *Advantages over the status quo*

- Better promotes competition and innovation by providing for traders to receive at least 90% of switch event meter readings within a period that should not result in gaining traders' customers having a negative switching experience.
- Better promotes operational efficiency by increasing the likelihood that the gaining and losing traders are allocated the correct amount of electricity at the switched ICP.

#### *Disadvantages over the status quo*

- Requires a change to traders' systems and processes.
- MEPs will need to amend meter reading and data delivery processes.

### Option 3

6.30 An option to address shortcomings 1, 3 and 4 under Issue 23, is to amend the Code to require MEPs to deliver, to the gaining trader in a trader ICP switch, meter readings from the switch event date.

#### *Advantages over the status quo*

- Better promotes competition and innovation, and operational efficiency, by enabling the trader ICP switching process to operate more efficiently, including:
    - enabling a gaining trader to use the replacement read process to ensure AMI meter readings are used for a trader ICP switch, where this is necessary
    - better enabling a gaining trader to meet their Code obligations relating to the provision of submission information to the reconciliation manager.

#### *Disadvantages over the status quo*

- May require MEPs to modify their systems and processes.

### Option 4

6.31 An option to address shortcoming 5 under Issue 23 is to amend the Code to require MEPs to deliver revised meter readings to the relevant trader, when an MEP receives:

(a) revised meter readings, or

(b) meter readings from a metering installation interrogated by the MEP, which were not delivered to the relevant trader.

***Advantages over the status quo***

- Better promotes operational efficiency, by improving the accuracy of customer invoicing, wholesale electricity market settlement, and the settlement of lines charges.

***Disadvantages over the status quo***

- May require MEPs to modify their systems and processes.

Table of options for Issue 23, shortcoming and options. The greyed cells indicate the Authority's preferred option.

| **Shortcoming** | **Options** | | | |
|---|---|---|---|---|
| | Option 1 | Option 2 | Option 3 | Option 4 |
| 1 – delivery of first meter reading after a trader ICP switch is delayed | | CO | CO | |
| 2 – MEPs do not receive pre-notification of a trader ICP switch | C | | | |
| 3 – delivery of first meter reading after a trader ICP switch is incomplete | | | C | |
| 4 – gaining trader cannot use the replacement read AMI process where MEP data is delivered later than five business days | | CO | CO | |
| 5 – MEPs do not always deliver backdated meter readings where meter readings had been missing at the time of regular data delivery | | | | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 24: Meter reading file formats are not standardised

6.32 Where only an MEP can read a meter (eg, an AMI meter), the MEP provides the meter reading information to the trader in accordance with the agreement between them.

6.33 Currently, the Code does not regulate the format of this information, although the Code provides for the Authority to do so.[73]

### Shortcoming: Non-standardisation of meter reading formats causes operational inefficiencies

6.34 The non-standardisation of meter reading formats creates operational inefficiencies, since traders must develop the capability to receive a different type of meter read file from each MEP that reads AMI meters.

6.35 The non-standardisation of meter reading formats may raise a barrier to new entrant traders entering the retail electricity market. New entrant traders need to develop an interface for each AMI MEP, depending on what file structure and content the MEP offers as part of its meter reading service. Creating a unique interface for each AMI MEP imposes costs on new entrant traders and increases the risk of error. This may reduce efficiency and competition in the retail market.

6.36 We note that regulating meter reading formats could also discourage innovation by both AMI MEPs and traders. Participants that develop special services in addition to meter reading (eg, disconnection/reconnection, load control, voltage information, current information) would need to receive two files rather than one (ie, one file for meter readings and another file for special services). This would add complexity and cost to the systems and processes of the MEP and the participant.

6.37 On balance, we believe the non-standardisation of meter reading file formats creates bigger barriers to competition and innovation than would standardised meter reading file formats.

6.38 The Authority's preferred option to mitigate this shortcoming is Option 2.

## Identified options to address Issue 24

6.39 We have identified two options to address the shortcoming associated with Issue 24, and thereby promote competition in, and the efficient operation of, the electricity industry.

### Option 1

6.40 The first option to address the shortcoming associated with Issue 24 is for the Authority to develop a standardised meter reading file, and require MEPs to use it.

#### *Advantages over the status quo*

- Better promotes operational efficiency and competition, and thereby innovation, by removing the need for a trader to develop a separate interface with each MEP that reads AMI meters.

#### *Disadvantages over the status quo*

- Requires MEPs that read AMI meters to develop a standard meter reading file.

[73] Refer to clause 10.16 of the Code.

### Option 2

6.41 The second option to address the shortcoming associated with Issue 24 is to amend the Code to require:

(a) MEPs to use an Authority-specified default standardised file format. The default format would have to be used, if the trader and the MEP could not agree on the meter reading file format within 20 business days of the trader requesting services from the MEP

(b) MEPs and traders to confirm their agreement to any contract at the time the Code amendment first becomes active, for the purpose of ensuring that traders that have existing agreement have the opportunity to negotiate the most efficient file delivery format.

#### *Advantages over the status quo*

- AMI MEPs and new participants can negotiate the meter reading delivery format. If agreement is not reached, the default will become the format to be delivered
- Better promotes operational efficiency and competition, and thereby innovation, by removing the need for a trader to develop a separate interface with each MEP that reads AMI meters, unless the trader elects to do so.

#### *Disadvantages over the status quo*

- Requires MEPs that read AMI meters to develop a standard meter reading file.

Table of options for Issue 24, shortcoming and options. The greyed cell indicates the Authority's preferred option.

| Shortcoming | Options | |
|---|---|---|
| | Option 1 | Option 2 |
| 1 – non-standardisation of meter reading formats | C | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 25: The gaining and losing MEPs cannot use the same MEP event date for an MEP switch

6.42 The registry operates using an events structure, where related fields are aggregated into the same event. Updating a field in the registry because of information changing (eg, the switch of an MEP at an ICP) requires all of the fields in the event to which the information relates to be replaced (in this example the trader event). When it receives an update for an event, the registry ends the old event and creates a new event that is effective from that point forward. The date of creation of the new event is called the event date.

6.43 Currently, the registry is limited to holding only one event per day, for any registry event. When two events are populated for the same day and for the same event type, the registry will:

(a) record both events populated, but in reports and summaries provide the last event populated, if the same participant populated both events (eg, the same trader updates the trader status event date twice)[74]

(b) record the first event populated, and reject the second event, if different participants populated the two events (eg, if the losing MEP updates a removal event prior to the gaining MEP updating the new metering records for an ICP recorded in the registry).

6.44 If an MEP switch occurs at an ICP, the Code requires the gaining MEP to update the registry metering records within 15 business days of becoming the MEP at the ICP.[75] The losing MEP is not required to provide a removal update to the registry, but if it decides to do so, then it must update the registry within 10 business days.[76]

6.45 The reason why the losing MEP does not have to provide a removal event to the registry is because the registry will automatically end date the losing MEP's registry metering records when it receives the gaining MEP's new registry metering records. The end date the registry uses is the day before the gaining MEP's registry metering records event date.

6.46 The Authority considers the event date used in both the gaining MEP and losing MEP updates should be either:

(a) the date the metering installation at the ICP switched to the gaining MEP; or

(b) the date the gaining MEP installed metering equipment at the ICP.

6.47 Some traders rely on the removal event. These traders prefer that this function be used in the registry to allow standardisation of the meter change process. Other traders do not appear to use the registry metering records in the registry. Instead, these traders rely on formal paperwork for the information associated with the removal of metering at the ICP (removed metering component reads).

6.48 Some MEPs also prefer to populate metering removal events in the registry:

(a) to communicate removal reads to the trader

---

74 The registry holds the earlier event as a replaced event.

75 Refer to clause 2 of Schedule 11.4.

76 Refer to clause 3 of Schedule 11.4.

(b) to indicate to the trader that a new MEP is responsible for a new metering installation at the ICP, and they do not have information on the new metering installation.

### Shortcoming: The inability of losing and gaining MEPs to both populate a meter event for the same day creates operational inefficiencies

6.49 If a gaining MEP replaces the losing MEP's metering installation but does not update the registry metering records for the ICP, then under the Code the losing MEP remains responsible for the metering installation. The handover of Code obligations does not occur until the gaining MEP populates the registry with its metering records for the ICP.

6.50 Reasons why a gaining MEP may delay populating registry metering records for an ICP include:

(a) MEPs' systems are set up so that information sits in them for a period of time before the MEP populates registry metering records, and

(b) delays receiving, or processing, paperwork from technicians.

6.51 When a losing MEP populates a removal event in the registry for the day that its metering installation is removed, the gaining MEP cannot populate an installation meter event for that same day. The gaining MEP's metering event must be populated for the next day.

6.52 When the type of the metering installation changes from NHH to HHR, the delay of one day in populating the registry metering records may present a problem to the gaining trader. The gaining trader may rely on the registry dates when preparing submission information to submit to the reconciliation manager. Possible consequences are that:

(a) the gaining trader's back-office system incorrectly counts ICP days for the ICP, which may cause the reconciliation manager to scale submission information

(b) the gaining trader's back-office system may have difficulty preparing submission information because the information will differ from the registry metering records.

6.53 It should be noted the gaining trader can already update the registry with "HHR" as the profile type for the ICP, in situations where the metering installation is NHH, provided the trader ICP switch initiation file triggers the update.

## The Authority's preferred option to mitigate this shortcoming is Option 2.Identified options to address Issue 25

6.54 We have identified two options to address Issue 25, and thereby promote competition in, and the efficient operation of, the electricity industry.

### Option 1

6.55 The first option to address the shortcoming associated with Issue 25 is to change the registry so that both a losing and gaining MEP can populate a meter event for the same day. The order of each event on the day would be determined by time stamps.

#### *Advantages over the status quo*

- Better promotes operational efficiency by improving the accuracy of submission information provided to the reconciliation manager, which in turn improves the accuracy of wholesale electricity market settlement.

***Disadvantages over the status quo***

- Requires a significant change to the registry, and to MEPs' systems.

**Option 2**

6.56 The second option to address the shortcoming associated with Issue 25 is to change the registry so that removal events for registry metering records are automatically given the date immediately before the date of a metering event in which metering assets are removed. In other words, the last day that a losing MEP is responsible for updating the registry metering records for an ICP is the last full day that the losing MEP was responsible for the metering installation.

6.57 The gaining MEP becomes responsible for updating the registry metering records of an ICP on the day the gaining MEP:

(a) assumes responsibility for the metering installation, or

(b) installs a new metering installation.

***Advantages over the status quo***

- Better promotes operational efficiency by improving the accuracy of submission information provided to the reconciliation manager, which in turn improves the accuracy of wholesale electricity market settlement.

***Disadvantages over the status quo***

- May require the registry, distributors, MEPs and traders to change their systems.

Table of options for Issue 25, shortcoming and options. The greyed cell indicates the Authority's preferred option.

| Shortcoming | Options | |
|---|---|---|
| | Option 1 | Option 2 |
| 1 – losing and gaining MEPs cannot both update the registry metering records for the same day | C | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 26: Registry metering records do not differentiate between different types of metering

6.58 Raw meter data from an AMI meter can be accessed electronically via an MEP's back office system.[77]

6.59 The registry contains a flag to indicate whether a metering component at an ICP is AMI.[78] Traders use the presence of AMI = "Y" for an ICP identifier in the registry as an indicator that the meter readings for that metering component will be available from the MEP.

6.60 Traders can contract with an MEP to use a metering installation and receive HHR raw meter data from the MEP's back office system.[79]

### Shortcoming 1: Operational inefficiencies arise from the registry metering records not differentiating between metering installation types

6.61 Registry metering records do not differentiate between metering that is:

(a) AMI[80] with the capability for remote two-way communications (ie, to/from an MEP's back office)

(b) AMI with no capability for remote two-way communications

(c) commercial and industrial (C&I) HHR metering, which:

(i) has no capability for remote two-way communications

(ii) can be read by anyone with the appropriate passwords

(iii) has no accumulating registers.

6.62 For HHR metering that is AMI with remote two-way communications, the registry's business rules do not differentiate between:

(a) AMI installations where communication is continuous, and

(b) AMI installations where communication is intermittent, or unavailable on a temporary basis.

6.63 Although metering records in the registry do not differentiate between these metering types, business rules within the registry do. The business rules look at the configuration of meter registers, as well as meter type, and determine what the configuration of the metering installation is. The output of the business rules (ie, metering installation type), is displayed on the registry summary screen. However the output is not contained in any registry reports.

6.64 Upon request, the Authority makes available to participants the registry business rules that differentiate between the three HHR metering types above. This is to enable participants to create this differentiation in their own systems.

---

77 Clause 8 of Schedule 10.6 of the Code covers instances where only the MEP can electronically interrogate a metering installation.

78 An MEP must record in the registry whether a metering component is AMI. Refer to line 18 of Table 1 of Schedule 11.4 of the Code.

79 Clause 1 of Schedule 10.6 of the Code requires an MEP to give a trader access to raw meter data if the trader has an arrangement with that MEP.

80 Noting that an AMI meter can be either NHH or HHR, or both NHH and HHR.

6.65 If traders want to import that information into their own back office systems, they must replicate the business rules within their own systems. There is a risk that business rules are not programed accurately in traders systems, or any innovation in metering technology, may change the information in fields that the traders business rules depend on. The business rules are then no longer valid, as is the derived information on metering installation types. The business rules will then require modification. This is an operational inefficiency.

6.66 The Authority's preferred option to mitigate this shortcoming is Option 1.

#### Shortcoming 2: An incorrect AMI flag can cause operational inefficiencies and dampen retail competition

6.67 Where an MEP has recorded AMI = "Y" for a metering component, a trader may contract to provide a specific service to a customer, such as HHR retail pricing, time of use retail pricing, information. The trader may also only have processes for purchasing electricity in the wholesale market using the HHR settlement methodology, and not have a process for purchasing electricity using the NHH settlement methodology.

6.68 A trader will check the AMI flag on the registry before making an offer to a customer. Where the registry records AMI = "Y", the trader may make an offer to the customer that is dependent on obtaining raw meter data from the MEPs back office system.

6.69 Raw meter data may not be available from an MEP's back office system if a metering installation has failed communications, or intermittent communications, with the MEP's back office system. If a trader is aware of communication issues, it may contract to provide a different service with a potential customer, or possibly not contract to provide a service at all. For example, the trader may have no standard pricing plans to deal with delays to the receipt of meter readings.

6.70 Once the trader has switched the ICP, it is too late for the trader to change its contract with the customer, and the customer may be unwilling to switch to another trader. This means that raw meter data must either be manually sourced by the MEP to meet its obligations in the Code, or the trader must displace the MEP. No matter what the solution is, the outcome is an inefficient process, with poor outcomes to the customer.

6.71 The Authority's preferred option to mitigate this shortcoming is Option 2.

### Identified options to address Issue 26

6.72 We have identified two options to address Issue 26, and thereby promote competition in, and the efficient operation of, the electricity industry.

#### Option 1

6.73 An option to address shortcoming 1 under Issue 26 is to amend the Code and develop business rules, to change the purpose of the registry AMI flag recorded at the metering component level. This flag would be repurposed as a "Read type", so that the MEP must identify the following metering configurations in metering records, by adding additional parameters to the existing registry field, as follows:

(a) "Y" = communicating AMI (MEP provides read in its back-office system)

(b) "Ixx" = intermittent communicating AMI (MEP provides read from its back-office system but read may be delayed or is intermittent) where "x" is a number that indicates the expected days between successful interrogations (eg, "I14" indicates that a successful interrogation can be expected once in every 14 days)

(c) “N” = non communicating AMI (trader reads)

(d) “L” = legacy NHH (trader reads)

(e) “C” = C&I HHR (trader reads - communicating non-AMI installation).

6.74 The registry’s reporting would be changed to include these meter configuration types.

***Advantages over the status quo***

- Better promotes competition and innovation by assisting traders to make informed decisions on the services they can offer potential customers, which in turn improves the switching experience for consumers.
- Better promotes operational efficiency by removing confusion over who has responsibility for the reading of metering components (by improved clarity on the registry’s screens and in the registry’s reports).

***Disadvantages over the status quo***

- Requires:
    - significant change to MEPs’ systems and processes
    - a change to the registry
    - a change to traders’ systems and processes.

**Option 2**

6.75 A simpler option to address shortcoming 2 under Issue 26 is to amend the Code, to require MEPs to update the AMI flag field in the registry:

(a) from “Y” to “N”, to record that a metering installation is no longer AMI because the AMI meter has ceased to communicate for more than a 7 day period, thereby requiring a manual meter read

(b) from “Y” to “I”, to record that a metering installation has intermittent communication because the AMI meter has missed more than 3 days of interrogation attempts.

***Advantages over the status quo***

- Better promotes competition and innovation by assisting traders to make informed decisions on the services they can offer potential customers, which in turn improves the switching experience for consumers.
- Better promotes operational efficiency by removing unnecessary switch withdrawals and, potentially, unnecessary workarounds by traders.

***Disadvantages over the status quo***

- Requires MEPs to change their systems and processes.
- May require traders to change their systems.
- ICPs where the customer has turned the main switch off will be listed with a changed AMI state. This may generate unwanted activity and alerts in traders’ systems and processes.

Table of options for Issue 26, shortcoming and options. The greyed cells indicate the Authority's preferred option.

| Shortcoming | Options | |
|---|---|---|
| | Option 1 | Option 2 |
| 1 – registry metering records do not differentiate between metering installation types | C | |
| 2 – traders rely on MEPs interrogating meters that are AMI | | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 27: MEPs not updating the registry to record the removal of a metering component can cause safety issues and operational inefficiencies

6.76 Some traders rely on paperwork from an MEP to obtain:

(a) the date on which a metering installation is decommissioned, and

(b) where relevant, final (removal) readings for each meter channel.

6.77 However, MEPs can update the metering records for an ICP in the registry to show that a metering component has been removed because a metering installation has been decommissioned.[81] When making this update, the MEP can also record a final reading for each meter channel.

6.78 Updating the registry is more transparent to distributors and other traders than is a paper-based approach, where only the current trader has access to the relevant information.

### Shortcoming: Safety issues and operational inefficiencies can arise when an MEP does not populate registry metering record removal events when ICPs are decommissioned

6.79 It appears that most MEPs do not remove metering records from the registry when an ICP is decommissioned. Usually, this is not an issue because a decommissioned ICP typically remains decommissioned.

6.80 However, in rare instances, an ICP may be decommissioned in error, in which case the distributor may be required to reinstate the ICP. However, the MEP is likely to have removed metering components from the metering installation. The metering installation will not be functional and may be unsafe if electrically connected.

6.81 In these instances, unless the MEP has updated the registry metering records with a removal event, the registry will show the metering installation as being in place at the ICP. So, when the distributor removes its decommissioned status update against the ICP, anyone viewing the registry will incorrectly think there is a functioning and safe metering installation at the ICP.

6.82 The trader responsible for that ICP may then rely on those registry metering records:

(a) to have the ICP electrically connected, or

(b) to commence trading activities at the ICP.

6.83 This is a potential electrical safety issue. There is also an operational inefficiency. This stems from the delay resulting from a trader discovering that metering is required at the ICP, and then needing to arrange for an MEP to provide it. This adds unnecessary time to a trader ICP switch, inconveniencing the customer at the ICP.

6.84 It should be noted that the registry manager must notify the MEP of the reversal of the decommissioning event. However, the MEP may take time to process the change of ICP status and update the registry metering records appropriately. This gives time for the issue described above to arise.

6.85 This is an inefficient process, which can take some time for traders to resolve manually, using workarounds or corrections.

---

[81] The registry then notifies the trader responsible for the ICP

6.86 The Authority's preferred option to mitigate this shortcoming is Option 2.

## Identified options to address Issue 27

6.87 We have identified two options to address Issue 27, and thereby promote competition in, and the efficient operation of, the electricity industry.

### Option 1

6.88 An option to address the shortcoming under Issue 27 is to amend the Code to require MEPs to populate metering component removal events in the registry if metering components are removed from an ICP, regardless of whether or not the ICP is decommissioned.

#### *Advantages over the status quo*

- Removes a potential electrical safety issue.
- Registry metering records remain accurate despite the connection status of an ICP.
- All participants have clarity on the actual state of the metering installation regardless of the status of an ICP.

#### *Disadvantages over the status quo*

- Requires a change to MEPs' systems and processes.
- Requires a change to the registry's validation rule.

### Option 2

6.89 Another option to address the shortcoming under Issue 27 is to amend the Code and registry, so that when a distributor changes an ICP identifier's status in the registry to "Decommissioned", the registry automatically end dates all relevant metering records. In the event that an ICP identifier was decommissioned in error:

(a) if the MEP had not removed metering equipment, the MEP would be required to re-populate the registry metering records.

(b) if the MEP had removed metering equipment, the MEP would be required to re-commission the metering installation and re-populate registry metering records.

#### *Advantages over the status quo*

- As for option 1.

#### *Disadvantages over the status quo*

- As for option 1, plus MEPs would need to monitor changes to ICP identifiers that are re-commissioned, if the MEP had previously been responsible.

Table of options for Issue 27, shortcoming and options. The greyed cell indicates the Authority's preferred option.

| Shortcoming | Options | |
|---|---|---|
| | Option 1 | Option 2 |

| Shortcoming | Options | |
|---|---|---|
| | Option 1 | Option 2 |
| 1 – Safety issues and operational inefficiencies can arise when an MEP does not populate registry metering record removal events when ICPs are decommissioned | C | C |

Key

(c) Blank = addresses none of the issue

(d) P = partly addresses the issue

(e) C = addresses the issue on its own

(f) CO = addresses the issue but requires another option to fully address the issue

## Issue 28: The time taken by some MEPs to update registry metering records affects ICP switching

6.90 Under the Code, an MEP has the following maximum timeframes to update changes to registry metering records for an ICP:

(a) 15 business days, where the MEP has just gained responsibility for an ICP[82]

(b) 10 business days, where the MEP has existing responsibility for an ICP.[83]

6.91 These are maximum timeframes. They are not targets. The Authority expects MEPs will update registry metering records as soon as the new or changed information is available.

6.92 In most cases, MEPs update registry metering records as soon as they can. However, in some cases MEPs do not.

### Shortcoming: Slow updates of registry metering records causes operational inefficiencies and potentially dampens retail competition

6.93 When an MEP is relatively slow to update registry metering records, the following key adverse effects tend to arise:

(a) Trader ICP switching may be delayed, or the switch may be withdrawn, causing:

(i) the losing trader to breach its Code obligations, or

(ii) the gaining trader to breach its arrangement with its new customer.

(b) Customer invoicing errors, which require invoice revisions:

(i) that are manually generated

(ii) that need to be discussed with the customer.

(c) Market settlement errors, which require settlement wash-ups to be undertaken.

6.94 These effects represent operational inefficiencies. In addition, the processes surrounding these effects can take some time to complete.

6.95 These effects can also dampen competitive pressures in the retail market, by creating a bad switching experience for customers, which reduces the customer's propensity to switch retailers.

6.96 The Authority's preferred option to mitigate this shortcoming is Option 3.

### Identified options to address Issue 28

#### Option 1

6.97 We have identified an option to resolve the shortcoming associated with Issue 28, and thereby promote competition in, and the efficient operation of, the electricity industry.

6.98 The option is to amend the Code to require MEPs to populate new or amended registry metering events for ICPs, within the following (shorter) timeframes:

(a) Where the MEP has just gained responsibility for an ICP, unless exceptional circumstances exist, within five business days of the metering installation:

(i) being installed

82 Clause 2 of Schedule 11.4.

83 Clause 3 of Schedule 11.4.

(ii) being assigned the status of “Active” in the registry.

If the metering installation is active but uncertified, the certification date and the certification expiry date must be the installation date.

(b) Where the MEP has existing responsibility for an ICP, and recertifies or modifies the metering installation, unless exceptional circumstances exist, within five business days of the metering installation:

(i) being modified

(ii) being assigned the status of “Active” in the registry.

If the metering installation is active but uncertified, the certification date and the certification expiry date must be the installation date.

***Advantages over the status quo***

- Better promotes operational efficiency and retail competition, by
    - reducing the information asymmetry between traders in relation to metering installation changes (including certifications)
    - reducing instances of mismatched meter records in trader ICP switches.

***Disadvantages over the status quo***

- Requires a change to MEPs’ systems and processes.

Table of options for Issue 28, shortcoming and options. The greyed cell indicates the Authority’s preferred option

| **Shortcoming** | **Options** |
|---|---|
| | Option 1 |
| 1 – activities impacted where an MEP delays updating registry metering records | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

## Issue 29: Gaining MEP unable to accept notification and update registry metering records

6.99 The Code permits a gaining MEP to populate registry metering records only if:

(a) the trader responsible for the ICP has notified the registry manager of the gaining MEP's participant identifier via an MEP ICP switch (MEP nomination), and

(b) the nominated MEP has accepted the registry notification using the registry MEP ICP switch process.[84]

6.100 Before switching an ICP, a trader must have an arrangement with an MEP to be responsible for each metering installation at the ICP.[85] This arrangement may include instructions to replace or modify metering installations at the ICP.

### Shortcoming: A trader not notifying the registry manager of an MEP switch causes operational inefficiencies

6.101 Some traders are not nominating the MEP at an ICP until the trader receives paper copies of metering records for new metering that has been installed by the gaining MEP at the request of the gaining trader. This can be up to 10 business days after the new metering has been installed at the ICP, but at times significantly longer. In the meantime, the gaining MEP cannot update the registry metering records for the ICP.

6.102 Also, the losing MEP is still recorded in the registry as being the responsible MEP for the ICP during this period. The losing MEP may update metering records, and the presence of this metering event prevents the gaining MEP from taking over responsibility for providing metering services at the ICP from the MEP ICP switch date.

6.103 The consequences of this delay in nominating MEPs has significant consequences, including:

(a) The losing MEP incorrectly retains responsibility under the Code for:

(i) the accuracy of the registry metering records for the ICP

(ii) certification of the metering installations at the ICP

(iii) delivery of meter readings for an AMI meter.

(b) The ICP's metering records in the registry are incorrect. A gaining trader may make an incorrect decision about acquiring the customer at the ICP. Under extreme circumstances, the gaining trader may not be able to provide its contracted services to the customer at the ICP without a further meter change. This cost may be applied to the customer.

(c) The ICP could switch to another trader before the losing trader has notified the registry manager of the participant identifier of the losing trader's new MEP. Once the trader ICP switch occurs, the losing trader loses the ability to notify the registry manager of the change in MEP. Currently, there are two ways to correct this instance, both of which require workarounds:

(i) reverse any events subsequent to the losing trader's MEP becoming responsible for the metering installation(s) at the ICP—this would include:

(A) reversing the trader ICP switch, then

84 Refer to clause 10.21 of the Code.

85 Refer to clause 11.16 of the Code.

(B) inserting the MEP nomination and acceptance, and

(C) remaking all of the events that were reversed.

This is an inefficient process that is very time consuming, often manual, and which can be prone to error. Not all participants that have events subsequent to the missing MEP nomination and acceptance may agree to reversing the events

(ii) use the Authority process to push registry metering records into the registry. This is a manual process, requiring checks by the registry manager, and manually recording audit details in the registry.

(d) The trader ICP switch process may not work for the ICP, because the meter reads conveyed in the switch completion file may not match the registry's metering records for the ICP.

6.104 The Authority's preferred option to mitigate this shortcoming is Option 3.

## Identified options to address Issue 29

### Option 1

6.105 We have identified an option to address Issue 29, and thereby promote competition in, and the efficient operation of, the electricity industry.

6.106 The option is to amend the Code to require traders:

(a) to notify the registry manager on, or before, the date that the trader provides a service request to a gaining MEP to install, or modify, a metering installation at the ICP subject to the trader ICP switch

(b) to include an audit of this requirement in the trader's audit for reconciliation participant certification.

#### *Advantages over the status quo*

- Better promotes operational efficiency and retail competition, by:
    - giving traders increased confidence in the accuracy of the registry metering records
    - avoiding the need for inefficient workarounds to be used when an MEP nomination and acceptance does not occur prior to a subsequent event, such as the ICP switching to a different trader.

#### *Disadvantages over the status quo*

- May require a change to traders' systems and processes.

Table of options for Issue 29, shortcoming and options. The greyed cell indicates the Authority's preferred option.

| **Shortcoming** | Options |
|---|---|
| | Option 1 |
| 1 – trader fails to notify registry of an MEP switch | C |

Key

(a) Blank = addresses none of the issue

(b) P = partly addresses the issue

(c) C = addresses the issue on its own

(d) CO = addresses the issue but requires another option to fully address the issue

**General comments**

**Q1. Which, if any, of the 29 issues raised in this paper do you consider should not be investigated further? Please give reasons.**

**Q2. Are there any issues not raised in this paper that you consider should be investigated? Please identify these other issues and give reasons why they should be investigated.**

**Q3. Do you consider the ICP switching processes set out in the Code, together with the amendments discussed in this paper, are likely to remain fit for purpose over the next 10 years? Please give reasons.**

**Q4. Should any alternative ICP switching processes be considered in the longer term? Please give reasons and outline an alternative.**

**Q5. Should the registry be modified to enable event maintenance to be conveyed via an API (application programming interface)? Please give reasons.**

**For each issue 1 to 28**

**Q6. Do you agree with the description of the issue? Please give reasons.**

**Q7. How material is this issue?**

**Q8. Where there are multiple options, rank your preference for the options starting at 1 for preferred.**

**Q9. Are there any advantages or disadvantages that are not included for each option?**

**Q10. Are there any foreseen implementation issues?**

**Q11. Can you give an indication of cost and benefit?**

**Q12. Which, if any, options for changing the ICP switching processes do you consider should be fast tracked?. Please give reasons.**

**Q13. Which, if any, options for changing the ICP switching processes do you consider could be implemented using a combination of a fast-tracked option, followed by a more substantial change at a later time. Please give reasons.**

# Appendix A Format for submissions

| Submitter | |
|---|---|

| Question | | Comment |
|---|---|---|
| General comments | | |
| Q1. | Which, if any, of the 29 issues raised in this paper do you consider should not be investigated further? Please give reasons. | |
| Q2. | Are there any issues not raised in this paper that you consider should be investigated? Please identify these other issues and give reasons why they should be investigated. | |
| Q3. | Do you consider the ICP switching processes set out in the Code, together with the amendments discussed in this paper, are likely to remain fit for purpose over the next 10 years? Please give reasons. | |
| Q4. | Should any alternative ICP switching processes be considered in the longer term? Please give reasons and outline an alternative. | |
| Q5. | Should the registry be modified to enable event maintenance to be conveyed via an API? Please give reasons. | |
| Issue #1 | | |
| Q6. | Do you agree with the description of the issue? Please give reasons. | |
| Q7. | How material is this issue? | |
| Q8. | Where there are multiple options, rank your preference for the options starting at 1 for preferred. | |
| Q9. | Are there any advantages or disadvantages that are not included for each option? | |
| Q10. | Are there any foreseen implementation issues? | |
| Q11. | Can you give an indication of cost and benefit? | |

| | |
|---|---|
| Q12. Which, if any, options for changing the ICP switching processes do you consider should be fast tracked?. Please give reasons.<br>Q13. Which, if any, options for changing the ICP switching processes do you consider could be implemented using a combination of a fast-tracked option, followed by a more substantial change at a later time. Please give reasons.……<br>Issue #28<br>Q6. Do you agree with the description of the issue? Please give reasons.<br>Q7. How material is this issue?<br>Q8. Where there are multiple options, rank your preference for the options starting at 1 for preferred.<br>Q9. Are there any advantages or disadvantages that are not included for each option?<br>Q10. Are there any foreseen implementation issues?<br>Q11. Can you give an indication of cost and benefit?<br>Q12. Which, if any, options for changing the ICP switching processes do you consider should be fast tracked?. Please give reasons.<br>Q13. Which, if any, options for changing the ICP switching processes do you consider could be implemented using a combination of a fast-tracked option, followed by a more substantial change at a later time. Please give reasons. | |

# Glossary of abbreviations and terms

| | |
|---|---|
| **Act** | Electricity Industry Act 2010 |
| **AMI** | Advanced metering infrastructure (smart meters, remote communications and supporting back office systems) |
| **AN file** | "Acknowledgement of notice" file |
| **Authority** | Electricity Authority |
| **Code** | Electricity Industry Participation Code 2010 |
| **CS file** | "Complete switch" file |
| **HHR metering** | Half-hour metering – the process of measuring and recording information—<br>a) related to electricity conveyed; and<br>b) during—<br>(i) an interval that is 30 minutes; or<br>(ii) intervals that can be aggregated to 30 minutes |
| **HH switch type** | An ICP switch made using the "gaining trader" switch process |
| **ICP** | Installation control point |
| **MEP** | Metering equipment provider |
| **MI switch type** | An ICP switch made using the "move-in" switch process |
| **NHH metering** | Non half-hour metering – the process of measuring and recording information—<br>a) relating to electricity conveyed; and<br>b) at intervals that are greater than 30 minutes. |
| **NSP** | Network supply point |
| **NT file** | "Notification of transfer" file |
| **STG** | Switch Technical Group |
| **TR switch type** | An ICP switch made using the "standard" switch process |
| **Trader** | A retailer or a generator or a (direct) purchaser who<br>a) buys electricity from the clearing manager, or<br>b) sells electricity to the clearing manager, or<br>c) enters into an arrangement with another retailer or generator or purchaser to buy or sell contracts (or parts of contracts) for electricity for the purposes of the Code |
| **UFE** | Unaccounted for electricity |