Code Review Programme 4

Decision

21 September 2021

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We have decided to amend the Code

1.1 The Electricity Authority (Authority) has decided to amend several areas of the Electricity Industry Participation Code (Code).

1.2 On 24 September 2019, we published a consultation paper titled, *Code Review Programme number 4 -September 2019*.[1] We consulted on a set of proposals to amend the Code.

1.3 Ordinarily, Code change proposals have a single theme. These omnibus proposals allow the Authority to make several independent and relatively small amendments. The Authority considers that the omnibus approach allows it to use its resources efficiently, and that the Code benefits from regular minor improvements.

1.4 The Code Review Programme number 4 also included a proposal to correct minor typographical errors in the Code. These errors include outdated cross-references, incorrect headings, incorrectly bolded terms, and other minor drafting errors.

Table 1: List of CRP4 proposed amendments

Reference number	Topic	Page
2019-01	Revised timeframe for distributors to change price category code information in the registry	6
2019-02	Returning retail market share transparency at GXPs to its former level	8
2019-03	Requirement to provide complete and accurate information under Part 8	10
2019-04	Improving the event of default provisions (Not included, decision made previously)	N/A
2019-05	Issues with the definition and use of Historical Estimates	12
2019-06	Clarifying definition of Point of Connection	17
2019-07	Clarifying definitions of Block Security Constraint and Station Security Constraint	19
2019-08	Clarifying manner of providing final audit report and compliance plan	23
2019-09	Clarifying use of “electricity supplied” in clause 15.8	24
2019-10	Improving the process for converting secondary networks	25

1 https://www.ea.govt.nz/assets/dms-assets/25/25654Consultation-paper-Code-Review-Programme-September-2019.pdf

Reference number	Topic	Page
2019-11	Clarifying when obligations linked to clause 22 of Schedule 11.3 begin	30
2019-12	Removing provision for supply shortage declarations to trigger payments under the Customer Compensation Scheme	38
2019-13	Broadening the definitions of Generating Unit and Intermittent Generating Station (Not included, decision made previously)	N/A
N/A	Typographical amendments	41

Source: Electricity Authority

1.5 This paper sets out the Authority's decision to amend the Code and gives reasons for that decision.

1.6 Eleven Code change proposals are set out in this paper each with a unique reference number. Two of the proposals consulted on have already had decisions published:

(a) an amended version of proposal 2019-04, improving the event of default provisions (August 2020)[2]

(b) an amended version of proposal 2019-13, broadening the definitions of Generating Unit and Intermittent Generating Station (February 2020).[3]

1.7 The final proposal for the typographical errors does not have a reference number and is included at the end of this paper.

1.8 Because each proposal is discrete from the others, some may proceed while others may not. Showing the changes separately allows participants to assess how each amendment will affect Code obligations. This means the format of this decision paper is different from the decision papers the Authority usually publishes. In this case, all the proposals are proceeding, some in an amended version from what was proposed.

1.9 More information about the Code Review Programme is available on our website at: https://www.ea.govt.nz/development/work-programme/operational-efficiencies/code-review-programme/.

2 The amendments promote our statutory objective

2.1 The Authority's statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

2 https://www.ea.govt.nz/assets/dms-assets/27/27329CRP-2019-event-of-default-decision-and-reasons-paper.pdf

3 https://www.ea.govt.nz/assets/dms-assets/26/26430Broadening-definitions-of-Generating-Unit-and-intermittent-Generating-Station-Decision-Paper.pdf

The amendments either promote, or have no effect on the Authority's statutory objectives

2.2 After considering all submissions on the Code amendment proposal, the Authority believes the final Code amendment will deliver long-term benefits to consumers, as set out in each proposal below.

The benefits of the proposals are greater than the costs

2.3 The Authority has assessed the economic benefits and costs of the amendments, and over all expects them to deliver a net economic benefit.

2.4 Each proposal in the consultation paper describes the costs and benefits of the proposal in more detail. Additional considerations arising from submissions are set out in the proposals below (as needed).

3 The amendments are consistent with regulatory requirements

3.1 The Code amendments are consistent with the requirements of section 32(1) of the Electricity Industry Act 2010.

3.2 The amendments are also consistent with the Authority's Code amendment principles: they are lawful and will improve the reliability and efficiency of the electricity industry for the long-term benefit of consumers.

The Authority considered the following matters in making this decision

We received several submissions on our September 2019 consultation paper from the 16 parties listed in Table 2. Submissions are available on our website at: https://www.ea.govt.nz/development/work-programme/operational-efficiencies/code-review-programme/consultations/.

Table 2: List of submitters

Submitter	Category
Contact	Proposals 1, 5, 9 and 10
Electric Kiwi	Proposals 1 and 11
Genesis Energy	Proposals 1-12
Intellihub	Proposals 1-12
Meridian Energy	Proposals 1 and 3
Network Tasman	Proposals 1 and 6
Network Waitaki	Proposal 1
Nova Energy	Proposal 1
Orion New Zealand	Proposals 1, 6, 8, and 10

Submitter	Category
Powerco	Proposal 6
Transpower	Proposals 3, 6, 7, and 10
Trustpower	Proposals 1, 3-12
Unison	Proposal 1
Vector	Proposals 1, 6, 8, 10, and 12
Wellington Electricity	Proposals 1, 3, 6, 8 and 10
Other	Proposal 6

4.2 Issues brought up by submitters are discussed in the section for the relevant proposal.

Proposal 2019-01, Revised timeframe for distributors to change price category code information in the registry

5.1 The Authority proposed to insert a new clause 8(2)(aa) in Schedule 11.1 of the Code. The new clause will allow a distributor to backdate a change to a price category code provided under clause 7(1)(g) of Schedule 11.1, if the distributor and the trader responsible for the ICP agreed to a date.

5.2 We included a change to the registry alongside the Code amendment proposal, so that participants could comment on both matters under the same process. The Authority proposed a change to the registry to ensure that when a losing trader receives an ICP back, it is notified of any change to the price category code.

5.3 The obligation to send a notice will be accommodated under the service provider agreement between the Authority and the registry service provider.

We have decided to implement an amended form of the proposal

5.4 We have decided to insert a new Clause 8(2)(aa) in Schedule 11.1 of the Code to allow a distributer to backdate a price category code change, if the distributor and the trader responsible for the ICP agree a date. In order of events:

(a) day zero: the date that the distributor and the trader agree to a date on which the change takes effect

(b) days one to three: starting from the day after the agreement is made, the distributor has three business days to provide the registry manager with a backdated change to a price category code assigned to an ICP in accordance with clause 7(1)(g) of Schedule 11.1.

(c) day four: notification to the registry from this day onwards would be non-compliant with the Code.

5.5 The registry will generate a notification to a losing trader when:

(a) a trader ICP switch is withdrawn

(b) the registry's information for the ICP differs from the registry's information for the ICP at the time the switch withdrawal request is made.

5.6 Nine submitters agreed with the proposed code changes, of those four recommended some additional changes. Two submitters partially agreed.

Submitters view

5.7 Genesis and Meridian would like to see the amendment also extend to allow corrections for historical data errors. Currently there are occasions where a participant has conflicting Code obligations – the timely advice of a change and providing an accurate effective date.

Our decision

5.8 We agree there are occasions where a conflict occurs. The registry is expected to reflect the real world situation, however backdated information that impacts on another participant must be managed carefully. There is no one solution to fix all scenarios. We encourage participants to use the Code amendment request process or contact Market Operations to advise the Authority of instances where this occurs.

Submitters view

5.9 Contact and Network Waitaki note the proposal is not clear on the resolution if the distributor and retailer do not agree the date on which the change takes effect. Contact would prefer to see a simple accept/decline model if agreement cannot be reached between the participants included in the amendment. Additionally, Contact note that not all corrections/updates are in the customers interest and in this instance, they believe distributors should not be able to back date such a correction.

Our decision

5.10 The operation of the clause is conditional on agreement between the distributor and the registry manager. If no agreement is reached, the new clause cannot apply. Although the Authority does not consider that a change to the proposed amendment is required to state this, a minor drafting change has been made to make the conditions for enactment of the clause more explicit.

Submitters view

5.11 Nova Energy would prefer to see included a reference to 7(h) & 7(i) as well (chargeable capacity & installation details). Sometimes a trader would also want to agree to backdating these fields on the registry to correct prior period charges.

Our decision

5.12 We agree that this should be considered. As this is a substantive change in the scope of the amendment that was not included in the original proposal, we will need to consult on this addition. We will add this to CRP5, due to start at the end of this year, which will provide opportunity for the Authority to hear from submitters on the further proposed changes.

Submitters view

5.13 Network Tasman disagrees with changing the registry to send a notification of any change to the price category code when a losing trader receives an ICP back. Network Tasman notes the trader has access to the registry and should be able to reconcile the pricing between their systems and the registry.

Our decision

5.14 The price category code has a direct link to lines charges. We consider it in the best interests of consumers to ensure that a change to the price category code is identified as soon as possible to avoid unexpected charges.

The amendment will promote the efficient operation of the electricity industry

5.15 The Code amendment will promote the efficient operation of the electricity industry by:

(a) making a distributor's timeframe for giving the registry manager notice of an ICP's decommissioning compatible with the timeframe for a trader to give the registry manager notice of making the ICP inactive

(b) removing unnecessary compliance costs for distributors and the Authority.

5.16 The Code amendment will come into force on 31 December 2021.

Final amendment showing track change

Schedule 11.1

8 Distributors to change ICP information provided to registry manager

(1) If information about an ICP provided to the **registry manager** in accordance with clause 7 changes, the **distributor** in whose **network** the **ICP** is located must give written notice to the **registry manager** of the change.

(2) The **distributor** must give the notice—

(a) in the case of a change to the information referred to in clause 7(1)(b) (other than a change that is the result of the **commissioning** or **decommissioning** of an **NSP**), no later than 8 **business days** after the change takes effect; and

<u>(aa) in the case of a change to the information provided under clause 7(1)(g), where the change is backdated, no later than 3 **business days** after the **distributor** and the **trader** responsible for the **ICP** agree on the change; and</u>

(ab) in the case of **decommissioning** an **ICP**, by the later of—

(i) 3 **business days** after the **registry manager** has advised the **distributor** under clause 11.29 that the **ICP** is ready to be **decommissioned**; and

(i) 3 **business days** after the **distributor** has **decommissioned** the **ICP**:

(b) in every other case, no later than 3 **business days** after the change takes effect.

Proposal 2019-02, Returning retail market share transparency at GXPs to its former level

6.1 As a result of the Demand-side Bidding and Forecasting (DSBF) Code amendment in 2012, purchasers in the wholesale electricity market no longer must submit bids for a grid exit point (GXP) that the Authority has determined to be a "conforming GXP". This means purchasers no longer need to submit bids for almost 95% of GXPs.

6.2 Prior to the DSBF Code amendment, a retailer was able to estimate its market share at a GXP, by looking at the published bids on WITS for that GXP. Retailers could place some reliance on the accuracy of these bids, because the Code required a bid to represent that purchaser's reasonable endeavours to predict the quantity of electricity that purchaser would demand at the GXP for the relevant trading period. Now, a retailer is only able to estimate its market share using this approach for a small percentage of GXPs.

6.3 To give retailers a similar level of transparency of retail market shares to that which existed prior to the DSBF Code amendment, the Authority proposed an amendment to clause 27(b) of Schedule 15.4.

We have decided to implement the proposal without change

6.4 We have decided to amend clause 27(b) of Schedule 15.4 to require the reconciliation manager to provide more granular information in its reporting on the difference between:

(a) electricity supplied, as reported by retailers; and

(b) submission information submitted by retailers.

6.5 All submitters agreed with the proposal.

The amendment will promote the efficient and competitive operation of the electricity industry

6.6 The Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act. The amendment contributes to the efficient operation of the electricity industry by enabling retailers to more accurately hedge their transmission risk at GXPs.

6.7 The amendment may also have a minor, positive effect on competition. Retailers, on average, may currently tend to over-hedge their transmission risk at GXPs in the absence of market share information. If this is the case, then the amendment will mean retailers would face a lower cost to serve customers at a GXP, which should have a positive influence on retail competition.

6.8 The proposed amendment is expected to have no effect on reliability of supply.

6.9 The Code amendment will come into force on 1 March 2022.

Final amendment showing track change

Schedule 15.4

Reconciliation procedures

...

27 Surveillance reports

The **reconciliation manager** must make the following reports available to the **Authority** and all **participants**:

...

(b) reports by **retailers** ~~for each **balancing area**~~ of the variation between **electricity supplied** as reported by **retailers** (in accordance with clause 17) and **submission information** submitted for reconciliation by **retailers**<u>,</u> <u>specified for each—</u>

<u>(i) **point of connection** to the **grid**; and</u>

<u>(ii) **NSP identifier**; and</u>

<u>(iii) **balancing area**</u>

Proposal 2019-03, Requirement to provide complete and accurate information under Part 8

7.1 Complete and accurate information is fundamental to a competitive, reliable and operationally efficient electricity market. It enables industry participants to make well-informed decisions.

7.2 The obligation in Clause 8.1A currently only applies to information a participant provides to the extended reserve manager and not to other information provided by participants under Part 8. This means a participant is not explicitly required to provide complete and accurate information to another person under Part 8, except to the extended reserve manager.

We have decided not to proceed with the proposal at this time

7.3 After considering submissions, the Authority has decided not to amend clause 8.1A of the Code at this time.

Submitters' views

7.4 Genesis Energy and Wellington Electricity supported the Code amendment proposal with no additional comments. Meridian Energy, Transpower and Trustpower disagreed with the Code amendment proposal.

7.5 Submitters suggested that the Authority had not shown that the current Part 8 information provisions are failing:

(a) Meridian Energy considers the Authority has not provided any evidence of a problem—ie, that participants are providing incomplete or inaccurate information, or failing to act reasonably to inform others of a change in the information provided.

(b) Transpower considers the Authority has not clearly defined the problem it wants to correct or provided transparent evidence demonstrating that existing Part 8 information provisions are failing. Creating new obligations without having done so is not an optimal regulatory approach and risks creating new problems/unintended consequences without realising any incremental long-term benefit for consumers.

Transpower notes the primary Code obligations have been in operation since 2004 and that Transpower is not aware of any evidence of a problem with erroneous information being provided. Existing data transfers under Part 8 are covered by accuracy standards and obligations for generator performance (refer to Schedule 8.3 of the Code for generator performance requirements).

(c) Trustpower considers the Code amendment proposal is unnecessary. All information (including supporting information and test reports/data) necessary for the system operator to operate the power system in accordance with the objectives set out in the Code is currently supplied to the system operator. The system operator can, and regularly does, challenge asset owners on the provision of this information.

Trustpower states the Authority has not provided any examples of misinformation and so has not proved there is a risk to system security. Trustpower believes it is unlikely that an asset owner would knowingly and deliberately deceive the system operator.

Our decision

7.6 In the cost-benefit analysis for the Code amendment proposal we noted that participants typically act in a reasonable and responsible manner when providing information under Part 8. The Code amendment will reinforce this behaviour for existing participants and encourage this behaviour in new participants. As more participants become subject to Part 8 through new and evolving technologies, it becomes increasingly important for the Code to clearly set out expected standards of participant behaviour.

Submitter's view

7.7 Meridian Energy considers any proposal should apply a specific solution to a specific, identified problem and ensure the Code is coherent. In Meridian Energy's view, a blunt generic rule such as that proposed will lead to ambiguity, uncertainty, inefficiency and costs. A blanket requirement relating to the provision and updating of information under Part 8 also risks unintended consequences. Meridian Energy notes:

> *Throughout Part 8 there are different obligations regarding the provision of information along with different obligations with respect to accuracy and revisions. Many clauses in Part 8 require the provision of information to certain participants, at certain times, for certain purposes, and to meet certain standards of accuracy (i.e. something other than absolute accuracy). The proposed change to clause 8.1A will sit awkwardly with these provisions and lead to ambiguity, interpretation issues, and inefficiency.*[4]

7.8 Meridian Energy supports this statement with four examples.

7.9 Meridian Energy proposes that if the Authority identifies a problem that needs addressing, then clause by clause drafting for specific situations might be more appropriate, avoiding ambiguity and unintended consequences.

Our decision

7.10 We have decided the amendment needs further work before it can be implemented to balance ensuring accurate and complete information is provided, with practical application of the information. Any amendment will need clarification that its obligations on participants do not override or replace other Part 8 obligations relating to the provision and updating of information.

Submitter's view

7.11 Transpower believes the proposed intervention would create additional risk for the system operator in instances where it produces information based on data it has received (eg, the system security forecast) and someone claims that data is inaccurate or misleading. Transpower submitted that if the Authority were to proceed with the proposed Code amendment (which Transpower does not support), then to mitigate the increased compliance risk, the Code must be clear that the accuracy obligation is on the originating participant.

Our decision

7.12 We agree with Transpower's point that the Code amendment should not unnecessarily increase the compliance risk of participants receiving information from another participant. It is reasonable for participants to expect that, under the Code amendment,

4 Refer to page 3 of Meridian Energy's submission.

the information they receive from other participants will be complete and accurate. After all, this is the objective of the Code amendment.

Submitter's view

7.13 Trustpower considers the Code drafting, if accepted, would not remove uncertainty—for example, Trustpower queries who “any person” is and what information a person is entitled to request. Trustpower believes the Code wording needs to be much more specific—setting out who can request specific information, what information is needed and why.

Our decision

7.14 We have decided not to amend clause 8.1A to set out who can request specific information, what information is needed and why. This is done in those Part 8 clauses that require the provision of information from one person to another.

Proposal 2019-05, Issues with the definition and use of Historical Estimates

Enabling reconciliation participants to use Authority approved profiles instead of seasonal adjustment shapes

8.1 Clause 4 and 5 of Schedule 15.3 do not explicitly provide for a reconciliation participant to use a profile approved by the Authority when preparing an historical estimate. Although clause 5 infers the ability to do so by stating a reconciliation participant can choose a profile approved by the Authority as its own methodology, it would only be possible when a seasonal adjustment shape is not available.

8.2 Some reconciliation participants prepare historical estimates of volume information using profiles we have approved (eg, telecommunication cabinet load), instead of a seasonal adjustment shape. Currently, these participants are breaching the Code despite supplying more accurate information into the reconciliation process.

8.3 The Authority proposed to insert a new clause to expressly allow a reconciliation participant to use a profile approved by the Authority, instead of the seasonal adjustment shape. Clause 10 of Schedule 15.3 will be amended to refer to the new clause (4A of Schedule 15.3).

Amending the definition of “historical estimate”

8.4 The current definition of “historical estimate” does not include historical estimates calculated under clause 5 of Schedule 15.3. The definition requires historical estimations of volume information to have applied the seasonal adjustment shape or a profile approved by the Authority (for the purpose of apportioning the volume information to part or full consumption periods). In contrast, historical estimates of volume information calculated under clause 5 of Schedule 15.3 do not use the seasonal adjustment shape or any other profile approved by the Authority for the same purpose.

8.5 Currently, a forward estimate may only be used for a period for which a historical estimate, as defined under clause 1.1(1), cannot be calculated (clause 6 of Schedule 15.3). This means that when allocating volume information from a non half hour metering installation to a consumption period where the relevant seasonal adjustment shape is not available, a reconciliation participant can choose between:

(a) using a “historical estimate” calculated under clause 5 of Schedule 15.3, but not being a historical estimate of the type defined under clause 1.1(1); or

(b) using a forward estimate, in accordance with clause 6 of Schedule 15.3.

8.6 Being able to use a forward estimate in this manner is inconsistent with the policy intent[5] of clause 6 of Schedule 15.3. The policy intent is to only allow a reconciliation participant to use a forward estimate if the participant cannot calculate a historical estimate under either clause 4 or clause 5 of Schedule 15.3. The reason for restricting the use of forward estimates in this manner is to help the Authority and participants to better monitor the quality of volume information.

8.7 The Authority proposed to:

(a) amend the definition of ‘historical estimate’ to clarify that its meaning includes a historical estimate prepared in accordance with clause 5 of Schedule 15.3

(b) amend clause 10 of Schedule 15.3 to refer to clauses 4 and 5 of Schedule 15.3, and inset a new clause 4A (thereby ensuring the most accurate historical estimate input data is used in volume information provided to the reconciliation manager, consistent with the current definition of historical estimate).

Incorrect clause reference

8.8 Clause 3(1) of Schedule 15.3 contains a reference to “this” clause, which should instead direct the reader to clauses 4, 5, 6, and 7 of Schedule 15.3. The reference to “this clause” stems from when clauses 3 to 7 of Schedule 15.3 together formed a single clause in Schedule J3 of the Electricity Governance Rules 2003. When the Code was made the clauses were broken out into 4 clauses.

8.9 The Authority proposed to amend clause 3(1) of Schedule 15.3 to refer clauses 4 to 7 of Schedule 15.3 for creating historical estimates and forward estimates.

We have decided to implement the proposal without change

8.10 We have decided to amend the definition of “historical estimate” in Part 1 and clauses 4 to 7 of Schedule 15.3 of the Code to clarify the use of historical estimates.

8.11 Genesis, Intellihub and Trustpower agree. Contact partially agreed with the problem definition but proposed that it should include providing complete and accurate information as the underlying reason for requiring retailers to use specific profile shapes applicable to particular consumption patterns. Contact disagreed with the proposed solutions.

Submitters’ views

8.12 Contact submitted that the proposed solutions fall short and simply address a few technical issues.

8.13 Contact submitted that the Authority does not address the fact that traders wishing to submit volumes against accurate generic profile shapes must get approval from the Authority to use their own “trader specific” profile shapes. Contact considered that traders will generally submit generic loads with specific shape or engineering profiles

5 This policy intent is set out on page 62 of the Report of the Electricity Commission Reconciliation Project Team, December 2004, available at https://www.ea.govt.nz/dmsdocument/5383-annex-1-final-report-from-commission-reconciliation-project-team.

using the default residual profile shape (RPS) (corrupting the residual seasonal shape for other participants) instead of following the approval process.

8.14 Contact believes there is an opportunity for the Authority to instruct the Reconciliation Manager to produce profiles for generic loads (in a similar manner to how the Authority instructed for both PV1 and EG1 profiles for distributed generation). Contact encourages the Authority to amend the Code and require the Reconciliation Manager to develop generic profile shapes for traders to use to improve the accuracy of the RPS and unaccounted for energy intra-day allocation to participants.

Our decision

8.15 The profiles administered by the Authority are designed to be default fall backs. As noted in Contact's submission, there are mechanisms in place for participants to create bespoke solutions, we encourage participants to use this process to ensure estimated submission information is as accurate as possible.

8.16 The CRP is designed to address technical issues. The changes suggested are out of scope for the Code Review Project and would involve a substantive policy change. Contact can submit a Code amendment request in relation to their proposed changes. If following detailed analysis of the proposal, the proposed changes are desirable then an amendment would be consulted on.

8.17 We agree that enabling reconciliations participants to provide complete and accurate information is one of the underlying reasons for this Code amendment.

The amendment will promote the efficient operation of the electricity industry

8.18 The Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act. It will contribute to the efficient operation of the electricity industry by clarifying the use of historical estimates and forward estimates. This will make the Code easier to understand and reduce participants', and the Authority's, compliance costs.

8.19 The proposed Code amendment is expected to have little or no effect on competition and the reliable supply of electricity.

8.20 The Code amendment will come into force on 31 December 2021.

Final amendment showing track change

Part 1 Preliminary Provisions

1.1 Interpretation

(1)

…

historical estimate means, in relation to non **half hour** metered **ICPs**, **volume information** (in kWh)—

(a) ~~,~~apportioned to part or full **consumption periods** after having applied—

(i) the **seasonal adjustment shape**;~~,~~ or

(ii) any other **profile** that has, from time to time, been approved by the **Authority** for this purpose;~~,~~ ~~applied,~~ or

(iii) any other **profile** permitted under clause 5 of Schedule 15.3; and

(b) being 1 of the following:

~~(a)~~(i) the difference between 2 **validated** actual **meter readings**:

~~(b)~~(ii) the difference between 2 **permanent estimates**:

~~(c)~~(iii) any relevant **unmetered load**:

~~(d)~~(iv) the difference between a **validated meter reading** and a **permanent estimate**.

…

Part 15 Reconciliation

Schedule 15.3 Calculation and provision of submission information

…

3 Historical estimates and forward estimates

(1) Each **reconciliation participant** must, for each **ICP** that has a non **half hour metering installation**, allocate **volume information** derived from **validated meter readings**, **estimated readings** or **permanent estimates**, to **consumption periods** using the techniques described in ~~this~~ clauses 4 to 7 to create **historical estimates** and **forward estimates**.

(2) Each estimate that is a **forward estimate** or an **historical estimate**, must be clearly identified as such.

(3) If a **validated meter reading** is not available for the purpose of clauses 4, 4A, and 5, a **permanent estimate** may be used in place of a **validated meter reading**.

4 Historical estimates with seasonal adjustment

The methodology that must be used by each **reconciliation participant** to prepare an **historical estimate** of **volume information** for each **ICP** when the relevant **seasonal adjustment shape** is available and the **reconciliation participant** is not using an approved **profile** in accordance with clause 4A, is as follows:

(a) if the period between any 2 consecutive **validated meter readings** encompasses an entire **consumption period**, an **historical estimate** must be prepared in accordance with the following formula:

$$HE_{ICP} = kWh_p \times A/B$$

where

HE_{ICP} is the quantity of **electricity** allocated to a **consumption period** for an **ICP**

kWh_P is the difference in kWh between the last **validated meter reading** before the **consumption period** and the 1st **validated meter reading** after the **consumption period**

A is the sum of the **seasonal adjustment shape** values for the **consumption period**

B is the sum of the **seasonal adjustment shape** values for the same time period as is covered by kWh_P as published by the **reconciliation manager**:

(b) if the period between any 2 consecutive **validated meter readings** encompasses the 1st part of a **consumption period** and the period between the 2nd **validated meter reading** and the subsequent **validated meter reading** encompasses the rest of that **consumption period**, an **historical estimate** must be prepared in accordance with the following formula:

$$HE_{ICP} = \quad kWh_{P1} \times A_1/B_1 + kWh_{P2} \times A_2/B_2$$

where

HE_{ICP} is the quantity of **electricity** allocated to a **consumption period** for an **ICP**

kWh_{P1} is the difference in kWh between the +last **validated meter reading** before the **consumption period** and the **validated meter reading** during the **consumption period**

A_1 is the sum of the **seasonal adjustment shape** values for the relevant days in the 1st part of the **consumption period**

B_1 is the sum of the **seasonal adjustment shape** values for the same time period as is covered by kWh_{P1}

kWh_{P2} is the difference in kWh between the first **validated meter reading** during the **consumption period** and the 1st **validated meter reading** after the **consumption period**

A_2 is the sum of the **seasonal adjustment shape** values for the relevant days in the latter part of the **consumption period**

B_2 is the sum of the **seasonal adjustment shape** values for the same time period as is covered by kWh_{P2}.

4A Historical estimates using approved profile

If the **Authority** has approved a **profile** for the purpose of apportioning **volume information** (in kWh) to part or full **consumption periods**, a **reconciliation participant—**

(a) may use the **profile** despite the relevant **seasonal adjustment shape** being available; and

(b) if it uses the **profile**, must otherwise prepare the **historical estimate** in accordance with the methodology in clause 4.

5 Historical estimates without seasonal adjustment

If a **seasonal adjustment shape** is not available, either due to timing (for the provision of **submission information** by the 4th **business day** of each **reconciliation period**) or for any other reason, and the **reconciliation participant** is not using an approved **profile** under clause 4A, the methodology for preparing an **historical estimate** of **volume information** for each **ICP** must be the same as in clause 4, except that the relevant quantities kWh_{Px} must be prorated as determined by the **reconciliation participant** using its own methodology or on a flat shape basis using the relevant number of days that are—

(a) within the **consumption period**; and

(b) within the period covered by kWh_{Px}.

…

10 Reporting requirements

(1) By 1600 hours on the 13th **business day** of each **reconciliation period**, each **reconciliation participant** must report to the **reconciliation manager** the proportion of **historical estimates** prepared under clauses 4 or 4A, per **NSP** contained within its non **half hour submission information**.

(2) By 1200 hours on the last **business day** of each **reconciliation period**, the **reconciliation manager** must provide to the **Authority** a report of the proportion of **historical estimates** prepared under clause 4 or clause 4A, per **NSP**~~,~~ and per **reconciliation participant**, being used to create non **half hour consumption information** in respect of each **consumption period** being reconciled, and the **Authority** must publish the information.

(3) The proportion of **submission information** per **retailer** per **NSP** that is comprised of **historical estimates** prepared under clause 4 or clause 4A must, unless **exceptional circumstances** exist, be—

(a) at least 80% for revised data provided at the month 3 revision; and

(b) at least 90% for revised data provided at the month 7 revision; and

(c) 100% for revised data provided at the month 14 revision.

Proposal 2019-06, Clarifying definition of Point of Connection

9.1 The Authority received comments that the definition of “point of connection” means a three-phase metering installation is three points of connection, ie, that each phase of a three phase metering installation is a separate “point” of connection between load and/or generation, and the network to which the load and/or generation is connected. The Authority disagrees with this interpretation—we consider it to be too narrow.

9.2 The Authority proposed to amend the definition of “point of connection” to explicitly state that a point of connection can have multiple phases or conductors, with load in either direction. The intent is that the meaning of “point of connection” includes the entire connection for an ICP, regardless of how many individual phases or wires are needed for the connection.

We have decided to implement an amended form of the proposal

9.3 We have decided to amend the definition of “point of connection” in Part 1 of the Code, with a minor drafting amendment to the proposal.

9.4 Genesis, Intellihub, Network Tasman, Orion, Vector and Wellington Electricity agree. Four submitters disagreed with the proposal.

Submitters’ views

9.5 Four submitters think the change is unnecessary and/or there isn’t evidence of a widespread problem. One submitter also believes the new definition is not consistent with definitions of ‘point of connection’ and ‘point of supply’ in the Act.

Decision

9.6 We have decided it is beneficial to proceed with this clarification in order to ensure the Code clearly reflects the intended policy, thereby reducing uncertainty and improving compliance.

9.7 Our definitions are in relation to the use of those defined terms within the Code. ‘Point of connection’ is not included in the Interpretation for ether the Electricity Act 1992, or the Electricity Industry Act 2010. ‘Point of supply’ relates to where exclusive fittings enter a property. While there are similarities, each should be used in the context within the document in which they are used, and do not need to align with each other.

Submitters’ views

9.8 Transpower notes the proposed Code drafting introduces a concept that power flows in and out of the point of connection at the same time. This concept would conflict with existing policy for how flows are recorded at points of connection to the grid. It could also affect the definitions for ‘losses’ and ‘metering information’. Transpower submit that the Code would also need to clarify that a ‘point of connection’ is defined differently depending on whether the connections is at grid or consumer (ICP) level.

Decision

9.9 We agree the wording could be better regarding the concept of concurrent power flows and have made a change to the draft amendment.

9.10 We disagree that the definitions for ‘losses’ and ‘metering information’ will be affected. The original meaning remains and is clarified to include a situation that is pre-existing.

Submitters’ views

9.11 Trustpower submits that the definition of network should be broadened instead. The POC is where the networks connect, and the phasing is immaterial to this.

Decision

9.12 The Authority agrees the point of connection is the point at which networks connect. A change to the definition of ‘network’ will not clarify that a point of connection can consist of multiple conductors or phases.

Submitters' views

9.13 One submitter submitted that the definition is intended to ensure three-phase metering is correctly configured and accurate measures the quantity of electricity.

Decision

9.14 The Authority does not agree. The 'point of connection' definition should not prevent multiple phases being connected.

The amendment will promote the efficient operation of the electricity industry

9.15 The proposed Code amendment will contribute to the efficient operation of the electricity industry by clarifying the Code requirements relating to a point of connection. This would make the Code easier to understand and would reduce participants', and the Authority's, compliance costs.

9.16 The proposed Code amendment is expected to have little or no effect on competition and the reliable supply of electricity.

9.17 The Code amendment will come into force on 31 December 2021.

Final amendment showing track change

Part 1

point of connection means—

(a) a point at which **electricity** may flow, via one or more phases or conductors—

(i) into or out of a **network**; or

(ii) both into and out of a **network** at the same time, where each directional flow is on different phases or conductors; and~~,~~

(b) for the purposes of **Technical Code** A of Schedule 8.3, means a **grid injection point** or a **grid exit point**

Proposal 2019-07, Clarifying definitions of Block Security Constraint and Station Security Constraint

10.1 The definitions of "block security constraint" and "station security constraint" in Part 1 of the Code are not as clear or are unnecessarily hard to understand and comply with. The Authority proposed to clarify these definitions:

(a) The policy intent is that a security constraint applied by the system operator can be the result of the need for voltage support or frequency keeping. Paragraph (a) of the definition of station security constraint does not express this policy intent clearly, because it uses the words "voltage support or frequency reserve capacity". The Authority proposed to replace the words "frequency reserve capacity" with "frequency keeping".

(b) By not referencing the system operator's first principal performance obligation, the definitions of "block security constraint" and "station security constraint" do not adequately provide for a system security constraint to limit grid capacity. The Authority proposed to correct this by inserting references to Part 7 of the Code in the definitions.

(c) The Authority also proposed minor drafting changes to both definitions, to replace the first reference (in each definition) to “constraint” with “limitation”.

We have decided to implement an amended form of the proposal

10.2 We have decided to slightly amend the proposal we consulted on:

(a) to remove the proposed reference to Part 7

(b) to replace the current reference to Part 8 with a reference to the policy statement.

10.3 Three submitters provided feedback. Genesis Energy and Trustpower support the proposal with no change. Transpower agrees with clarifying the policy intent to allowing the system operator to apply a security constraint as the result of the need for voltage support or frequency keeping. However, Transpower disagrees with two of the identified problems.

10.4 We have decided to implement the Code amendment addressing the first problem identified with no change.

Submitter’s view

10.5 Transpower considers that not referencing the system operator’s first principal performance obligation is not a problem. Transpower believes it is correct to refer only to Part 8, since Part 8 points to the process for drafting and approving the policy statement incorporated by reference in the Code under clause 8.10. The policy statement describes how the system operator manages security constraints—see clauses 25 to 30H and relevant definitions in the policy statement.

Our decision

10.6 In relation to the definitions of block security constraint and station security constraint, we have decided to:

(a) remove the proposed reference to Part 7

(b) replace the current reference to Part 8 with a reference to the policy statement.

10.7 We agree with Transpower that adding a reference to Part 7 of the Code in the definitions of block security constraint and station security constraint is not necessary for enabling the system operator to develop and manage a security constraint in accordance with the policy statement. However, the purpose of the proposed reference to Part 7 in the definitions was to provide a direct link between the system operator’s first principal performance obligation (PPO) and the voltage support and frequency keeping obligations under a block security constraint and a station security constraint. Under its first PPO, the system operator must dispatch assets made available in a manner that avoids cascade failure of assets, resulting in a loss of electricity to consumers, arising from:

(a) a frequency or voltage excursion

(b) a supply and demand imbalance.

10.8 Currently, this link is indirect. The two definitions refer to Part 8. Part 8 contains a process for the development and approval of the policy statement. The policy statement contains the policies and means that the system operator considers appropriate for it to observe in complying with its PPOs.[6] Included in these policies and means is the development and management of security constraints.

10.9 After considering Transpower's submission, we have concluded that the proposed reference to Part 7 in the definitions of block security constraint and station security constraint is unnecessary if there is a clear link between the definitions and the policy statement. A clear link in the definitions to clarify that the system operator determines security constraints in accordance with the policy statement will help enable the system operator to meet its PPOs. The system operator does not develop and manage security constraints under Part 8 per se—the role of Part 8 in relation to security constraints is to enable the creation of the policy statement.

Submitter's view

10.10 Transpower considers the third problem identified in Proposal 2019-07 is not a problem. That is, Transpower does not consider the current drafting of the definitions makes them unnecessarily hard to understand and comply with.

10.11 The Code amendment proposal contained three examples supporting the problem definition:

(a) the definitions of block security constraint and station security constraint could be interpreted as applying to a network other than the grid, in instances where a grid owner owns a local network and/or embedded network

(b) the use of "offered capacity" in the definitions could be interpreted as requiring the system operator to ask a grid owner to revise the grid owner's offered network capacity if the system operator were to determine a grid system security constraint

(c) the use of "grid system security constraint" in the definition of "block security constraint" has a different meaning to "grid system security limit" in the definition of "station security constraint" since the term "constraint" is defined in Part 1 of the Code, whereas "limit" takes its ordinary meaning.

10.12 Transpower submitted:[7]

> *In respect of the first example, a security constraint may need to apply to an embedded generator or to grid connected generators that own their own transmission.*
>
> *In respect of the second example, the context within which the defined terms are used clarifies the intent that the block or security constraint conveys information to the generator about the limitation of available grid capacity available to convey electricity.*
>
> *In respect of the third example the use of the word "limit" is adequate.*

Our decision

10.13 We have decided to implement the Code amendment addressing the third problem identified in Proposal 2019-07 with a few minor clarifications to the Code drafting.

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6 See clause 8.11 of the Code.

7 Page 8 of Transpower's submission on Code Review Programme 4.

10.14 We believe Transpower has misunderstood the first example. This example applies to paragraphs (b) and (c) of the definitions of block security constraint and station security constraint. Transpower's point is covered by paragraph (a) of each definition.

10.15 In relation to Transpower's comments on the second and third examples, we consider that from a Code drafting standpoint—

(a) the context within which the defined terms are used is not sufficiently clear to assist in coming to a certain and unambiguous interpretation of the clause

(b) it is not best practice for Code clauses that are intended to have identical meanings to use different terms, particularly as that could lead to differing interpretations. In fact, the different terminology used could be interpreted to require a different meaning.

The amendment will promote the efficient operation of the electricity industry

10.16 The proposed amendment will improve the efficient operation of the electricity industry by clarifying the Code requirements relating to block security constraints and station security constraints, thereby making the Code easier to understand and reducing compliance costs.

10.17 The proposed Code amendment will also promote the reliable supply of electricity to the extent that it reduces the possibility of a misunderstanding over whether a block security constraint or station security constraint should be applied.

10.18 The Code amendment will come into force on 31 December 2021.

Final amendment showing track change

block security constraint means any of the following:

(a) a security constraint as determined in accordance with the **policy statement** and applied by the **system operator** to a **generating unit** or **generating station** to provide **voltage support** or **frequency keeping**: ~~as determined in accordance with Part 8~~

(b) a limitation in **grid** capacity that:

(i) is a limitation in the ~~offered~~ capacity of ~~a **grid owner's network**~~ the **grid** to convey **electricity** between either:

(A) **generating stations** constituting a **block dispatch group**; or

(B) ~~a limitation in the offered capacity of a **grid owner's network** to convey **electricity** between~~ **generating stations** constituting a **block dispatch group** and ~~a **grid owner's network**~~ the **grid**;~~—~~ and~~,~~

(ii) ~~in paragraphs (b) and (c), such~~ arises because of either—

(A) a limitation in the ~~offered capacity being the~~ offered capacity of ~~a **grid owner's network**~~ the **grid**; or

(B) a security constraint as determined by the **system operator** in accordance with the **policy statement** ~~Part 8~~

station security constraint means any of the following:

(a) a security constraint as determined in accordance with the **policy statement** and applied by the **system operator** to a **generating unit** to provide **voltage support** or ~~frequency reserve capacity~~ **frequency keeping**~~as determined in accordance with Part 8~~:

(b) a limitation in **grid** capacity that:

(i) is a limitation in the ~~offered~~ capacity of ~~a **grid owner's** network~~ the **grid** to convey **electricity**

between either—

(A) **generating units** constituting a **station dispatch group**; or

(B) ~~a limitation in the offered capacity of a **grid owner's network** to convey **electricity** between~~ **generating units** constituting a **station dispatch group** and ~~a **grid owner's network**~~ the **grid**;— and~~,~~

(ii) ~~if in paragraphs (b) and (c) above, the~~ arises because of either:

(A) a limitation in the ~~offered capacity is either the~~ offered capacity of ~~a **grid owner's network**~~ the **grid**; or

(B) a ~~**grid system security** limit,~~"security constraint" as determined by the **system operator** in accordance with the **policy statement**~~Part 8~~

Proposal 2019-08, Clarifying manner of providing final audit report and compliance plan

11.1 The Authority proposed to amend the Code to clarify that participants must provide final audit reports and compliance plans to the Authority in the manner prescribed by the Authority (currently via the audit portal) under clause 16A.13.

11.2 The Authority also proposed to amend clause 16A.13(3) to clarify that the participant must provide a "final audit report" rather than "audit report" to the Authority in the form prescribed by the Authority.

We have decided to implement an amended form of the proposal

11.3 All submitters agreed with the proposal. One submission included a slight amendment to the drafting. We have included this suggestion in the final drafting.

Submitters' views

11.4 Orion noted the proposed code drafting could suggest that the prescribed form is the manner specified. Orion suggested adding "delivered" to proposed clause 16A.13(3)(b) to make it clear that the Authority wants the prescribed form delivered/submitted in the manner specified by the Authority.

Our decision

11.5 We have decided to amend clause 16.13(3) further. We agree additional drafting will clarify that a participant must provide the compliance plan and final audit report in the prescribed form, and must deliver those documents in the manner specified by the Authority.

The amendment will promote the efficient operation of the electricity industry

11.6 The Code amendment is consistent with the Authority's objective, and section 32(1)(c) of the Act. The Code amendment will improve the efficient operation of the electricity industry by clarifying the Code requirements relating to the manner in which final audit reports and compliance plans are provided to the Authority. This will reduce the overall cost of administering an audit.

11.7 The proposed Code amendment is expected to have no effect on competition and the reliable supply of electricity.

11.8 The Code amendment will come into force on 31 December 2021.

Final amendment showing track change

16A.13 Participants to give final audit report and compliance plan to the Authority

(1) A **participant** must give the final **audit** report to the **Authority** no later than the date by which the **audit** is due to be completed.

(2) Each **participant** must submit a compliance plan to the **Authority** when it gives a final **audit** report to the **Authority** under subclause (1).

(3) Each **participant** must—

(a) provide the compliance plan and final **audit** report~~be~~ in the **prescribed form**; and

(b) deliver the compliance plan and final **audit** report in the manner specified by the **Authority**.

(4) Each compliance plan must specify—

(a) the actions that the **participant** intends to take to address any breaches or potential breaches of this Code identified in the **audit** report; and

(b) the time frames within which the **participant** intends to complete those actions.

(5) Subclause (2) does not apply if the relevant final **audit** report in relation to a **participant** identifies no breaches or potential breaches of this Code.

Proposal 2019-09, Clarifying use of "electricity supplied" in clause 15.8

12.1 The Authority identified that the words "electricity supplied" in clause 15.8 are not conveying the policy intent of this clause:

(a) The term does not apply to direct purchasers who are defined to be consumers that purchase, or agree to purchase, electricity directly from the clearing manager for their own consumption at a point of connection.

(b) Sourcing the information to be provided under clause 15.8 from retailers'/direct purchasers' financial records does not enable the purpose of clause 15.8 to be met, because as-billed volumes do not always align with volumes sourced from metering data.[8]

[8] In other words, the volumes a retailer/direct purchaser invoiced its customers will not always align with the customers' consumption during that month.

12.2 To address the problems identified above, the Authority proposed to amend clause 15.8 of the Code to clarify that a retailer or direct purchaser (excluding direct consumers) must provide the reconciliation manager with a file containing monthly totals of metered, not billed, consumption data by individual half hourly metered ICP.

We have decided to implement the proposal without change

12.3 We have decided to amend clause 15.8 of the Code to clarify that a retailer or direct purchaser (excluding direct consumers) must provide the reconciliation manager with a file containing monthly totals of metered, not billed, consumption data by individual half hourly metered ICP.

12.4 All submitters that made a submission on the proposal support it.

The amendment will promote the efficient operation of the electricity industry

12.5 The Code amendment will promote the efficient operation of the electricity industry by clarifying the policy intent of clause 15.8. This will reduce retailers' and direct purchasers' costs of understanding and complying with the Code.

12.6 The Code amendment will come into force on 31 December 2021.

Final amendment showing track change

15.8 Retailer and direct purchaser half hourly metered ICPs monthly kWh information

Using relevant **volume information**, each ~~Each~~ **retailer** and **direct purchaser** (excluding **direct consumers**) must deliver to the **reconciliation manager** the ~~**retailer's** or **direct purchaser's**~~ total monthly quantity of **electricity** ~~**supplied** for~~ consumed at each **half hourly** metered **ICP** for which the **retailer** or **direct purchaser** has provided **submission information** to the **reconciliation manager**, including—

(a) **submission information** for the immediately preceding **consumption period**, by 1600 hours on the 4th **business day** of each **reconciliation period**; and

(b) revised **submission information** provided in accordance with clause 15.4(2), by 1600 hours on the 13th **business day** of each **reconciliation period**.

Proposal 2019-10, Improving the process for converting secondary networks

13.1 In a review of secondary networks, the Retail Advisory Group identified some operational efficiency problems associated with:

(a) converting an embedded network to another type of secondary network

(b) converting a network extension to another type of secondary network.

13.2 This amendment makes improvements in on three of these problem areas.

Allowing 40 business days to consent to secondary network conversion

13.3 We have decided to amend Schedule 11.2 to provide that all participants (except market operation service providers) affected by a proposed conversion of an embedded network or a network extension to another type of secondary network, will have 40 business days to decide whether to consent to the conversion. The period can be varied if all affected parties agree.

13.4 Under the amendment the distributor/trader is deemed to have consented if it does not provide a response by the end of the 40 day period. The deemed consent only applies if the applicant distributor has checked the registry to ensure it is approaching the correct distributor/trader, and made reasonable endeavours to contact and obtain a response.

13.5 The 40 business day period is designed to give retailers time to:

(a) assess the requirements of the proposed secondary network

(b) make any necessary changes to the configuration of their systems

(c) communicate price changes or contract cessation notices to their customers, in accordance with the notice period(s) set out in the contract with their customers on the secondary network

(d) amend, as necessary, any arrangements with MEPs in relation to the secondary network.

Setting the date at which an embedded network owner is no longer responsible for the NSP identifier

13.6 We have decided to amend clause 25 of Schedule 11.1 to provide that an embedded network owner will not be able to set a date after which it would no longer be responsible for the embedded network's NSP identifier—until each ICP on the NSP is either 'Decommissioned' or transferred.

Assignment of 'Active' or 'Inactive' ICP identifiers to the parent network's NSP identifier

13.7 We have decided to amend clause 25(5) of Schedule 11.1 to provide that an embedded network owner cannot end date the embedded network's NSP identifier, unless the embedded network owner has assigned all ICP identifiers with an 'Active' or 'Inactive' status to the relevant parent network NSP identifier.

We have decided to implement the proposal without change

13.8 We have decided to implement the proposed amendments without any change.

13.9 Genesis Energy, Orion New Zealand and Wellington Electricity support the Code amendment proposal without any changes. Contact, Trustpower and Vector provided some comments on the proposal.

13.10 In our view the comments received from Contact, Trustpower and Vector do not necessitate a change to the proposal. We explain our reasoning below.

Submitter's view

13.11 Contact considers the problem definition is incorrect because it:

(a) refers to ICPs needing to be decommissioned as part of the creation of an embedded network, which is not a correct reflection of the Code

(b) does not discuss the absence of a requirement to assess the benefit of a proposed embedded network to the customers on the embedded network.

13.12 Contact considers the primary objective and benefit of the Code amendment should be about assessing the benefit to customers from a proposed embedded network. In Contact's view the absence of this from the amendment means the amendment's benefits will not outweigh its costs.

13.13 Contact notes that currently a decision by the Authority on whether to approve a proposed embedded network is informed only by the consent/refusal of the retailers supplying the customers on the proposed network. Contact believes the Authority's decision should also be informed by the owner of the proposed embedded network confirming they will provide clear and measurable benefits to the customers on the proposed network.

13.14 Lastly, Contact proposes the Authority should actively monitor line charges on embedded networks, to ensure embedded network customers are no worse off than if they were connected to the local network by way of a network extension.

Our decision

13.15 We have decided to make no changes to the Code amendment in response to Contact's submission points. The Code amendment proposal's problem definition does not refer to the *creation* of an embedded network necessitating the decommissioning of ICPs. The problem definition refers to the *conversion* of an embedded network to a customer network necessitating the decommissioning of the ICPs on the embedded network.

13.16 Consumers on a proposed embedded network are best placed to assess the benefits to them, from the change in network types. Consumers can then share this assessment with their respective electricity retailers, who then reflect their customers' views to the Authority by granting/withholding written consent to the transfer of ICPs from the existing network type to the proposed embedded network.

13.17 Lastly, we note Contact's proposal that the Authority actively monitor line charges on embedded networks, to ensure embedded network customers are no worse off than if they were connected to the local network by way of a network extension. This activity falls within the Authority's industry and market monitoring function under the Electricity Industry Act 2010.[9] It does not require a change to the Code amendment proposal.

Submitter's view

13.18 Trustpower supports the Code being amended to require a retailer to not ignore requests for network conversions. However, Trustpower strongly advocates that the trader's agreement be required, since traders are the participants with the customer relationship. Trustpower is concerned property owners can use their monopoly status as the landlord to pressure customers into accepting changes not in their best interests. Trustpower considers the Authority must be mindful of this potential dynamic.

Our decision

13.19 We have decided to make no changes to the Code amendment in response to Trustpower's submission point. The agreement of the trader at each ICP on a network is required before an ICP on the network can be transferred to another network type, unless the transfer is the correction of an error.

9 Refer to section 16(1)(g) of the Electricity Industry Act.

13.20 We note Trustpower's concern that property owners can use their monopoly status as the landlord to pressure customers into accepting changes not in their best interests. We expect that Trustpower would provide any evidence of such behaviour to the appropriate regulatory body.

Submitter's view

13.21 Vector wishes to clarify whether:

(a) the Code amendment applies to correcting an incorrect distributor code assigned to an ICP in the registry, or if such a transaction falls outside the scope of the Code's regulation

(b) backdating the correction of an incorrect distributor code [identifier] assigned to an ICP is permitted, so that the correct information is recorded in the registry.

13.22 Vector also notes that terms such as "secondary network" and "embedded network" are defined in the Code, while terms such as "network extension", "customer network" and "types of secondary networks" are not, despite being widely, but loosely used, jargon in the electricity industry. Vector suggests that if a network type is affected (or potentially affected) under a Code amendment proposal, the Authority describe or define the network type in the proposal.

Our decision

13.23 We have decided to make no changes to the Code amendment in response to Vector's submission points. The Code amendment does not apply to the correction of incorrect distributor participant identifiers against ICPs. This is covered by clause 11.2 of the Code, and can be adjusted through a distributor ICP transfer (which allows for backdating, with approval from the Authority).

13.24 We agree with and note Vector's point about defining/describing undefined network types when consulting on Code amendment proposals affecting, or potentially affecting, these network types.

The amendment will promote the efficient operation of the electricity industry

13.25 The Code amendment will promote the efficient operation of the electricity industry by:

(a) removing inefficient costs and delays from the process of converting an embedded network or network extension to a different type of secondary network

(b) having more accurate information in the registry.

13.26 The Code amendment will come into force on 1 March 2022.

Final amendment showing track change

Schedule 11.1 Creation and management of ICPs, ICP identifiers and NSPs

…

25 Creation and decommissioning of NSPs and transfer of ICPs from 1 distributor's network to another distributor's network

(1) If an **NSP** is to be created or **decommissioned**,—

(a) the **participant** specified in subclause (3) in relation to the **NSP** must give written notice to the **reconciliation manager** of the creation or **decommissioning**; and

(b) the **reconciliation manager** must give written notice to the **Authority** and affected **reconciliation participants** of the creation or **decommissioning** no later than 1 **business day** after receiving the notice in paragraph (a).

(2) If a **distributor** wishes to change the record in the **registry** of an **ICP** that is not recorded as being usually connected to an **NSP** in the **distributor's network**, so that the **ICP** is recorded as being usually connected to an **NSP** in the **distributor's network** (a "transfer"), the **distributor** must give written notice to the **reconciliation manager**, the **Authority**, and each affected **reconciliation participant** of the transfer.

(3) The notice required by subclause (1) must be given by—

(a) the **grid owner**, if—

(i) the **NSP** is a **point of connection** between the **grid** and a **local network**; or

(ii) if the **NSP** is a **point of connection** between a **generator** and the **grid**; or

(b) the **distributor** for the **local network** who initiated the creation or **decommissioning**, if the **NSP** is an **interconnection point** between 2 **local networks**; or

(c) the **embedded network** owner who initiated the creation or **decommissioning**, if the **NSP** is an **interconnection point** between 2 **embedded networks**; or

(d) the **distributor** for the **embedded network**, if the **NSP** is a **point of connection** between an **embedded network** and another **network**.

(4) A **distributor** who is required to give written notice of a transfer under subclause (2) or subclause (3)(d) must comply with Schedule 11.2.

<u>(5) An **embedded network** owner must not give written notice of **decommissioning** an **NSP** under subclause (3)(c) or subclause (3)(d) unless—</u>

<u>(a) the **embedded network** owner has changed the status in the **registry** of all **ICPs** recorded as being usually connected to the **NSP** to 'Decommissioned'; or</u>

<u>(b) a **distributor** has changed the record in the **registry** of each **ICP** previously recorded as being usually connected to the **NSP,** and with a status in the **registry** of 'Active' or 'Inactive', to record the **ICP** as being usually connected to an **NSP** in the **distributor's network**; or</u>

<u>(c) a combination of the changes described in paragraphs (a) and (b) has occurred, so that no **ICP** with a status in the **registry** of 'Active' or 'Inactive' is recorded as being connected to the **NSP** that is to be **decommissioned.**</u>

Schedule 11.2 Transfer of ICPS between distributors' networks

…

5 The applicant **distributor** must give the **Authority** confirmation that the applicant **distributor** has received written consent to the proposed transfer from—

(a) the **distributor** whose **network** is associated with the **NSP** to which the **ICP** is recorded as being connected immediately before the notice, except if the notice relates to the creation of an **embedded network**; and

(b) every **trader** who trades **electricity** at any **ICP** nominated at the time of notice as being supplied from the same **NSP** to which the notice relates.

5A For the purposes of clause 5, the **distributor** (under subclause 5(a)) or the **trader** (under subclause 5(b)) is deemed to have consented to the proposed transfer if the applicant **distributor** has requested in writing the **distributor's** or **trader's** written consent and—

(a) the **distributor** or **trader** (as the case may be)—

(i) has not provided written consent; and

(ii) has not indicated in writing that it refuses to give written consent; and

(b) more than 40 **business days** (or such other period as the applicant **distributor** agrees with the **distributor** or **trader**) have passed since the applicant **distributor** requested the **distributor's** or **trader's** written consent; and

(c) during the 40 **business days** (or such other period as the applicant **distributor** agrees with the **distributor** or **trader**) the applicant **distributor** has—

(i) checked the **registry** to ensure it has sought consent from the correct **distributor** or **trader**; and

(ii) made reasonable endeavours to contact the **distributor** or **trader** and obtain a response.

5B For the purposes of clause 5, the **distributor** (under subclause 5(a)) or the **trader** (under subclause 5(b)) must not unreasonably withhold consent to the proposed transfer.

Proposal 2019-11, Clarifying when obligations linked to clause 22 of Schedule 11.3 begin

14.1 When a notice from the registry manager is received under clause 22 of Schedule 11.3, participants must meet various obligations within specified periods. It is important to determine exactly when participants "receive" a notice from the registry manager to calculate the time period for subsequent Code obligations.

14.2 We also proposed two minor drafting amendments.

We have decided to implement an amended form of the proposal

14.3 We have decided to amend the Code to clarify that a participant's time-bound obligation begins when the registry manager makes the written notice under clause 22 of Schedule 11.3 available to the participant.

14.4 There is no change to the policy intent or effect of the Code amendment proposal we consulted on in September 2019. However, instead of amending clause 11.15AB(5) as proposed, we have amended the definition of 'switch protected period' in Part 1 of the Code. This definition was inserted in the Code under the '*Prohibition of Save and Win-Back Approaches by Losing Retailers During a Switch Protected Period*' Code amendment in 2020.[10] This definition originated from the (former version of) clause 11.15AB(5) that we consulted on. The amendment to the definition of 'switch protected period' has the same effect as the amendment to clause 11.15AB that we consulted on. The other amendments remain unchanged from the proposal we consulted on.

Submitter's view

14.5 Electric Kiwi said clause 11.15AB(5)(b) should be amended as shown in the yellow highlighted text:

(5) The period:

(a) starts on the ~~day~~ date on which the **registry manager**, under clause 22(a) of Schedule 11.3, makes ~~the **trader** receives~~ written notice of the switch request ~~under clause 22(a) of Schedule 11.3~~ available to the **trader**;~~,~~ and

(b) ends on the **event date** ~~for the switch~~ date and time on which the **registry manager**, under clause 22(d), makes written notice of switch completion information available to the gaining **trader**.

14.6 Electric Kiwi considered this would address a loophole that would otherwise exist in clause 11.15AB(5)(b). If switch save protection were to end on the event (effective) date rather than the date on which the registry manager made available the switch completion (CS) file to the gaining trader, the losing retailer would be able to "save" a customer who had a backdated switch.

Our decision

14.7 Electric Kiwi's submission relates to Code that has been superseded by the Saves and Win-backs Code amendment. That amendment prohibits a losing retailer from attempting to save or win back a former customer until 180 days after the customer has switched retailer.

Submitter's view

14.8 Genesis Energy said it does not believe the full benefits of the Code amendment will be realised. The time and effort expected to be saved on understanding Code obligations will still be spent.

14.9 In addition, Genesis Energy believes clarifying that a participant's time-bound obligation now starts on delivery, not receipt, may result in traders incurring a cost by altering their systems to adjust for files received the day after delivery. This would occur for files 'delivered' by the registry manager after the last polling by a trader of the registry manager's SFTP service for a business day.

Our decision

14.10 It is expected that some time and effort will be spent understanding Code clauses in general. We consider participants and the Authority will find it easier to interpret and comply with the clauses being clarified, therefore saving time and effort.

10 Available on our website at https://www.ea.govt.nz/code-and-compliance/the-code/amendments/2020-code-amendments/.

14.11 We have received no other feedback from traders, or participants more generally, in relation to potential systems costs incur costs altering their systems in response to the Code amendment. We accept some traders may incur a cost and consider that the benefits of clarity exceed the potential for cost.

The amendment will contribute to the efficient operation of the electricity industry

14.12 The Code amendment will improve the efficient operation of the electricity industry, by clarifying when a participant is meant to fulfil an obligation arising from a notice made available by the registry manager under clause 22 of Schedule 11.3. The amendment will reduce the cost to participants of understanding and complying with the Code.

14.13 The amendment may promote competition, to the extent that it results in participants meeting their switching-related obligations in a timelier manner.

14.14 The Code amendment will come into force on 1 March 2022.

Final amendment showing track change

Part 1

switch protected period means the period that:

(a) starts on the earlier of–

(i) the day on which <u>the **registry manager**, under clause 22(a) of Schedule 11.3, makes written</u> ~~a **losing retailer** receives~~ <u>notice available to the **losing retailer**</u> or <u>the **losing retailer**</u> otherwise becomes aware that a customer is switching to a **gaining retailer**; or

(ii) the day on which a **gaining retailer** assumes responsibility for billing a customer of a **losing retailer** for **electricity**; and

(b) ends on the earlier of –

(i) the date that is 180 days after the relevant date specified in paragraph (a); or

(ii) the date on which the **losing retailer** receives a notice under clause 4A(1) of Schedule 11.5 from the **Authority** or otherwise becomes aware that the customer is switching from the **gaining retailer** back to the **losing retailer** due to an **event of default**; or

(iii) if the **gaining retailer** is a **trader** and makes a withdrawal request, the date on which the <u>**registry manager**, under clause 22(b) of Schedule 11.3, makes</u> ~~**losing retailer** (if a **trader**) receives~~ <u>written</u> notice of ~~that~~ <u>the</u> withdrawal request <u>available to the losing **retailer** (if a **trader**)</u> ~~under clause 22(b) of Schedule 11.3~~; or

(iv) if the **trader** for the **losing retailer** and **gaining retailer** (neither of whom is a **trader**) is the same, the date on which the **trader** receives advice from the **gaining retailer** withdrawing the switch request from the **losing retailer**.

Schedule 11.3

…

3 Losing trader response to standard switch request

No later than 3 **business days** after the date on which the **registry manager**, under clause 22(a), makes written ~~receiving~~ notice of a switch request ~~from the **registry manager** under clause 22(a)~~ available to the losing **trader**, the losing **trader** must,**—**

(a) either—

(i) acknowledge the switch request by providing the following information to the **registry manager**:

(A) the proposed **event date**; and

(B) a valid switch response code approved by the **Authority**; or

(ii) provide the final information specified in clause 5(a) to (c) to complete the switch; or

(b) *[Revoked]*

(c) request that the switch be withdrawn in accordance with clause 17.

4 Event dates

(1) The losing **trader** must establish **event dates** so that—

(a) no **event date** is more than 10 **business days** after the date on~~-~~which the **registry manager**, under clause 22(a), makes ~~the losing **trader** receives~~ written notice ~~from the **registry manager** in accordance with clause 22(a)~~ available to the losing **trader**; and

(b) in any 12 month period at least 50% of the **event dates** established by the losing **trader** are no more than 5 **business days** after the date on which the **registry manager**, under clause 22(a), makes ~~the losing **trader** receives~~ written notice ~~from the **registry manager** in accordance with clause 22(a)~~ available to the losing **trader**.

(2) For the purpose of determining whether it complies with subclause (1)(b), the losing **trader** may disregard every **event date** it has established for an **ICP** for which, ~~when~~ on the date on which the **registry manager**, under clause 22(a), made ~~the losing **trader** received~~ written notice ~~from the **registry manager** under clause 22(a)~~ available to the losing **trader**, the losing **trader** had been responsible for less than 2 months.

…

6 Traders must use same reading

(1) The losing **trader** and the gaining **trader** must both use the same **switch event meter reading** for the **event date** as determined by the following procedure:

(a) if the **switch event meter reading** provided by the losing **trader** differs by less than 200 kWh from a value established by the gaining **trader**, the gaining **trader** must use the losing **trader's switch event meter reading**; or

(b) if the **switch event meter reading** provided by the losing **trader** differs by 200 kWh or more from a value established by the gaining **trader**, the gaining **trader** may dispute the **switch event meter reading**.

(2) Despite subclause (1), subclause (3) applies if—

- (a) the losing **trader** trades **electricity** at the **ICP** through a **metering installation** with a submission type of non **half hour** in the **registry**; and
- (b) the gaining **trader** will trade **electricity** at the **ICP** through a **metering installation** with a submission type of **half hour** in the **registry**, as a result of the gaining **trader's** arrangement to trade **electricity** with the customer or the **embedded generator**; and
- (c) a **switch event meter reading** provided by the losing **trader** under subclause (1) has not been obtained from an **interrogation** of a **certified metering installation** with an AMI flag of Y in the **registry**.

(3) No later than 5 **business days** after the date on which ~~receiving final information from~~ the **registry manager**, under clause 22(d), makes written notice of switch completion information ~~under clause 22(d)~~ available to the gaining **trader**,—

- (a) the gaining **trader** may provide the losing **trader** with a **switch event meter reading** obtained from an **interrogation** of a **certified metering installation** with an AMI flag of Y in the **registry**; and
- (b) the losing **trader** must use that **switch event meter reading.**

6A Gaining trader disputes reading

(1) If a gaining **trader** disputes a **switch event meter reading** under clause 6(1)(b), the gaining **trader** must, no later than 4 months after the date on which the **registry manager**, under clause 22(d), ~~gives the gaining **trader**~~ made written notice of switch completion information ~~under clause 22(d)~~ available to the gaining **trader** ~~of having received information about the switch completion~~, provide to the losing **trader** a revised **switch event meter reading** supported by 2 **validated meter readings**.

(2) On receipt of a revised **switch event meter reading** from the gaining **trader** under subclause (1), the losing **trader** must either,—

- (a) if the losing **trader** accepts the revised **switch event meter reading**, or does not respond to the gaining **trader**, use the revised **switch event meter reading**; or
- (b) if the losing **trader** does not accept the revised **switch event meter reading**, advise the gaining **trader** (giving all relevant details) no later than 5 **business days** after receiving the revised **switch event meter reading**.

…

10 Losing trader response to switch move request

(1) ~~After receiving notice of a switch request from the **registry manager** under clause 22(a), the~~ The **trader** that is recorded in the **registry** as being responsible for ~~the~~ an **ICP** that is subject to a switch request (the "losing **trader**") must, no later than 5 **business days** after the date on which the **registry manager**, under clause 22(a), makes ~~receiving the~~ written notice of the switch request available to the losing **trader**,—

- (a) if the losing **trader** accepts the **event date** proposed by the gaining **trader**, complete the switch by providing to the **registry manager**—

(i) *[Revoked]*

(ia) confirmation of the **event date**; and

(ib) a valid switch response code approved by the **Authority**; and

(ii) final information in accordance with clause 11; or

(b) if the losing **trader** does not accept the **event date** proposed by the gaining **trader**, acknowledge the switch request to the **registry manager** and determine a different **event date** that—

(i) is not earlier than the gaining **trader's** proposed **event date**; and

(ii) is no later than 10 **business days** after <u>the date on which</u> the ~~date~~ **<u>registry manager</u>**<u>, under clause 22(a), made</u> ~~the losing **trader** receives the~~ <u>written</u> notice <u>of the switch request available to the losing **trader**</u>; or

(c) request that the switch be withdrawn in accordance with clause 17.

(2) If the losing **trader** determines a different **event date** under subclause (1)(b), the losing **trader** must, no later than 10 **business days** after <u>the date on which the **registry manager** made</u> ~~receiving the~~ <u>written</u> notice referred to in subclause (1) <u>available to the losing **trader**</u>, also complete the switch by providing to the **registry manager** the information described in subclause (1)(a), but in that case the **event date** is the **event date** determined by the losing **trader**.

…

12 Gaining trader may change switch event meter reading

…

(2B) No later than 5 **business days** after <u>the date on which</u> ~~receiving final information from~~ the **registry manager**<u>, under clause 22(d), makes written notice</u> ~~under clause 22(d)~~ available to the losing **trader**,—

(a) the gaining **trader** may provide the losing **trader** with a **switch event meter reading** obtained from an **interrogation** of a **certified metering installation** with an AMI flag of Y in the **registry**; and

(b) the losing **trader** must use that **switch event meter reading**<u>.</u>

(3) If the gaining **trader** disputes a **switch event meter reading** under subclause (2)(b), the gaining **trader** must, no later than 4 months after <u>the date on which</u> the **registry manager**<u>, under clause 22(d),</u> ~~gives~~ <u>made</u> ~~the gaining **trader**~~ written notice <u>of switch completion information</u> ~~under clause 22(d)~~ <u>available to the gaining trader</u> ~~of having received information about the switch completion~~, provide to the losing **trader** a <u>revised</u> ~~changed~~ **validated meter reading** or a **permanent estimate** supported by 2 **validated meter readings**, and the losing **trader** must either,—

(a) no later than 5 **business days** after receiving the **switch event meter reading** from the gaining **trader**, the losing **trader**, if it does not accept the **switch event meter reading**, must advise the gaining **trader** (giving all relevant details), and the losing **trader** and the gaining **trader** must use reasonable endeavours to resolve the dispute in accordance with the disputes procedure contained in clause 15.29 (with all necessary amendments); or

(b) if the losing **trader** advises its acceptance of the **switch event meter reading** received from the gaining **trader**, or does not provide any response, the losing **trader** must use the **switch event meter reading** supplied by the gaining **trader**.

…

15 Losing trader provides information

No later than 3 **business days** after the date on which the **registry manager**, under clause 22(a), makes ~~the losing **trader** receives~~ written notice ~~from the **registry manager** in accordance with clause 22(a)~~ available to the losing **trader**, the losing **trader** must—

(a) provide the **registry manager** with a valid switch response code approved by the **Authority**; or

(b) request that the switch be withdrawn in accordance with clause 17.

16 Gaining trader obligations

(1) The gaining **trader** must complete the switch by advising the **registry manager** of the **event date** no later than 3 **business days** after the date on which the **registry manager**, under clause 22(c), makes written notice of ~~receiving~~ a valid switch response code ~~from the **registry manager** under clause 22(c)~~ available to the gaining **trader**.

(2) If the **ICP** is being **electrically disconnected** or if **metering** equipment is being removed, the gaining **trader** must either—

(a) give the losing **trader** or the **metering equipment provider** for the **ICP** an opportunity to **interrogate** the **metering installation** immediately before the **ICP** is **electrically disconnected** or the **metering** equipment is removed; or

(b) carry out an **interrogation** and, no later than 5 **business days** after the **metering installation** is **electrically disconnected** or removed, advise the losing **trader** of—

(i) the results of the **interrogation**; and

(ii) the **metering component** numbers for each data channel in the **metering installation**.

…

18 Withdrawing a switch request

If a **trader** requests the withdrawal of a switch under clause 17, the following provisions apply:

(a) the **Authority** must determine the valid codes for withdrawing a switch request (“withdrawal advisory codes”):

(b) the **Authority** must **publish** the withdrawal advisory codes:

(c) for each **ICP**, the **trader** withdrawing the switch request must provide the **registry manager** with the following information:

(i) the **participant identifier** of the **trader**; and

(ii) the withdrawal advisory code **published** by the **Authority** in accordance with paragraph (b):

(d) no later than 5 **business days** after the date on which the **registry manager**, under clause 22(b), makes written ~~receiving~~ notice ~~from the **registry manager** in accordance with clause 22(b)~~ available to the **trader** receiving the withdrawal, the **trader** must advise the **registry manager** that the switch withdrawal request is accepted or rejected. A switch withdrawal request must not become effective until accepted by the **trader** who received the withdrawal:

(e) on receipt of a rejection notice from the **registry manager** in accordance with paragraph (d), a **trader** may re-submit a switch withdrawal request for an **ICP** in accordance with paragraph (c). All switch withdrawal requests must be resolved no later than 10 **business days** after the date of the initial switch withdrawal request:

(f) if a **trader** requests that a switch request be withdrawn and the resolution of that switch withdrawal request results in the switch proceeding, no later than 2 **business days** after the date on which the **registry manager**, under clause 22(b), makes written ~~receiving~~ notice ~~from the **registry manager** in accordance with clause 22(b)~~ available to the losing **trader**, the losing **trader** must comply with clauses 3, 5, 10 and 11 (whichever is appropriate) and the gaining **trader** must comply with clause 16.

22 Registry manager notices

The **registry manager** must provide notice to **participants** required by this Schedule as follows:

(a) on receipt of information about a switch request in accordance with clauses 2, 9 and 14, the **registry manager** must ~~give~~ make written notice available to the losing **trader** of the information received:

(b) on receipt of information about a withdrawal request in accordance with clauses 18(c) and (d), the **registry** ma**n**ager must ~~give~~ make written notice available to the other relevant **trader** of the information received:

(c) on receipt of information about a switch acknowledgement in accordance with clauses 3(a) and 15, the **registry manager** must make ~~give~~ written notice available to the gaining **trader** of the information received:

(d) on receipt of information about a switch completion in accordance with clauses 3(a)(ii), 5, 10 and 16, the **registry manager** must make ~~give~~ written notice available to the gaining **trader**, the losing **trader**, the **metering equipment provider**, and the relevant **distributor** of the information received.

Proposal 2019-12, Removing provision for supply shortage declarations to trigger payments under the Customer Compensation Scheme

15.1 During an official conservation campaign (OCC), retailers must pay Customer Compensation Scheme (CCS) payments to consumers. The mechanism is an incentive on retailers to manage their dry year risk through hedging to avoid unnecessary OCCs. If hydro levels continued to drop, the next step is rolling outages.

15.2 CCS payments can also be triggered by another route. The Code requires CCS payments to be paid during a public conservation period, which includes any period during which a supply shortage declaration is in force for 1 week or more. Under clause 9.14 of the Code, the system operator may make a supply shortage declaration:

(a) for a capacity shortage (insufficient operating capacity, eg, resulting from an outage on the transmission network)

(b) for an energy shortage (insufficient 'fuel' to generate electricity, eg, during a dry period)11

(c) on a regional or national basis.

15.3 A supply shortage may be managed with rolling outages.

15.4 Therefore, the CCS can be triggered by prolonged capacity shortages, even regional ones, without regard to the hydro storage situation. This does not make sense as the CCS is not designed to incentivise against capacity events.

Official conservation campaigns should be the only trigger for the CCS

15.5 Following a review of CCS in October 2017[12], we proposed deleting the 'public conservation period' defined term in Part 1, and replacing all references to 'public conservation period' with 'official conservation campaign'.

15.6 We do not consider the CCS should be used to compensate for forced disconnections caused by rolling outages during prolonged capacity shortages, because the CCS minimum weekly amount is designed to compensate for OCCs.

15.7 Our initial assessment is that we also currently do not consider any compensation payment is needed in this circumstance. Rolling outages triggered by other causes do not have compensation arrangements, and it is a non-trivial exercise to work out what would be an appropriate methodology (this could be something looked at in future).

15.8 We also proposed two minor drafting amendments.

We have decided to implement the proposal without change

15.9 We have decided to amend clauses 9.19, 9.21, 9.22, 9.24, 9.25, 9.29 and the definition of 'public conservation period' to ensure only official conservation campaigns trigger the customer compensation scheme.

15.10 All submitters agreed with the proposal.

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11 Refer: https://www.ea.govt.nz/dmsdocument/21364-the-security-of-supply-framework-information-paper

12 Decision paper on review of CCS, 3 October 2017 https://www.ea.govt.nz/development/work-programme/risk-management/review-of-the-customer-compensation-scheme-ccs/development/decision-paper-on-review-of-ccs/

The amendment will promote the efficient and competitive operation of the electricity industry

15.11 The efficient and competitive benefits would arise because:

(a) CCS payments triggered by regional capacity shortages would be an unjustified, inappropriate, and inefficient penalty for retailers, as this was not a purpose the CCS was designed to incentivise against

(b) removing a confusing term from the Code would improve certainty and clarity for participants, and hence the efficiency of their decision making.

15.12 We would not expect this amendment to have any significant impact on the reliability of the system.

15.13 The Code amendment will come into force 28 days after the amendment is Gazetted.

Final amendment showing track change

Part 1

~~**public conservation period** means—~~

~~(a) any period during which an **official conservation period** is running:~~

~~(b) any period during which a **supply shortage declaration** is in force for 1 week or more~~

9.19 Contents of this subpart

This subpart provides a framework under which each **retailer** must have a **customer compensation scheme** for all the **retailer's qualifying customers**, including—

(a) a **default customer compensation scheme** that a **retailer** must have; and

(b) **additional customer compensation schemes** that a **retailer** may have; and

(c) determining when a<u>n **official conservation campaign**</u> ~~**public conservation period**~~ commences and ends, during which a **retailer** must make payments under its **customer compensation schemes**; and

(d) a process by which the **Authority** can require that a **retailer's** compliance with this subpart is **audited**.

9.21 Qualifying customers

(1) A **retailer's qualifying customer** is a person who, at any time during a<u>n **official conservation campaign**</u> ~~**public conservation period**~~,—

(a) is a customer of the **retailer**; and

(b) has a contract with the **retailer** for the supply of **electricity** in respect of an **ICP** at which—

(i) there is a **category 1 metering installation** or a **category 2 metering installation**; and

(ii) there was consumption, in the 12 months immediately before the start of the <u>**official compensation campaign**</u> ~~**public conservation period**~~, of 3000 kWh or more.

…

(3) For the purposes of subclause (1)(b)(ii), if a **qualifying customer's** consumption at the **ICP** in the 12 months immediately before the start of the **official conservation campaign** ~~**public conservation period**~~ is not available to the **retailer**, the **retailer** must make a reasonable estimate of the consumption.

(4) To avoid doubt, the **retailer** is not required to make payments under **a customer compensation scheme** to a **qualifying customer** at an **ICP** in respect of any period during an **official conservation period** ~~**public conservation period**~~, when—

(a) the premises to which the **ICP** is **electrically connected** are vacant; or

(b) the **ICP** is **electrically disconnected**.

9.22 Requirement to implement customer compensation schemes

(1) A **retailer** must make payments to its **qualifying customers**, in respect of **ICPs** described in clause 9.21(1)(b), under its **customer compensation schemes** during an **official conservation campaign** ~~**public conservation period**~~.

(2) Despite subclause (1), if ~~a **public conservation period** is running because~~ the **system operator** has commenced an **official conservation campaign** under clause 9.23(1), a **retailer** must make payments under its **customer compensation scheme** to its **qualifying customers** only in respect of **ICPs**, as described in clause 9.21(1)(b), in the South Island.

9.24 Requirements of default customer compensation schemes

(1) A **retailer's default customer compensation scheme** must provide for the **retailer**—

(a) during an **official conservation campaign** for the South Island, to pay each of its **qualifying customers** in the South Island at least the minimum weekly amount of compensation determined by the **Authority** under clause 9.25, at a pro rata daily rate for each day of the **official conservation campaign** that the **qualifying customer** is the **retailer's customer**; and

(b) at any other time during an **official conservation campaign** ~~**public conservation period**~~, to pay each of its **qualifying customers** at least the minimum weekly amount of compensation determined by the **Authority** under clause 9.25, at a pro rata daily rate for each day of the **official conservation campaign** ~~**public conservation period**~~ that the **qualifying customer** is the **retailer's customer**; and

(c) to pay at least the minimum weekly amount, at a pro rata daily rate, for each day of an **official conservation campaign** ~~**public conservation period**~~ that the **qualifying customer** is the **retailer's customer**—

(i) to each of its **qualifying customers** in the South Island or New Zealand (as the case may be), for each of the **qualifying customer's ICPs** described in clause 9.21(1)(b):

(ii) no later than the end of 2 **billing periods** after the last day of an **official conservation campaign** ~~**public conservation period**~~.

9.25 Authority must determine minimum weekly amount

(1) ....

(2) The **Authority** must—

(a) **publish** the minimum weekly amount; and

(b) review the minimum weekly amount—

(i) after each **official conservation campaign** ~~**public conservation period**~~ ends; and

(ii) at least once every 3 years; and

(c) following a review under paragraph (b), ensure that it gives **participants** at least 3 months' notice if it determines a new minimum weekly amount.

9.29 Each retailer must provide certification

…

(3) A **retailer** must provide certifications as follows:

(a) within 7 months of the end of an **official conservation campaign** ~~**public conservation period**~~:

Typographical amendments

16.1 The consultation for Code Review Programme number 4 in September 2019 also included a standalone proposal to correct minor typographical errors in the Code.

16.2 The minor amendments are predominantly editorial, for example correcting cross references, or adding bold to terms that are defined in Part 1. There is also a list of clauses in Part 17 of the Code, which were required in 2010 for the transition from the Electricity Governance Rules 2003 to the Code. We are revoking these clauses as they are no longer required.

16.3 We are proceeding with these changes under section 39(3)(a) of the Act, as the amendments are technical and non-controversial, with one minor change. We received two submissions on the typographical errors. Both submissions noted that in Clause 1.1(1) definition of 'good electricity industry practice' the word 'experience' should be 'experienced'. We agree with the submissions.

16.4 Noting the original proposed change was to bold "owner" as "asset owner" is the defined term. Also, "network" is a defined term, so it should be in bold too.

Final amendment showing track change

Part 1

good electricity industry practice in relation to transmission, means the exercise of that degree of skill, diligence, prudence, foresight and economic management, as determined by reference to good international practice, which would be reasonably be expected from a skilled and experienced **asset** ~~owner~~ **owner** engaged in the management of a transmission ~~network~~ **network** under conditions comparable to those applicable to the **grid** consistent with applicable law, safety and environmental protection. The determination is to take into account factors such as the relative size, duty, age and technological status of the relevant transmission ~~network~~ **network** and the applicable law

Appendix A Approved Code amendment

The Code amendment is as follows:

Part 1

1.1 Interpretation

(1)

…

block security constraint means any of the following:

(a) a security constraint as determined in accordance with the **policy statement** and applied by the **system operator** to a **generating unit** or **generating station** to provide **voltage support** or **frequency keeping**: ~~as determined in accordance with Part 8~~

(b) a limitation in **grid** capacity that:

(i) is a limitation in the ~~offered~~ capacity of ~~a **grid owner's network**~~ the **grid** to convey **electricity** between either:

(A) **generating stations** constituting a **block dispatch group**; or

(B) ~~a limitation in the offered capacity of a **grid owner's network** to convey **electricity** between~~ **generating stations** constituting a **block dispatch group** and ~~a **grid owner's network**~~ the **grid**;**—** and~~,~~

(ii) ~~in paragraphs (b) and (c), such~~ arises because of either—

(A) a limitation in the ~~offered capacity being the~~ offered capacity of ~~a **grid owner's network**~~ the **grid**; or

(B) a security constraint as determined by the **system operator** in accordance with the **policy statement** ~~Part 8~~

…

good electricity industry practice in relation to transmission, means the exercise of that degree of skill, diligence, prudence, foresight and economic management, as determined by reference to good international practice, which would be reasonably be expected from a skilled and experienced **asset** ~~owner~~ **owner** engaged in the management of a transmission ~~network~~ **network** under conditions comparable to those applicable to the **grid** consistent with applicable law, safety and environmental protection. The determination is to take into account factors such as the relative size, duty, age and technological status of the relevant transmission ~~network~~ **network** and the applicable law

…

historical estimate means, in relation to non **half hour** metered **ICPs**, **volume information** (in kWh)—

(a) ~~,~~ apportioned to part or full **consumption periods** after having applied—

(i) the **seasonal adjustment shape**;~~,~~ or

(ii) any other **profile** that has, from time to time, been approved by the **Authority** for this purpose;~~,~~ ~~applied,~~ or

(iii) any other **profile** permitted under clause 5 of Schedule 15.3; and

(b) being 1 of the following:

~~(a)~~(i) the difference between 2 **validated** actual **meter readings**:

~~(b)~~(ii) the difference between 2 **permanent estimates**:

~~(c)~~(iii) any relevant **unmetered load**:

~~(d)~~(iv) the difference between a **validated meter reading** and a **permanent estimate**.

…

point of connection means—

(a) a point at which **electricity** may flow, via one or more phases or conductors—

(i) into or out of a **network**; or

(ii) both into and out of a **network** at the same time, where each directional flow is on different phases or conductors; and~~,~~

(b) for the purposes of **Technical Code** A of Schedule 8.3, means a **grid injection point** or a **grid exit point**

…

~~**public conservation period** means—~~

~~(a) any period during which an **official conservation period** is running:~~

~~(b) any period during which a **supply shortage declaration** is in force for 1 week or more~~

…

station security constraint means any of the following:

(a) a security constraint as determined in accordance with the **policy statement** and applied by the **system operator** to a **generating unit** to provide **voltage support** or ~~frequency~~ ~~reserve capacity~~ **frequency keeping**~~as determined in accordance with Part 8~~:

(b) a limitation in **grid** capacity that:

(i) is a limitation in the ~~offered~~ capacity of ~~a **grid owner's** network~~ the **grid** to convey **electricity**

between either—

(A) **generating units** constituting a **station dispatch group**; or

(B) ~~a limitation in the offered capacity of a **grid owner's network** to convey **electricity** between~~ **generating units** constituting a **station dispatch group** and ~~a **grid owner's network**~~ the **grid**;~~—~~ and~~,~~

(ii) ~~if in paragraphs (b) and (c) above, the~~ arises because of either:

(A) a limitation in the ~~offered capacity~~ ~~is either~~ ~~the~~ offered capacity of ~~a **grid owner's network**~~ the **grid**; or

(B) a ~~**grid system security** limit,~~ "security constraint" as determined by the **system operator** in accordance with the **policy statement**~~Part 8~~

…

switch protected period means the period that:

(a) starts on the earlier of–

(i) the day on which the **registry manager**, under clause 22(a) of Schedule 11.3, makes written ~~a **losing retailer** receives~~ notice available to the **losing retailer** or the **losing retailer** otherwise becomes aware that a customer is switching to a **gaining retailer**; or

(ii) the day on which a **gaining retailer** assumes responsibility for billing a customer of a **losing retailer** for **electricity**; and

(b) ends on the earlier of –

(i) the date that is 180 days after the relevant date specified in paragraph (a); or

(ii) the date on which the **losing retailer** receives a notice under clause 4A(1) of Schedule 11.5 from the **Authority** or otherwise becomes aware that the customer is switching from the **gaining retailer** back to the **losing retailer** due to an **event of default**; or

(iii) if the **gaining retailer** is a **trader** and makes a withdrawal request, the date on which the **registry manager**, under clause 22(b) of Schedule 11.3, makes ~~**losing retailer** (if a **trader**) receives~~ written notice of ~~that~~ the withdrawal request available to the losing **retailer** (if a **trader**) ~~under clause 22(b) of Schedule 11.3~~; or

(iv) if the **trader** for the **losing retailer** and **gaining retailer** (neither of whom is a **trader**) is the same, the date on which the **trader** receives advice from the **gaining retailer** withdrawing the switch request from the **losing retailer**.

…

--

Part 9

…

9.19 Contents of this subpart

This subpart provides a framework under which each **retailer** must have a **customer compensation scheme** for all the **retailer's qualifying customers**, including—

(a) a **default customer compensation scheme** that a **retailer** must have; and

(b) **additional customer compensation schemes** that a **retailer** may have; and

(c) determining when an **official conservation campaign** ~~**public conservation period**~~ commences and ends, during which a **retailer** must make payments under its **customer compensation schemes**; and

(d) a process by which the **Authority** can require that a **retailer's** compliance with this subpart is **audited**.

9.21 Qualifying customers

(1) A **retailer's qualifying customer** is a person who, at any time during an **official conservation campaign** ~~**public conservation period**~~,—

(a) is a customer of the **retailer**; and

(b) has a contract with the **retailer** for the supply of **electricity** in respect of an **ICP** at which—

(i) there is a **category 1 metering installation** or a **category 2 metering installation**; and

(ii) there was consumption, in the 12 months immediately before the start of the **official compensation campaign** ~~**public conservation period**~~, of 3000 kWh or more.

…

(3) For the purposes of subclause (1)(b)(ii), if a **qualifying customer's** consumption at the **ICP** in the 12 months immediately before the start of the **official conservation campaign** ~~**public conservation period**~~ is not available to the **retailer**, the **retailer** must make a reasonable estimate of the consumption.

(4) To avoid doubt, the **retailer** is not required to make payments under **a customer compensation scheme** to a **qualifying customer** at an **ICP** in respect of any period during an **official conservation period** ~~**public conservation period**~~, when—

(a) the premises to which the **ICP** is **electrically connected** are vacant; or

(b) the **ICP** is **electrically disconnected**.

9.22 Requirement to implement customer compensation schemes

(1) A **retailer** must make payments to its **qualifying customers**, in respect of **ICPs** described in clause 9.21(1)(b), under its **customer compensation schemes** during an **official conservation campaign** ~~**public conservation period**~~.

(2) Despite subclause (1), if ~~a **public conservation period** is running because~~ the **system operator** has commenced an **official conservation campaign** under clause 9.23(1), a **retailer** must make payments under its **customer compensation scheme** to its **qualifying customers** only in respect of **ICPs**, as described in clause 9.21(1)(b), in the South Island.

9.24 Requirements of default customer compensation schemes

(1) A **retailer's default customer compensation scheme** must provide for the **retailer—**

(a) during an **official conservation campaign** for the South Island, to pay each of its **qualifying customers** in the South Island at least the minimum weekly amount of compensation determined by the **Authority** under clause 9.25, at a pro rata daily rate for each day of the **official conservation campaign** that the **qualifying customer** is the **retailer's customer**; and

(b) at any other time during an **official conservation campaign** ~~**public conservation period**~~, to pay each of its **qualifying customers** at least the minimum weekly amount of compensation determined by the **Authority** under clause 9.25, at a pro rata daily rate for each day of the **official conservation campaign** ~~**public conservation period**~~ that the **qualifying customer** is the **retailer's customer**; and

(c) to pay at least the minimum weekly amount, at a pro rata daily rate, for each day of an **official conservation campaign** ~~**public conservation period**~~ that the **qualifying customer** is the **retailer's customer—**

(i) to each of its **qualifying customers** in the South Island or New Zealand (as the case may be), for each of the **qualifying customer's ICPs** described in clause 9.21(1)(b):

(ii) no later than the end of 2 **billing periods** after the last day of an **official conservation campaign** ~~**public conservation period**~~.

9.25 Authority must determine minimum weekly amount

(1) ....

(2) The **Authority** must—

(a) **publish** the minimum weekly amount; and

(b) review the minimum weekly amount—

(i) after each **official conservation campaign** ~~**public conservation period**~~ ends; and

(ii) at least once every 3 years; and

(c) following a review under paragraph (b), ensure that it gives **participants** at least 3 months' notice if it determines a new minimum weekly amount.

9.29 Each retailer must provide certification

…

(3) A **retailer** must provide certifications as follows:

(a) within 7 months of the end of an **official conservation campaign** ~~**public conservation period**~~:

Part 11

…

Schedule 11.1 Creation and management of ICPs, ICP identifiers and NSPs

…

8 Distributors to change ICP information provided to registry manager

(1) If information about an ICP provided to the **registry manager** in accordance with clause 7 changes, the **distributor** in whose **network** the **ICP** is located must give written notice to the **registry manager** of the change.

(2) The **distributor** must give the notice—

(a) in the case of a change to the information referred to in clause 7(1)(b) (other than a change that is the result of the **commissioning** or **decommissioning** of an **NSP**), no later than 8 **business days** after the change takes effect; and

(aa) in the case of a change to the information provided under clause 7(1)(g), where the change is backdated, no later than 3 **business days** after the **distributor** and the **trader** responsible for the **ICP** agree on the change; and

(ab) in the case of **decommissioning** an **ICP**, by the later of—

(i) 3 **business days** after the **registry manager** has advised the **distributor** under clause 11.29 that the **ICP** is ready to be **decommissioned**; and

(i) 3 **business days** after the **distributor** has **decommissioned** the **ICP**:

(b) in every other case, no later than 3 **business days** after the change takes effect.

…

25 Creation and decommissioning of NSPs and transfer of ICPs from 1 distributor's network to another distributor's network

(1) If an **NSP** is to be created or **decommissioned**,—

(a) the **participant** specified in subclause (3) in relation to the **NSP** must give written notice to the **reconciliation manager** of the creation or **decommissioning**; and

(b) the **reconciliation manager** must give written notice to the **Authority** and affected **reconciliation participants** of the creation or **decommissioning** no later than 1 **business day** after receiving the notice in paragraph (a).

(2) If a **distributor** wishes to change the record in the **registry** of an **ICP** that is not recorded as being usually connected to an **NSP** in the **distributor's network**, so that the **ICP** is recorded as being usually connected to an **NSP** in the **distributor's network** (a "transfer"), the **distributor** must give written notice to the **reconciliation manager**, the **Authority**, and each affected **reconciliation participant** of the transfer.

(3) The notice required by subclause (1) must be given by—

(a) the **grid owner**, if—

(i) the **NSP** is a **point of connection** between the **grid** and a **local network**; or

(ii) if the **NSP** is a **point of connection** between a **generator** and the **grid**; or

(b) the **distributor** for the **local network** who initiated the creation or **decommissioning**, if the **NSP** is an **interconnection point** between 2 **local networks**; or

(c) the **embedded network** owner who initiated the creation or **decommissioning**, if the **NSP** is an **interconnection point** between 2 **embedded networks**; or

(d) the **distributor** for the **embedded network**, if the **NSP** is a **point of connection** between an **embedded network** and another **network**.

(4) A **distributor** who is required to give written notice of a transfer under subclause (2) or subclause (3)(d) must comply with Schedule 11.2.

(5) An **embedded network** owner must not give written notice of **decommissioning** an **NSP** under subclause (3)(c) or subclause (3)(d) unless—

(a) the **embedded network** owner has changed the status in the **registry** of all **ICPs** recorded as being usually connected to the **NSP** to 'Decommissioned'; or

(b) a **distributor** has changed the record in the **registry** of each **ICP** previously recorded as being usually connected to the **NSP,** and with a status in the **registry** of 'Active' or 'Inactive', to record the **ICP** as being usually connected to an **NSP** in the **distributor's network**; or

(c) a combination of the changes described in paragraphs (a) and (b) has occurred, so that no **ICP** with a status in the **registry** of 'Active' or 'Inactive' is recorded as being connected to the **NSP** that is to be **decommissioned**.

…

Schedule 11.2 Transfer of ICPs between distributors' networks

…

5 The applicant **distributor** must give the **Authority** confirmation that the applicant **distributor** has received written consent to the proposed transfer from—

(a) the **distributor** whose **network** is associated with the **NSP** to which the **ICP** is recorded as being connected immediately before the notice, except if the notice relates to the creation of an **embedded network**; and

(b) every **trader** who trades **electricity** at any **ICP** nominated at the time of notice as being supplied from the same **NSP** to which the notice relates.

5A For the purposes of clause 5, the **distributor** (under subclause 5(a)) or the **trader** (under subclause 5(b)) is deemed to have consented to the proposed transfer if the applicant **distributor** has requested in writing the **distributor's** or **trader's** written consent and—

(a) the **distributor** or **trader** (as the case may be)—

(i) has not provided written consent; and

(ii) has not indicated in writing that it refuses to give written consent; and

(b) more than 40 **business days** (or such other period as the applicant **distributor** agrees with the **distributor** or **trader**) have passed since the applicant **distributor** requested the **distributor's** or **trader's** written consent; and

(c) during the 40 **business days** (or such other period as the applicant **distributor** agrees with the **distributor** or **trader**) the applicant **distributor** has—

(i) checked the **registry** to ensure it has sought consent from the correct **distributor** or **trader**; and

(ii) made reasonable endeavours to contact the **distributor** or **trader** and obtain a response.

5B For the purposes of clause 5, the **distributor** (under subclause 5(a)) or the **trader** (under subclause 5(b)) must not unreasonably withhold consent to the proposed transfer.

…

Schedule 11.3 Switching

…

3 Losing trader response to standard switch request

No later than 3 **business days** after the date on which the **registry manager**, under clause 22(a), makes written ~~receiving~~ notice of a switch request ~~from the **registry manager** under clause 22(a)~~ available to the losing **trader**, the losing **trader** must,**—**

(a) either—

(i) acknowledge the switch request by providing the following information to the **registry manager**:

(A) the proposed **event date**; and

(B) a valid switch response code approved by the **Authority**; or

(ii) provide the final information specified in clause 5(a) to (c) to complete the switch; or

(b) *[Revoked]*

(c) request that the switch be withdrawn in accordance with clause 17.

4 Event dates

(1) The losing **trader** must establish **event dates** so that—

(a) no **event date** is more than 10 **business days** after the date on-which the **registry manager**, under clause 22(a), makes ~~the losing **trader** receives~~ written notice ~~from the **registry manager** in accordance with clause 22(a)~~ available to the losing **trader**; and

(b) in any 12 month period at least 50% of the **event dates** established by the losing **trader** are no more than 5 **business days** after the date on which the **registry manager**, under clause 22(a), makes ~~the losing **trader** receives~~ written notice ~~from the **registry manager** in accordance with clause 22(a)~~ available to the losing **trader**.

(2) For the purpose of determining whether it complies with subclause (1)(b), the losing **trader** may disregard every **event date** it has established for an **ICP** for which, ~~when~~ on the date on which the **registry manager**, under clause 22(a), made ~~the losing **trader** received~~ written notice ~~from the **registry manager** under clause 22(a)~~ available to the losing **trader**, the losing **trader** had been responsible for less than 2 months.

…

6 Traders must use same reading

(1) The losing **trader** and the gaining **trader** must both use the same **switch event meter reading** for the **event date** as determined by the following procedure:

(a) if the **switch event meter reading** provided by the losing **trader** differs by less than 200 kWh from a value established by the gaining **trader**, the gaining **trader** must use the losing **trader's switch event meter reading**; or

(b) if the **switch event meter reading** provided by the losing **trader** differs by 200 kWh or more from a value established by the gaining **trader**, the gaining **trader** may dispute the **switch event meter reading**.

(2) Despite subclause (1), subclause (3) applies if—

(a) the losing **trader** trades **electricity** at the **ICP** through a **metering installation** with a submission type of non **half hour** in the **registry**; and

(b) the gaining **trader** will trade **electricity** at the **ICP** through a **metering installation** with a submission type of **half hour** in the **registry**, as a result of the gaining **trader's** arrangement to trade **electricity** with the customer or the **embedded generator**; and

(c) a **switch event meter reading** provided by the losing **trader** under subclause (1) has not been obtained from an **interrogation** of a **certified metering installation** with an AMI flag of Y in the **registry**.

(3) No later than 5 **business days** after the date on which ~~receiving final information from~~ the

(d) on receipt of information about a switch completion in accordance with clauses 3(a)(ii), 5, 10 and 16, the **registry manager** must make ~~give~~ written notice available to the gaining **trader**, the losing **trader**, the **metering equipment provider**, and the relevant **distributor** of the information received.

…

Part 15

…

15.8 Retailer and direct purchaser half hourly metered ICPs monthly kWh information

Using relevant **volume information**, each ~~Each~~ **retailer** and **direct purchaser** (excluding **direct consumers**) must deliver to the **reconciliation manager** the ~~**retailer's** or **direct purchaser's**~~ total monthly quantity of **electricity** ~~**supplied** for~~ consumed at each **half hourly** metered **ICP** for which the **retailer** or **direct purchaser** has provided **submission information** to the **reconciliation manager**, including—

(a) **submission information** for the immediately preceding **consumption period**, by 1600 hours on the 4th **business day** of each **reconciliation period**; and

(b) revised **submission information** provided in accordance with clause 15.4(2), by 1600 hours on the 13th **business day** of each **reconciliation period**.

…

Schedule 15.3

…

3 Historical estimates and forward estimates

(1) Each **reconciliation participant** must, for each **ICP** that has a non **half hour metering installation**, allocate **volume information** derived from **validated meter readings**, **estimated readings** or **permanent estimates**, to **consumption periods** using the techniques described in ~~this~~ clauses 4 to 7 to create **historical estimates** and **forward estimates**.

(2) Each estimate that is a **forward estimate** or an **historical estimate**, must be clearly identified as such.

(3) If a **validated meter reading** is not available for the purpose of clauses 4, 4A, and 5, a **permanent estimate** may be used in place of a **validated meter reading**.

4 Historical estimates with seasonal adjustment

The methodology that must be used by each **reconciliation participant** to prepare an **historical estimate** of **volume information** for each **ICP** when the relevant **seasonal adjustment shape** is available and the **reconciliation participant** is not using an approved **profile** in accordance with clause 4A, is as follows:

(a) if the period between any 2 consecutive **validated meter readings** encompasses an entire **consumption period**, an **historical estimate** must be prepared in accordance with the following formula:

$$HE_{ICP} = \quad kWh_p \times A/B$$

where

HE_{ICP} is the quantity of **electricity** allocated to a **consumption period** for an **ICP**

kWh_P is the difference in kWh between the last **validated meter reading** before the **consumption period** and the 1st **validated meter reading** after the **consumption period**

A is the sum of the **seasonal adjustment shape** values for the **consumption period**

B is the sum of the **seasonal adjustment shape** values for the same time period as is covered by kWh_P as published by the **reconciliation manager**:

(b) if the period between any 2 consecutive **validated meter readings** encompasses the 1st part of a **consumption period** and the period between the 2nd **validated meter reading** and the subsequent **validated meter reading** encompasses the rest of that **consumption period**, an **historical estimate** must be prepared in accordance with the following formula:

$$HE_{ICP} = \quad kWh_{P1} \times A_1/B_1 + kWh_{P2} \times A_2/B_2$$

where

HE_{ICP} is the quantity of **electricity** allocated to a **consumption period** for an **ICP**

kWh_{P1} is the difference in kWh between the +last **validated meter reading** before the **consumption period** and the **validated meter reading** during the **consumption period**

A_1 is the sum of the **seasonal adjustment shape** values for the relevant days in the 1st part of the **consumption period**

B_1 is the sum of the **seasonal adjustment shape** values for the same time period as is covered by kWh_{P1}

kWh_{P2} is the difference in kWh between the first **validated meter reading** during the **consumption period** and the 1st **validated meter reading** after the **consumption period**

A_2 is the sum of the **seasonal adjustment shape** values for the relevant days in the latter part of the **consumption period**

B_2 is the sum of the **seasonal adjustment shape**

values for the same time period as is covered by kWh_{P2}.

4A Historical estimates using approved profile

If the **Authority** has approved a **profile** for the purpose of apportioning **volume information** (in kWh) to part or full **consumption periods**, a **reconciliation participant**—

(a) may use the **profile** despite the relevant **seasonal adjustment shape** being available; and

(b) if it uses the **profile**, must otherwise prepare the **historical estimate** in accordance with the methodology in clause 4.

5 Historical estimates without seasonal adjustment

If a **seasonal adjustment shape** is not available, either due to timing (for the provision of **submission information** by the 4th **business day** of each **reconciliation period**) or for any other reason, and the **reconciliation participant** is not using an approved **profile** under clause 4A, the methodology for preparing an **historical estimate** of **volume information** for each **ICP** must be the same as in clause 4, except that the relevant quantities kWh_{Px} must be prorated as determined by the **reconciliation participant** using its own methodology or on a flat shape basis using the relevant number of days that are—

(a) within the **consumption period**; and

(b) within the period covered by kWh_{Px}.

…

10 Reporting requirements

(1) By 1600 hours on the 13th **business day** of each **reconciliation period**, each **reconciliation participant** must report to the **reconciliation manager** the proportion of **historical estimates** prepared under clauses 4 or 4A, per **NSP** contained within its non **half hour submission information**.

(2) By 1200 hours on the last **business day** of each **reconciliation period**, the **reconciliation manager** must provide to the **Authority** a report of the proportion of **historical estimates** prepared under clause 4 or clause 4A, per **NSP**~~,~~ and per **reconciliation participant**, being used to create non **half hour consumption information** in respect of each **consumption period** being reconciled, and the **Authority** must publish the information.

(3) The proportion of **submission information** per **retailer** per **NSP** that is comprised of **historical estimates** prepared under clause 4 or clause 4A must, unless **exceptional circumstances** exist, be—

(a) at least 80% for revised data provided at the month 3 revision; and

(b) at least 90% for revised data provided at the month 7 revision; and

(c) 100% for revised data provided at the month 14 revision.

…

Schedule 15.4

Reconciliation procedures

...

27 Surveillance reports

The **reconciliation manager** must make the following reports available to the **Authority** and all **participants**:

...

(b) reports by **retailers** ~~for each **balancing area**~~ of the variation between **electricity supplied** as reported by **retailers** (in accordance with clause 17) and **submission information** submitted for reconciliation by **retailers**<u>, specified for each—</u>

<u>(i) **point of connection** to the **grid**; and</u>

<u>(ii) **NSP identifier**; and</u>

<u>(iii) **balancing area**</u>

…

Part 16A

…

16A.13 Participants to give final audit report and compliance plan to the Authority

(1) A **participant** must give the final **audit** report to the **Authority** no later than the date by which the **audit** is due to be completed.

(2) Each **participant** must submit a compliance plan to the **Authority** when it gives a final **audit** report to the **Authority** under subclause (1).

(3) Each <u>**participant** must—</u>

<u>(a) provide the </u>compliance plan and <u>final </u>**audit** report~~be~~ in the **prescribed form**<u>; and</u>

<u>(b) deliver the compliance plan and final **audit** report in the manner specified by the **Authority**</u>.

(4) Each compliance plan must specify—

(a) the actions that the **participant** intends to take to address any breaches or potential breaches of this Code identified in the **audit** report; and

(b) the time frames within which the **participant** intends to complete those actions.

(5) Subclause (2) does not apply if the relevant <u>final </u>**audit** report in relation to a **participant** identifies no breaches or potential breaches of this Code.