Electricity Industry Participation Code

2010

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Code

1 Title

This Code is the Electricity Industry Participation Code 2010.

2 Commencement

In accordance with section 36(1) of the Act, this Code comes into force on 1 November 2010.
Electricity Industry Participation Code 2010

Part 1
Preliminary provisions

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1.1 Interpretation
(1) In this Code, unless the context otherwise requires,—

*Act* means the Electricity Industry Act 2010

*active energy* means the integration over time of the product of voltage, current and the cosine of the phase angle between them, and which is normally measured in kilowatt hours (kWh)

*active meter* means a *meter* used for the measurement of *active energy*

*active power* means the product of voltage, current and the cosine of the phase angle between them, and which is normally measured in kilowatts (kW)

*additional customer compensation scheme* means a scheme operated by a *retailer* under clause 9.26, in addition to the *retailer’s default customer compensation scheme*


*adjustment* means, for the purposes of the definitions of *error compensation, loss compensation*, and Part 10, an operation or process intended to reduce the differences between the values indicated by an instrument and the values realised by a *reference standard* or *working standard* to within a predetermined tolerance, and *adjust* and *adjusted* have corresponding meanings

adjustment clause means a clause in a contract for differences or a fixed-price physical supply contract under which the price or prices of a specified volume of electricity may be adjusted, including an adjustment relating to the Consumer Price Index, the Producers Price Index or any other index.

administrative cost means, in relation to an ancillary service, the significant costs that are incurred by the system operator in relation to the development of ancillary service provision, that are specifically attributable to an ancillary service, and that have been agreed to by the Authority and the system operator.

allocable cost has the meaning set out in clauses 8.55 to 8.58.

alternative ancillary service arrangement means an arrangement between a participant and another participant or other person, or an arrangement involving only a participant, which is authorised by the system operator in accordance with clause 8.48.

ancillary service means black start, over frequency reserve, frequency keeping, instantaneous reserve or voltage support.

ancillary service agent means a person who provides an ancillary service.

ancillary service arrangement means a contract between the system operator and an ancillary service agent for the procurement of ancillary services in accordance with clause 8.45.

annual consumption list means the list published by the reconciliation manager in accordance with clause 13.188.

approved calibration laboratory means the Measurement Standards Laboratory of New Zealand, or a calibration laboratory that has been accredited under the Testing Laboratory Registration Act 1972 to ISO 17025, or an international laboratory that has been recognised by the Chief Metrologist for the specific calibration required.

approved investment means—
(a) an investment approved by the Electricity Commission under section III of part F of the rules before this Code came into force; or
(b) an investment approved by the Commerce Commission under section 54R of the Commerce Act 1986; or
(c) an investment that is permitted under an input methodology determined by the Commerce Commission under section 54S of the Commerce Act 1986.

approved system means the system or systems required to convey information between persons in accordance with this Code, as may be approved from time to time by the Authority.
Electricity Industry Participation Code 2010
Part 1


approved test house means a facility that has been approved by the Authority in accordance with Part 10 to do one or more of the following:
(a) calibrate metering installations or metering components
(b) certify metering installations or metering components

approved test laboratory means a test laboratory that has been accredited under the Standards and Accreditation Act 2015 to ISO 17025 for the specific test required

asset means equipment or plant that is connected to or forms part of the grid and, in the case of Part 8, includes equipment or plant that is intended to become connected to the grid and equipment or plant of an embedded generator
Clause 1.1(1) asset: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

asset capability statement means a statement of capability and operational limitations that applies to specific assets during the normal and abnormal conditions that may arise on the grid, provided to the system operator in accordance with clause 2(5) of Technical Code A of Schedule 8.3

asset owner means a participant who owns an asset used for the generation or conveyance of electricity and a person who operates such asset and, in the case of Part 8, includes a consumer with a point of connection to the grid

asset owner performance obligations and AOPO means a performance obligation specified in subpart 2 of Part 8 that an asset owner must comply with so that the system operator can plan to comply and comply with its principal performance obligations

associated equipment, for the purposes of the definition of distribution network and Part 6, means any equipment that is used, or designed or intended for use, in relation to any works or consumer installation, if such use is for construction, maintenance, or safety purposes and not for purposes that relate directly to the generation, conversion, transformation, conveyance, or use of electricity

assumed co-efficient of variation [Revoked]
at risk HVDC transfer means the quantity of MWh for each trading period calculated in accordance with Tables 1 and 2, where—

\[ \text{INJ}_{HVDC}^{\text{HAY}_t} \] is the electricity injected from the HVDC link into the North Island grid assets at the North Island HVDC injection point in trading period \( t \); and

\[ \text{INJ}_{HVDC}^{\text{BEN}_t} \] is the electricity injected from the HVDC link into the South Island grid assets at the South Island HVDC injection point in trading period \( t \); and

\[ \text{INJ}_{\text{Pole2HAY}}^{\text{HAY}_t} \] is the electricity injected from Pole 2 of the HVDC link into the North Island grid assets at the North Island HVDC injection point in trading period \( t \).

**Table 1:** HVDC northward transfer – if electricity is injected at the North Island HVDC injection point in the relevant trading period

<table>
<thead>
<tr>
<th>HVDC configuration at the beginning of trading period ( t )</th>
<th>At risk HVDC transfer north in trading period ( t ) (expressed in MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pole 1 one half pole only</td>
<td>( \text{INJ}_{HVDC}^{\text{HAY}_t} )</td>
</tr>
<tr>
<td>Pole 2 only</td>
<td>( \text{INJ}_{HVDC}^{\text{HAY}_t} )</td>
</tr>
<tr>
<td>Pole 3 only</td>
<td>( \text{INJ}_{HVDC}^{\text{HAY}_t} )</td>
</tr>
<tr>
<td>Pole 2 and Pole 1 one half pole</td>
<td>( \text{INJ}_{\text{Pole2HAY}}^{\text{HAY}_t} )</td>
</tr>
<tr>
<td>Pole 3 and Pole 2 bipole round power</td>
<td>( \text{INJ}_{HVDC}^{\text{HAY}_t} )</td>
</tr>
<tr>
<td>Pole 3 and Pole 2 bipole not round power</td>
<td>( \max(0, \text{INJ}_{HVDC}^{\text{HAY}_t} - 263) )</td>
</tr>
</tbody>
</table>

**Table 2:** HVDC southward transfer – if electricity is injected at the South Island HVDC injection point in the relevant trading period

<table>
<thead>
<tr>
<th>HVDC configuration at the beginning of trading period ( t )</th>
<th>At risk HVDC transfer south in trading period ( t ) (expressed in MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pole 2 only</td>
<td>( \text{INJ}_{HVDC}^{\text{BEN}_t} )</td>
</tr>
<tr>
<td>Pole 3 only</td>
<td>( \text{INJ}_{HVDC}^{\text{BEN}_t} )</td>
</tr>
<tr>
<td>Pole 3 and Pole 2 bipole round power</td>
<td>( \text{INJ}_{HVDC}^{\text{BEN}_t} )</td>
</tr>
<tr>
<td>Pole 3 and Pole 2 bipole not round power</td>
<td>( \max(0, \text{INJ}_{HVDC}^{\text{BEN}_t} - 263) )</td>
</tr>
</tbody>
</table>

Clause 1.1(1) at risk HVDC transfer: substituted, on 1 July 2012, by clause 4(1) of the Electricity Industry Participation (HVDC Pole 3 Minor Amendments) Code Amendment 2012.

ATH means a person who is approved under Schedule 10.3 to operate an approved test house

Clause 1.1(1) ATH: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

auction means a must-run dispatch auction conducted by the clearing manager under subpart 3 of Part 13

auction bid means a bid made for an auction under clauses 13.117 to 13.130
**auction revenue** means, for a **generator**, the amount owing by the **generator** in accordance with clause 13.112(2) and, for a **purchaser**, the amount owing to the **purchaser** in accordance with clause 13.111


**auction right** means the right (but not the obligation) to offer for sale a specified quantity of **electricity** to the **clearing manager** at 0 price in accordance with clause 13.116(1)

**audit** means a process of inspection of the facilities, processes, procedures, and other relevant items, to confirm compliance with this Code, and **audited** has a corresponding meaning

**auditor** means,—

(a) for the purposes of Parts 10, 11, 15 and 16A, a person—

(i) approved or appointed by the **Authority** to carry out an **audit**; or

(ii) the **Authority**, if the **Authority** carries out an **audit** itself; and

(b) for all other Parts of this Code, a person carrying out an **audit**

Clause 1.1(1) **auditor**: replaced, on 1 June 2017, by clause 4(1) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

**Authority** has the meaning given to it by section 5 of the Act

**automatic control plant** means any hydro **generating plant** that has a pre-programmed generation profile and an automatic override if uncontrollable water inflows change

**automatic under-frequency load shedding** means a form of **extended reserve** in which electrical load is automatically shed when frequency falls below a preset frequency, or falls at a rate, specified by the **system operator** in the relevant **extended reserve provider's statement of extended reserve obligations**

Clause 1.1(1) **automatic under-frequency load shedding**: amended, on 7 August 2014, by clause 4(1) of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

**availability cost** means a cost (other than an **administrative cost**), incurred by the **system operator** in purchasing **instantaneous reserve** and providing that

**instantaneous reserve** for a **trading period**, and includes—

(a) payments made by the **system operator** for that **trading period** under contracts that secure the availability of **instantaneous reserves**; and

(b) the annual and variable costs (including any constrained-on costs) incurred by the **system operator** under any other contracts allocated by the **system operator** to that **trading period**; less

(c) the costs of **instantaneous reserves** procured as a direct result of a **generator** being granted a **dispensation** under clause 8.31(1); and

(d) **instantaneous reserve constrained on compensation** calculated in accordance with clause 13.212(6)

**back office** means a part of an **interrogation** system—

(a) that sends or receives information to or from a **metering installation**; and

(b) stores the information in a form that can be made available at the **services access interface** to another person
Clause 1.1(1) **back office**: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

**back-up metering information** means **half-hour metering information** from any alternative **metering installation** that measures the same flow of **electricity** at the relevant **grid exit points** and **grid injection points** as would have been given under clause 13.166(1)(b)

**back up protection system** means a protection system—
(a) that **electrically disconnects** faulted **assets** from the **grid** because a **main protection system** or a **circuit breaker** has failed to **electrically disconnect** a faulted **asset** from the **grid** in the allocated time; and
(b) that may **electrically disconnect** non-faulted **assets** as well as a faulted **asset**

Clause 1.1(1) **back up protection system**: amended, on 5 October 2017, by clause 4(6)(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

**balancing area** means, in relation to any particular **ICP**,—
(a) the **embedded network**; or
(b) that part of the relevant **local network** owned by 1 **network owner**—having 1 or more **NSPs**, to which that ICP is **electrically connected** from time to time under normal circumstances

Clause 1.1(1) **balancing area**: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.


**bank** means a registered bank within the meaning of the Reserve Bank of New Zealand Act 1989 that is carrying on in New Zealand the business of banking

**bank bill bid rate** means the rate per annum (rounded upwards to 2 decimal places) displayed at or about 10.45am on the Reuters Screen on page BKBM (or its successor or equivalent page) on the relevant date as the bank bill “settlement” bid rate for bank bills having a tenor of 1 month, provided that if such a rate is not available, **bank bill bid rate** means the rate determined by the **clearing manager** to be the nearest practicable equivalent

**base case** means a base case **published** by the **Authority** under clause 13.236D

Clause 1.1(1) **base case**: inserted, on 1 December 2011, by clause 4 of the Electricity Industry Participation Code (Spot Price Risk Disclosure) Amendment 2011.


**benchmark agreement** means the agreement for the connection to and/or use of the **grid**, that is incorporated by reference in this Code under clause 12.34

Clause 1.1(1) **benchmark agreement**: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.


**benefit to the public** means public benefit net of any costs and detriments, including those detriments associated with a lessening of competition as those concepts are applied under the Commerce Act 1986

**bid**,—
(a) **means**—
(i) a nominated bid; 
(ii) a difference bid; and 
(b) includes a bid revised in accordance with clause 13.19A or 13.19B 

(c) [Revoked]

Clause 1.1(1) bid: substituted, on 28 June 2012, by clause 4(b) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clause 1.1(1) bid paragraph (c): revoked, on 29 June 2017, by clause 4(1)(b) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.

binding constraint means a constraint that is likely to cause a significant difference between the price at 1 node and the price at another node

billing period means a period of 1 calendar month

black start means an ancillary service required to enable a generating unit isolated from the grid to be—
(a) made live, as defined in the Electricity (Safety) Regulations 2010; and 
(b) electrically connected to the grid

Clause 1.1(1) black start: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

block dispatch group means a group of generating stations on 1 continuous water course, which is the subject of an agreement between the system operator and a generator under clause 13.60

block security constraint means any of the following:
(a) a constraint 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 the offered capacity of a grid owner’s network to convey electricity between generating stations constituting a block dispatch group
(c) 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—

and, in paragraphs (b) and (c), such a limitation in the offered capacity being the offered capacity of a grid owner’s network or a grid system security constraint as determined by the system operator in accordance with Part 8

bona fide physical reason includes,—
(a) in relation to a generator, or a purchaser, or an ancillary service agent or a grid owner, a situation where personnel or plant safety is at risk; and 
(b) in relation to a generator or an ancillary service agent providing partly loaded spinning reserve, tail water depressed reserve or frequency keeping,—

(i) a reasonably unforeseeable change in generating capability, reserve capability, or frequency keeping capability (as the case may be) from an item of generating plant that is the subject of an existing offer, reserve
offer, or offer to provide frequency keeping by that generator or ancillary service agent; or

(ii) a reasonably unforeseeable change in the level of expected uncontrollable water inflows into the head pond of a hydro station that is the subject of an existing offer, reserve offer, or offer to provide frequency keeping by that generator or ancillary service agent; or

(iii) a reasonably unforeseeable change in circumstances such that the generator or ancillary service agent will breach any consent held by it under the Resource Management Act 1991; or

(iv) a reasonably unforeseeable physical infeasibility that arises from a price-responsive schedule, a non-response schedule, or a dispatch schedule; and

(c) in relation to a purchaser, or an ancillary service agent providing interruptible load,—

(i) a reasonably unforeseeable full or partial loss of demand or reserve capability (as the case may be) at a grid exit point that is the subject of an existing bid or reserve offer by the purchaser or the ancillary service agent; or

(ii) a reasonably unforeseeable change in circumstances such that the purchaser or ancillary service agent will breach any consent held by it under the Resource Management Act 1991; or

(iii) a reasonably unforeseeable full or partial loss of generating capability from an item of generating plant owned by, or the subject of a supply contract with, that purchaser during the relevant trading periods; and

(d) in relation to a grid owner, a reasonably unforeseeable loss of full or partial capacity on transmission plant forming part of the grid

Clause 1.1(1) bona fide physical reason paragraph(b)(iv): substituted, on 28 June 2012, by clause 4(c)(i) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 1.1(1) bona fide physical reason paragraph(c)and(c)(i): amended, on 28 June 2012, by clause 4(c)(ii)and(iii) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

bound, in relation to a transmission security constraint, means that the flow of electricity through 1 or more transmission lines or transformers is equal to or greater than the transmission security constraint applied to those transmission lines or transformers, and bind has a corresponding meaning


branch means an electrical link between—

(a) 2 or more nodes; or

(b) a node and a point of connection to the grid

business means the business carried out as a participant

business day means,—

(a) for the purposes of Part 6, any day of the week other than Saturday, Sunday, or a public holiday within the meaning of the Holidays Act 2003; and

(b) for the rest of the Code, any day of the week except Saturdays, Sundays, national
holidays and any other day from time to time declared by the Authority not to be a business day by notice to each registered participant


buyer, for the purposes of subpart 5 of Part 13, means—
(a) in respect of a contract for differences, the fixed-price payer, being the party obliged to make payments at a fixed price from time to time during the term of the contract; or
(b) in respect of a fixed-price physical supply contract, the purchaser of electricity; or
(c) in respect of an options contract, either—
(i) the party paying the premium; or
(ii) if there is no premium, the party who agrees to be the buyer for the purposes of subpart 5 of Part 13; or
(iii) if neither party agrees to be the buyer, the party whose name is the first alphabetically

calibration means the set of operations that establishes, under specified conditions, the relationship between the values indicated by the measuring system and the corresponding values of a quantity realised by a reference standard or working standard, and calibrate and calibrated have corresponding meanings

calibration report means a report that contains the results of all calibration tests carried out on—
(a) a metering installation; or
(b) a metering component in a metering installation; or
(c) a working standard

call [Revoked]

capacity [Revoked]

capacity reserve means—
(a) demand that can be decreased for the purpose of adjusting a constraint; or
(b) generation that can be increased or decreased for the purpose of adjusting a constraint

cash deposit means the cash deposited in cleared funds by a participant in accordance with clause 2 of Schedule 14A.1, and includes any interest under clause 14A.14 that has not been paid out
cash deposit accounts means the trust accounts established by the clearing manager in accordance with clause 14A.11

cash interest rate [Revoked]

category 1 metering installation means a metering installation that has the required defining characteristics for a metering installation of that category in Table 1 of Schedule 10.1
Clause 1.1(1) category 1 metering installation: inserted, on 1 December 2011, by clause 4(a) of the Electricity Industry Participation Code (Distributor Use-of-System Agreements and Distributor Tariffs) Amendment 2011.
Clause 1.1(1) category 1 metering installation: substituted, on 29 August 2013, by clause 4(2)(c) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

category 2 metering installation means a metering installation that has the required defining characteristics for a metering installation of that category in Table 1 of Schedule 10.1
Clause 1.1(1) category 2 metering installation: inserted, on 1 December 2011, by clause 4(a) of the Electricity Industry Participation Code (Distributor Use-of-System Agreements and Distributor Tariffs) Amendment 2011.

causers, in relation to an under-frequency event, means—
(a) if the under-frequency event is caused by an interruption or reduction of electricity from a single generator’s or grid owner’s asset or assets, the generator or grid owner; unless—
   (i) the under-frequency event is caused by an interruption or reduction of electricity from a single generator’s asset or assets but another generator’s or a grid owner’s act or omission or property causes the interruption or reduction of electricity, in which case the other generator or the grid owner is the causer; or
   (ii) the under-frequency event is caused by an interruption or reduction of electricity from a single grid owner’s asset or assets but a generator’s or another grid owner’s act or omission or property causes the interruption or reduction of electricity, in which case the generator or other grid owner is the causer; or
(b) if the under-frequency event is caused by more than 1 interruption or reduction of electricity, the generator or grid owner who, in accordance with paragraph (a), would be the causer of the under-frequency event if it had been caused by the first in time of the interruption or reduction of electricity; but
(c) if an interruption or reduction of electricity occurs in order to comply with this Code, the interruption or reduction of electricity must be disregarded for the purposes of determining the causer of the under-frequency event

centralised data set [Revoked]

certification means—
(a) if applied to a metering installation, confirmation that the metering installation meets the requirements of this Code; and
(b) if applied to a metering component, confirmation that the metering component meets the requirements of this Code; and
(c) if applied to a reconciliation participant, confirmation that the reconciliation participant has met the requirements of Schedule 15.1


certification report means a report that contains—
(a) the calibration report or calibration reports:
(b) all other information relevant to the certification of a metering installation or a metering component required under Part 10


certification sticker means a sticker that is valid for a specific period and that is attached—
(a) to a metering installation, confirming that the metering installation has been certified by an ATH under Schedule 10.7; or
(b) to a metering component, confirming that the metering component has been certified by an ATH under Schedule 10.8

Clause 1.1(1) certification sticker: substituted, on 29 August 2013, by clause 4(2)(g) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

certified means having achieved certification
certify means to carry out a certification

chargeable capacity means the capacity that the distributor may charge for, but that may not be the actual installed capacity at the relevant ICP

check metering information means half-hour metering information from a meter, located at the grid exit point or grid injection point that gives equivalent information, but not necessarily of the same accuracy, as the relevant grid exit point or grid injection point meter

circuit branch means a branch that is not a transformer branch or the HVDC link
circuit breaker means a switching device capable of making, carrying and breaking currents under normal circuit conditions, and capable of making, carrying for a specified time and breaking currents under specified abnormal conditions (such as a short circuit)
circuit breaker failure protection system means a protection system that—
(a) operates because a circuit breaker has failed to electrically disconnect a faulted asset from the grid in the allocated time; and
(b) may electrically disconnect non-faulted assets from the grid as well as a faulted asset


class A approved test house [Revoked]
Clause 1.1(1) class A approved test house: revoked, on 29 August 2013, by clause 4(3) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

class A ATH means an ATH who is approved under clause 3 of Schedule 10.3
Clause 1.1(1) class A ATH: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

class B approved test house [Revoked]
Clause 1.1(1) class B approved test house: revoked, on 29 August 2013, by clause 4(3) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

class B ATH means an ATH who is approved under clause 4 of Schedule 10.3
Clause 1.1(1) class B ATH: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

cleared funds, in relation to a business day, means funds that are immediately available for disbursement on that day

clearing auction price means the lowest successful price bid at an auction in dollars per MW per half hour

clearing manager has the meaning given to it in section 5 of the Act

Code information means all information that is supplied by a participant or group of participants, under this Code (other than excluded Code information and information that is supplied under Parts 2 to 6 and 9 of this Code)

code of practice means a code of practice issued under this Code

co-efficient of variation means the ratio of the standard deviation to the mean of the distribution for the random variable under consideration

co-generator [Revoked]

commissioning means to verify the correct operation of—
(a) an asset; or
(b) a point of connection; or
(c) metering equipment installed in a metering installation,—

and commissioned has a corresponding meaning
Clause 1.1(1) commissioning: amended, on 29 August 2013, by clause 4(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

commissioning report [Revoked]
Clause 1.1(1) commissioning report: revoked, on 29 August 2013, by clause 4(3) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

committed projects means transmission augmentation projects and non-transmission projects that are reasonably likely to proceed in a similar timeframe for which the assessment of costs and benefits under a net benefits test set out in Part 12 is undertaken, and in relation to which either—
(a) all of the following are satisfied:
   (i) the proponent has obtained all required planning consents, construction approvals, and licences, and fulfilled any other regulatory requirement that must be met before commencing construction:
   (ii) construction has commenced or a firm commencement date for construction has been set:
   (iii) the proponent has acquired or executed an agreement to acquire land (or commenced legal proceedings to acquire land), or has executed an agreement for the leasing of land, for the purposes of construction:
   (iv) contracts for supply and construction of the major components of the plant and equipment (including any generating units, turbines, boilers, transmission towers, conductors, termination station equipment) have been executed (i.e. all the necessary formal legal requirements have been observed to make the contract valid and complete):
   (v) contracts for the financing of the project, including any debt plans, have been executed (i.e. all the necessary formal legal requirements have been observed to make the contract valid and complete); or
(b) in the case of transmission augmentation projects, the project is an approved investment

common quality means those elements of quality of electricity conveyed across the grid that cannot be technically or commercially isolated to an identifiable person or group of persons

communication means, for the purposes of Part 10, the electronic transfer of information, or instructions, to or from a metering installation
Clause 1.1(1) communication: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

communication equipment means a device, used for communication, in—
   (a) a metering installation; or
   (b) a back office
Clause 1.1(1) communication equipment: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

comparative recertification means recertification of a category 2 metering installation under clause 12(3) of Schedule 10.7

compensation factor means 1 of the following factors used to compensate for errors, losses, or ratios within a metering installation, to produce accurate volume information:
   (a) error compensation:
   (b) loss compensation:
   (c) ratio compensation
Clause 1.1(1) compensation factor: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

complete [Revoked]

confidential information, for the purposes of Schedule 6.2, means all data and other information of a confidential nature provided by 1 party (A) to another party (B) under the regulated terms, but excludes—
(a) information known to B before the date it was provided by B to A and that was not obtained directly or indirectly from A; and
(b) information obtained bona fide from another person who is in lawful possession of the information and who did not acquire the information directly or indirectly from A under an obligation of confidence

configuration, in relation to the HVDC link, means the following modes of operation of the HVDC link:
(a) Pole 1 one half pole only:
(b) Pole 2 only:
(c) Pole 3 only:
(d) Pole 2 and Pole 1 one half pole:
(e) Pole 3 and Pole 2 bipole round power:
(f) Pole 3 and Pole 2 bipole not round power

conforming GXP means a GXP that—
(a) has been determined by the Authority to be a conforming GXP under clause 13.27A or 13.27B(4); or
(b) is deemed to be a conforming GXP under clause 13.27F

congestion management policy means the policies, clauses, or conditions referred to in clause 6.3(2)(d)

connect[Revoked]
Clause 1.1(1) connect: amended, on 23 February 2015, by clause 4(2) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

connected asset owner means a direct consumer, or a distributor in its capacity as the owner or operator of a local network

connection and operation standards, in relation to a distributor or distributed generation,—
(a) means requirements, as amended from time to time by the distributor, that—
(i) are set out in written policies and standards of the distributor; and
(ii) relate to connecting distributed generation to a distribution network or to a consumer installation that is connected to a distribution network, and the operation of the distribution network, including requirements relating to the planning, design, construction, testing, inspection, and operation of distributed generation that is, or is proposed to be, connected; and
(iii) are made publicly available in accordance with clause 6.3; and
(iv) reflect, or are consistent with, reasonable and prudent operating practice; and

(b) includes the following, as amended from time to time by the distributor:

(i) the distributor's congestion management policy, as referred to in clause 6.3(2)(d); and
(ii) the distributor's emergency response policies; and
(iii) the distributor's safety standards

Clause 1.1(1) connection and operation standards: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

connection asset, for the purposes of subparts 2, 6 and 7 of Part 12, has the meaning set out in the transmission pricing methodology

Connection Code means the Connection Code that is incorporated by reference in this Code under clause 12.26

connection location means a substation or other location at which lines, equipment and plant owned or managed by a designated transmission customer that are directly related to a point of connection, and that are used for the consumption, conveyance, or generation of electricity, are directly connected to the grid

Clause 1.1(1) connection location: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

constrained off amounts means the amounts calculated by the clearing manager under clauses 13.194 to 13.196

constrained off compensation means either—
(a) constrained off amounts owing to a dispatched purchaser under clause 13.201A; or
(b) constrained off amounts owing to the clearing manager under clause 13.201A by purchasers


constrained off situation means a situation as defined in clause 13.192

constrained on amounts means the amounts calculated by the clearing manager under clauses 13.204 and 13.205

constrained on compensation means, as the case may be,—
(a) the constrained on amounts owing to—
(i) a generator under clause 13.212(1)(a); or
(ii) an ancillary service agent under clause 13.212(1)(a); or
(iii) a dispatched purchaser under clause 13.212(1)(b); or
(b) the constrained on amounts owing by—
   (i) the system operator under clause 13.212(2); or
   (ii) a purchaser under clause 13.212(5)

Clause 1.1(1) constrained on compensation: substituted, on 15 May 2014, by clause 5(2) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

constrained on situation means a situation as defined in clause 13.202

constraint means a limitation in the capacity of the grid to convey electricity caused by limitations in capability of available assets forming the grid or limitations in the performance of the integrated power system

constraint price, in relation to a transmission security constraint, means the amount in dollars and cents per MW per hour by which the objective function described in clause 8 of schedule 13.3 is increased by relaxing the transmission security constraint by a very small amount

construct, for the purposes of the definition of associated equipment and Part 6, includes to erect, to lay, and to place, and construction has a corresponding meaning

consumer means a person who is supplied electricity for consumption, and includes a distributor, a retailer or a generator if the distributor, or the retailer or the generator is supplied with electricity for its own consumption

consumer installation, for the purposes of the definition of associated equipment and Part 6, means—
(a) all fittings that are part of a system for conveying electricity from a consumer’s point of supply to any point from which electricity conveyed through that system may be consumed; and
(b) includes any fittings that are used, or designed or intended for use, by any person in, or in relation to, the generation of electricity—
   (i) for that person’s use and not for supply to any other person; or
   (ii) so that electricity can be injected into a distribution network; but
(c) does not include any appliance that uses, or is designed or intended to use, electricity, whether or not it also uses, or is designed or intended to use, any other form of energy
Clause 1.1(1) consumer installation: substituted, on 23 February 2015, by clause 4(4)(a) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

consumption information means the information describing the quantity of electricity conveyed during the period for which the information is required, which may be directly measured or calculated from information obtained from a metering installation, or calculated in accordance with this Code
consumption pattern means, for the purposes of this Part and Schedule 15.5, the shape of the half hourly consumption

consumption period means a calendar month during which electricity is supplied to consumers (and conversely produced by generators)

contract for differences, for the purposes of subpart 5 of Part 13, means a financial derivative contract—
(a) under which 1 or both parties makes or may make a payment to the other party; and
(b) in which the payment to be made depends on, or is derived from, the price of a specified quantity of electricity at a particular time; and
(c) that may provide a means for the risk to 1 or both parties of an increase or decrease in the price of electricity to be reduced or eliminated; and
(d) that either—
   (i) relates to a quantity of electricity that equals or exceeds 0.25 MW of electricity; or
   (ii) is entered into through a derivatives exchange, being a market in which parties trade standardised financial derivative contracts, and contracts containing the right to buy or sell standardised financial derivative contracts, with a central counterparty

contract price means, in respect of a risk management contract, a single price that has, in accordance with clause 13.220, been calculated, time weighted, adjusted to a location factor for the relevant grid zone area, and corrected for losses, for the purposes of subpart 5 of Part 13

contract price schedule means, in respect of a risk management contract, a price or series of prices to be paid under that contract in respect of specified times or amounts and at a single location

contract specifications means specifications prescribing the specific terms of, and terms of trading in, each class of contract that may from time to time be traded on a market under this Code

control device means a device in a metering installation that controls either or both of the following:
(a) electricity—
   (i) conveyed through the metering installation; and
   (ii) used to satisfy controllable load:
(b) a meter register in the metering installation

controller means,—
(a) in relation to a company,—
   (i) any person in accordance with whose directions and instructions the persons
occupying the position of directors of the company are accustomed to act (but disregarding advice given in a professional capacity); or

(ii) any person who is entitled to exercise, or control the exercise of, 50% or more of the voting power at any general meeting of the company or of another company of which the company is a subsidiary; and

(b) in relation to an unincorporated body of persons,—

(i) any person in accordance with whose directions and instructions the officers of the body are accustomed to act (but disregarding advice given in a professional capacity); or

(ii) any person who is entitled to exercise, or control the exercise of, 50% or more of the voting power on any resolution of the body;

(c) in relation to any person, any person who has the power to appoint or remove a majority of the participants of the governing body of that person or otherwise controls or has the power to control the affairs or policies of that person,—

and control and controlled have corresponding meanings. 

control room means the location at which asset owners have facilities to receive operational instructions from the system operator and to act on those instructions.

core grid means the assets that form part of the core grid as specified in the core grid determination.

core grid determination means the determination specifying the assets forming part of the core grid, developed in accordance with clauses 12.63 to 12.69, including variations.

customer [Revoked]


customer compensation scheme means a default customer compensation scheme or an additional customer compensation scheme


data logger [Revoked]


data storage device means a device in a metering installation, whether or not integral to the meter, that—

(a) electronically stores data and event logs used to provide information for the purposes of Part 15; and

(b) makes the data and event logs available during an interrogation

Clause 1.1(1) data storage device: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.
**declaration date** means the date, nominated by the **profile applicant**, on which the **Authority** must, for a particular **profile**, give written notice to every **registered participant** of the information set out in clause 13 of Schedule 15.5 for that **profile**


**decommissioning** means—

(a) the permanent removal from service of—

(i) an **asset**; or

(ii) a **point of connection**; or

(iii) a **metering installation** associated with a **point of connection**; or

(b) for the purposes of Parts 11 and 15, the permanent removal of a **point of connection** by—

(i) permanently removing an **electrical installation** associated with the **point of connection**; or

(ii) changing the allocation of electrical loads between **points of connection** with the effect of making the **point of connection** obsolete; or

(iii) in the case of a distributor-only ICP for an **embedded network**, the **embedded network** ceasing to exist.

and **decommission** and **decommissioned** have corresponding meanings.

Clause 1.1(1) **decommissioning**: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.


**de-energisation [Revoked]**

Clause 1.1(1) **de-energisation**: amended, on 29 August 2013, by clause 4(2)(i) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.


Clause 1.1(1) **de-energisation**: revoked, on 5 October 2017, by clause 4(60) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

**de-energise [Revoked]**

Clause 1.1(1) **de-energise**: inserted, on 29 August 2013, by clause 4(3) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

Clause 1.1(1) **de-energise**: revoked, on 1 February 2016, by clause 4(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

**default customer compensation scheme** means a scheme that complies with clause 9.24

Clause 1.1(1) **default customer compensation scheme**: inserted, on 1 April 2011, by clause 4(1) of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

**default interest rate** means the **bank bill bid rate** plus 5% per annum

**demand** means the rate of consumption of electrical energy

**designated transmission customers** means **participants** who are required to enter into **transmission agreements** with **Transpower** under subpart 2 of Part 12

**difference bid** means the information that a **purchaser** submits to the **system operator** under clause 13.7AA to indicate a reasonable estimate of an increase or decrease in the **purchaser's usual non-dispatch-capable load** purchased at a **conforming GXP**

Clause 1.1(1) **difference bid**: inserted, on 28 June 2012, by clause 4(a) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clause 1.1(1) difference bid: substituted, on 15 May 2014, by clause 5(2) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.


direct consumer means a consumer with a point of connection to the grid

direct purchaser means a consumer who purchases, or agrees to purchase, electricity directly from the clearing manager for its own consumption at a point of connection

disclosed [Revoked]

disclosing participant means any of the following:
(a) a person who consumes electricity that is conveyed to the person directly from the national grid:
(b) a person who buys electricity from the clearing manager
Clause 1.1(1) disclosing participant: inserted, on 1 December 2011, by clause 4 of the Electricity Industry Participation Code (Spot Price Risk Disclosure) Amendment 2011.

disclosure information, in relation to a participant, means information that—
(a) is about the participant; and
(b) is held by the participant; and
(c) the participant expects, or ought reasonably to expect, if made available to the public, will have a material impact on prices in the wholesale market
Clause 1.1(1) disclosure information: inserted, on 1 October 2013, by clause 4(1) of the Electricity Industry Participation (Disclosure Obligations) Code Amendment 2013.

disconnected [Revoked]
Clause 1.1(1) disconnected: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

dispatch means the process of—
(a) pre-dispatch scheduling, to match expected supply with expected demand, and to allocate ancillary service offers and transmission offers to match expected grid conditions; and
(b) rescheduling to meet forecast demand; and
(c) issuing instructions based on the dispatch schedule and the real-time conditions to manage resources to meet the actual demand,—
and dispatching has a corresponding meaning
Clause 1.1(1) dispatch paragraphs (a) and (c): amended, on 28 June 2012, by clause 4(d) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

dispatch arc flows [Revoked]
Clause 1.1(1) dispatch arc flows: revoked, on 28 June 2012, by clause 4(i) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

dispatch group constraint arc flows [Revoked]
Clause 1.1(1) dispatch group constraint arc flows: revoked, on 28 June 2012, by clause 4(i) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
**dispatch instruction** means an instruction issued by the **system operator** under clause 13.72(1)

Clause 1.1(1) **dispatch instruction**: substituted, on 15 May 2014, by clause 5(2) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

**dispatch objective** means the objective defined in clause 13.57

**dispatch prices** [Revoked]

Clause 1.1(1) **dispatch prices**: revoked, on 28 June 2012, by clause 4(i) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

**dispatch quantities** [Revoked]

Clause 1.1(1) **dispatch quantities**: revoked, on 28 June 2012, by clause 4(i) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

**dispatch schedule** means the schedule produced by the **system operator** under clause 13.69A

Clause 1.1(1) **dispatch schedule**: substituted, on 15 May 2014, by clause 5(2) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

**dispatchable load information** means the **volume information**—

(a) of each **dispatch-capable load station** for each **trading period** in a **consumption period**; and

(b) that is—

(i) prepared under clause 15.5A or 15.5B; and

(ii) aggregated and rounded in accordance with clause 15.5C

Clause 1.1(1) **dispatchable load information**: inserted, on 15 May 2014, by clause 5(1) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

**dispatchable load purchaser** means a **purchaser** that purchases **electricity** for a **dispatch-capable load station**

Clause 1.1(1) **dispatchable load purchaser**: inserted, on 15 May 2014, by clause 5(1) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

**dispatch-capable load station** means a device or a group of devices approved as a **dispatch-capable load station** under clause 13.3A

Clause 1.1(1) **dispatch-capable load station**: inserted, on 15 May 2014, by clause 5(1) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

**dispatch-capable load station identifier** means a unique code—

(a) assigned to a **dispatch-capable load station** under clause 6(2) of Schedule 13.8; and

(b) that is used to identify the **dispatch-capable load station**

Clause 1.1(1) **dispatch-capable load station identifier**: inserted, on 15 May 2014, by clause 5(1) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

**dispatched purchaser** means a **dispatchable load purchaser**—

(a) issued with a **dispatch instruction** under clause 13.72(1)(b) for 1 or more **dispatch-capable load stations**; or

(b) issued with a **dispatch instruction** in accordance with backup procedures under clause 13.81(2) for 1 or more **dispatch-capable load stations**

Clause 1.1(1) **dispatched purchaser**: inserted, on 15 May 2014, by clause 5(1) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

**dispensation** means an exclusion from compliance with an **AOPO** or **technical code** granted by the **system operator** in accordance with the process set out in clauses 8.29 to 8.31
distributed generation means generating plant that is connected, or that a distributed generator proposes to connect, to a distribution network or to a consumer installation that is connected to a distribution network, but does not include—
(a) generating plant that is connected, or that a participant proposes to connect, to a distribution network and that is operated by a distributor for the purpose of maintaining or restoring the provision of electricity to part or all of the distributor’s distribution network—
   (i) as a result of a planned distribution network outage; or
   (ii) as a result of an unplanned distribution network outage; or
   (iii) during a period when the distribution network capacity would otherwise be exceeded on part or all of the distribution network; or
(b) generating plant that is only momentarily synchronised, or that a participant proposes only to momentarily synchronise, with the distribution network for the purpose of switching operations to start or stop the generating plant

Clause 1.1(1) distributed generation: substituted, on 23 February 2015, by clause 4(4)(b) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.


distributed unmetered load means unmetered load with a single profile supplied across more than 1 point of connection to either 1 customer of a retailer or to 1 direct purchaser


distribution has the meaning given to it by section 5 of the Act


distribution network means the electricity lines, and associated equipment, owned or operated by a distributor


distribution network capacity means the capacity of a distribution network to convey electricity under a range of load and generation conditions in accordance with reasonable and prudent operating practice


distributor has the meaning given to it by section 5 of the Act

**distributor installation details** means any information, additional to **price category** and **chargeable capacity**, that may be used to calculate line charges applicable to an **ICP**.

**distributor kvar reference node** means a notional node that represents a group of **grid exit points** within a **zone** for which a **distributor** nominates peak demand in kvar, and for which the individual kvar quantities measured at the individual **grid exit points** within the group are aggregated for **voltage support** charging purposes, as approved by the **system operator** (such approval not to be unreasonably withheld).

**document**, for the purposes of paragraph (b) of the definition of **publish**, and Parts 2 and 6, has the meaning given to it in section 2(1) of the Official Information Act 1982.

Clause 1.1(1) **document**: amended, on 16 December 2013, by clause 4(3)(a) and (b) of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.

**domestic consumer** means a person who acquires **electricity** for personal, domestic or household use or consumption and does not acquire **electricity** or hold himself or herself out as acquiring **electricity** for the purpose of resupplying it in trade or consuming it in the course of production or manufacture.

**draft policy statement** means a document provided for in clause 8.10A(2), 8.11A(1), or 8.12A(1).


**draft procurement plan** means a document provided for in clause 8.42A(2), 8.43A(1), or 8.44A(1).


**effective date**, for the purposes of subpart 5 of Part 13, means the date of the first **trading period** to which a **risk management contract** applies.

**EIEP** means an electricity information exchange protocol that sets out standard formats for the exchange or provision of information.

Clause 1.1(1) **EIEP**: inserted, on 16 December 2013, by clause 4(a) of the Electricity Industry Participation (Electricity Information Exchange Protocols) Code Amendment 2013.


**EIEP12 [Revoked]**

Clause 1.1(1) **EIEP12**: inserted, on 1 December 2011, by clause 4(a) of the Electricity Industry Participation Code (Distributor Use-of-System Agreements and Distributor Tariffs) Amendment 2011.

Clause 1.1(1) **EIEP12**: revoked, on 16 December 2013, by clause 4(b) of the Electricity Industry Participation (Electricity Information Exchange Protocols) Amendment 2013.

**electrical installation** means,—

(a) **[revoked]**

(b) all fittings that form part of a system for conveying **electricity** at any point from an **ICP** to any point from which **electricity** conveyed through that system may be consumed (including any fittings that are used or designed or intended for use by any person in, or in relation to, the generation of **electricity** for that person’s use and not for supply to any other person), but does not include any electrical appliance.
Clause 1.1(1) electrically connect means to operate a device so that electricity is able to flow, including through a point of connection, and electrically connected, electrically connecting, electrical connection, and similar phrases have corresponding meanings.


electrically disconnect means to operate a device so that electricity is unable to flow, including through a point of connection, and electrically disconnected, electrically disconnecting, electrical disconnection, and similar phrases have corresponding meanings.


electricity means electrical energy measured in kilowatt-hours (kWh).

electricity supplied means, for any particular period, the information relating to the quantities of electricity supplied by retailers across points of connection to consumers, sourced directly from the retailer’s financial records, including quantities—

(a) that are metered or unmetered; and
(b) supplied through normal customer supply and billing arrangements; and
(c) supplied under sponsorship arrangements; and
(d) supplied under any other arrangement.


embedded generating station means 1 or more generating units that are directly connected to a local network or an embedded network and that injects into a local network or an embedded network at a single point of injection.

Clause 1.1(1) embedded generating station: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.


embedded generator means a generator who owns or operates 1 or more embedded generating stations.

embedded network means a system of lines, substations, and other works, used primarily for the conveyance of electricity, that—

(a) is indirectly connected to the grid through 1 or more other networks; and
(b) has 1 or more ICP identifiers recorded in the registry as being connected to it.


emergency management policy means the emergency management policy that is incorporated by reference in this Code under clause 7.4

EMP departure situation means any situation in which the system operator believes on reasonable grounds that complying with the emergency management policy will not—

(a) adequately mitigate an emergency situation; or
(b) minimise risk to public safety or significant damage to assets


end date, for the purposes of subpart 5 of Part 13, means the date of the final trading period to which the risk management contract applies

equivalence arrangement means an arrangement put in place in accordance with the process set out in clauses 8.29 and 8.30

equivalent day means the day of a previous week corresponding to the day for which an initial estimate or final estimate is required to be made. However, if the day is a national holiday, the equivalent day will be deemed to be the previous Sunday. If the day for which an initial estimate is required to be made is a business day, but the corresponding day of the previous week is a national holiday, the equivalent day is deemed to be the next earlier corresponding day that is not a national holiday

error claimant means a person who—

(a) considers that prices contain a pricing error; and
(b) claims, in accordance with subpart 4 of Part 13, that a pricing error has occurred

equivalent day means the day of a previous week corresponding to the day for which an initial estimate or final estimate is required to be made. However, if the day is a national holiday, the equivalent day will be deemed to be the previous Sunday. If the day for which an initial estimate is required to be made is a business day, but the corresponding day of the previous week is a national holiday, the equivalent day is deemed to be the next earlier corresponding day that is not a national holiday

error claimant means a person who—

(a) considers that prices contain a pricing error; and
(b) claims, in accordance with subpart 4 of Part 13, that a pricing error has occurred

error compensation means the application of a predetermined adjustment or process to the data within or obtained from, a metering component or metering installation in order to correct such data for known errors in any metering component


estimated reading means a value, used in the place of a meter reading, that is—

(a) created using an estimation algorithm; and
(b) not a validated meter reading

event charge means the amount calculated under clause 8.64
event date, in relation to an ICP, means the earlier of the following dates:
(a) the date on which the gaining trader commences trading electricity at the ICP under clauses 1(1), 8(1) or 13(1) of Schedule 11.3:
(b) the date on which the gaining trader otherwise assumes responsibility under clause 11.18(1) for the ICP

Clause 1.1(1) event date: substituted, on 1 February 2016, by clause 4(1)(d) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

event log means an automatically generated record of activity in a data storage device, that can be extracted or manually read as part of an interrogation
Clause 1.1(1) event log: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

event of default means any event listed in clause 14.41

exceptional circumstances means, for the purposes of Part 15, circumstances in which access to the relevant meter is not achieved despite the reconciliation participant’s best endeavours

excluded Code information means information—
(a) that relates to bids, offers, reserve offers, or any asset capability statement; or
(b) that is provided to the Authority, any investigator, or the Rulings Panel and that is required to be kept confidential under this Code or the Act; or
(c) in relation to which the Rulings Panel has prohibited publication or communication
Clause 1.1(1) excluded Code information paragraph (a): substituted, on 1 October 2013, by clause 4(2) of the Electricity Industry Participation (Disclosure Obligations) Code Amendment 2013.

excluded generating station has the meaning set out in clause 8.21(1)

existing assets means transmission assets and non-transmission projects that have been commissioned before, and are in operation at the time of, application of a net benefits tests set out in Part 12. To avoid doubt, an investment in the expansion of generating capacity of an existing generating unit is not an existing asset or part of an existing asset, unless the additional generating capacity associated with the investment has been commissioned before, and is in operation at the time of, the application of the relevant net benefits test

expected interruption costs [Revoked]
Clause 1.1(1) expected interruption costs: revoked, on 7 August 2014, by clause 4(2) of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

expected near-constraint arc flows means the scheduled quantity of energy flow on a transmission line or a transformer, if the energy flow is equal to or greater than 95% of the maximum energy flow limit (in MW) of the transmission line or transformer as set by the system operator in accordance with Schedule 13.3
Clause 1.1(1) expected near-constraint arc flows: inserted, on 28 June 2012, by clause 4(a) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
**expected near-group-constraint arc flows** means the scheduled quantity of energy flow on a group of transmission lines or a group of transformers or a group of transmission lines and transformers, calculated according to a group constraint formula covering the group, if the scheduled quantity of energy flow is equal to or above 95% of the maximum energy flow limit (in MW) for the group as set by the **system operator** in accordance with Schedule 13.3

Clause 1.1(1) **expected near-group-constraint arc flows**: inserted, on 28 June 2012, by clause 4(a) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clause 1.1(1) **expected near-group-constraint arc flows**: amended, on 1 February 2016, by clause 4(9) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

**expected unserved energy** means a forecast of the aggregate amount by which the demand for electricity exceeds the supply of electricity at each grid exit point as a result of likely planned or unplanned outages of primary transmission equipment

**extended emergency situation** [Revoked]
Clause 1.1(1) **extended emergency situation**: revoked, on 21 September 2012, by clause 4(4) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

**export congestion** means a situation in which a distribution network is unable to accept electricity exported from distributed generation because the injection of an additional unit of electricity into the distribution network would—
(a) directly cause a component in the network to operate beyond the component's rated maximum capacity; or
(b) give rise to an unacceptably high level of voltage at the point of connection between the distribution network and the distributed generation

Clause 1.1(1) **export congestion**: inserted, on 23 February 2015, by clause 4(12) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

**extended reserve** means services provided to restore frequency to the normal band after disturbances of a magnitude that make it impracticable or uneconomic to restore frequency using ancillary services
Clause 1.1(1) **extended reserve**: inserted, on 7 August 2014, by clause 4(3) of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

**extended reserve manager** means the **market operation service provider** that is for the time being appointed as the **extended reserve manager** under this Code, or if no regulations have been made establishing the **extended reserve manager** as a **market operation service provider**, the **Authority**
Clause 1.1(1) **extended reserve manager**: inserted, on 7 August 2014, by clause 4(3) of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

**extended reserve procurement notice** means the notice given to an asset owner by the **extended reserve manager** under clause 8.54L
Clause 1.1(1) **extended reserve procurement notice**: inserted, on 7 August 2014, by clause 4(3) of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

**extended reserve procurement schedule** means the schedule published by the **extended reserve manager** under clause 8.54J
Clause 1.1(1) **extended reserve procurement schedule**: inserted, on 7 August 2014, by clause 4(3) of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.
extended reserve provider means an asset owner required to provide extended reserve under Schedule 8.3, Technical Code B, clause 7
Clause 1.1(1) extended reserve provider: inserted, on 7 August 2014, by clause 4(3) of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

extended reserve schedule means the schedule published by the system operator under clause 8.54O
Clause 1.1(1) extended reserve schedule: inserted, on 7 August 2014, by clause 4(3) of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

extended reserve selection methodology means the methodology published by the extended reserve manager under clause 8.54G

extended reserve technical requirements report means the report published by the system operator under clause 8.54D

extended reserve technical requirements schedule means the schedule of requirements published by the system operator under clause 8.54D
Clause 1.1(1) extended reserve technical requirements schedule: inserted, on 7 August 2014, by clause 4(3) of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

fast instantaneous reserve means—
(a) for providers of partly loaded spinning reserve and tail water depressed reserve, the additional capacity (in MW) provided 6 seconds after a “Contingent Event” (as defined in the policy statement) that is sustained for a period of at least 60 seconds; and
(b) for providers of interruptible load, the drop in load (in MW) that occurs within 1 second of the grid system frequency falling to or below 49.2 Hertz that is sustained for a period of at least 60 seconds

final application, for the purposes of Part 6, means an application made under clause 15 of Schedule 6.1

final estimate means the mean of the metering data for each of the previous 4 equivalent days for the relevant trading period weighted in accordance with the quantity of electricity sold in the relevant trading period on the equivalent days in the relevant island as determined in accordance with the following formula:

$$
\frac{E_{day_4} + E_{day_3} + E_{day_2} + E_{day_1}}{4} \times \frac{(IslandLoad_0)}{\frac{IslandLoad_4 + IslandLoad_3 + IslandLoad_2 + IslandLoad_1}{4}}
$$

where

$E_{day_1}$ is the quantity of electricity measured at the relevant metering installation in kWh for the trading period of the equivalent day 1 week before the trading day for which the estimate is required
Electricity Industry Participation Code 2010
Part 1

**Eday**₂ is the quantity of *electricity* measured at the relevant *metering installation* in kWh for the *trading period* of the *equivalent day* 2 weeks before the *trading day* for which the estimate is required.

**Eday**₃ is the quantity of *electricity* measured at the relevant *metering installation* in kWh for the *trading period* of the *equivalent day* 3 weeks before the *trading day* for which the estimate is required.

**Eday**₄ is the quantity of *electricity* measured at the relevant *metering installation* in kWh for the *trading period* of the *equivalent day* 4 weeks before the *trading day* for which the estimate is required.

**Island Load**₀ means the quantity of *electricity*, measured in kWh, for the relevant *trading period* (as measured before the commencement of the calculation of this estimate) supplied in the *island* in which the relevant *metering installation* is located, less any measurement taken at any *metering installation* for which an estimate is being obtained for the same *trading period* and *island*.

**Island Load**₁ means the quantity of *electricity*, measured in kWh, for the *trading period* of the *equivalent day* 1 week before the *trading day* for which the estimate is required (as measured before the commencement of the calculation of this estimate) supplied in the *island* in which the relevant *metering installation* is located, less any measurement taken at any *metering installation* for which an estimate is being obtained for the same *trading period* and *island*.

**Island Load**₂ means the quantity of *electricity*, measured in kWh, for the *trading period* of the *equivalent day* 2 weeks before the *trading day* for which the estimate is required (as measured before the commencement of the calculation of this estimate) supplied in the *island* in which the relevant *metering installation* is located, less any measurement taken at any *metering installation* for which an estimate is being obtained for the same *trading period* and *island*.

**Island Load**₃ means the quantity of *electricity*, measured in kWh, for the *trading period* of the *equivalent day* 3 weeks before the *trading day* for which the estimate is required (as measured before the commencement of the calculation of this estimate) supplied in the *island* in which the relevant *metering installation* is located, less any measurement taken at any *metering installation* for which an estimate is being obtained for the same *trading period* and *island*.

**Island Load**₄ means the quantity of *electricity*, measured in kWh, for the *trading period* of the *equivalent day* 4 weeks before the *trading day* for which the estimate is required (as measured before the commencement of the calculation of this estimate) supplied in the *island* in which the relevant *metering installation* is located, less any measurement taken at any *metering installation* for which an estimate is being obtained for the same *trading period* and *island*.
final marginal location factor means the factor that is determined by dividing the
final price at any grid exit point or grid injection point by the final price at the
relevant reference point

final price means a price in dollars and cents for each grid injection point, each grid
exit point and each reference point determined in accordance with the methodology
specified by clause 13.135

final reserve price means the price calculated in dollars and cents for fast
instantaneous reserve and sustained instantaneous reserve determined in each island
in accordance with the methodology specified by clause 13.135

financial year [Revoked]
Clause 1.1(1) financial year: revoked, on 5 October 2017, by clause 4(60) of the Electricity Industry Participation

fittings [Revoked]
Clause 1.1(1) fittings: revoked, on 23 February 2015, by clause 4(11) of the Electricity Industry Participation Code
Amendment (Distributed Generation) 2014.

fixed-price physical supply contract means a contract that provides for the physical
supply of electricity, if—
(a) the buyer is reasonably expected to purchase 1 MW or more of electricity on
average during the term of the contract (for the purposes of determining whether
a contract meets this 1 MW threshold, the total purchases under the contract
should be used despite clause 13.219(6)); and
(b) the contract allows the buyer to purchase either—
(i) variable amounts of electricity linked to actual consumption of electricity
at a fixed price or prices; or
(ii) a fixed amount of electricity at a fixed price or prices; and
(c) excludes a contract for the physical supply of electricity, that is generated by an
embedded generating station, directly to a consumer

floating-price payer means the party obliged to make 1 or more payments, from time
to time during the term of a contract for differences, of a floating amount for a
quantity of electricity

force majeure clause, for the purposes of subpart 5 of Part 13, means a clause in a risk
management contract under which some or all obligations may be suspended and/or
the risk management contract may terminate due to 1 or more events (not being
events specified in a suspension clause) beyond the control of the party and that could
not reasonably have been foreseen, including—
(a) any event or circumstance occasioned by, or in consequence of, any act of God
(being an event or circumstance—
(i) due to natural causes, directly or indirectly and exclusively without human
intervention; and
(ii) that could not reasonably have been foreseen or if foreseen, could not
reasonably have been resisted); or
(b) strikes, lockouts, other industrial disturbances, acts of public enemy, wars,
blockades, insurrections, riots, epidemics, or civil disturbances; or
(c) the binding order of any court, government or a local authority beyond the control of the party

force majeure event, for the purposes of Parts 3 and 4,—

(a) means an event or circumstance beyond the reasonable control of a market operation service provider or ancillary service agent that results in, or causes, the market operation service provider or ancillary service agent to be unable to perform any of its obligations under this Code or the Electricity Industry (Enforcement) Regulations 2010; and

(b) includes (without limitation)—

(i) fire, flood, storm, earthquake, landslide, volcanic eruption, or other act of God; and

(ii) explosion or nuclear, biological, or chemical contamination; and

(iii) sabotage, terrorism, or act of war (whether declared or not); and

(c) includes an act or omission by a party to an agreement with a market operation service provider (not being the Authority) or an ancillary service agent only if—

(i) the act or omission is a breach of an obligation under the agreement; and

(ii) the obligation is in all material respects the same as an obligation in the market operation service provider agreement, or the ancillary service agent's agreement with the system operator; and

(iii) the act or omission would have been a force majeure event if it had been an act or omission of the market operation service provider or ancillary service agent and not an act or omission of the party; and

(d) does not include that a market operation service provider, ancillary service agent, or other person—

(i) is unable or unwilling to pay any amount necessary to meet the obligations under this Code or the Electricity Industry (Enforcement) Regulations 2010; or

(ii) is unable to pay its debts; or

(iii) calls a meeting for the purpose of Part 14 of the Companies Act 1993; or

(iv) is adjudicated bankrupt; or

(v) in the case of a company, society, or partnership, has a receiver or statutory manager or similar person appointed in respect of it or of all or any of its assets; or

(vi) is put into liquidation; and

(e) does not include an event that could have been prevented by the exercise of a reasonable standard of care

Clause 1.1(1) force majeure event: substituted, on 1 November 2012, by clause 4 of the Electricity Industry Participation (Force Majeure) Code Amendment 2012.

forecast marginal location factor means the factor that is determined by dividing the forecast price at any grid exit point or grid injection point by the forecast price at the relevant reference point
forecast prices means the prices for electricity at all grid exit points, grid injection points, and reference points scheduled in the price-responsive schedule or the non-response schedule (whichever is the case) in dollars and cents

forecast reserve prices means the prices for fast instantaneous and sustained instantaneous reserve for each island scheduled in the price-responsive schedule or the non-response schedule (whichever is relevant) in dollars and cents

formal notice means a notice issued by the system operator in accordance with clause 5 of Technical Code B of Schedule 8.3

forward estimate means, in relation to non half hour metered ICPs, any volume information (in kWh) submitted for a part or full consumption period that is not an historical estimate

frequency fluctuation means a deviation in frequency outside the normal band

frequency keeping means an ancillary service that maintains the system frequency within the normal band

frequency keeping unit means any equipment that provides frequency keeping services

FTR means a financial transmission right created under subpart 6 of Part 13

FTR account [Revoked]

FTR acquisition cost means—
(a) the amount a participant owes or is owed in respect of the acquisition of an FTR in an FTR auction; or
(b) if an FTR has been assigned by the first holder of the FTR, the amount that becomes owing under clause 13.249(3); or
(c) an amount described in paragraph (a) or (b) that is adjusted under clause 13.242A

FTR payment [Amended]

FTR payment amended to FTR acquisition cost, on 1 November 2012, by clause 4(2) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.


**FTR allocation plan** means the FTR allocation plan prepared and **published** by the **FTR manager** under clause 13.238

Clause 1.1(1) **FTR allocation plan**: inserted, on 1 October 2011, by clause 4(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

**FTR auction** means an auction conducted by the **FTR manager** in accordance with the **FTR allocation plan** approved under subpart 6 of Part 13

Clause 1.1(1) **FTR auction**: inserted, on 1 October 2011, by clause 4(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

**FTR hedge value** means the gross amount that becomes due and owing by the **clearing manager** or the holder of an **FTR** on the settlement of the **FTR** in accordance with the terms of the **FTR** (excluding the **FTR acquisition cost** and any amount owing under clause 13.249(4) or (7))

Clause 1.1(1) **FTR hedge value**: inserted, on 1 November 2012, by clause 4(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.


**FTR manager** means the **market operation service provider** who is for the time being appointed as the FTR manager under this Code

Clause 1.1(1) **FTR manager**: inserted, on 1 October 2011, by clause 4(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 1.1(1) **FTR payment**: inserted, on 1 October 2011, by clause 4(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 1.1(1) **FTR payment**: amended to **FTR acquisition cost**, on 1 November 2012, by clause 4(2) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.


**FTR period means a period for which an FTR applies**

Clause 1.1(1) **FTR period**: inserted, on 1 October 2011, by clause 4(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

**FTR reconfiguration amount** means the amount a **participant** that sells a reconfigured **FTR**—

(a) is entitled to be paid for the **reconfigured FTR**, if the amount is positive; or

(b) is liable to pay in respect of the **reconfigured FTR**, if the amount is negative

Clause 1.1(1) **FTR reconfiguration amount**: inserted, on 1 November 2014, by clause 4(1) of the Electricity Industry Participation (FTR Reconfiguration Auctions) Code Amendment 2014.

**FTR reconfiguration auction** means an **FTR auction** that allows a holder of an **FTR** to offer for sale a portion of the **FTR** expressed in terms of all or a specified amount of the **electricity** (in MW) to which the **FTR** relates


**FTR register** means the register created and operated by the FTR manager under clause 13.247

Clause 1.1(1) **FTR register**: inserted, on 1 October 2011, by clause 4(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.
fully calibrated certification means certification of a metering installation under clause 13(3) of Schedule 10.7
Clause 1.1(1) fully calibrated certification: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

fully certified metering installation means a certified metering installation other than an interim certified metering installation
Clause 1.1(1) fully certified metering installation: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

gaining metering equipment provider means, for the purposes of Parts 10 and 11,—
(a) the person who a trader records in the registry as the metering equipment provider for each metering installation for a point of connection; or
(b) the person with whom the participant responsible for ensuring there is a metering installation for a point of connection enters into an arrangement to become the metering equipment provider for each metering installation for the point of connection
Clause 1.1(1) gaining metering equipment provider: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

gate closure period, in relation to a trading period for which a generator or ancillary service agent has submitted an offer or reserve offer, or for which a dispatchable load purchaser has submitted a nominated dispatch bid, means—
(a) the trading period immediately preceding the trading period to which the offer or reserve offer relates, for—
   (i) an embedded generator:
   (ii) an intermittent generator:
   (iii) an ancillary service agent that is also an embedded generator; and
(b) the 2 trading periods immediately preceding the trading period to which the offer, reserve offer, or nominated dispatch bid relates, for—
   (i) any other generator:
   (ii) any other ancillary service agent:
   (iii) a dispatchable load purchaser
Clause 1.1(1) gate closure period: inserted, on 29 June 2017, by clause 4(3) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.

generally available retail tariff plan—
(a) means a retail tariff plan that a retailer will make available to any consumer (subject to credit requirements) if the consumer satisfies the requirements specified for the retail tariff plan relating to:
   (i) physical location:
   (ii) metering configuration:
   (iii) price category code; but
(b) does not include a retail tariff plan made available by a retailer only under an agreement reached as a result of the retailer directly contacting a consumer to offer a retail tariff plan that provides the consumer with a financial discount or
other benefit when compared with any other of the retailer's tariff plans to which paragraph (a) applies that are available to that consumer.


generating plant means equipment collectively used for generating electricity.

generating station means 1 or more generating units that are directly connected to the grid or to a local network and that inject into the grid or a local network (as the case may be) at a single point of injection.

Clause 1.1(1) generating station: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.


generating unit means a machine that generates electricity.

generating unit gross means the output of a generating unit measured or calculated at its output terminals, inclusive of any generating unit load supplied.

Clause 1.1(1) generating unit gross: inserted, on 1 June 2011, by clause 4(1) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2011.

generating unit load means the active and reactive power supplied or injected via connections between the generating unit’s output terminals and its generating unit circuit breaker.

Clause 1.1(1) generating unit load: inserted, on 1 June 2011, by clause 4(1) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2011.

Clause 1.1(1) generating unit load: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.


generating unit net means the output of a generating unit measured or calculated at its point of connection, but does not include generating unit load or any other active or reactive power supplied (including losses) between the generating unit and the point of connection.


generator means a person who owns generating units connected to a network, or any person who acts, in respect of Parts 13, 14 and 15, on behalf of any person who owns such generating units, and includes embedded generators, intermittent generators, type A co-generators, and type B co-generators.

Clause 1.1(1) generator: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.


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 reasonably be expected from a skilled and experienced asset owner engaged in the management of a transmission 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 and the applicable law.

grid means the system of transmission lines, substations and other works, including the HVDC link used to connect grid injection points and grid exit points to convey electricity throughout the North Island and the South Island of New Zealand.

grid economic investment report means the report prepared under clause 12.115, either as part of Transpower’s annual planning report or in some other form, if the Authority so determines.

grid emergency means a situation where—
(a) in the reasonable opinion of the system operator, 1 or more of the events set out in clause 5(1) of Technical Code B of Schedule 8.3 has occurred, or is reasonably expected to occur and urgent action is required of the system operator or participants to alleviate the situation; or
(b) independent action (as set out in clause 9 of Technical Code B of Schedule 8.3) is required of a participant to alleviate the situation.

grid exit point and GXP mean any point of connection on the grid—
(a) at which electricity predominantly flows out of the grid; or
(b) determined as being such by the Authority following an application in accordance with clause 13.28,—
and such point of connection may, at any given time, be a grid exit point or a grid injection point, but may not be both at the same time.

grid injection point and GIP mean any point of connection on the grid at which electricity predominantly flows into the grid. A point of connection may, at any given time, be a grid injection point or a grid exit point, but may not be both at the same time.

grid interface means the assets used to make a connection to the grid (as the case may be), including associated protection, control and communication systems. The term includes the interface between assets forming part of the grid.

grid owner means a person who owns or operates any part of the grid.

grid reliability report means a report on grid reliability published by Transpower under clause 12.76(1).

grid reliability standards means standards for reliability of the grid developed in accordance with clauses 12.55 to 12.58, 12.61 and 12.62.
grid zone area means a geographical area, which includes many nodes, as determined by the Authority and published under clause 13.221(1)

group constraint formula means the mathematical formula applied by the system operator, in accordance with Schedule 13.3, to constrain the energy flows on a group of transmission lines, transformers or both

GST means goods and services tax payable under the Goods and Services Tax Act 1985

half hour means a thirty minute period ending on any hour or half hour, and half hourly has a corresponding meaning

half-hour metering means the process of measuring and recording information—
(a) relating to electricity conveyed; and
(b) during—
   (i) an interval that is a trading period; or
   (ii) intervals that can be aggregated to 1 trading period
Clause 1.1(1) half-hour metering: substituted, on 29 August 2013, by clause 4(2)(k) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

half-hour metering information—
(a) means information describing the quantity of electricity conveyed in each trading period that is—
   (i) recorded directly by a metering installation; or
   (ii) calculated or estimated using information recorded directly by a metering installation; and
(b) in respect of a generator that is selling electricity to the clearing manager and other persons at the same grid injection point in the same trading period, includes the file recording the quantity of electricity sold to the clearing manager during each such trading period constructed in accordance with dispatch instructions issued by the system operator under this Code.
Clause 1.1(1) half-hour metering information: substituted, on 19 December 2014, by clause 4(2) of the Electricity Industry Participation Code Amendment (Minor Code Amendments) (No 3) 2014.

half-hour metering installation means a metering installation used for half-hour metering

hedge settlement agreement means an agreement in a form set out in Schedule 14.4 between participants that provides for settlement by the clearing manager of payments for differences in respect of the price of electricity

high spring washer price relaxation factor means, in relation to a high spring washer price situation in a trading period, 1MW

high spring washer price situation means a situation in a trading period in which—
(a) 1 or more transmission security constraints bind; and
(b) the software used by the pricing manager to calculate provisional prices, interim prices, and final prices (or used by the system operator to determine, under clause 13.134(4), whether a high spring washer price situation still exists) calculates a price for electricity at any grid injection point or grid exit point, excluding grid injection points and grid exit points that are electrically disconnected, that is equal to or greater than the product of the high spring washer price trigger ratio and the highest unconstrained cleared offer price in that trading period.


Clause 1.1(1) high spring washer price situation methodology means the methodology described in clauses 13.134(2) and 13.134(4)

Clause 1.1(1) high spring washer price trigger ratio means the ratio in clause 13.133

Clause 1.1(1) high voltage terminal means the point at which the higher voltage side of a grid owner’s transformer connects to the grid.
Clause 1.1(1) high voltage terminal: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 1.1(1) historical annual consumption means the annual consumption of a grid exit point or grid injection point for the 12-month period ended 3 months preceding publication of the annual consumption list.


Clause 1.1(1) historical estimate means, in relation to non half hour metered ICPs, volume information (in kWh), apportioned to part or full consumption periods after having the seasonal adjustment shape, or any other profile that has, from time to time, been approved by the Authority for this purpose, applied, being 1 of the following:
(a) the difference between 2 validated actual meter readings:
(b) the difference between 2 permanent estimates:
(c) any relevant unmetered load:
(d) the difference between a validated meter reading and a permanent estimate.


Clause 1.1(1) hub means a node or group of nodes (and in the case of a group of nodes, nodes in the group may be given different weightings) identified as either hub A or hub B in an FTR.

HV, for the purposes of subparts 2, 6 and 7 of Part 12, means high voltage.

HVDC component flows means the quantity of energy flow on each component of the HVDC link as calculated by the modelling system in accordance with the model.
formulation set out in the system operator's market operation service provider agreement (as amended from time to time)

**HVDC injection point** means the point at which electricity is injected into the North Island or the South Island from the **HVDC link**

**HVDC link** means the converter stations at Benmore in the South Island and Haywards in the North Island and the high voltage transmission lines and undersea cables linking them (and including all associated equipment)


**HVDC owner** means the grid owner who owns and/or operates the **HVDC link**

**HVDC risk offsets** means the values by which HVDC flows are adjusted by the system operator to determine the relevant reserve risk on the **HVDC link**

**ICP** means an installation control point being 1 of the following:
(a) a point of connection at which the electrical installation for a retailer's customer is connected to a network other than the grid:
(b) a point of connection between a network and an embedded network:
(c) a point of connection between a network and shared unmetered load

Clause 1.1(1) **ICP**: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

**ICP day** means any day when an ICP with the installation type L or B is recorded on the registry as having the status of Active


**ICP identifier** means a unique identifier for an ICP created by a distributor in accordance with clause 1 of Schedule 11.1

**identification costs** means any reasonable identification and testing costs incurred by the system operator in accordance with clause 8.3 that are unable to be recovered from participants by the system operator

**incremental costs**, for the purpose of Part 6, means the reasonable costs that an efficient distributor would incur in providing electricity distribution services with connection services to distributed generation, less the costs that the efficient distributor would incur if it did not provide those connection services

Clause 1.1(1) **incremental costs**: inserted, on 23 February 2015, by clause 4(12) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

**industrial co-generating station** means a generating station that —
(a) [Revoked]
(b) is reliant on a co-located industrial process because—
(i) it derives its fuel source from that co-located industrial process; or
(ii) it provides some or all of the electricity that it generates to that co-located
industrial process; or

(iii) it provides some or all of any by-product of generating electricity to that co-located industrial process; and

(c) is tightly coupled to an industrial process; and

(d) has been approved by the Authority under clause 8(1)(a) of Schedule 13.4


industrial process means a process that has a primary purpose of producing an output other than electricity

infeasibility situation means a situation where the software used to determine final prices and final reserve prices calculates a model variable with a value (either positive or negative) as set out in the list given to the pricing manager under Schedule 13.2

information system [Revoked]


inherent characteristics means the permanent and fundamental characteristics of an asset that are outside the reasonable control of the asset owner and affect the output or response of that asset and includes the effects of water temperature, ambient air temperature and performance during ramping on asset performance

initial application, for the purposes of Part 6, means an application under clause 11 of Schedule 6.1

initial estimate means an estimate of metering information to be made by giving the metering information of all participants of the equivalent day of the previous week

injection means the flow of electricity into a network

input connection contract means the fixed term input connection and input connection assets contracts between Transpower and each of the following: Tuaropaki Power Company Limited, Carter Holt Harvey Limited, Contact Energy Limited, Empower Limited, and Mighty River Power Limited


input information means information given to the pricing manager in accordance with clause 13.141

installation type means a category based on whether an ICP consumes electricity, generates electricity, or both consumes and generates electricity
instantaneous reserve means an ancillary service comprising 1 or more of the following:
(a) interruptible load:
(b) partly loaded spinning reserve:
(c) tail water depressed reserve

interconnecting transformer means a transformer (other than a transformer that is required to supply demand to distributors or direct consumers) that allows for the transfer of power within the grid between any of the following voltage levels:
(a) 220kV:
(b) 110kV:
(c) 66kV:
(d) 50kV

interconnection asset, for the purposes of subparts 2, 6 and 7 of Part 12—
(a) has the meaning set out in the transmission pricing methodology; and
(b) includes the HVDC link

interconnection branch means an interconnection circuit branch, and an interconnection transformer branch

interconnection circuit branch means a circuit branch that comprises or includes interconnection assets

interconnection point means a point of connection between—
(a) a local network and any other local network; or
(b) an embedded network that is not a gateway NSP and a local network; or
(c) an embedded network that is not a gateway NSP and any other embedded network

Clause 1.1(1) interconnection point: substituted, on 29 August 2013, by clause 4(2)(m) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

interconnection transformer branch means a transformer branch comprising interconnection assets

interim certified metering installation means a metering installation referred to in clause 10.51(3)(a)(i)
Clause 1.1(1) interim certified metering installation: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

interim marginal location factor means the factor that is determined by dividing the interim price at any grid exit point or grid injection point by the interim price at the relevant reference point

interim price means a price in dollars and cents for each grid injection point and each grid exit point, determined in accordance with the methodology specified in clause 13.135

interim reserve price means a price in dollars and cents for fast instantaneous reserve and sustained instantaneous reserve, determined in each island in accordance with methodology specified in clause 13.135

*intermittent generating station* means a *wind generating station*

*intermittent generator* means the owner of an *intermittent generating station*. To avoid doubt, clauses referring to an *intermittent generator* apply only to the *intermittent generating stations* owned by the *intermittent generator*

*interrogation* means the extraction or manual reading of stored data from a *metering installation* and *interrogated* and *interrogating* have corresponding meanings


*interruptible load* means a form of *instantaneous reserve* comprised of energy being consumed that is able to be *electrically disconnected* to balance the *injection supply* and the *offtake of electricity* following a drop in system frequency to a specified level below 50 Hz


*interruptible load group GXP* means the *grid exit point*, as approved by the *system operator* (such approval not to be unreasonably withheld), at which a *reserve offer* for *interruptible load* comprises the aggregate quantity of *interruptible load* available at a number of specified *grid exit points* for the purposes of *offer* and *dispatch*

*interruption*, for the purposes of Part 12, means an interruption in the conveyance of *electricity* between *assets* owned or operated by a *designated transmission customer* and the *grid assets* owned by *Transpower* at a *point of connection*, other than an interruption by reason of *Transpower* being directed to *electrically disconnect* a *point of connection* by the *Authority* or the *Rulings Panel* under the *Act* or this Code or by any other person authorised to do so by this Code


*investment contracts* means contracts for investments that are agreed between *Transpower* and a *designated transmission customer*

*island* means the South Island or the North Island of New Zealand (as the case may be)

*island GWAP* means the generation weighted average price for an *island* for a *trading period* calculated in accordance with clause 1(2) of Schedule 13.3A

Clause 1.1(1) *island GWAP*: inserted, on 1 June 2013, by clause 4(a) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

*island scarcity pricing situation* means a situation determined to be an *island scarcity pricing situation* by the *pricing manager* under clause 13.135A(3)

Clause 1.1(1) *island scarcity pricing situation*: inserted, on 1 June 2013, by clause 4(a) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

*island shortage situation* means a situation specified in a notice to be an *island wide shortage* by the *system operator* under clause 5(1A) of Technical Code B of Schedule 8.3

Clause 1.1(1) *island shortage situation*: inserted, on 1 June 2013, by clause 4(a) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.
line function services has the meaning given to it by section 5 of the Act

line owner, for the purposes of the definition of specified participant, means a person who owns works that are used or intended to be used for the conveyance of electricity

lines has the meaning given to it by section 5 of the Act

livening [Revoked]
Clause 1.1(1) livening: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.
Clause 1.1(1) livening: revoked, on 29 August 2013, by clause 4(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).

local authority, for the purposes of Part 6, means a territorial authority within the meaning of the Local Government Act 2002

local losses means losses applying to the conveyance of electricity over a local network or an embedded network

local network means the lines, equipment and plant that are used to convey electricity between the grid and 1 of the following:
(a) an embedded generator:
(b) an embedded network:
(c) an ICP

location factor, for the purposes of subpart 5 of Part 13, means the location factor calculated in accordance with clause 13.221(2)

losing metering equipment provider means, for the purposes of Parts 10 and 11, the existing metering equipment provider responsible for each metering installation for a point of connection at which there is a gaining metering equipment provider
Clause 1.1(1) losing metering equipment provider: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

loss adjusted demand means the total demand determined by taking all actual demand half-hour metering information given to the pricing manager under clause 13.138 and multiplying the total by 1.05

loss and constraint excess means the difference between purchaser and generator payments as defined in clause 14.16

loss category means the relevant code in the schedule published by the registry manager that identifies the relevant loss factors that apply to submission information or dispatchable load information
Clause 1.1(1) **loss category**: amended, on 15 May 2014, by clause 5(3) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.


**loss compensation** means the application of a predetermined adjustment or process to the data within, or obtained from, a metering component or metering installation in order to correct such data for known losses in primary plant (such as power transformers and cables)


**losses** means the difference between the delivered electricity at a point of connection and the electricity required to be injected into an other point of connection in order to supply the delivered electricity

**loss factor** means the factor, identified by reference to a loss category within the registry, to be applied to submission information or dispatchable load information to obtain adjusted for losses information at the relevant NSP, which factor is—

(a) as set out in the report to be provided by the registry in accordance with clause 11.26(b); or

(b) if a report has not been provided by the registry, as directed by the Authority under clause 15.20B(3) or 15(1) of Schedule 15.4


**loss of communication** means a sustained disruption of communications between the system operator and 1 or more generators, ancillary service agents, extended reserve providers, or dispatchable load purchasers such that operation of the grid is affected or is likely to be affected


**LV**, for the purposes of subparts 2, 6 and 7 of Part 12, means low voltage

**main protection system** means a protection system that detects 1 or more types of faults and electrically disconnects a faulted asset from the grid with the least possible disruption to the grid and non-faulted assets


**maintain**, for the purposes of Part 6, includes to repair, and **maintenance** has a corresponding meaning

**manufacturer’s specification**, for the purposes of Part 12, means the specifications for an asset, as stated by the manufacturer

**market administrator** [Revoked]


**market operation service provider** has the meaning given to it in section 5 of the Act
**market operation service provider agreement** means the agreement entered into between the **Authority** and a **market operation service provider** for the provision of services for the purposes of this Code

**maximum continuous rating** means the maximum electrical performance of an **asset** that can be maintained continuously in normal service

**maximum South Island frequency** means the maximum frequency permitted in the South Island, which is 55 Hertz

**measuring transformer** means—
(a) a current transformer; or
(b) a voltage transformer; or
(c) both a current transformer and a voltage transformer
Clause 1.1(1) **measuring transformer**: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

**meter** means a device that measures either or both of the following—
(a) **active energy**:
(b) **reactive energy**
Clause 1.1(1) **meter**: substituted, on 29 August 2013, by clause 4(2)(p) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

**meter reading** means a **meter** register value or the equivalent, obtained from **raw meter data** or such other reading as detailed in clause 3(1) of Schedule 15.2, which is not an estimated reading

**metering** means the process used to measure **electricity** conveyed
Clause 1.1(1) **metering**: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

**metering component** means a component of a **metering installation** including—
(a) a **measuring transformer**:
(b) all wiring and intermediate terminals in the **metering installation**:
(c) a **control device**:
(d) a **meter**:
(e) a **data storage device**:
(f) a **test facility**:
(g) a fuse:
(h) a **circuit breaker**:
(i) **communication equipment**:
(j) an **error compensation** device
Clause 1.1(1) **metering component**: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

**metering data** means, in relation to a **metering installation**,—
(a) all **metering records** about the **metering installation**; and
(b) all **raw meter data** obtained from the **metering installation**
Clause 1.1(1) **metering data**: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

**metering equipment owner** means the **participant** who owns any or all of the items of metering equipment installed in a **metering installation**
metering equipment provider has the meaning given to it in section 5 of the Act
Clause 1.1(1) metering equipment provider: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

metering information means the quantity of electricity measured by a metering installation and adjusted for local losses (if relevant) to represent the equivalent amount of electricity at the point of connection with the grid and consolidated into a single quantity per trading period

metering infrastructure means, in relation to a metering installation,—
(a) the metering installation:
(b) if a back office process is necessary, the metering equipment owner’s back office for the metering installation:
(c) a system that collects and sends information to or from the metering installation
Clause 1.1(1) metering infrastructure: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

metering installation means—
(a) equipment, including all metering components, used, or intended to be used, for metering:
(b) in the context of unmetered load, the calculation process used to derive the quantity of unmetered load:
(c) in the context of instances of both metered electricity quantities and unmetered load, both (a) and (b)

metering records means all specifications for, attributes of, and information relating to or concerning, a metering installation (other than raw meter data), including—
(a) the relevant records of the metering equipment provider responsible for the metering installation:
(b) the relevant records of each ATH who certified the metering installation or any metering component of the metering installation:
(c) all factors applied in a meter in the metering installation and relating to that data (for example the k factor and m factor):
(d) the metering installation's maintenance and repair history and requirements:
(e) details of each metering component in the metering installation including information about its ownership:
(f) all certification reports and supporting documents and records
Clause 1.1(1) metering records: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

metering situation means a situation in which—
(a) the metering information to be given is incomplete or incorrect or is and remains an initial estimate for—
(i) a grid exit point or grid injection point specified on the annual consumption list as having historical annual consumption greater than 500 GWh; or
(ii) any 2 or more grid exit points or grid injection points specified on the annual consumption list as having historical annual consumption greater than 300 GWh; or

(iii) any 10 or more grid exit points or grid injection points; or

(iv) an intermittent generating station with a point of connection to the grid; or

(v) a type B industrial co-generating station with a point of connection to the grid; or

(b) the metering information for a dispatch-capable load station given for a trading period is incomplete or incorrect or is and remains an initial estimate for a grid exit point at which a nominated dispatch bid has been submitted for the trading period

Clause 1.1(1) metering situation: substituted, on 15 May 2014, by clause 5(2) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.


metering testing requirements [Revoked]

Clause 1.1(1) metering testing requirements: revoked, on 29 August 2013, by clause 4(3) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

metering standards means the metering requirements set out in the Schedules to Part 10


metrology layer means a part of a metering installation used for either or both of the following:

(a) measuring and recording electricity conveyed; or

(b) recording event logs

Clause 1.1(1) metrology layer: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

minimum South Island frequency means the minimum frequency permitted in the South Island, which is 45 Hertz

model formulation means the model from which software specifications have been developed for the system operator

modelled projects means transmission augmentation projects and non-transmission projects that are reasonably expected to occur within the time period for which the assessment of costs and benefits under a net benefits test set out in Part 12 is undertaken

momentary fluctuations [Revoked]

Clause 1.1(1) momentary fluctuations: revoked, on 19 May 2016, by clause 4(1) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.

MV, for the purposes of subparts 2, 6 and 7 of Part 12, means medium voltage

MW means a megawatt of electrical power

MWh means a megawatt hour of electrical energy

N-1 criterion means that, with all assets that are reasonably expected to be in service, the power system would be in a secure state
nameplate capacity means the lesser of—
(a) the full-load continuous rating of generating plant under conditions specified by its designer in MW or kilowatts; or
(b) the full-load continuous rating of the generating plant’s inverter (if any) under conditions specified by its designer in MW or kilowatts

classified as/[Revoked]


national GWAP means the generation weighted average price for both islands for a trading period calculated in accordance with clause 2(2) of Schedule 13.3A
Clause 1.1(1) national GWAP: inserted, on 1 June 2013, by clause 4(a) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

national holiday means any day on which any of the following are observed as a statutory holiday:
(a) Good Friday:
(b) Easter Monday:
(c) ANZAC Day:
(d) Queen’s Birthday:
(e) Labour Day:
(f) Christmas Day:
(g) Boxing Day:
(h) New Year’s Day:
(i) the day after New Year’s Day:
(j) Waitangi Day

national scarcity pricing situation means a situation determined to be a national scarcity pricing situation by the pricing manager under clause 13.135A(4)
national scarcity pricing situation: inserted, on 1 June 2013, by clause 4(a) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

national shortage situation means concurrent island shortage situations in the North Island and the South Island
national shortage situation: inserted, on 1 June 2013, by clause 4(a) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

negative sequence voltage means a measure of difference in magnitude and phase angle in each phase

net grid exit point means any grid exit point or grid injection point that is not a net grid injection point

net grid injection point means a grid exit point or grid injection point for which the most recent information provided by the grid owner under clauses 13.141(1)(b) and 13.166 is less than or equal to 0

net purchase quantity assessment means the quantity of an ancillary service derived from the following formula:
\[ a = b - c \]
where

a  is the net purchase quantity of the **ancillary service** to be procured by the **system operator** in accordance with the **procurement plan**

b  is the gross amount of an **ancillary service** that the **system operator** believes is required in order to meet the **principal performance objectives**;

c  is the amount of the **ancillary service** that is made available to the **system operator** under **alternative ancillary service arrangements**

**network** means the **grid**, a **local network** or an **embedded network**

**new investment agreement contracts** means contracts entered into before 1 April 2008 between **Transpower** and its customers, under which **Transpower** agrees to provide new or upgraded plant and the customer agrees to pay charges based on **Transpower's** cost of providing the new or upgraded plant

**New Zealand daylight time** means New Zealand daylight time declared by Order in Council under section 4 of the **Time Act 1974**

**New Zealand standard time** has the meaning given to it by section 2 of the **Time Act 1974**

**node** means—
(a)  a bus; or
(b)  a location at which an electrical link that is not part of or does not contain a **transformer**, diverges or terminates (such as a "tee" point or a deviation); or
(c)  a point at a substation at which 2 or more electrical links join at which there is no bus

**nominal voltage** means the voltage at which particular equipment is designed to operate under normal circumstances

**nominated bid**—
(a)  [Revoked]
(b)  [Revoked]
(c)  [Revoked]
(d)  means the information that a **purchaser** submits to the **system operator** under clause 13.7 to indicate a reasonable estimate of the—
(i)  **electricity** that the **purchaser** will purchase for a **dispatch-capable load station** at a GXP; or
(ii)  **non-dispatch-capable load** that the **purchaser** will purchase at a **non-conforming GXP**; and
(e)  includes a deemed **nominated bid** under clause 13.8A

Clause 1.1(1) **nominated bid**: inserted, on 28 June 2012, by clause 4(a) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

nominated dispatch bid means a nominated bid that a purchaser submits to the system operator in relation to a dispatch-capable load station that the purchaser is making available to be dispatched

nominated non-dispatch bid means a nominated bid that a purchaser submits to the system operator in relation to—
(a) non-dispatch-capable load at a non-conforming GXP; or
(b) a dispatch-capable load station that the purchaser is not making available to be dispatched

non-conforming GXP means a GXP that has been determined by the Authority to be a non-conforming GXP under clause 13.27A or 13.27B(4)
Clause 1.1(1) non-conforming GXP: inserted, on 28 March 2012, by clause 4(a) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

non-dispatch-capable load means a quantity of electricity purchased at a GXP that is not purchased for 1 or more dispatch-capable load stations.

non half-hour metering means the process of measuring and recording information—
(a) relating to electricity conveyed; and
(b) at intervals that are greater than 1 trading period
Clause 1.1(1) non half-hour metering: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

non half-hour metering installation means a metering installation used for non half-hour metering
Clause 1.1(1) non half-hour metering installation: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

non-response schedule means the schedule prepared by the system operator—
(a) under clause 13.58(1)(b); and
(b) for the purpose of assisting generators, purchasers, consumers, ancillary service agents, and grid owners to manage their resources
Clause 1.1(1) non-response schedule: inserted, on 28 June 2012, by clause 4(a) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

non-transmission projects includes investments in any of the following:
(a) generation:
(b) energy efficiency:
(c) demand-side management:
(d) local network augmentation:
(e) improvements to the systems and processes of the system operator:
(f) the provision of ancillary services

normal band means a frequency band between 49.8 Hertz and 50.2 Hertz (both inclusive)
notified planned outage means the outage of an asset that forms part of, or is connected to, the grid or local network—
(a) that is planned by the relevant asset owner; and
(b) for which the asset owner has given written notice to the system operator in accordance with Technical Code D of Schedule 8.3
Clause 1.1(1) notified planned outages: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

notify [Revoked]

notional embedding contracts means contracts entered into before 1 April 2008 between Transpower and its customers, under which a customer’s generation assets are treated as if they were physically connected to load in lieu of their existing connection to the grid
Clause 1.1(1) notional embedding contracts: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

NSP means a network supply point that is a point of connection between—
(a) a local network and the grid; or
(b) 2 local networks; or
(c) a local network and an embedded network; or
(d) 2 embedded networks; or
(e) a generator and the grid

NSP identifier means a unique identifier for an NSP created by the reconciliation manager in accordance with clause 28 of Schedule 11.1

obligation FTR means an FTR for which the terms and conditions provide that—
(a) (excluding the FTR acquisition cost) the holder of the FTR is entitled to receive a payment when, for the FTR period, the difference between the price (calculated in accordance with the terms of the FTR) at the hub identified as hub B and the price at the hub identified as hub A in the FTR is positive; and
(b) (excluding the FTR acquisition cost) the holder must make a payment when the difference between those prices is negative

offer means the information that a generator submits to the system operator under clause 13.6(1), and includes any revised offer that a generator submits under clauses 13.17 to 13.19
Clause 1.1(1) offer: substituted, on 29 June 2017, by clause 5(a) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.
offer stack means the stack generated from ranking in price order, from lowest to highest, all offers to sell electricity as given to the pricing manager under clause 13.141(1)(c)

offered FTR means an FTR that has been offered into an FTR reconfiguration auction

official conservation campaign is a campaign to encourage electricity conservation that—
(a) is commenced by the system operator; and
(b) lasts for 1 week or more; and
(c) covers—
   (i) the South Island; or
   (ii) all of New Zealand

offtake means the flow of electricity from the grid at a grid exit point

operating account means the trust account established by the clearing manager in accordance with clause 14.66

option FTR means an FTR for which the terms and conditions provide that—
(a) (excluding the FTR acquisition cost) the holder of the FTR is entitled to receive a payment when, for the FTR period, the difference between the price (calculated in accordance with the terms of the FTR) at the hub identified as hub B and the price at the hub identified as hub A in the FTR is positive; but
(b) (excluding the FTR acquisition cost) the holder is not required to make a payment when the difference between those prices is negative

options contract means a contract containing the right to buy or sell a financial derivative contract

other party, for the purposes of subpart 5 of Part 13, means the party to a risk management contract who did not submit information under clauses 13.219(1) to (4), 13.223(1), or 13.224, as the case may be

outage, for the purposes of Part 12, has the meaning given to it by clause 12.130

outage constraint means any grid injection point or grid exit point that has no load or generation connected to it in the modelling system, and of which the system operator gives written notice to the reconciliation manager under clause 15.15(a)
outage plan, for the purposes of Part 12, means the annual outage plan developed under the Outage Protocol

Outage Protocol, for the purposes of Part 12, means the Outage Protocol that is incorporated by reference in this Code under clause 12.150

overall accuracy [Revoked]
Clause 1.1(1) overall accuracy: revoked, on 29 August 2013, by clause 4(3) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

over frequency limit means the maximum frequency of 50.5 Hz

over frequency reserve means an ancillary service that comprises an automatic reduction in the level of injection by a generating set to arrest an unplanned rise in system frequency

participant has the meaning given to it in section 5 of the Act and, for the purposes of Parts 8, 13, 14, and 14A, has the additional meaning set out in clause 1.5

participant identifier means a unique 4 letter code assigned to a participant under clause 15.39 that is used to identify the participant, including in the reconciliation and registry processes

participant rolling outage plan means a plan developed by a specified participant under clauses 9.6 to 9.13

partly loaded spinning reserve means a form of instantaneous reserve consisting of spare capacity, held in reserve on a generating unit, generating, but not operating at full output, which is able to provide fast instantaneous reserve or sustained instantaneous reserve following a drop in system frequency to a specified level below 50 Hz

party, for the purposes of subpart 5 of Part 13, means either the buyer or seller under a risk management contract or both the buyer and seller under a risk management contract, as the case may be

payee [Revoked]

payer [Revoked]
permanent estimate means—
(a) a value sourced from an estimated reading that has passed the validation process in clauses 16 and 17 of Schedule 15.2 and has been calculated from validated meter readings; or
(b) if, despite using reasonable endeavours, a reconciliation participant cannot replace volume information created using estimated readings with volume information created using validated meter readings by the month 14 revision cycle, a value created by the reconciliation participant using its best estimates of validated meter readings.


pivotal means—
(a) in relation to a generator, that the total demand in a trading period at any 1 or more nodes would not have been met if the generator had not submitted offers for all or any of its generating plant; and
(b) in relation to an ancillary service agent, that the total demand in a trading period for an ancillary service supplied by the ancillary service agent in an island would not have been met if the ancillary service agent had not submitted reserve offers for all or any of its capacity to provide instantaneous reserve in the island.


planned interruption, for the purposes of Part 12, means an interruption caused by a planned outage

planned outage, for the purposes of Part 12, means an outage carried out in accordance with the planning requirements set out in the Outage Protocol

point of connection means a point at which electricity may flow into or out of a network and, for the purposes of Technical Code A of Schedule 8.3, means a grid injection point or a grid exit point

point of measurement [Revoked]

Clause 1.1(1) point of measurement: revoked, on 29 August 2013, by clause 4(3) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

point of service means a normally contiguous electrical busbar of a particular voltage at which Transpower, as a grid owner, has agreed to provide services to 1 or more designated transmission customers

point of supply, in relation to any premises, means the point at which fittings, used or intended to be used for the purposes of supplying electricity to those premises, enter those premises

policy statement means the policy statement that is incorporated by reference in this Code under clause 8.10

preceding year [Revoked]


preceding year day [Revoked]

pre-dispatch schedule [Revoked]
Clause 1.1(1) pre-dispatch schedule: revoked, on 28 June 2012, by clause 4(i) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

preliminary sample means the statistical sample that is required in order to establish parameter estimates to determine the appropriate size of the profile sample

preliminary sample size means the required size of the preliminary sample

premium, in relation to an options contract, means the dollar amount paid by the buyer of the options contract to the seller

prescribed form means a form prescribed from time to time by the Authority

price, for the purposes of Part 5, includes—
(a) valuable consideration in any form, whether direct or indirect; and
(b) any consideration that in effect relates to the acquisition of goods or services or the acquisition or disposition of any interest in land, although ostensibly relating to any other matter or thing

price category means the relevant code in the schedule published by a distributor that is used to unambiguously define the line charges for an ICP

price-responsive schedule means the schedule prepared by the system operator—
(a) under clause 13.58(1)(a); and
(b) for the purpose of assisting generators, purchasers, consumers, ancillary service agents, and grid owners to manage their resources
Clause 1.1(1) price-responsive schedule: inserted, on 28 June 2012, by clause 4(a) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

pricing error means an interim price or interim reserve price is incorrect or is likely to be incorrect, as the result of—
(a) an incorrect input being used in calculating the interim price or interim reserve price; or
(b) the pricing manager having followed an incorrect process in calculating that interim price or interim reserve price, in contravention of this Code

pricing manager means the market operation service provider who is for the time being appointed as pricing manager under this Code

primary transmission equipment means any plant or equipment forming part of the grid that enables the bulk transfer of electricity, including without limitation transmission circuits, busbars and switchgear

principal performance obligation and PPO mean a system operator obligation set out in any of clauses 7.2A to 7.2D
Clause 1.1(1) principal performance obligations and PPOs: amended, on 19 May 2016, by clause 4(3) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.

procurement plan means the procurement plan that is incorporated by reference in this Code under clause 8.42
profile means a fixed or variable electricity consumption pattern assigned to a particular group of meter registers or unmetered loads

profile acceptance limit means the maximum value allowed for the sample co-efficient of variation calculated from the preliminary sample

profile applicant means the participant who submitted an application to the Authority to approve a new profile or a change to an existing profile, and may be a joint entity with more than 1 participant or an independent commercial entity acting on behalf of 1 or more participants

profile class means the grouping of 1 or more individual profiles that are applied to metering installations and loads with similar generic descriptions

profile owner means the legal entity that introduced the approved profile or is nominated as the profile owner in accordance with Schedule 15.5

profile population means all ICP identifiers included in a profile

profile sample means the statistical sample used to generate consumption data that is to be used to represent the load patterns of all ICP identifiers included in the profile

profile sample size means the required size of the profile sample

provisional marginal location factor means the factor that is determined by dividing the provisional price at a grid exit point or grid injection point by the provisional price at the relevant reference point

provisional price means a price in dollars and cents that has been published based on data relating to a provisional price situation. When a provisional price is published, the provisional price applies to all trading periods on the relevant trading day

provisional price situation means a metering situation, or a SCADA situation, or an infeasibility situation, or a high spring washer price situation

provisional reserve price means a price calculated in dollars and cents that has been published based on data relating to a provisional price situation

public conservation period means—
(a) any period during which an official conservation campaign is running:
(b) any period during which a supply shortage declaration is in force for 1 week or more

publicise [Revoked]


publish means—
(a) in respect of information that the Authority is required to publish under this Code, to make the information available to the public, at no cost, on a website maintained by, or on behalf of, the Authority; or

(b) in respect of information that a participant is required to publish under this Code, to make the information available to the public, at no cost, on a website maintained by, or on behalf of, the participant,—

and published, publishes, publication, and publishing have corresponding meanings


purchaser means a person who buys electricity from the clearing manager and, for the purposes of Parts 8, 13, 14, and 14A, has the additional meaning set out in clause 1.5


qualifying customer has the meaning set out in clause 9.21


qualifying date [Revoked]

Clause 1.1(1) qualifying date: inserted, on 1 April 2011, by clause 4(1) of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.


quantity, for the purposes of subpart 5 of Part 13, means—

(a) for a contract for differences or options contract the total volume in MWh of electricity to which the contract relates; or

(b) for a fixed-price physical supply contract, the volume in MWh of electricity reasonably likely to be supplied under the contract

ratio compensation means a multiplier, used to convert raw meter data into volume information, that is developed from—

(a) the connected ratio of measuring transformers; and

(b) the number of metering elements; and

(c) the resolution of the meter


raw meter data means—

(a) for the purposes of Part 10, information obtained by the interrogation of a metering installation; or

(b) for the purposes of Part 15, information obtained from a metering installation by 1 of the following interrogation methods:

(i) locally by way of a handheld computer or recording device (in which case it must take the form of a downloaded file); or

(ii) locally by way of any other manual record (in which case it must take the form of the first entry in a database system); or
(iii) remotely (in which case it must take the form of database records), but excluding data transmission between meters and data concentrators that are relaying information into the back office

Clause 1.1(1) raw meter data: substituted, on 29 August 2013, by clause 4(2)(s) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

reactive means that component of the impedance at which the current and voltage are 90 degrees out of phase

reactive capability means the reactive power injection or absorption capability of generating units and other reactive power resources such as Static Var Compensators, capacitors and synchronous condensers, and includes reactive power capability of a generating unit during the normal course of the generating unit operations

reactive current means the component of electrical current on a line 90 degrees out of phase with the voltage on the line


reactive energy means the integration over time of the product of voltage and current and the sine of the phase angle between them, normally measured in kilovar hours (kvarh)

Clause 1.1(1) reactive energy: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

reactive meter means a meter used for the measurement of reactive power

reactive power means the product of voltage and current and the sine of the phase angle between them, and which is normally measured in kiloVolt-Amps reactive (kVAr)

real time price means a price for electricity at a grid exit point or a grid injection point, and the price for instantaneous reserve in dollars and cents for the real time pricing period determined in accordance with clause 13.88


real time pricing period means a period of 5 minutes starting on the hour or any multiple of 5 minutes past the hour on any trading day

reasonable and prudent operating practice, in relation to distributed generation, includes—

(a) the industry operating standards; and

(b) measures to avoid the injection of electricity from distributed generation that—

(i) exceeds the distribution network capacity at the point of injection; or

(ii) results in a significant adverse effect on voltage levels; or

(iii) results in a significant adverse effect on the quality and reliability of electricity conveyed to other users of the distribution network; and

(c) the use or proposed use of reasonable and prudent measures to enable the connection of distributed generation

Clause 1.1(1) reasonable and prudent operating practice: amended, on 23 February 2015, by clause 4(10) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 1.1(1) reasonable and prudent operating practice: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.


reasonable and prudent system operator [Revoked]
Clause 1.1(1) reasonable and prudent system operator: revoked, on 19 May 2016, by clause 4(1) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.

recalibration means to repeat a calibration because a previous calibration has expired or become suspect, and recalibrate has a corresponding meaning.

recertification means to repeat a certification because a previous certification has expired or been cancelled, and recertified and recertify have corresponding meanings.

reconciled quantity means a quantity of electricity that has been reconciled by the reconciliation manager.

reconciliation information means information specifying the amount of electricity sold to or purchased from the clearing manager in each half hour of a reconciliation period (or such other period as has been agreed to), calculated from and reconciled with submission information and the relevant losses, and after the process of balancing in accordance with clause 22 of Schedule 15.4.

reconciliation manager means the market operation service provider who is for the time being appointed as reconciliation manager under this Code.

reconciliation participant means a participant (excluding the Authority (even if the Authority acts as a market operation service provider) and the Rulings Panel) who is any of the following:
(a) a retailer when purchasing electricity from, or selling electricity to, the clearing manager;
(b) a generator;
(c) a network owner;
(d) a distributor;
(e) a person who purchases electricity from or sells electricity to the clearing manager.

reconciliation period means a calendar month, subsequent to a consumption period, during which the reconciliation process is performed in respect of the electricity conveyed during 1 or more consumption periods.

reconciliation type means a code that identifies the type of processing to be performed during reconciliation.

reconfigured FTR means the portion of an FTR that was sold at an FTR reconfiguration auction.

reference point means,—
(a) for the North Island,—
(i) the Haywards 220 kV bus to which the HVDC Pole 2 or Pole 3 injection or offtake is electrically connected; or
(ii) if there is no Pole 2 or Pole 3 injection or offtake that is electrically connected to a Haywards 220 kV node:

(b) for the South Island,—
(i) the Benmore 220 kV bus to which the HVDC Pole 2 or Pole 3 injection or offtake is electrically connected; or
(ii) if there is no Pole 2 or Pole 3 injection or offtake that is electrically connected to a Benmore 220 kV bus, the first indexed Benmore 220 kV node:


reference standard means a measuring instrument that has been calibrated by an approved calibration laboratory and is not used as a working standard

register means the register of participants maintained by the Authority under section 16 of the Act

registered, in relation to a participant, means that details of the participant are kept in the register

registry means the database maintained by the Authority to record information about ICPs

registry manager means the market operation service provider for the time being appointed as registry manager under this Code

registry metering records means the metering records set out in Table 1 of clause 7 of Schedule 11.4
Clause 1.1(1) registry metering records: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

regulated terms means the terms set out in Schedule 6.2

relative standard error means the error expressed as a percentage of the estimated parameter

relevant contracts [Revoked]

relevant information [Revoked]
Clause 1.1(1) relevant information: revoked, on 1 October 2013, by clause 4(3) of the Electricity Industry
relevant local reconciliation contracts means the contracts for the sale and/or the purchase of electricity within a local network

relevant participant [Revoked]
Clause 1.1(1) relevant participant: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.
Clause 1.1(1) relevant participant: revoked, on 1 June 2017, by clause 4(2) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

relevant registration factor means the mean difference over time between metering installation readings and check metering information readings at the relevant grid exit point

republish [Revoked]

reserve offer means the information that an ancillary service agent submits to the system operator under clauses 13.37 to 13.54 specifying the instantaneous reserve the ancillary service agent is willing and able to provide
Clause 1.1(1) reserve offer: substituted, on 28 June 2012, by clause 4(g) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clause 1.1(1) reserve offer: substituted, on 29 June 2017, by clause 5(b) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.

residual loss and constraint excess means, in respect of a billing period, an amount available for the settlement of FTRs that is not required to settle FTRs for the billing period, but does not include any amount that is retained for the settlement of FTRs in a future billing period in accordance with clause 13.249(6)

resistive means that component of the impedance that is where the current and voltage are in phase

responsible party means the person responsible for the installation, maintenance, operation and interrogation of a metering installation and the supply of submission information to the reconciliation manager

retailer means as follows:
(a) except as provided in paragraphs (b) and (c), a participant who supplies electricity to another person for any purpose other than for resupply by the other person:
(b) in Parts 1 (except for the definition of specified participant), 8, 10, and 12 to 15, a participant who supplies electricity to a consumer or to another retailer:
(c) in subpart 4 of Part 9, the retailer defined in paragraph (a) who is recorded in the registry as being responsible for the ICP described in clause 9.21(1)(b)
Clause 1.1(1) retailer: substituted, on 1 April 2011, by clause 4(2) of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.
Clause 1.1(1) retailer para (b): amended, on 28 February 2015, by clause 4 of the Electricity Industry Participation Code Amendment (Trader Default) 2014.

Rio Tinto agreement [Revoked]

Rio Tinto party [Revoked]

risk management contract, for the purposes of subpart 5 of Part 13, means—
(a) a contract for differences; or
(b) a fixed-price physical supply contract; or
(c) an options contract; but
(d) does not include an FTR

round power means a mode of operation of the HVDC link where power is transferred in opposite directions on Pole 2 and Pole 3

rules means the Electricity Governance Rules 2003

Rulings Panel has the meaning given to it in section 5 of the Act

sample date means the most recent date when the profile sample was drawn or updated

satisfactory state means that none of the following occur on the power system:
(a) insufficient supply of electricity to satisfy demand for electricity at any grid exit point:
(b) unacceptable overloading of any primary transmission equipment:
(c) unacceptable voltage conditions:
(d) system instability

SCADA means the monitoring and remote control of equipment from a central location using computing technologies

SCADA situation means a situation where the input information to be given under clause 13.141(1)(a) is incorrect or incomplete, except when a reasonable estimate has been made by the grid owner under clause 13.141(1)(a)(ii)

scaling factor, for the purpose of Appendix A of Technical Code C of Schedule 8.3, means a factor applied to a measurement at 1 point to calculate a corresponding measurement at another point

schedule of dispatch prices, dispatch quantities, dispatch arc flows, dispatch group constraint arc flows, group constraint formulas and HVDC component flows [Revoked]
Clause 1.1(1) schedule of dispatch prices, dispatch quantities, dispatch arc flows, dispatch group constraint arc flows, group constraint formulas and HVDC component flows: revoked, on 28 June 2012, by clause 4(i) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

scarcity pricing situation means an island scarcity pricing situation or a national scarcity pricing situation
Clause 1.1(1) scarcity pricing situation: inserted, on 1 June 2013, by clause 4(a) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

schedule length period means,—
(a) in relation to a price-responsive schedule or a non-response schedule prepared under clause 13.62(1)(a), the current trading period and the following 71 trading periods; and
(b) in relation to a price-responsive schedule or a non-response schedule prepared under clause 13.62(1)(b), the current trading period and the following 7 trading periods
Clause 1.1(1) schedule length period: inserted, on 28 June 2012, by clause 4(a) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

schedule period means the current trading period and the following 71 trading periods
Clause 1.1(1) schedule period: substituted, on 28 June 2012, by clause 4(h) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

scheduled quantity, for the purposes of clauses 13.194 and 13.204(1)(a) and (b), means the sum of all the offer quantities at the relevant grid injection point at which the final price is equal to or greater than the offer price for each of those offer quantities in the relevant trading period. For the grid injection points that form part of a block dispatch group, scheduled quantity is the sum of all the offer quantities of the individual grid injection points that form that block dispatch group at which the final price is equal to or greater than the offer price for each of those offer quantities in the relevant trading period

scorecard rating means the numerical value, pursuant to clauses 17 and 18 of Schedule 15.4, to rate the quality of each retailer’s processes for the production of submission information

seasonal adjustment shape means the total energy consumption (expressed as daily kWh values) for all NSP derived profiles for all retailers in each balancing area

secure state means that the power system—
(a) would be in a satisfactory state; and
(b) would remain in a satisfactory state during and following a single credible contingency event occurring on the grid

security of supply forecasting and information policy means the security of supply forecasting and information policy that is incorporated by reference in this Code under clause 7.4

selected component certification means certification of a metering installation under clause 11(3) of Schedule 10.7
Clause 1.1(1) selected component certification: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.
seller, for the purposes of subpart 5 of Part 13, means—
(a) in respect of a contract for differences, the floating-price payer; or
(b) in respect of a fixed-price physical supply contract, the party selling the electricity; or
(c) in respect of an options contract, either—
(i) the party receiving the premium; or
(ii) if there is no premium under the options contract, the party who agrees to be the seller for the purposes of subpart 5 of Part 13; or
(iii) if neither party agrees to be the seller, the party whose name is the second alphabetically

series, for the purposes of determining the level of impedance of branches under Part 12, means an arrangement of assets where the assets comprising a branch have the same current flowing through them

serious financial breach—
(a) means a failure by a retailer—
(i) to pay to a distributor an amount due and owing that exceeds the greater of $100,000 or 20% of the actual charges payable by the retailer for the previous month, unless the amount is genuinely disputed by the retailer; or
(ii) to comply with the prudential requirements under a use-of-system agreement between the retailer and a distributor; but
(b) does not include a failure by a retailer to comply with prudential requirements to the extent that the prudential requirements exceed what is permitted under clauses 12A.4 and 12A.5.


services access interface means the point, at which access may be gained to the services available from a metering installation, that is—
(a) recorded in the certification report by the certifying ATH for the metering installation; and
(b) where information received from the metering installation can be made available to another person; and
(c) where signals for services such as remote control of load (but not ripple control) can be injected

Clause 1.1(1) services access interface: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

settlement default means failure of a participant to pay any amount payable when it becomes due under Part 14

shared unmetered load means unmetered load at a single point of connection that is distributed across more than 1 ICP

shortage situation means an island shortage situation or a national shortage situation
Clause 1.1(1) shortage situation: inserted, on 1 June 2013, by clause 4(a) of the Electricity Industry Participation
Electricity Industry Participation Code 2010
Part 1

65 1 February 2019

(Scarcity Pricing) Code Amendment 2011.

**shunt**, for the purposes of determining the level of impedance of **branches** under Part 12, means an arrangement of **assets** where the **assets** comprising a **branch** have the same voltage across the terminals

**shunt asset**, for the purposes of Part 12, means a shunt connected **asset** that is an **interconnection asset**

Clause 1.1(1) **shunt asset**: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

**simple random sampling without replacement** means the general procedure of drawing **consumers** from a **profile population** to form a sample. Each **consumer** in the **profile population** must have an equal probability of being drawn and may only be drawn once

**single credible contingency event** means an individual credible contingency event comprising any of the following:
(a) a single transmission circuit interruption:
(b) the failure or removal from operational service of a single **generating unit**:
(c) an **HVDC link** single pole interruption:
(d) the failure or removal from service of a single bus section:
(e) a single inter-connecting transformer interruption:
(f) the failure or removal from service of a single shunt connected reactive component

Clause 1.1(1) **single credible contingency event**: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

**single-line diagram** means a schematic diagram of a **network interface**

**software** means, other than in Parts 10 and 15, any software—
(a) developed by or on behalf of a **market operation service provider** that is used by that **market operation service provider** to perform its obligations under this Code or its **market operation service provider agreement**; or
(b) used by a **market operation service provider** exclusively for the purposes of performing its obligations under this Code or its **market operation service provider agreement**

Clause 1.1(1) **software**: amended, on 29 August 2013, by clause 4(2)(t) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

**software specification** means the user requirements and other information describing the **software** in respect of the **market operation service providers**

**special credit clause** means a clause in a **contract for differences** that specifies that, if a **party** defaults during the **term** of the contract, the **party** that is not in default will be paid a specified amount or that on execution of the contract, the **party** that is not in default, is provided with a guarantee that payment will be made when the settlement amount reaches a certain threshold
special protection scheme means a protection scheme that takes predetermined action, including reconfiguration of the grid, changes of demand, or changes of generation, to counteract a particular condition once that condition is detected. Special protection schemes allow a power system to be operated to a higher pre-event capacity limit while still in a secure state. Automatic under frequency load shedding systems and instantaneous reserves are excluded from the requirements for special protection schemes.

Clause 1.1(1) special protection scheme: inserted, on 1 June 2011, by clause 4(1) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2011.  

specified participant for the purposes of Part 9,—
(a) means any of the following:
   (i) distributor:
   (ii) retailer:
   (iii) a line owner; and
(b) includes a person who uses electricity that is conveyed to the person directly from the grid

spot price risk disclosure statement means a spot price risk disclosure statement prepared and submitted under clause 13.236A

statement of extended reserve obligations, in relation to an asset owner, means the latest statement of obligation given to the asset owner by the system operator under clause 8.54P

statement of proposal, in relation to a proposal, means a statement that contains—
(a) a detailed statement of the proposal; and
(b) a statement of the reasons for the proposal; and
(c) an assessment of the reasonably practicable options, including the proposal; and
(d) any other information relevant to considering the proposal.

station dispatch group means—
(a) 1 or more generating units that inject into a single grid injection point; or
(b) 1 or more generating units that are the subject of an agreement between the system operator and a generator,—
and is not a block dispatch group

station net means the sum of all generating unit net outputs for generating units at a single generating station, measured or calculated at its point of connection, but excludes generating unit load and any other active or reactive power (including losses) supplied between the generating station and the point of connection
station security constraint means any of the following:
(a) a constraint applied by the system operator to a generating unit to provide voltage support or frequency reserve capacity as determined in accordance with Part 8:
(b) a limitation in the offered capacity of a grid owner’s network to convey electricity between generating units constituting a station dispatch group:
(c) 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—
and, if in paragraphs (b) and (c) above, the limitation in the offered capacity is either the offered capacity of a grid owner’s network or a grid system security limit, as determined by the system operator in accordance with Part 8

stress test means a stress test published by the Authority under clause 13.236D

sub-block dispatch groups means a grouping of generating stations or generating units within a block dispatch group into subgroups to take account of any block security constraints of which the system operator gives notice in accordance with clauses 13.61(1) and 13.73(1)(j)
Clause 1.1(1) sub-block dispatch groups: amended, on 1 November 2018, by clause 4(8)(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

sub-station dispatch group means a grouping of generating units or generating stations within a station dispatch group into subgroups to take account of any station security constraints of which the system operator gives notice in accordance with clauses 13.65(1) and 13.75(1)(g)
Clause 1.1(1) sub-station dispatch groups: amended, on 15 May 2014, by clause 5(9) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

submission expiry date means—
(a) in the case of a submission on a draft policy statement, the date the Authority advises in accordance with clause 8.12(2); and
(b) in the case of a submission on a draft procurement plan, the date the Authority advises in accordance with clause 8.44(2); and
(c) in the case of a submission on the transmission agreement structure, the date the Authority advises in accordance with clause 12.6(3); and
(d) in the case of a submission on the draft benchmark agreement, the date the Authority advises in accordance with clause 12.32(2); and
(e) in the case of a submission on the draft grid reliability standards, the date
published by the Authority in accordance with clause 12.61(3); and

(f) in the case of a submission on the issues paper, the date published by the Authority in accordance with clause 12.82(1); and

(g) in the case of a submission on the proposed transmission pricing methodology, the date published by the Authority in accordance with clause 12.92(2)

Clause 1.1(1) submission expiry date: amended, on 19 December 2014, by clause 4(4) of the Electricity Industry Participation Code Amendment (Minor Code Amendments) (No 3) 2014.

Clause 1.1(1) submission expiry date: amended, on 1 November 2018, by clause 4(10)(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

submission information means volume information aggregated in accordance with clause 8 of Schedule 15.3 (and includes, if relevant, any profile shape or control times associated with a profile)

subsidiary means a subsidiary as defined in section 5 of the Companies Act 1993

supply means a measure of the rate of production of electrical energy

supply shortage declaration means a declaration made under clause 9.14

suspension clause means a clause in a risk management contract under which some or all of the obligations may be suspended due to an event directly relating to the supply (including transmission) or generation of electricity or the price at which electricity is supplied, including an inability to inject electricity into the grid as a result of an outage of or damage to the grid or a grid injection point or the price of electricity exceeding a level specified in the contract

sustained instantaneous reserve means—

(a) for providers of partly loaded spinning reserve and tail water depressed reserve, the average additional output (in MW) provided during the first 60 seconds after a Contingent Event (as defined in the policy statement) that is sustained for at least 15 minutes after the Contingent Event (unless a new dispatch instruction is given before the expiry of that 15 minute period); and

(b) for providers of interruptible load, the average drop in load (in MW) that occurs over the first 60 seconds after the grid system frequency falls to or below 49.2 Hz that is sustained until instructed by the system operator

switch event meter reading, in relation to a meter or data storage device that is located at an ICP that is being switched under Schedule 11.3, means—

(a) a validated meter reading, if one is available; or

(b) a reasonable estimate of the meter reading based on the meter reading contained in the final information provided in the switch file that the losing trader received when it gained the ICP if—

(i) a validated meter reading is not available; and

(ii) the losing trader has been recorded in the registry as being responsible for the ICP for a period of less than 3 months; or

(c) in every other case, a permanent estimate

Clause 1.1(1) switch event meter reading: amended, on 9 October 2015, by clause 4 of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.
synchronised means the condition whereby a synchronous machine is electrically connected to a network and the electrical angular velocity of the machine corresponds with the network frequency and synchronise, de-synchronise, synchronising, synchronism and synchronisation have corresponding meanings. Asynchronous intermittent generating stations must be treated as being synchronised for the purposes of subpart 2 of Part 8
Clause 1.1(1) synchronised: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

system instability means operating conditions under which it is reasonably likely that 1 or more generating units may cease to be synchronised with the grid

system number means a coded number assigned to assets referred to in clause 2(1)(a) of Technical Code A of Schedule 8.3 for the purposes of the operation of the grid and the management of the assets that, when used in conjunction with a locality name, uniquely identifies the assets

system operator has the meaning given to it in section 5 of the Act

system operator register means the register kept by the system operator for recording equivalence arrangements, dispensations, and alternative ancillary service arrangements in accordance with clause 8 of Schedule 8.1 and clause 4 of Schedule 8.2. The system operator must maintain an up to date copy of the system operator register and publish it and keep it published

system operator rolling outage plan means the system operating rolling outage plan that is incorporated by reference in this Code under clause 9.3

system security means the security and quality objectives set out in Part 8

system security forecast means the forecast prepared by the system operator under clause 8.15

system security situation means any situation that the system operator believes on reasonable grounds is not adequately mitigated by the current policy statement and 1 of the following exists:
(a) the system operator reasonably considers that its ability to comply with the principal performance obligations is at risk:
(b) there is a risk of significant damage to assets:
(c) public safety is at risk

system test means a test conducted on an asset, with the asset electrically connected to the grid, to assess the interaction of the asset with the grid
Clause 1.1(1) system test: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
tail water depressed reserve means a form of instantaneous reserve comprising a generating capacity on a motoring hydro generation set with no water flowing through the turbine that is available following a drop in system frequency

technical codes means the technical codes contained in Schedule 8.3

temporary energisation [Revoked]
Clause 1.1(1) temporary energisation: inserted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

term, for the purposes of subpart 5 of Part 13, means the term of a risk management contract, being the period between the effective date and the end date

test facility means a device that permits access to voltage and current circuits for testing purposes while the metering installation is in normal service

time block means a block of trading periods either from 1 to 16 (inclusive) or from 17 to 48 (inclusive) in each trading day. On the day on which New Zealand daylight time begins, time block means a block of trading periods either from 1 to 14 (inclusive) or from 15 to 46 (inclusive). On the day on which New Zealand daylight time ends, time block means a block of trading periods either from 1 to 18 (inclusive) or from 19 to 50 (inclusive)

total auction revenue means, for each auction, the aggregate of all amounts owing by all generators in the relevant time block

traceable means having the property of traceability

traceability is the property of the result of a measurement whereby it can be related to the SI units of measurement through an unbroken chain of comparisons, each with a stated uncertainty

trade date, for the purposes of subpart 5 of Part 13, means the date on which legally binding rights and obligations are created between the parties to a risk management contract

trader means a retailer or a generator or a purchaser who—
(a) buys electricity from the clearing manager; or
(b) sells electricity to the clearing manager; or
(c) enters into an arrangement with another retailer or generator or purchaser to buy or sell contracts (or parts of contracts) for electricity for the purposes of this Code

trading day means the period from 0000 hours until 2400 hours on any day

trading period means a period of 30 minutes ending on each hour or 30 minutes past each hour on any trading day
trading rights means, in relation to a generator or a purchaser, the rights conferred on the generator or purchaser by this Code in relation to the trading of electricity

transfer means transfer, sell, assign or otherwise dispose of an ownership interest

transformer branch means a branch that contains a transformer

transmission alternative [Revoked]

transmission agreement means an agreement for connection and/or use of the grid under subpart 2 of Part 12 (including, if relevant, an agreement for investment in the grid)
Clause 1.1(1) transmission agreement: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

transmission alternative means an alternative to investment in the grid, including investment in local generation, energy efficiency, demand-side management and distribution network augmentation set out in Part 12

transmission pricing methodology means the pricing methodology developed in accordance with subpart 4 of Part 12

transmission security constraint means a flow limit covered by clause 15(d)(i) or (iii) of Schedule 13.3, including any adjustments that have been made in accordance with clause 13(2)(d) and (f) of Schedule 13.3, but excluding a flow limit in relation to the HVDC link

Transpower means Transpower New Zealand Limited

type A co-generator means the owner of a type A industrial co-generating station, in its capacity as owner of that industrial co-generating station

type A industrial co-generating station means an industrial co-generating station approved by the Authority under clause 8(1)(a)(i) of Schedule 13.4

type B co-generator means the owner of a type B industrial co-generating station, in its capacity as owner of that industrial co-generating station

type B industrial co-generating station means an industrial co-generating station approved by the Authority under clause 8(1)(a)(ii) of Schedule 13.4
type-testing means subjecting a sample or samples of a device to testing by an approved test laboratory accredited for the appropriate form of type-testing to verify compliance of that device with a prescribed standard or defined requirements, and type-test and type-tested have corresponding meaning.

unacceptable overloading means that 1 or more grid assets exceed their stated capability, as set out in the asset capability statements for those grid assets, for the prevailing conditions, including without limitation ambient and seasonal temperature, pre-fault loading and time dependent loading cycles.

unaccounted for electricity and UFE mean, for any balancing area, the quantity of electricity, as calculated per trading period by the reconciliation manager under clause 16 of Schedule 15.4.

unacceptable voltage conditions means voltages on the grid outside the limits specified in Part 8 of this Code.

uncertainty means a parameter associated with the result of a measurement that characterises the dispersion of the values that could reasonably be attributed to the quantity being measured, and must be determined to a confidence level of 95% or greater unless otherwise specifically stated.

unconstrained cleared offer price means the highest amount in dollars and cents per MWh specified for a grid injection point or a grid exit point in an offer that is—

(a) provided to the pricing manager in accordance with clause 13.63; and

(b) less than or equal to the price for electricity at that grid injection point or grid exit point calculated by the software used by the pricing manager to calculate provisional prices and final prices.

under-frequency event means—

(a) an interruption or reduction of electricity injected into the grid; or

(b) an interruption or reduction of electricity injected from the HVDC link into the South Island HVDC injection point or the North Island HVDC injection point—

if there is, within any 60 second period, an aggregate loss of injection of electricity in excess of 60 MW (being the aggregate of the net reductions in the injection of electricity (expressed in MW) experienced at grid injection points and HVDC injection points by reason of paragraph (a) or (b)), and such loss causes the frequency on the grid (or any part of the grid) to fall below 49.25 Hz (as determined by system operator frequency logging).

under-frequency limit means the minimum frequency of 48hz for a contingent event.

undesirable trading situation means any situation—

(a) that threatens, or may threaten, confidence in, or the integrity of, the wholesale market; and

(b) that, in the reasonable opinion of the Authority, cannot satisfactorily be resolved by any other mechanism available under this Code (but for the purposes of this paragraph a proceeding for a breach of clause 13.5A is not to be regarded as
another mechanism for satisfactory resolution of a situation)


**unit cost** means the quantity calculated by dividing the product of the consumer’s half hour consumption and the corresponding half hour prices over a defined time period by the sum of the consumer’s half hour consumption over the same period of time (note that the half hour prices are based on the prices for trading at the grid exit point supplying energy to the consumer)

**unmetered load** means electricity consumed that is not directly recorded using a meter, but is calculated or estimated in accordance with this Code, and includes shared unmetered load and distributed unmetered load

**unoffered generation** means electricity supplied from a generating station for which an offer has not been made in accordance with clause 13.25, but which is purchased by the clearing manager

**unplanned interruption**, for the purposes of Part 12, means an interruption caused by an unplanned outage

**unplanned outage**, for the purposes of Part 12, means an outage not planned in accordance with the planning requirements set out in the Outage Protocol

**use-of-system agreement** means an agreement between a distributor and a trader that allows the trader to trade on the distributor’s local network or embedded network

Clause 1.1(1) use-of-system agreement: inserted, on 1 December 2011, by clause 4(a) of the Electricity Industry Participation Code (Distributor Use-of-System Agreements and Distributor Tariffs) Amendment 2011.


**validated meter reading** means a meter reading that has passed a reconciliation participant’s validation process in accordance with clauses 16 and 17 of Schedule 15.2

**value of expected unserved energy** means the value of any expected unserved energy that applies under clause 4 of Schedule 12.2 or clause 12.39


**verification notice**, for the purposes of subpart 5 of Part 13, means the notice provided by the other party in accordance with clause 13.226(2)(b) or (c)

**voltage support** means an ancillary service comprising reactive power injection to the power system to boost voltage at the point of injection

**volume information** means the information describing the quantity of electricity generated, conveyed, or consumed that is calculated or estimated from raw meter data and supporting data, and in the case of unmetered load, calculated in accordance with this Code
**washup** means the correction procedure followed as set out in subpart 6 of Part 14 if incorrect information, including **volume information**, has been used in calculating an amount owing under Part 14.


**wholesale market** means—

(a) the spot market for **electricity**, including the processes for setting—

(i) **real time prices**;

(ii) **forecast prices** and **forecast reserve prices**;

(iii) **provisional prices** and **provisional reserve prices**;

(iv) **interim prices** and **interim reserve prices**;

(v) **final prices** and **final reserve prices**;

(b) markets for **ancillary services**;

(c) the hedge market for **electricity**, including the market for **FTRs**

Clause 1.1(1) **wholesale market**: substituted, on 18 July 2013, by clause 4(2) of the Electricity Industry Participation (Undesirable Trading Situation) Code Amendment 2013.

**wind generating station** means 1 or more **generating units** that are connected to the **grid** or to a **local network** and that inject into the **grid** or a **local network** (as the case may be) at a single point of **injection**, and for which wind is the primary power source.

Clause 1.1(1) **wind generating station**: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.


**winter capacity margin** means the difference between a measure of the expected capacity and expected demand from 1 April to 31 October between 7am and 10pm, expressed as a MW margin over demand.

**winter energy margin** means the difference between the expected amount of energy that can be supplied and expected demand during the period 1 April to 30 September, expressed as a percentage of expected demand.

**WITS** means the system operated by the **WITS manager**


**WITS manager** means the **market operation service provider** for the time being appointed as wholesale information trading system provider under this Code.


**working day** [Revoked]

Clause 1.1(1) **working day**: revoked, on 5 October 2017, by clause 4(60) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

**working standard** means a measuring instrument that has been **calibrated** by an **approved calibration laboratory** or an **ATH**, that is used routinely for the **calibration** of **metering installations** and **metering components**


**works** has the meaning given to it in section 5 of the **Act**
year [Revoked]

zone means the following points of connection:
(a) zone 1: all points of connection to the grid in the North Island on circuits north of Huntly (excluding the Thames Valley spur):
(b) zone 2: all points of connection to the grid in the North Island not in zone 1:
(c) zone 3: all points of connection to the grid in the South Island on circuits north of (and not including) Islington, Coleridge, Hororata and Papanui:
(d) zone 4: all points of connection to the grid in the South Island not in zone 3

(2) Any term that is defined in the Act and used, but not defined in this Code, has the same meaning as in the Act.

1.2 General principles of construction
In this Code—
(a) a participant who carries on the functions or business of a generator, a purchaser, a distributor, a grid owner or a market operation service provider is, for the purpose of this Code, to be treated as a separate person for each such function or business, notwithstanding that at law all or any of the functions or businesses may be carried on by the same person; and
(b) for the purpose of the arrangements expressed in this Code as to the supply and conveyance of electricity by a generator or a purchaser to another generator or purchaser, the supply and conveyance is deemed to have been made, notwithstanding that the physical flow of electricity from generators to consumers will not necessarily correspond with the contractual supply of electricity from generators to purchasers.

1.3 Special definition of “related”
For the purposes of this Code a person (the “first person”) is deemed to be related to another person (the “second person”) if the first person is related to the second person by reason of any domestic or business relationship (other than because the second person is a customer of the first person), such that the first person can reasonably be expected to have influence over the second person’s judgment in trading or investment matters, or to be consulted by the second person before any such judgment is formed, and if the first person is deemed to be so connected, the second person is also deemed to be related to the first person. No person is deemed to be related to any other person if either person is a shareholding minister as that term is defined in section 2 of the State-Owned Enterprises Act 1986 or any other New Zealand legislation, provided that person is acting in his or her capacity as a shareholding minister.

Compare: Electricity Governance Rules 2003 rule 2 part A
1.4 Special definition of “independent”
A person is deemed to be independent for the purposes of this Code, unless the person—
(a) is a director or employee of a participant; or
(b) has a direct or indirect financial interest, whether legal or beneficial, and whether
as a shareholder, a partner or another equity holder in a participant, other than an
interest not greater than 0.1% of the equity capital or funds of the relevant entity
or, if that entity is a subsidiary of another entity, of the other entity; or
(c) is a director or employee of a shareholder, a partner or another equity holder
referred to in paragraph (b); or
(d) is a person who regularly or from time to time trades, directly or indirectly, under
this Code.

Compare: Electricity Governance Rules 2003 rule 4 part A

1.5 Special definition of “purchaser” and “participant”
(1) For any matter that relates to a trading period during which a notice given under
subclause (2) is in effect, a reference in Parts 8, 13, 14, or 14A of this Code to a
purchaser or a participant that incurs financial obligations under this Code or owes an
amount to the clearing manager, if it refers to a participant who is described as
participant B in the notice, must be read as a reference to the participant who is
described as participant A in the notice.
(2) A participant (participant A) may, by notice in the form set out in Schedule 1.1, give
notice to the Authority that, from a date specified in the notice, participant A will
assume all rights and obligations under Parts 8, 13, 14, and 14A of this Code of another
participant named in the notice (participant B) in participant B’s capacity as a
purchaser and a participant that incurs financial obligations under this Code or owes
an amount to the clearing manager.
(3) A notice given under subclause (2) takes effect from the first trading period on the date
specified in the notice. That date must be at least 30 business days after the date that
the notice is given to the Authority.
(4) A notice given under subclause (2) does not take effect unless the Authority approves it
by notice to the clearing manager, participant A, and participant B.
(5) Participant A or participant B may revoke a notice given under subclause (2) by giving
notice to the Authority in the form set out in Schedule 1.2.
(6) A revocation takes effect from the first trading period on the date specified in the
notice. That date must be at least 15 business days after the date that the notice is given
to the Authority.
(7) A notice given under subclauses (2) or (5) must be signed by both participant A and
participant B.
(8) The Authority must publish notice of—
(a) each approval given by the Authority under subclause (4); and
(b) each revocation under subclause (5).
(9) If, but for this clause, a provision in Parts 8, 13, 14, or 14A of this Code would confer a right or impose an obligation on participant B in participant B’s capacity as a purchaser or a participant that incurs financial obligations under this Code or owes an amount to the clearing manager, that provision must be read as conferring the right or imposing the obligation on participant A in respect of every trading period during which a notice under subclause (2) is in effect.

(10) Participant A is able to comply with any obligation that arises from the operation of subclause (9) by complying in aggregate with its own obligations under this Code and obligations that arise from the operation of subclause (9).

(11) To avoid doubt, for any trading period during which a notice under subclause (2) is in effect, participant A is deemed to be the person who buys electricity from the clearing manager for participant B.

Compare: Electricity Governance Rules 2003 rule 5 part A

1.5A Application of Code to distributors
Except in Parts 6, 9, and 12A, nothing in this Code applies to a distributor in respect of its distribution activities that are not conducted on a network that is—
(a) directly connected to the grid; or
(b) indirectly connected to the grid through 1 or more other networks.

1.6 Contents tables
The contents tables that appear at the beginning of this Code, and at the beginning of each Part, are included only to assist in reading this Code, and do not form part of it.

1.7 Defined terms appear in bold
Words and phrases appear in bold in this Code only to alert the reader to the fact that they are defined in this Part.
Schedule 1.1

Notice of assumption of rights and obligations under Parts 8, 13, 14, and 14A of the Electricity Industry Participation Code 2010


1. ________________________________ (participant A) gives notice to the Electricity Authority under clause 1.5(2) of the Electricity Industry Participation Code 2010 that it will assume all rights and obligations of ________________________________ (participant B) under Parts 8, 13, 14, and 14A of the Electricity Industry Participation Code 2010 in participant B's capacity as a purchaser and as a participant that incurs financial obligations under that Code or owes an amount to the clearing manager.

2. The notice given under clause 1 will, if approved by the Electricity Authority under clause 1.5(4) of the Electricity Industry Participation Code 2010, take effect from the first trading period on ______________ and will continue until it is revoked by participant A or participant B under clause 1.5(5) of the Electricity Industry Participation Code 2010.

SIGNED for and on behalf of

______________________________ by

(participant A)

______________________________

(insert name)

______________________________

(insert occupation)

______________________________

(insert date)

SIGNED for and on behalf of

______________________________ by

(participant B)

______________________________

(insert name)

______________________________

(insert occupation)

______________________________

(insert date)

Compare: Electricity Governance Rules 2003 schedule A1 part A
Schedule 1.2

Revocation of notice of assumption of rights and obligations under Parts 8, 13, 14, and 14A of the Electricity Industry Participation Code 2010


1. _______________ gives notice to the Electricity Authority that the notice given to the Authority under clause 1.5(2) of the Electricity Industry Participation Code 2010 by __________________________ (participant A) on ________________ that it would assume all rights and obligations under Parts 8, 13, 14, and 14A of the Electricity Industry Participation Code 2010 of __________________________ (participant B) in participant B’s capacity as a purchaser and as a participant that incurs financial obligations under that Code or owes an amount to the clearing manager is revoked.

2. The revocation under clause 1 will take effect from the first trading period on __________________________.

SIGNED for and on behalf of __________________________
_____________________________ by __________________________
(participant A)

_____________________________
[insert name]

_____________________________
[insert occupation]

_____________________________
[insert date]

SIGNED for and on behalf of __________________________
_____________________________ by __________________________
(participant B)

_____________________________
[insert name]

_____________________________
[insert occupation]

_____________________________
[insert date]

Compare: Electricity Governance Rules 2003 schedule A2 part A
Power to request Code information

2.1 Requests for Code information

Information held by Authority

2.2 Information held by Authority

Information held by other participants

2.3 Information not held by Authority

2.4 Authority must contact participant believed to hold requested information

2.5 Participant must consider request

2.6 Code information should be made available to all participants unless good reason

2.7 Other reasons

2.8 Transfer of requests

2.9 Participants must not enter contracts that prejudice supply of Code information

2.10 Decision about supplying information

2.11 Process if participant agrees to supply information

2.12 Charges payable

2.13 Documents may include deletions

2.14 Process if participant refuses to supply information

2.15 Appeal

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Power to request Code information

2.1 Requests for Code information

(1) A participant may request the Authority to make available to the participant (the requesting participant) any Code information held by the Authority or by any other participant.

(2) The request must specify, with as much particularity as possible, the nature of the information sought and the name of the participant who is believed to hold the information.

Compare: SR 2003/374 r 15

Information held by Authority

2.2 Information held by Authority

If the Authority receives a request for the supply of Code information that the Authority holds, the Authority must—

(a) consider and process the request in accordance with the Official Information Act 1982; and

(b) if the Authority proposes to provide the information to the requester, give prior written notice to the participant that supplied the information to the Authority.
Information held by other participants

2.3 Information not held by Authority
The rest of this Part applies if the Authority receives a request for the supply of Code information that the Authority does not hold.

2.4 Authority must contact participant believed to hold requested information
The Authority must, as soon as practicable after receiving a request for Code information that it does not hold, send a written notice to the participant who the Authority believes holds the relevant Code information—
(a) giving the participant written notice of the request made to the Authority, and the name and address of the requesting participant; and
(b) requesting the participant to either—
   (i) supply the information, together with a note of the participant’s charges (if any) in relation to the supply of information; or
   (ii) supply reasons for refusing to supply the information.

2.5 Participant must consider request
A participant who receives a request under clause 2.4(b) must consider that request in accordance with clauses 2.6 to 2.8.

2.6 Code information should be made available to all participants unless good reason
(1) The general principle to be followed by participants in relation to Code information is that Code information should be made available to all participants unless there is good reason for refusing to supply it.
(2) A participant has good reason for refusing to supply Code information if the supply of the information would be likely to—
   (a) breach a legislative, regulatory, or other legal requirement; or
   (b) prejudice the maintenance and supervision of this Code, including the prevention, investigation, and detection of Code breaches and the right to a fair hearing before the Rulings Panel; or
   (c) result in a disclosing participant breaching an obligation of confidentiality; or
   (d) interfere with the privacy of natural persons; or
   (e) create an improper gain or improper advantage for the requesting participant or any other participant or person; or
(f) commercially disadvantage the disclosing participant or any other participant or person, in a material manner; or
(g) prejudice the future supply of information that is required by a market operation service provider to perform any obligation under this Code.

Compare: SR 2003/374 r 20

2.7 Other reasons
A participant may also refuse to supply Code information if—
(a) the information requested is, or will soon be, made available to the public; or
(b) the information requested does not exist or cannot be found; or
(c) the information requested cannot be made available without substantial collation or research and the Authority agrees that it is unreasonable to undertake the collation or research; or
(d) the request is frivolous or vexatious or the information requested is trivial.

Compare: SR 2003/374 r 21

2.8 Transfer of requests
(1) This clause applies if—
(a) a notice is sent to a participant under clause 2.4(b); and
(b) the information to which the request relates—
(i) is not held by the participant but is believed by the person dealing with the notice to be held by another participant; or
(ii) is believed by the person dealing with the notice to be more closely related to the activities of another participant.

(2) The participant to which the notice was sent must promptly, and in any case not later than 10 business days after the day on which the notice is received, transfer the notice to the other participant, and inform the Authority accordingly.

Compare: SR 2003/374 r 22

2.9 Participants must not enter contracts that prejudice supply of Code information
A participant must, so far as is reasonably practicable without materially affecting its business or its ability to meet its obligations under this Code, avoid entering into an obligation with a person that would have the effect of prejudicing that participant’s ability to comply freely with the provisions of this Part.

Compare: SR 2003/374 r 23

2.10 Decision about supplying information
A participant must, as soon as practicable after considering a request, inform the Authority and the requesting participant of whether it agrees or refuses to supply all or part of the Code information requested.

Compare: SR 2003/374 r 24
2.11 Process if participant agrees to supply information
(1) If a participant agrees to supply all or part of the Code information requested, the participant must, as soon as practicable,—
(a) inform the Authority and the requesting participant of the information that will be supplied, and the amount of any charges to be paid for the supply of that information under clause 2.12; and
(b) supply that information, with any deletions authorised by clause 2.13, to the Authority.
(2) The Authority must, as soon as practicable after receiving the information, and any charges required to be paid in respect of it by the requesting participant, send the information to the requesting participant.

Compare: SR 2003/374 r 25

2.12 Charges payable
(1) A participant that supplies Code information may charge the requesting participant for—
(a) the reasonable cost of labour and materials involved in supplying the information to the requesting participant; and
(b) any additional costs incurred as a result of a request for urgent availability.
(2) The participant that supplies the Code information, or the Authority, may require the whole or any part of the charge to be paid in advance by the requesting participant.

Compare: SR 2003/374 r 26

2.13 Documents may include deletions
If the Code information requested is contained in a document, and there are good reasons for refusing to supply some of the information contained in the document, the participant supplying the information may supply a copy of the document with any deletions or alterations that are necessary.

Compare: SR 2003/374 r 27

2.14 Process if participant refuses to supply information
(1) If the participant refuses to supply all or any of the Code information requested, the participant must, as soon as practicable, give written notice to the Authority and the requesting participant of both the refusal and of the reasons for the refusal.
(2) The Authority must, as soon as practicable after receiving the notice, advise the requesting participant of its rights to appeal under clause 2.15.

Compare: SR 2003/374 r 28
2.15 Appeal

A requesting participant who receives written notice under clause 2.14 that another participant refuses to supply any Code information may appeal that refusal by notice of appeal to the Rulings Panel.

Compare: SR 2003/374 r 29
Electricity Industry Participation Code 2010

Part 3
Market operation service providers

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3.1 Appointment of market operation service providers

(1) The Authority must appoint a person or persons to perform each of the following market operation service provider roles:
   (a) registry manager;
   (b) reconciliation manager;
   (c) pricing manager;
   (d) clearing manager;
   (e) FTR manager;
   (f) WITS manager;
   (g) extended reserve manager:
(h) any other role identified in regulations as a market operation service provider role and for which market operation services are provided under this Code.

(2) [Revoked].

(3) The system operator is also a market operation service provider, but clauses 3.3, 3.10 and 3.15 do not apply to the system operator.

(4) The Authority may also appoint a person or persons to act as an industry service provider in providing any service under this Code.

Compare: SR 2003/374 r 30

3.2 Functions, rights, powers, and obligations of market operation service providers

A market operation service provider has the functions, rights, powers, and obligations set out in relation to that market operation service provider under this Code and Part 2 and Subpart 1 of Part 4 of the Act.

Compare: SR 2003/374 r 31

3.2A Market operation service providers to assist Authority to give effect to Authority's statutory objective

(1) Each market operation service provider must perform its obligations under this Code in a way that assists the Authority to give effect to the Authority’s statutory objective.

(2) The system operator must progressively increase the extent to which it assists the Authority to give effect to the Authority’s statutory objective.

(3) The system operator is not required to comply with subclause (1) when exercising discretion in real time in performing its functions.

(4) This clause does not permit a market operation service provider to contravene any other provision of this Code.

Clause 3.2A: inserted, on 19 May 2016, by clause 6 of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.

3.3 Term of appointment of market operation service provider

(1) A market operation service provider’s term of appointment, and the date on which the term begins, is as agreed between the Authority and the market operation service provider.

(2) The Authority may at any time terminate, re-appoint, or change the appointment of a person as a market operation service provider, subject to the terms of any agreement between that market operation service provider and the Authority.

Compare: SR 2003/374 r 32(1) and (2)
3.4 Terms of market operation service provider agreements

(1) The remuneration of a market operation service provider is as agreed between the Authority and the market operation service provider.

(2) The Authority and the market operation service provider may agree on any other terms and conditions, not inconsistent with the functions, rights, powers, and obligations of that market operation service provider under this Code and Part 2 and Subpart 1 of Part 4 of the Act.

Compare: SR 2003/374 r 33

3.5 Publication of market operation service provider agreements

The Authority must publish each market operation service provider agreement.

Compare: SR 2003/374 r 34

3.6 Insurance cover

Each market operation service provider must at all times maintain any insurance cover that is required by the Authority, on terms and in respect of risks approved by the Authority, with an insurer approved by the Authority.

Compare: SR 2003/374 r 36

Force majeure provisions relating to market operation service providers

3.7 Relief of obligation because of force majeure

(1) A market operation service provider is relieved of an obligation under this Code and under the Electricity Industry (Enforcement) Regulations 2010 to the extent that, and for so long as, it is unable to perform the obligation as a result of a force majeure event.

(2) Subclause (1) applies only—

(a) if the market operation service provider promptly advises the Authority of—

(i) the details of the force majeure event; and

(ii) the obligation that cannot be performed; and

(iii) the likely duration of the inability to perform the obligation; and

(b) for so long as the market operation service provider uses its reasonable endeavours to overcome the inability to perform the obligation from which it seeks relief and to remove or mitigate the effect of the force majeure event; and

(c) if the market operation service provider provides the Authority with reports in accordance with subclauses (3) and (4).

(3) As soon as practicable, but in any event no later than by the end of the month following the month in which the market operation service provider advises the Authority of a force majeure event under subclause (2)(a), the market operation service provider must provide the Authority with a written report that sets out—

(a) the full details of the force majeure event; and
Electricity Industry Participation Code 2010
Part 3

(b) the actions the market operation service provider is taking or intends to take to comply with subclause (2)(b); and
(c) the proposed timeline for completing the actions.

(4) By the end of each following month (unless the Authority advises that reports may be provided less frequently or are not required) the market operation service provider must provide the Authority with a written report that updates the information previously provided and includes any other matters related to the force majeure event that the Authority requests.

(5) The Authority must publish the information provided under subclause (2)(a) and the reports provided under subclauses (3) and (4) as soon as practicable after receiving the information.

(6) Despite subclause (5), the Authority must not publish or otherwise make available to the public any information or any part of a report if the market operation service provider advises the Authority (with reasons) that the market operation service provider considers that it would have good reason to refuse to supply the information or the part under clause 2.6 or clause 2.7.

3.8 Effect of relief
If a market operation service provider is relieved of an obligation under clause 3.7,—
(a) the market operation service provider is not liable for a breach of this Code or with the Electricity Industry (Enforcement) Regulations 2010 in respect of that obligation during the period for which the relief applies under that clause; and
(b) any costs arising from the relief from the obligation lie where they fall, except that the Authority and the market operation service provider may agree to adjust the remuneration of the market operation service provider.

3.9 Authority may contract elsewhere during force majeure event
For the duration of a force majeure event, the Authority may contract with others for the performance of an obligation that the market operation service provider fails to perform in accordance with this Code or with the Electricity Industry (Enforcement) Regulations 2010, or the relevant market operation service provider agreement.

3.10 Authority may terminate market operation service provider agreements
If a force majeure event results in a market operation service provider being relieved of a material obligation for more than 30 continuous days, the Authority may terminate
the relevant market operation service provider agreement by written notice with immediate effect.  
Compare: SR 2003/374 r 41(1)

Disclosure to Authority

3.11 Disclosure to Authority
  Each market operation service provider is entitled to disclose to the Authority all information received by it from any person as part of its provision of services under this Code and Part 2 and Subpart 1 of Part 4 of the Act.
  Compare: SR 2003/374 r 42  

Performance standards

3.12 Performance standards to be agreed
  The Authority and the relevant market operation service provider must, at the beginning of each year ending 30 June, seek to agree on a set of performance standards against which the market operation service provider’s actual performance must be reported and measured at the end of the financial year.
  Compare: SR 2003/374 r 43  

Accountability of market operation service providers via self-review

3.13 Self-review must be carried out by market operation service providers
  (1) Each market operation service provider must conduct, on a monthly basis, a self-review of its performance.
  (2) The review must concentrate on the market operation service provider’s compliance with—
      (a) its obligations under this Code and Part 2 and Subpart 1 of Part 4 of the Act; and
      (b) the operation of this Code and Part 2 and Subpart 1 of Part 4 of the Act; and
      (c) any performance standards agreed between the market operation service provider and the Authority; and
      (d) the provisions of the market operation service provider agreement.
  Compare: SR 2003/374 r 44  

3.14 Market operation service providers must report to Authority
  (1) Each market operation service provider must prepare a written report for the Authority on the results of the review carried out under clause 3.13.
  (1A) A market operation service provider must provide the report prepared under subclause (1) to the Authority—
(a) within 10 business days after the end of each calendar month except after the month of December:

(b) within 20 business days after the end of the month of December.

(2) The report must contain details of—

(a) any circumstances identified by the market operation service provider in which it has failed, or may have failed, to comply with its obligations under this Code and Part 2 and Subpart 1 of Part 4 of the Act; and

(b) any event or series of events that, in the market operation service provider’s view, highlight an area where a change to this Code may need to be considered; and

(c) any other matters that the Authority, in its reasonable discretion, considers appropriate and asks the market operation service provider, in writing within a reasonable time before the report is provided, to report on.

Compare: SR 2003/374 r 45

3.14A Market operation service providers to self-report breaches to Authority

(1) If a market operation service provider believes on reasonable grounds that it has breached a provision of this Code, the market operation service provider must report the alleged breach to the Authority in writing as soon as practicable after the market operation service provider becomes aware of the alleged breach.

(2) The written report must specify—

(a) the provision of this Code allegedly breached; and

(b) the date and time the alleged breach occurred; and

(c) the circumstances relating to the alleged breach, including any participants the market operation service provider believes the alleged breach may have affected.


3.15 Review of market operation service providers

(1) At the end of each year ending 30 June, the Authority may review the manner in which each market operation service provider has performed its duties and obligations under this Code and Part 2 and Subpart 1 of Part 4 of the Act.

(2) The review must concentrate on the market operation service provider’s compliance with—

(a) its obligations under this Code and Part 2 and Subpart 1 of Part 4 of the Act; and

(b) the operation of this Code and Part 2 and Subpart 1 of Part 4 of the Act; and

(c) any performance standards agreed between the market operation service provider and the Authority; and

(d) the provisions of the market operation service provider agreement.
Market operation service provider software

3.16 Software specifications for market operation service providers

(1) This clause and clauses 3.17 and 3.18, apply only to software that the market operation service provider agreement requires the market operation service provider to use.

(2) Unless otherwise agreed by the Authority in writing, the software specification for all software to be used by a market operation service provider must be set out or described in the market operation service provider agreement for that market operation service provider.

(3) Each market operation service provider must ensure that its software performs in accordance with the relevant software specification and this Code.

3.17 Market operation service provider must arrange audit of software

(1) Unless otherwise agreed by the Authority in writing, each market operation service provider must arrange and pay for a suitably qualified independent person approved by the Authority to carry out—

(a) before any software is first used by the market operation service provider in relation to this Code and Part 2 and Subpart 1 of Part 4 of the Act, an audit of all software and software specifications to be used by the market operation service provider; and

(b) an annual audit of all software used by the market operation service provider, within 1 month after 1 March in each year; and

(c) an audit of any changes to the software or the software specification, before it is used by the market operation service provider.

(2) A market operation service provider must ensure that the person carrying out an audit under subclause (1) provides a report to the Authority as to—

(a) the performance (including likely future performance) of all of the software in accordance with the relevant software specification; and

(b) any other matters that the Authority requires.

3.18 Requirements for using software

A market operation service provider may not use any software unless—

(a) the market operation service provider has provided to the Authority, in respect of that software, an auditor’s report issued in accordance with clause 3.17(2); or

(b) the Authority has agreed that no audit is required under clause 3.17(1).
Electricity Industry Participation Code 2010

Part 4

Force majeure provisions relating to ancillary service agents

Contents

4.1 Relief of obligation because of force majeure
4.2 Effect of relief

4.1 Relief of obligation because of force majeure

(1) An ancillary service agent is relieved of an obligation under this Code and under the Electricity Industry (Enforcement) Regulations 2010 to the extent that, and for so long as, it is unable to perform the obligation as a result of a force majeure event.

(2) Subclause (1) applies only—

(a) if the ancillary service agent advises the system operator, immediately after becoming aware of the existence of a force majeure event, of—

(i) the details of the force majeure event; and

(ii) the obligation that cannot be performed; and

(iii) the likely duration of the inability to perform the obligation; and

(b) for so long as the ancillary service agent uses its reasonable endeavours to overcome the inability to perform the obligation from which it seeks relief and to remove or mitigate the effect of the force majeure event; and

(c) if the ancillary service agent provides the Authority with reports in accordance with subclauses (4) and (5).

(3) To avoid doubt, the relief in subclause (1) applies only if an ancillary service agent is acting in its capacity as an ancillary service agent under an ancillary service arrangement.

(4) As soon as practicable, but in any event no later than by the end of the month following the month in which the ancillary service agent advises the system operator of a force majeure event under subclause (2)(a), the ancillary service agent must provide the Authority with a written report that sets out—

(a) the full details of the force majeure event; and

(b) the actions the ancillary service agent is taking or intends to take to comply with subclause (2)(b); and

(c) the proposed timeline for completing the actions.

(5) By the end of each following month (unless the Authority advises that reports may be provided less frequently or are not required) the ancillary service agent must provide the Authority with a written report that updates the information previously provided and includes any other matters related to the force majeure event that the Authority requests.

(6) The Authority must publish the information provided under subclause (2)(a) and the reports provided under subclauses (4) and (5) as soon as practicable after receiving the information.
(7) Despite subclause (6), the Authority must not publish or otherwise make available to the public any information or any part of a report if the ancillary service agent advises the Authority (with reasons) that the ancillary service agent considers that it would have good reason to refuse to supply the information or the part under clause 2.6 or clause 2.7.

Compare: SR 2003/374 r 53B
Clause 4.1: substituted, on 1 November 2012, by clause 8 of the Electricity Industry Participation (Force Majeure) Code Amendment 2012.

4.2 Effect of relief
If an ancillary service agent is relieved of an obligation under clause 4.1,—

(a) the ancillary service agent is not liable for a breach of this Code or of the Electricity Industry (Enforcement) Regulations 2010 in respect of that obligation during the period for which the relief applies under that clause; and

(b) any costs arising from the relief from the obligation lie where they fall, except that the system operator and the ancillary service agent may agree to adjust the remuneration of the ancillary service agent.

Compare: SR 2003/374 r 53C
Electricity Industry Participation Code 2010

Part 5
Regime for dealing with undesirable trading situations

Contents

5.1 Occurrence of undesirable trading situation
5.1A Time limit for investigating undesirable trading situation
5.2 Actions Authority may take to correct undesirable trading situation
5.3 Authority must consult with system operator
5.4 Authority must consult with participants
5.5 Authority must attempt to correct and restore normal operation as soon as possible

5.1 Occurrence of undesirable trading situation
(1) If the Authority suspects or anticipates the development, or possible development, of an undesirable trading situation, the Authority may investigate the matter.
(2) The following are examples of what the Authority may consider to constitute an undesirable trading situation:
   (a) manipulative or attempted manipulative trading activity:
   (b) conduct in relation to trading that is misleading or deceptive, or is likely to mislead or deceive:
   (c) unwarranted speculation or an undesirable practice:
   (d) material breach of any law:
   (e) a situation that threatens orderly trading or proper settlement:
   (f) any exceptional or unforeseen circumstance that is contrary to the public interest.
(3) To avoid doubt,—
   (a) the list of examples in subclause (2) is not an exhaustive list, and does not prevent the Authority from finding that an undesirable trading situation is developing or has developed in other circumstances; and
   (b) an example listed in subclause (2) does not constitute an undesirable trading situation unless the example comes within the definition of that term in Part 1.

5.1A Time limit for investigating undesirable trading situation
Despite clause 5.1(1), the Authority must not commence an investigation if more than 10 business days have passed since the situation, which the Authority suspects or anticipates may be an undesirable trading situation, occurred.


5.2 Actions Authority may take to correct undesirable trading situation

(1) If the Authority finds that an undesirable trading situation is developing or has developed, it may take any action that—
   (a) the Authority considers is necessary to correct the undesirable trading situation; and
   (b) relates to an aspect of the electricity industry that the Authority could regulate in this Code under section 32 of the Act.

(2) The actions that the Authority may take under subclause (1) include any 1 or more of the following:
   (a) directing that an activity be suspended, limited, or stopped, either generally or for a specified period;
   (b) directing that completion of trades be deferred for a specified period:
   (c) directing that any trades be closed out or settled at a specified price:
   (d) directing a participant to take any actions that will, in the Authority’s opinion, correct or assist in overcoming the undesirable trading situation.

(2A) A direction given to a participant under subclause (2)(d)—
   (a) may be inconsistent with this Code; but
   (b) must not be inconsistent with the Act, or any other law.

(3) The participant must comply promptly with a direction given to it in writing.

(4) A participant is not liable to any other participant in relation to the taking of an action, or an omission, that is reasonably necessary for compliance with an Authority direction under this clause.

(5) A participant does not breach this Code if it acts in accordance with a direction given under subclause (2)(d).

Compare: SR 2003/374 r 56

5.3 Authority must consult with system operator

(1) The Authority must consult with the system operator if—
   (a) the Authority is considering taking an action under clause 5.2 to correct an undesirable trading situation; and
   (b) it is possible that the action may have an effect on system security.

(2) The system operator must maintain procedures that are necessary to enable it to respond immediately to the Authority, and provide information as soon as reasonably practicable, if the Authority consults the system operator under this clause.

Compare: SR 2003/374 r 58
5.4 Authority must consult with participants
If the Authority finds that an undesirable trading situation is developing or has developed, the Authority must—
(a) immediately advise all registered participants of its findings and of any actions that the Authority intends to take, or has taken, to correct the undesirable trading situation; and
(b) unless the Authority considers that it is impractical to do so, consult with affected participants before taking the action.

Compare: SR 2003/374 r 59

5.5 Authority must attempt to correct and restore normal operation as soon as possible
The Authority must attempt to correct every undesirable trading situation and, consistently with section 15 of the Act, restore the normal operation of the wholesale market as soon as possible.

Compare: SR 2003/374 r 60
Electricity Industry Participation Code 2010

Part 6
Connection of distributed generation

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Schedule 6.2
Regulated terms for distributed generation
6.1 Contents of this Part

This Part specifies—

(a) a framework to enable the connection and continued connection of distributed generation if consistent with connection and operation standards; and

(b) in Schedule 6.1, processes (including time frames) under which distributed generators may—
   (i) connect distributed generation; or
   (ii) continue an existing connection of distributed generation if the connection contract for the distributed generation—
        (A) is in force and the distributed generator wishes to extend the term of the connection contract; or
        (B) has expired; or
   (iii) continue an existing connection of distributed generation that is connected without a connection contract if the regulated terms do not apply; or
   (iv) change the nameplate capacity or fuel type of connected distributed generation; and

(c) in Schedule 6.2, the regulated terms that apply to the connection of distributed generation in the absence of contractually agreed terms; and

(d) in Schedule 6.3, a default dispute resolution process for disputes related to this Part; and

(e) in Schedule 6.4, the pricing principles to be applied for the purposes of this Part; and

(f) in Schedule 6.5, prescribed maximum fees.

6.2 Purpose
The purpose of this Part is to enable distributed generation to be connected to a distribution network or to a consumer installation that is connected to a distribution network, if being connected is consistent with connection and operation standards.

Compare: SR 2007/219 r 3

6.2A Application of Part to distributors in respect of embedded networks
Nothing in this Part applies to—
(a) a distributor in respect of the distributor's ownership or operation of an embedded network that conveys less than 5 GWh of electricity per annum; or
(b) a distributed generator when the distributed generator wishes to connect or has distributed generation connected to such an embedded network.


6.2B Application of Part to distributors in respect of systems of lines not directly or indirectly connected to grid
Nothing in this Part applies to—
(a) a distributor in respect of the distributor's ownership or operation of a system of lines that is used for providing line function services only to the distributor; or
(b) a distributor in respect of the distributor's ownership or operation of a system of lines—
(i) that conveys less than 5 GWh of electricity per annum; and
(ii) that is not—
(A) directly connected to the grid; or
(B) indirectly connected to the grid through 1 or more other networks; or
(c) a distributed generator when the distributed generator wishes to connect or has distributed generation connected to a system of lines described in paragraph (b).

6.3 Distributors must make information publicly available

(1) The purpose of this clause is to require each distributor to make certain information publicly available to enable the approval of distributed generation under Schedule 6.1.

(2) Each distributor must make publicly available, free of charge, from its office and Internet site,—
   (a) forms for applications under Schedule 6.1; and
   (b) the distributor's connection and operation standards; and
   (c) a copy of the regulated terms, together with an explanation of how the regulated terms will apply if—
      (i) approval is granted under Schedule 6.1; and
      (ii) the distributor and the distributed generator do not enter into a connection contract; and
   (d) a statement of the circumstances in which distributed generation will be, or may be, curtailed or interrupted from time to time in order to ensure that the distributor's other connection and operation standards are met; and
   (da) a list of all locations on its distribution network that the distributor—
      (i) knows to be subject to export congestion; or
      (ii) expects to become subject to export congestion within the next 12 months; and
   (e) a list of any fees that the distributor charges under Schedule 6.1, which must not exceed the relevant maximum fees prescribed in Schedule 6.5; and
   (f) a list of the makes and models of inverters that the distributor has approved for connection to its distribution network; and
   (g) the distributor's contact information for any enquiries relating to the connection of distributed generation to its distribution network.

(3) The application forms referred to in subclause (2)(a) must specify the information, including any supporting documents, that must be provided with an application under Schedule 6.1.

6.4 Process for obtaining approval

(1) Schedule 6.1 applies if a distributed generator wishes to—
(a) connect distributed generation, whether on the regulated terms or on other terms; or
(b) continue an existing connection of distributed generation if the connection contract for the distributed generation—
   (i) is in force and the distributed generator wishes to extend the term of the connection contract; or
   (ii) has expired; or
(c) continue an existing connection of distributed generation that is connected without a connection contract if the regulated terms do not apply; or
(d) change the nameplate capacity or fuel type of connected distributed generation.

(2) A distributor must approve an application submitted under Schedule 6.1 if the application complies with the requirements of that Schedule.

(3) Except as provided in clause 6.4A, a distributor cannot contract out of the provisions of Schedule 6.1 with a distributed generator.

6.4A Distributor and distributed generator may agree to simpler process for existing connection

A distributor and a distributed generator may agree a simpler process for the continued connection of distributed generation to the distributor’s distribution network than the relevant process set out in Schedule 6.1 if—

(a) a connection contract for the distributed generation—
   (i) is in force and the distributed generator wishes to extend the term of the connection contract; or
   (ii) has expired; or
(b) the distributed generation is connected without a connection contract; or
(c) there is a change in the nameplate capacity or fuel type of the distributed generation.

6.5 Connection contract

If a distributor and a distributed generator enter into a contract for the connection of distributed generation,—

(a) their rights and obligations in respect of the connection of the distributed generation are governed by that contract, and accordingly the regulated terms do not apply; and
(b) a breach of the terms of that contract is not a breach of this Code.
6.6 Connection on regulated terms

(1) Schedule 6.2 sets out the regulated terms for the connection of distributed generation.

(2) The regulated terms apply in the following circumstances:
   (a) if a distributor and a distributed generator do not enter into a connection contract by the expiry of the period for negotiating a connection contract under clauses 9 or 24 of Schedule 6.1:
   (b) in accordance with clause 9G of Schedule 6.1.

(3) If the regulated terms apply,—
   (a) the parties' rights and obligations in respect of the connection of the distributed generation are governed by the regulated terms; and
   (b) a breach of the regulated terms is not a breach of contract.

(4) Despite this clause, a distributor and a distributed generator may at any time, by agreement, enter into a connection contract that will apply instead of the regulated terms.

Compare: SR 2007/219 r 9
Clause 6.6(2) and (4): substituted, on 23 February 2015, by clause 10 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

6.7 Extra terms

(1) The parties' rights and obligations in respect of a connection on the regulated terms are also governed by any other terms and conditions that—
   (a) were made publicly available under clause 6.3(2)(d) in a statement of the terms and conditions that would apply to distributed generation if there is congestion on the distribution network; or
   (b) cover any other incidental matters (for example, invoicing procedures) if—
      (i) the matters are not covered by the regulated terms; and
      (ii) the other matters are reasonable terms and conditions that either were proposed by the distributor during the 30 business day negotiation period as part of a connection contract or are terms that would be implied by law if the connection was under a connection contract; and
      (iii) the other terms and conditions do not contradict any of the regulated terms.

(2) In this Part, if the parties have agreed to change all or any part of 1 or more of the regulated terms as part of a binding contract, the resulting contract is, in total, a connection contract on terms that apply instead of the regulated terms for the purposes of this Part.

Compare: SR 2007/219 r 10
6.8 Dispute resolution

(1) Subject to subclause (2), Schedule 6.3 applies to a dispute between a distributed generator that is a participant and a distributor arising from any one of the following—

(a) an allegation that a party has breached any of the regulated terms that apply under clause 6.6(2); and

(aa) an allegation that conditions specified by the distributor under clause 18 of Schedule 6.1 are not reasonably required; and

(ab) an allegation that a party has not attempted to negotiate in good faith under clause 6 or clause 21 of Schedule 6.1; and

(b) an allegation that a party has breached any of the other provisions of this Part.

(2) However, Schedule 6.3 does not apply to disputes between a distributed generator and a distributor—

(a) arising from an allegation that a party has breached any of the terms of a connection contract; or

(b) arising from an allegation that a party has breached any of the extra terms referred to in clause 6.7(1); or

(c) that the distributed generator and the distributor have agreed should be determined by any other agreed method (for example, under any dispute resolution scheme under section 95 of the Act).

Compare: SR 2007/219 r 11
Clause 6.8(1) and (1)(a): amended, on 23 February 2015, by clause 12(1) and (2) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 6.8(1)(aa) and (ab): inserted, on 23 February 2015, by clause 12(3) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

6.9 Pricing principles

Schedule 6.4 applies in accordance with—

(a) clause 19 of Schedule 6.2; and

(b) clause 4 of Schedule 6.3.

Compare: SR 2007/219 r 12

6.10 [Revoked]

Compare: SR 2007/219 r 13

6.11 Distributors must act at arm’s length

A distributor must use, in respect of all distributed generators, the same reasonable efforts in processing and considering applications and notices under Schedule 6.1, regardless of—
(a) whether the **distributor** has an ownership interest or a beneficial interest in the **distributed generator**; or

(b) who the **distributed generator** is.

Compare: SR 2007/219 r 14


### 6.12 This Part does not affect rights and obligations under Code

This Part does not affect any rights or obligations of a **distributor** or a **distributed generator** under any other clause in this Code.

Compare: SR 2007/219 r 15

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**Transitional provisions**

### 6.13 This Part does not apply to earlier connections

This Part does not apply in relation to, or affect, any **distributed generation** that was connected under a contract entered into before 30 August 2007, except for the purpose of renewing or extending the term of the contract.

Compare: SR 2007/219 r 17


Schedule 6.1

Process for obtaining approval


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Preliminary provisions
1A Contents of this Schedule
This Schedule specifies the procedures for processing applications from distributed generators for the connection or continued connection of distributed generation.

1B Distributed generator must apply
Subject to clause 6.4A and clause 1D, a distributed generator that owns or operates distributed generation must apply to a distributor if it wishes to—
(a) connect the distributed generation to the distributor’s distribution network; or
(b) continue an existing connection of the distributed generation to the distributor’s distribution network if a connection contract for the distributed generation—
(i) is in force and the distributed generator wishes to extend the term of the connection contract; or
(ii) has expired; or
(c) continue an existing connection of the distributed generation to the distributor's distribution network that is connected without a connection contract if the regulated terms do not apply; or
(d) change the nameplate capacity or fuel type of the distributed generation connected to the distributor's distribution network.


1C How Parts apply to applications
This Schedule applies to applications made under clause 1B as follows:
(a) Part 1 applies to applications in respect of distributed generation that has a nameplate capacity of 10 kW or less in total, unless the distributed generator has elected, under clause 1D, to apply under Part 1A:
(b) Part 1A applies to applications in respect of distributed generation that has a nameplate capacity of 10 kW or less in total, if the distributed generator has elected, under clause 1D, to apply under Part 1A:
(c) Part 2 applies to applications in respect of distributed generation that has a nameplate capacity of more than 10 kW in total.

1D When application may be made under Part 1A
A distributed generator may elect to apply to a distributor under Part 1A instead of Part 1 if the distributed generation to which the application relates—
(a) is designed and installed in accordance with AS 4777.1; and
(b) incorporates an inverter that has been tested and issued a Declaration of Conformity with AS/NZS 4777.2 by a laboratory with accreditation issued or recognised by International Accreditation New Zealand; and
(c) has protection settings that meet the distributor’s connection and operation standards.

Cross heading and clauses 1A to 1D: inserted, on 23 February 2015, by clause 18 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Part 1
Applications for distributed generation
10 kW or less in total


1 Contents of this Part
(1) This Part applies to applications relating to distributed generation that has a nameplate capacity of 10 kW or less in total, unless the distributed generator that owns or operates the distributed generation has elected, under clause 1D, to apply under Part 1A.
(2) This Part of this Schedule provides for a 1-stage application process.
Compare: SR 2007/219 clause 1 Schedule 1
Application process

2 Applications under this Part of this Schedule

(1) [Revoked]

(2) A distributed generator must apply to a distributor by—
   (a) using the application form provided by the distributor that is publicly available under clause 6.3(2)(a); and
   (b) providing any information in respect of the distributed generation to which the application relates that is—
      (i) referred to in subclause (3); and
      (ii) specified by the distributor under clause 6.3(3) as being required to be provided with the application; and
   (c) paying the application fee (if any) specified by the distributor in accordance with clause 6.3(2)(e).

(3) The information may include the following:
   (a) the full name and address of the distributed generator and the contact details of a person that the distributor may contact regarding the distributed generation:
      (aa) whether the application is to—
         (i) connect distributed generation; or
         (ii) continue an existing connection of distributed generation that is connected in accordance with a connection contract if the connection contract—
            (A) is in force and the distributed generator wishes to extend the term of the connection contract; or
            (B) has expired; or
         (iii) continue an existing connection of distributed generation that is connected without a connection contract; or
         (iv) change the nameplate capacity or fuel type of connected distributed generation:
      (b) evidence of the nameplate capacity that the distributed generation will have, or other suitable evidence that the distributed generation is or will only be capable of generating electricity at a rate of 10 kW or less:
      (ba) if the application is to change the nameplate capacity or fuel type of connected distributed generation—
         (i) the nameplate capacity that the distributed generation will have after the change; and
         (ii) the aggregate nameplate capacity that all distributed generation that is connected at the point of connection at which the distributed generation is connected will have after the change; and
         (iii) the fuel type that the distributed generation will have after the change:
   (c) details of the fuel type of the distributed generation (for example, solar, wind, or liquid fuel);
   (d) a brief description of the physical location at the address at which the distributed generation is or will be connected:
   (da) if the application is to connect distributed generation, when the distributed generator expects the distributed generation to be connected:
(e) technical specifications of the distributed generation and associated equipment, including the following:

(i) technical specifications of equipment that allows the distributed generation to be electrically disconnected from the distribution network on loss of mains voltage:

(ii) manufacturer's rating of equipment:

(iii) number of phases:

(iv) proposed or current point of connection to the distribution network (for example, the ICP identifier and street address):

(v) details of either or both of any inverter and battery storage:

(vi) details of any load at the proposed or current point of connection:

(vii) details of the voltage (for example, 415 V or 11 kV) when it is electrically connected:

(f) information showing how the distributed generation complies with the distributor's connection and operation standards:

(g) any additional information or documents that are reasonably required by the distributor.

(4) [Revoked]

(5) The distributor must, within 5 business days of receiving an application, give written notice to the applicant advising whether or not the application is complete.

Compare: SR 2007/219 clause 2 Schedule 1
Heading: amended, on 23 February 2015, by clause 21(1) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 2(1): revoked, on 23 February 2015, by clause 21(2) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 2(2): substituted, on 23 February 2015, by clause 21(3) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
3 Distributor's decision on application

(1) A distributor must, within 30 business days after the date of receipt of a completed application made in accordance with clause 2, give notice in writing to the applicant stating whether the application is approved or declined.

(2) A distributor must approve an application if—

(a) the application has been properly made in accordance with Part 6 of this Code; and

(b) the information provided in the application would reasonably support an assessment by the distributor that—

(i) the distributed generator will comply at all times with the requirements of the Health and Safety at Work Act 2015; and

(ii) the distributed generator will ensure that the distributed generation complies at all times with the Act, and this Code; and

(iii) the distributed generation meets the distributor's connection and operation standards.

(3) A notice stating that an application is declined must be accompanied by the following information:

(a) detailed reasons of why the application has been declined and the steps that the applicant can take to achieve approval if it makes a new application:

(b) information about the default process under Schedule 6.3 for the resolution of disputes between participants about an alleged breach of the regulated terms or any other provision of Part 6 of this Code:

(c) that if the distributed generator is not a participant, the distributed generator may report to the Authority under the Electricity Industry (Enforcement) Regulations 2010 if it considers that the distributor has breached any requirement in Part 6 of this Code.

4 Extension of time by mutual agreement for distributor to process application

(1) A distributor may seek an extension of the time specified in clause 3(1) by which the distributor must give notice in writing stating whether an application is approved or declined.

(2) The distributor must do this by notice in writing to the distributed generator specifying the reasons for the extension.
(3) The **distributed generator** that made the application—
   (a) may grant an extension which must not exceed 20 **business days**; and
   (b) must not unreasonably withhold consent to an extension.

Compare: SR 2007/219 clause 4 Schedule 1
Clause 4(3): substituted, on 23 February 2015, by clause 23(2) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

5 **Distributed generator must give notice of intention to negotiate**

(1) If a **distributor** advises a **distributed generator** that its application is approved, the **distributed generator** must give written notice to the **distributor** confirming whether the **distributed generator** intends to negotiate a connection contract under clause 6 and, if so, confirming the details of the **distributed generation** to which the application relates.

(2) The **distributed generator** must give the notice within 10 **business days** after the **distributor** gives notice of approval, or such later date as is agreed by the **distributor** and the **distributed generator**.

(3) The **distributor's** duties under Part 6 of this Code arising from the application no longer apply if the **distributed generator** fails to give notice to the **distributor** within the time limit specified in subclause (2).

(4) Subclause (3) does not prevent the **distributed generator** from making a new application under Part 6 of this Code.

Compare: SR 2007/219 clause 5 Schedule 1
Clause 5(3) and (4): amended, on 23 February 2015, by clause 24(3) and (4) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

**Post-approval process**

6 **30 business days to negotiate connection contract if distributed generator gives notice of intention to proceed**

(1) If a **distributed generator** whose application under clause 2 is approved gives notice to a **distributor** under clause 5, the **distributor** and the **distributed generator** have **30 business days**, starting on the date on which the **distributor** receives the notice, during which they must, in good faith, attempt to negotiate a connection contract.

(2) The **distributor** and the **distributed generator** may, by agreement, extend the time specified in subclause (1) for negotiating a connection contract.

Compare: SR 2007/219 clause 6 Schedule 1

7 Testing and inspection

(1) Subject to subclause (1A), a distributed generator whose application under clause 2 is approved by a distributor must test and inspect the distributed generation to which the application relates within a reasonable time frame specified by the distributor.

(1A) The distributor may waive the requirement that the distributed generator test and inspect if the distributor is satisfied that the distributed generation complies with the distributor's connection and operation standards.

(2) The distributed generator must give adequate notice of the testing and inspection to the distributor.

(3) The distributor may send qualified personnel to the site to observe the testing and inspection.

(4) The distributed generator must give the distributor with a written test report when testing and inspection is complete, including suitable evidence that the distributed generation complies with the distributor's connection and operation standards.

(5) The distributed generator must pay any fee specified by the distributor in accordance with clause 6.3(2)(e) for observing the testing and inspection.

Compare: SR 2007/219 clause 7 Schedule 1

Clause 7(1): substituted, on 23 February 2015, by clause 27(1) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 7(1A): inserted, on 23 February 2015, by clause 27(2) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 7(4) and (5): amended, on 23 February 2015, by clause 27(3) and (4) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

8 Connection of distributed generation if connection contract negotiated

(1) This clause applies if a distributor and a distributed generator whose application under this Part of this Schedule is approved enter into a connection contract before the period for negotiating a connection contract under this Part of this Schedule expires.

(2) If the application is to connect distributed generation under clause 1B(a), the distributor must allow the distributed generator to connect the distributed generation in accordance with the contract as soon as practicable.

(3) If the application is to continue an existing connection of distributed generation under clause 1B(b), the distributor must use its best endeavours to ensure that the new terms under which the distributed generator's existing connection continues apply—

(a) as soon as practicable, if the previous connection contract has expired; or

(b) no later than the expiry of the previous connection contract, if the contract is in force.

(4) If the application is to continue an existing connection for which there is no connection contract under clause 1B(c), the distributor must use its best endeavours to ensure that the new terms under which the distributed generator's existing connection continues apply as soon as practicable.

(5) If the application is to change the nameplate capacity or fuel type of connected distributed generation under clause 1B(d), the distributor must use its best endeavours to ensure that the new terms under which the distributed generator's existing connection continues apply as soon as practicable.

Compare: SR 2007/219 clause 8 Schedule 1
Clause 8: substituted, on 23 February 2015, by clause 28 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

9 Connection of distributed generation on regulated terms if connection contract not negotiated
(1) This clause applies if a distributor and a distributed generator whose application under this Part of this Schedule is approved do not enter into a connection contract before the period for negotiating a connection contract under this Part of this Schedule expires.
(2) If the application is to connect distributed generation under clause 1B(a), the distributor must allow the distributed generator to connect the distributed generation on the regulated terms as soon as practicable after the expiry of the period.
(3) If the application is to continue an existing connection of distributed generation under clause 1B(b), the regulated terms apply to the distributed generator’s existing connection as follows:
   (a) if the previous connection contract has expired, the regulated terms apply from the day after the date on which the period for negotiating a connection contract under this Part of this Schedule expires:
   (b) if the previous connection contract is still in force, the regulated terms apply from the day after the date on which the contract expired.
(4) If the application is to continue an existing connection for which there is no connection contract under clause 1B(c), the regulated terms apply from the day after the date that the period for negotiating a connection contract under this Part of this Schedule expires.
(5) If the application is to change the nameplate capacity or fuel type of connected distributed generation under clause 1B(d), the regulated terms apply from the day after the date that the period for negotiating a connection contract under this Part of this Schedule expires.

Compare: SR 2007/219 clause 9 Schedule 1

Part 1A
Applications for distributed generation of 10 kW or less in total in specified circumstances

9A Contents of this Part
(1) This Part applies to applications relating to distributed generation that has a nameplate capacity of 10 kW or less in total if the distributed generator that owns or operates the distributed generation has elected, under clause 1D, to apply under this Part of this Schedule.
(2) This Part of this Schedule provides for a simplified 1-stage application process.

9B Application for distributed generation of 10 kW or less in total in specified
(1) A distributed generator's application to a distributor must specify which of the following circumstances applies:

(a) the distributed generator wishes to connect distributed generation:
(b) the distributed generator wishes to continue an existing connection of distributed generation that is connected in accordance with a connection contract that—
   (i) is in force and the distributed generator wishes to extend the term of the connection contract; or
   (ii) has expired:
(c) the distributed generator wishes to continue an existing connection of distributed generation that is connected without a connection contract:
(d) the distributed generator wishes to change the nameplate capacity or fuel type of connected distributed generation.

(2) An application must include the following:

(a) the name, contact, and address details of the distributed generator and, if applicable, the distributed generator’s agent:
(b) a brief description of the physical location at the address at which the distributed generation is or will be connected:
(c) any application fee specified by the distributor in accordance with clause 6.3(2)(e):
(d) details of the make and model of the inverter:
(e) confirmation as to whether the inverter—
   (i) is included on the distributor’s list of approved inverters made publicly available under clause 6.3(2)(f); or
   (ii) conforms with the protection settings specified in the distributor’s connection and operation standards:
(f) if the inverter is not included on the distributor’s list of approved inverters, a copy of the AS/NZS 4777.2 Declaration of Conformity certificate for the inverter:
(g) details of—
   (i) the nameplate capacity of the distributed generation; and
   (ii) the fuel type of the distributed generation (for example, solar, wind, or liquid fuel).

(3) The distributed generator must also give the distributor the following information as soon as it is available, but no later than 10 business days after the approval of the application:

(a) a copy of the Certificate of Compliance issued under the Electricity (Safety) Regulations 2010 that relates to the distributed generation:
(b) the ICP identifier of the ICP at which the distributed generation is connected or is proposed to be connected, if one exists.

(4) A distributor must, no later than 2 business days after receiving an application from a distributed generator, acknowledge receipt of the application.

9C  Distributor may inspect distributed generation

(1) A distributor may inspect distributed generation that is connected or is proposed to be connected to its distribution network for the purpose of—
   (a) verifying that the distributed generation meets, or continues to meet, the requirements specified in clause 1D; or
   (b) verifying the information contained in an application made under this Part of this Schedule.

(2) If a distributor wishes to inspect distributed generation, the distributor must give the distributed generator at least 2 business days’ notice of the time and date on which the inspection will take place.

(3) Following receipt of a notice, the distributed generator must—
   (a) pay the fee specified by the distributor in accordance with clause 6.3(2)(e) for the inspection (if any); and
   (b) provide or arrange for the distributor to have reasonable access to the distributed generation.


9D  Export congestion

(1) This clause applies if a distributed generator applies to a distributor under this Part of this Schedule to connect distributed generation or continue an existing connection of distributed generation to a location on the distributor’s distribution network that is included in the list made publicly available in accordance with clause 6.3(2)(da).

(2) The distributor may advise the distributed generator that the distributed generation may be subject to export congestion as set out in the distributor’s congestion management policy.

(3) If a distributor has advised a distributed generator under subclause (2), the distributor must take reasonable steps to work with the distributed generator to assess whether solutions exist to mitigate the export congestion.


9E  Non-compliance or incomplete information

(1) This clause applies if a distributor considers that an application made to it by a distributed generator under this Part of this Schedule has 1 or more of the following deficiencies:
   (a) the distributed generation to which the application relates does not meet the requirements specified in clause 1D:
   (b) the distributed generation to which the application relates is not as described in the information given under clause 9B(2):
   (c) the distributed generator has not complied with clause 9B(2).

(2) If this clause applies, the distributor must advise the distributed generator of the deficiency or deficiencies.

(3) If the distributed generator is advised of a deficiency or deficiencies, it must remedy each deficiency to the satisfaction of the distributor no later than 10 business days after being advised of the deficiency.

(4) If the distributed generator is required to remedy a deficiency it must pay the relevant fee specified by the distributor in accordance with clause 6.3(2)(e).
(5) If the distributed generator does not remedy each deficiency of which it is advised within the time frame specified in subclause (3)—

(a) if the distributed generation to which the application relates is electrically connected to the distributor's distribution network at the time the distributor advises the distributed generator under subclause (2), the distributor may, by notice to the distributed generator, require the distributed generator to—

(i) electrically disconnect the distributed generation within a reasonable time frame specified by the distributor (if applicable); and

(ii) keep the distributed generation electrically disconnected until each deficiency is remedied to the distributor's satisfaction; or

(b) if the distributed generation is not connected to the distributor's distribution network at the time of being advised under subclause (2), the distributor may, by notice to the distributed generator, prohibit the distributed generator from connecting the distributed generation to the distributor's distribution network until each deficiency is remedied to the distributor's satisfaction.

(6) The distributor must approve connection of the distributed generation as soon as is reasonable in the circumstances if—

(a) the distributed generator complies with a notice given under subclause (5)(a) (if applicable); and

(b) the distributed generator remedies each deficiency advised under subclause (2)—

(i) to the satisfaction of the distributor; and

(ii) no later than 12 months after the date of the notice given under subclause (5) or such later date as is agreed by the distributor and the distributed generator.

(7) If the distributor approves the connection of distributed generation, it must give a notice of final approval to the distributed generator under clause 9F.


9F Notice of final approval

(1) A distributor must give a notice of final approval of distributed generation to a distributed generator that has made an application to the distributor under this Part of this Schedule if the distributor is satisfied that—

(a) the distributed generation meets the requirements specified in clause 1D; and

(b) the information given by the distributed generator under clause 9B(2) is complete and accurate.

(2) The distributor must give the notice no later than 10 business days after the date on which the application was submitted.

(3) If the distributed generator does not receive a notice by the date specified in subclause (2), the distributor is deemed to have given notice of final approval.
9G  **Regulated terms apply**

(1) If a *distributor* gives a notice of final approval to a *distributed generator* under clause 9F, the *regulated terms* apply.

(2) Despite subclause (1), and in accordance with clause 6.6(4), the *distributor* and *distributed generator* may at any time enter into a connection contract on terms that apply instead of the *regulated terms*.


9H  **When distributed generator may connect to distribution network**

(1) A *distributed generator* that has submitted an application to a *distributor* under clause 1D may connect the *distributed generation* to which the application relates to the *distributor's distribution network* if the *distributed generator* receives a notice of final approval under clause 9F(1), or is deemed to have received a notice of final approval under clause 9F(3).

(2) Despite subclause (1) a *distributor* may prohibit a *distributed generator* from connecting if—

(a) the *distributor* has advised the *distributed generator* of a deficiency under clause 9E(2) and the deficiency has not been remedied in accordance with clause 9E(3); or

(b) the *distributor* gave notice that it wished to inspect the *distributed generation* under clause 9C(2), but the *distributed generator* has not provided or arranged for the *distributor* to have reasonable access to the *distributed generation* under clause 9C(3)(b).


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**Part 2**

**Applications for distributed generation above 10 kW in total**


10  **Contents of this Part**

(1) This Part of this Schedule applies to applications relating to *distributed generation* that has a *nameplate capacity* of more than 10 kW in total.

(2) This Part of this Schedule provides for a 2-stage application process.

Compare: SR 2007/219 clause 10 Schedule 1

*Initial application process*

11  **Distributed generator must make initial application and give information**

(1) [Revoked]

(2) A *distributed generator* must apply to a *distributor* ("initial application") by—
(a) using the application form provided by the distributor that is publicly available under clause 6.3(2)(a); and

(b) providing any information in respect of the distributed generation to which the application relates that is—
   (i) referred to in subclause (3); and
   (ii) specified by the distributor under clause 6.3(3) as being required to be provided with the application; and

(c) paying the application fee (if any) specified by the distributor in accordance with clause 6.3(2)(e).

(3) The information may include the following:

(a) the full name and address of the distributed generator and the contact details of a person whom the distributor may contact regarding the distributed generation:

   (aa) whether the application is to—
      (i) connect distributed generation; or
      (ii) continue an existing connection of distributed generation that is connected in accordance with a connection contract if the connection contract—
         (A) is in force and the distributed generator wishes to extend the term of the connection contract; or
         (B) has expired; or
      (iii) continue an existing connection of distributed generation that is connected without a connection contract; or
      (iv) change the nameplate capacity or fuel type of connected distributed generation:

   (ba) if the application is to change the nameplate capacity or fuel type of connected distributed generation,—
      (i) the nameplate capacity that the distributed generation will have after the change; and
      (ii) the aggregate nameplate capacity that all distributed generation that is connected at the point of connection at which the distributed generation is connected will have after the change; and
      (iii) the fuel type that the distributed generation will have after the change:

(b) evidence of the nameplate capacity that the distributed generation will have:

(ba) if the application is to change the nameplate capacity or fuel type of connected distributed generation,—
      (i) the nameplate capacity that the distributed generation will have after the change; and
      (ii) the aggregate nameplate capacity that all distributed generation that is connected at the point of connection at which the distributed generation is connected will have after the change; and

(c) details of the fuel type of the distributed generation (for example, solar, wind, or liquid fuel):

(d) a brief description of the physical location at the address at which the distributed generation is or will be connected:

(da) if the application is to connect distributed generation, when the distributed generator expects the distributed generation to be connected:

(e) technical specifications of the distributed generation and associated equipment, including the following:
      (i) technical specifications of equipment that allows the distributed generation to be electrically disconnected from the distribution network on loss of mains voltage:
      (ii) manufacturer's rating of equipment:
      (iii) number of phases:
(iv) proposed or current point of connection to the distribution network (for example, the ICP identifier and street address):
(v) details of either or both of any inverter and battery storage:
(vi) details of any load at the proposed or current point of connection:
(vii) details of the voltage (for example, 415 V or 11 kV) when electrically connected:
(f) information showing how the distributed generation complies with the distributor's connection and operation standards:
(g) the maximum active power injected (MW max):
(h) the reactive power requirements (MVARs) (if any):
(i) resistance and reactance details of the distributed generation:
(j) fault level contribution (kA):
(k) method of voltage control:
(l) single line diagram of proposed connection:
(m) means of synchronising with, electrically connecting to, and electrically disconnecting from, the distribution network, including the type and ratings of the proposed circuit breaker:
(n) details of compliance with frequency and voltage support requirements as specified in this Code (if applicable):
(o) proposed periods and amounts of electricity injections into, and offtakes from, the distribution network (if known):
(p) any other information that is required by the system operator:
(q) any additional information or documents that are reasonably required by the distributor.

(4) [Revoked]

(5) The distributor must, within 5 business days of receiving an initial application, give written notice to the applicant advising whether or not the application is complete.

Compare: SR 2007/219 clause 11 Schedule 1
Clause 11(3)(c) and (d): substituted, on 23 February 2015, by clause 32(8) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 11(3)(m): amended, on 23 February 2015, by clauses 32(12) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

12 Distributor must give information to distributed generator
A distributor must give a distributed generator that makes an initial application the following within 30 business days of receiving the completed initial application:
(a) information about the capacity of the distribution network, including both the design capacity (including fault levels) and actual operating levels:
(b) information about the extent to which connection and operation of the distributed generation may result in a breach of the relevant standards for safety, voltage, power quality, and reliability of electricity conveyed to points of connection on the distribution network:
(c) information about any measures or conditions (including modifications to the design and operation of the distribution network or to the operation of the distributed generation) that may be necessary to address the matters referred to in paragraphs (a) and (b):
(d) the approximate costs of any distribution network related measures or conditions identified under paragraph (c) and an estimate of time constraints or restrictions that may delay connecting the distributed generation:
(e) information about any further detailed investigative studies that the distributor reasonably considers are necessary to identify any potential adverse effects the distributed generation may have on the system, together with an indication of—
(i) whether the distributor agrees to the distributed generator, or a suitably qualified agent of the distributed generator, undertaking those studies; or
(ii) if not, whether the distributor could undertake those studies and, if so, the reasonable estimated cost of the studies that the distributed generator would be charged:
(f) information about any obligations to other parties that may be imposed on the distributor and that could affect the distributed generation (for example, obligations to Transpower, in respect of other networks, or under this Code):

(g) any additional information or documents that the distributor considers would assist the distributed generator's application:

(h) information about the extent to which planned and unplanned outages may adversely affect the operation of the distributed generation.

Compare: SR 2007/219 clause 12 Schedule 1

Clause 12(b): amended, on 23 February 2015, by clauses 33(3) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 12(d): amended, on 23 February 2015, by clauses 33(4) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

13 Other matters to assist with decision making

(1) A distributor must provide, if requested by a distributed generator making an initial application, further information that is reasonably necessary to enable the distributed generator to consider and act on the information given by the distributor under clause 12.

(2) The information that the distributor must provide under subclause (1) may include single line diagrams, equipment ratings, normal switch configurations (including fault levels), and protection system details relevant to the current or proposed point of connection of the distributed generation to the distribution network.

(3) The distributor must provide the further information under this clause within 10 business days of the request being received.

Compare: SR 2007/219 clause 13 Schedule 1

14 Distributor and distributed generator must make reasonable endeavours regarding new information

If a distributor or a distributed generator has given information under this Part of this Schedule and subsequently becomes aware of new information that is relevant to the application, the party that becomes aware of the new information must use reasonable endeavours to provide the other party with the new information.

Compare: SR 2007/219 clause 14 Schedule 1
Final application process

15 Distributed generator must make final application
(1) A distributed generator that makes an initial application to a distributor must make a final application, no later than 12 months after receiving information under clauses 12 and 13, if the distributed generator wishes to proceed with the application, unless—
   (a) the distributor and the distributed generator agree that a final application is not required; and
   (b) there are no persons to whom the distributor must give written notice under clause 16 at the time that the distributor and distributed generator agree that a final application is not required.
(1A) If a final application is not required—
   (a) subclause (2) does not apply; and
   (b) the distributed generator’s initial application must be treated as a final application for the purposes of clauses 16 to 24.
(2) The distributed generator must make the final application by—
   (a) using the final application form provided by the distributor that is publicly available under clause 6.3(2)(a); and
   (b) providing the results of any investigative studies that were identified by the distributor under clause 12(e)(i) as to be undertaken by the distributed generator or the distributed generator's agent.

16 Notice to third parties
A distributor that receives a final application must give written notice to the following persons no later than 10 business days after receiving the final application:
   (a) all persons that have made an initial application relating to a particular part of the distribution network that the distributor considers would be affected by the approval of the final application; and
   (b) all distributed generators that have distributed generation with a nameplate capacity of 10 kW or more in total connected on the regulated terms to the particular part of the distribution network that the distributor considers would be affected by the approval of the final application.

17 Priority of final applications
(1) Subclause (2) applies if—
   (a) a distributor receives a final application (the first application); and
   (b) the distributor receives another final application, within 20 business days after receiving the first application, relating to a particular part of the distribution
network that the distributor considers would be affected by the approval of the first application.

(2) If this subclause applies, the distributor—
   (a) may consider the final applications together as if they were competitive bids to use the same part of the distribution network; and
   (b) must consider the final applications in light of the purpose of Part 6 of this Code.

(3) In any other case in which a distributor receives more than 1 final application relating to a similar part of the distribution network, the distributor must consider an earlier final application in priority to other final applications.

(4) Subclause (3) does not limit clause 19.

Compare: SR 2007/219 clause 17 Schedule 1
Clause 17(1) and (2): substituted, on 23 February 2015, by clause 38(1) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

18 Distributor's decision on application

(1) A distributor must, within the time limit specified in clause 19, give notice in writing to the applicant stating whether the final application is approved or declined.

(2) A distributor must approve a final application, subject to any conditions specified by the distributor that are reasonably required, if—
   (a) the application has been properly made in accordance with Part 6 of this Code; and
   (b) the information provided in the application would reasonably support an assessment by the distributor that—
      (i) the distributed generator will comply at all times with the requirements of the Health and Safety at Work Act 2015; and
      (ii) the distributed generator will ensure that the distributed generation complies at all times with the Act and this Code; and
      (iii) the distributed generation meets the distributor's connection and operation standards (assuming that the distributed generator meets the conditions (if any) referred to in subclause (3)).

(3) A notice stating that an application is approved must be accompanied by the following information:
   (a) a detailed description of any conditions (or other measures) that are conditions of the approval under subclause (2), and what the distributed generator must do to comply with them:
   (b) detailed reasons for those conditions (or other measures):
   (c) a detailed description of any charges payable by the distributed generator to the distributor or by the distributor to the distributed generator, and an explanation of how the charges have been, or will be, calculated:
   (d) the default process for resolving disputes under Schedule 6.3, if the distributed generator disputes all or any of the conditions (or other measures) or charges payable.

(4) A notice stating that an application is declined must be accompanied by the following information:
(a) detailed reasons as to why the application has been declined and what the applicant must do to get approval if it makes a new application:

(aa) if the application is one to which clause 17(2) applies, the criteria used in making a decision under clause 17(2)(a) and clause 17(2)(b):

(b) the default process for resolving disputes between participants under Schedule 6.3:

(c) that if the distributed generator is not a participant, the distributed generator may report to the Authority under the Electricity Industry (Enforcement) Regulations 2010 if it considers that the distributor has breached any requirement in Part 6 of this Code.

Compare: SR 2007/219 clause 18 Schedule 1

19  Time within which distributor must decide final applications

(1) A notice required by clause 18 must be given by a distributor to a distributed generator no later than—

(a) 45 business days after the date of receipt of the final application, in the case of distributed generation that will have a nameplate capacity of less than 1 MW; or

(b) 60 business days after the date of receipt of the final application, in the case of distributed generation that will have a nameplate capacity of 1 MW or more but less than 5 MW; or

(c) 80 business days after the date of receipt of the final application, in the case of distributed generation that will have a nameplate capacity of 5 MW or more.

(2) The distributor may seek 1 or more extensions of the time specified in subclause (1).

(3) The distributor must do this by notice in writing to the distributed generator specifying the reasons for the extension.

(4) A distributed generator that receives a notice seeking an extension—

(a) may grant an extension which must not exceed 40 business days; and

(b) must not unreasonably withhold consent to an extension.

Compare: SR 2007/219 clause 19 Schedule 1

20  Distributed generator must give notice of intention to proceed

(1) If a distributor advises a distributed generator that the distributed generator’s final application is approved, the distributed generator must give written notice to the


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**distributor** confirming whether or not the **distributed generator** intends to proceed to negotiate a connection contract under clause 21(1) and, if so, confirming—

(a) the details of the **distributed generation**; and

(b) that the **distributed generator** accepts all of the conditions (or other measures) that have been specified by the **distributor** under clause 18.

(2) The **distributed generator** must give the notice no later than 30 **business days** after the day on which the **distributor** gives notice of approval under clause 18, or such later date as is agreed by the **distributor** and the **distributed generator**.

(3) If the **distributed generator** is a **participant** and does not accept 1 or more of the conditions specified by the **distributor** under clause 18(2) (if any), but intends to proceed to negotiate a connection contract under clause 21(1), the **distributed generator** must—

(a) give notice of the dispute in accordance with clause 2 of Schedule 6.3 within 30 **business days** after the day on which the **distributor** gives notice of approval under clause 18; and

(b) give a notice under subclause (1) within 30 **business days** after the dispute is resolved.

(4) The **distributor**'s duties under Part 6 of this Code arising from the application no longer apply if the **distributed generator** fails to give notice to the **distributor** of an intention to proceed to negotiate a connection contract under clause 21(1) within the time limits specified in this clause.

(5) Subclause (4) does not prevent the **distributed generator** from making a new application under Part 6 of this Code.

Compare: SR 2007/219 clause 20 Schedule 1
Clause 20: substituted, on 23 February 2015, by clause 41 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

**Post-approval process**

*Cross heading: amended, on 23 February 2015, by clause 42 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.*

**21 30 business days to negotiate connection contract if distributed generator gives notice of intention to proceed**

(1) If a **distributed generator** whose **final application** is approved gives notice to a **distributor** under clause 20(1), the **distributor** and the **distributed generator** have 30 **business days**, starting on the date on which the **distributor** receives the notice, during which they must, in good faith, attempt to negotiate a connection contract.

(2) The **distributor** and the **distributed generator** may, by agreement, extend the time specified in subclause (1) for negotiating a connection contract.

Compare: SR 2007/219 clause 21 Schedule 1
22 Testing and inspection
(1) A distributed generator whose final application is approved by a distributor must test and inspect the distributed generation to which the final application relates within a reasonable time frame specified by the distributor.

(1A) The distributor may waive the requirement that the distributed generator test and inspect if the distributor is satisfied that the distributed generation complies with the distributor’s connection and operation standards.

(2) The distributed generator must give adequate notice of the testing and inspection to the distributor.

(3) The distributor may send qualified personnel to the site to observe the testing and inspection.

(4) The distributed generator must give the distributor with a written test report when testing and inspection is complete, including suitable evidence that the distributed generation complies with the distributor’s connection and operation standards.

(5) The distributed generator must pay any fee specified by the distributor in accordance with clause 6.3(2)(e) for observing the testing and inspection.

Compare: SR 2007/219 clause 22 Schedule 1
Clause 22(1): substituted, on 23 February 2015, by clause 44(1) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 22(1A): inserted, on 23 February 2015, by clause 44(2) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 22(4): amended, on 23 February 2015, by clause 44(3) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

23 Connection of distributed generation if connection contract negotiated
(1) This clause applies if a distributor and a distributed generator whose final application is approved enter into a connection contract before the period for negotiating a connection contract under this Part of this Schedule expires.

(2) If the application is to connect distributed generation under clause 1B(a), the distributor must allow the distributed generator to connect the distributed generation in accordance with the contract as soon as practicable.

(3) If the application is to continue an existing connection of distributed generation under clause 1B(b), the distributor must use its best endeavours to ensure that the new terms under which the distributed generator’s existing connection continues apply—
   (a) as soon as practicable, if the previous connection contract has expired; or
   (b) no later than the expiry of the previous connection contract, if the contract is in force.

(4) If the application is to continue an existing connection for which there is no connection contract under clause 1B(c), the distributor must use its best endeavours to ensure that the new terms under which the distributed generator’s existing connection continues apply as soon as practicable.

(5) If the application is to change the nameplate capacity or fuel type of connected distributed generation under clause 1B(d), the distributor must use its best endeavours to ensure that the new terms under which the distributed generator’s existing connection continues apply as soon as practicable.

Compare: SR 2007/219 clause 23 Schedule 1

24 Connection of distributed generation on regulated terms if connection contract not negotiated

(1) This clause applies if a distributor and a distributed generator whose final application is approved do not enter into a connection contract before the period for negotiating a connection contract under this Part of this Schedule expires.

(2) If the application is to connect distributed generation under clause 1B(a), the distributor must allow the distributed generator to connect the distributed generation on the regulated terms as soon as practicable after the later of the following:
   (a) the expiry of the period for negotiating a connection contract under this Part of this Schedule:
   (b) the date on which the distributed generator has fully complied with any conditions (or other measures) that were specified by the distributor under clause 18 as conditions of the connection.

(3) If the application is to continue an existing connection of distributed generation under clause 1B(b), the regulated terms apply to the distributed generator's existing connection from the later of the following:
   (a) the expiry of the period for negotiating a connection contract under this Part of this Schedule:
   (b) the expiry of the existing connection contract:
   (c) the date on which the distributed generator has fully complied with any conditions (or other measures) that were specified by the distributor under clause 18 as conditions of the connection.

(4) If the application is to continue an existing connection for which there is no connection contract under clause 1B(c), the regulated terms apply from the later of the following:
   (a) the expiry of the period for negotiating a connection contract under this Part of this Schedule:
   (b) the date on which the distributed generator has fully complied with any conditions (or other measures) that were specified by the distributor under clause 18 as conditions of the connection.

(5) If the application is to change the nameplate capacity or fuel type of connected distributed generation under clause 1B(d), the regulated terms apply from the later of the following:
   (a) the expiry of the period for negotiating a connection contract under this Part of this Schedule:
   (b) the date on which the distributed generator has fully complied with any conditions (or other measures) that were specified by the distributor under clause 18 as conditions of the connection.

Compare: SR 2007/219 clause 24 Schedule 1
Part 3
General provisions

Confidentiality

25 Confidentiality of information provided

(1) All information given with, or relating to, an application made under this Schedule to a distributor must be kept confidential by the distributor except as agreed otherwise by the person that gave the information.

(1A) A distributor may require a distributed generator to keep confidential information that—

(a) is given to the distributed generator by the distributor for the purpose of an application under this Schedule; and

(b) the distributor reasonably identifies as being confidential.

(1B) A distributor is excused from processing an application made by a distributed generator under this Schedule if the distributed generator does not agree to comply with a requirement to keep information confidential imposed under subclause (1A).

(2) Despite subclause (1), the distributor—

(a) may, in response to an application under this Schedule, disclose to the applicant that another distributed generator has made an application under this Schedule (without identifying who the other distributed generator is); and

(b) may, in the case of an application under Part 1 of this Schedule, generally indicate the location or proposed location of the distributed generation that is the subject of the other application; and

(c) may, in the case of an application under Part 2 of this Schedule, disclose the nameplate capacity and proposed location of the distributed generation that is the subject of the other application.

(3) The obligation to keep information confidential set out in subclause (1) includes—

(a) an obligation not to use the information for any purpose other than considering the application under this Schedule and enabling the connection or continued connection of the distributed generation; and

(b) an obligation to destroy the information as soon as is reasonably practicable after the later of—

(i) the date on which the information is no longer required for the purposes in paragraph (a); and

(ii) 60 months after receiving the information.

Compare: SR 2007/219 clause 25 Schedule 1
Heading: amended, on 23 February 2015, by clause 46(1) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 25(1): substituted, on 23 February 2015, by clause 46(2) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 25(1A) and (1B): inserted, on 23 February 2015, by clause 46(3) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 25(2) and (3): substituted, on 23 February 2015, by clause 46(4) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Record keeping
Heading: amended, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Additional Registry Fields) Code Amendment 2012

26 [Revoked]
Compare: SR 2007/219 clause 26 Schedule 1
Clause 26: revoked, on 29 August 2013, by clause 4(2) of the Electricity Industry Participation (Additional Registry Fields) Code Amendment 2012

27 [Revoked]
Compare: SR 2007/219 clause 27 Schedule 1
Clause 27: revoked, on 29 August 2013, by clause 4(2) of the Electricity Industry Participation (Additional Registry Fields) Code Amendment 2012

28 Distributors must keep records
A distributor must maintain records of each application and notice received under this Schedule and the resulting outcomes, including records of how long it took to approve or decline the application, and justification for these outcomes, for a minimum of 60 months after the day on which the application was approved or declined.
Compare: SR 2007/219 clause 28 Schedule 1

Costs

29 Responsibility for costs under this Schedule
A distributor and distributed generator must pay their respective costs (including legal costs) incurred under this Schedule.
Cross heading and clause 29: inserted, on 23 February 2015, by clause 48 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Schedule 6.2

Regulated terms for distributed generation


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General

1 Contents of this Schedule
This Schedule sets out the regulated terms that apply to a distributor and a distributed generator in respect of distributed generation that is connected in accordance with clause 6.6 of Part 6 of this Code and Schedule 6.1.

2 Interpretation
These regulated terms must be interpreted—
(a) in light of the purpose of Part 6 of this Code; and
(b) so as to give business efficacy to the relationship between the distributor and the distributed generator created by Part 6 of this Code.

3 General obligations
(1) The distributor and the distributed generator must perform all obligations under these regulated terms in accordance with connection and operation standards (where applicable).

(2) The distributor and the distributed generator must each construct, connect, operate, test, and maintain their respective equipment in accordance with—
(a) these regulated terms; and
(b) connection and operation standards (where applicable); and
(c) this Code.

(3) The distributed generator must, subject to subclause (2), construct, connect, operate, test, and maintain its distributed generation in accordance with—
(a) reasonable and prudent operating practice; and
(b) the applicable manufacturer's instructions and recommendations.

(4) The distributor and distributed generator must each be fully responsible for the respective facilities they own or operate.

(5) The distributor and distributed generator must each ensure that their respective facilities adequately protect each other's equipment, personnel, and other persons and their property, from damage and injury.

(6) The distributed generator must comply with any conditions specified by the distributor under clause 18 of Schedule 6.1 (or, to the extent that those conditions were the subject of a dispute under clause 20(3) of that Schedule, or of negotiation during the period for negotiation of the connection contract, the conditions or other measures as finally resolved or negotiated).

Compare: SR 2007/219 clause 2 Schedule 2
Meters

4 Installation of meters and access to metering information

(1) [Revoked]

(2) The distributed generator must give the distributor, at the distributor’s request, the interval data and cumulative data recorded by the metering installations at the point of connection at which the distributed generation is connected or is proposed to be connected.

(3) The distributed generator must provide reactive metering if—
(a) the meter for the distributed generation is part of a category 2 metering installation, or a higher category of metering installation; and
(b) the distributed generator is required to do so by the distributor.

(4) The distributor’s requirements in respect of metering measurement and accuracy must be the same as set out in Part 10 of this Code.

Compare: SR 2007/219 clause 4 Schedule 2
Clause 4(2) to (4): substituted, on 23 February 2015, by clause 52(2) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Access

5 Right of distributor to access distributed generator's premises

(1) The distributed generator must provide the distributor, or a person appointed by the distributor, with safe and unobstructed access onto the distributed generator's premises at all reasonable times—
(a) for the purpose of installing, testing, inspecting, maintaining, repairing, replacing, operating, reading, or removing any of the distributor’s equipment and for any other purpose related to these regulated terms; and
(b) for the purpose of verifying metering information; and
(c) for the purpose of ascertaining the cause of any interference to the quality of delivery services being provided by the distributor to the distributed generator; and
(d) for the purpose of protecting, or preventing danger or damage to, persons or property; and
(e) for the purposes of electrically connecting or electrically disconnecting the distributed generation; and
(f) for any other purpose relevant to either or both of—
(i) the distributor connecting distributed generation in accordance with connection and operation standards; and
(ii) maintaining the integrity of the distribution network.

(2) The rights of access conferred by these regulated terms are in addition to any right of access the distributor may have under a statute or regulation or contract.

Compare: SR 2007/219 clause 5 Schedule 2

6 Process if distributor wants to access distributed generator's premises

(1) The distributor must exercise its right of access under clause 5 by,—
(a) wherever practicable, giving to the distributed generator reasonable notice of its intention and of the purpose for which it will exercise its right of access; and
(b) causing as little inconvenience as practicable to the distributed generator in carrying out its work; and
(c) observing reasonable and prudent operating practice at all times; and
(d) observing any reasonable security or site safety requirements that are made known to the distributor by the distributed generator.

(2) However, the distributor may take all reasonable steps to gain immediate access where it reasonably believes there is immediate danger to persons or property.

Compare: SR 2007/219 clause 6 Schedule 2

7 Distributor must not interfere with distributed generator's equipment

(1) The distributor must not interfere with the distributed generator's equipment without the prior written consent of the distributed generator.

(2) However, if emergency action has to be taken to protect the health and safety of persons, or to prevent damage to property, the distributor—
(a) may interfere with the distributed generator's equipment without prior written consent; and
(b) must, as soon as practicable, inform the distributed generator of the occurrence and circumstances involved.

Compare: SR 2007/219 clause 7 Schedule 2

8 Distributed generator must not interfere with, and must protect, distributor's equipment

(1) The distributed generator must not interfere with the distributor's equipment without the prior written consent of the distributor.

(2) However, if emergency action has to be taken to protect the health and safety of persons, or to prevent damage to property, the distributed generator—
(a) may interfere with the distributor's equipment without prior written consent; and
(b) must, as soon as practicable, inform the distributor of the occurrence and circumstances involved.
(3) The **distributed generator** must protect the **distributor's** equipment against interference and damage.

Compare: SR 2007/219 clause 8 Schedule 2

9 **Obligation to advise if interference with distributor's equipment or theft of electricity is discovered**

(1) If the **distributor** or the **distributed generator** discovers evidence of interference with the **distributor's** equipment, or evidence of theft of **electricity**, the party discovering the interference or evidence must advise the other party within 24 hours.

(2) If interference with the **distributor's** equipment at the **distributed generator's** installation is suspected, the **distributor** may itself carry out an investigation and present the findings to the **distributed generator** within a reasonable period.

(3) The cost of the investigation—

(a) must be borne by the **distributed generator** if it is discovered that interference by the **distributed generator**, or by its subcontractors, agents, or invitees, has occurred, or if the interference has been by a third party, and the **distributed generator** has failed to provide reasonable protection against interference to the **distributor's** equipment; and

(b) must be borne by the **distributor** in any other case.

Compare: SR 2007/219 clause 9 Schedule 2
Heading: amended, on 23 February 2015, by clause 54(1) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

10 **General obligation relating to interruptions**

The **distributor** must make reasonable endeavours to ensure that the connection of the **distributed generation** is not interrupted.

Compare: SR 2007/219 clause 10 Schedule 2

11 **Circumstances allowing distributor to temporarily electrically disconnect distributed generation**

Despite clause 10, the **distributor** may interrupt the connection service, or curtail either the operation or output of the generation, or both, and may temporarily **electrically disconnect** the **distributed generation** in any of the following cases:

(a) in accordance with the **distributor's congestion management policy**:

(b) if reasonably necessary for planned **maintenance, construction**, and repairs on the **distribution network**:

(c) for the purpose of protecting, or preventing danger or damage to, persons or property:
(d) if the distributed generator fails to allow the distributor access as required by clause 5:
(e) [Revoked]
(f) in accordance with clause 13 (adverse operating effects):
(g) if the distributed generator fails to comply with the distributor’s—
   (i) connection and operation standards; or
   (ii) safety requirements.

Compare: SR 2007/219 clause 11 Schedule 2
Clause 11: amended, on 23 February 2015, by clauses 55(1) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 11(e): revoked, on 23 February 2015, by clause 55(2) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 11(g): inserted, on 23 February 2015, by clause 55(3) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

12 Obligations if distributed generation temporarily electrically disconnected by distributor
(1) The distributor must make reasonable endeavours to—
   (a) advise the distributed generator before an interruption under clause 11; and
   (b) co-ordinate with the distributed generator to minimise the impact of the interruption.
(2) The distributor and the distributed generator must co-operate to restore the distribution network and the distributed generation to a normal operating state as soon as is reasonably practicable following the distributed generation being temporarily electrically disconnected.
(3) In the case of a forced outage, the distributor must, subject to the need to restore the distribution network, make reasonable endeavours to—
   (a) restore service to the distributed generator; and
   (b) advise the distributed generator of the expected duration of the outage.

Compare: SR 2007/219 clause 12 Schedule 2

13 Adverse operating effects
(1) The distributor must advise the distributed generator as soon as is reasonably practicable if it reasonably considers that operation of the distributed generation may—
   (a) adversely affect the service provided to other distribution network customers; or
   (b) cause damage to the distribution network or other facilities; or
   (c) present a hazard to a person.
(2) If, after receiving that advice, the distributed generator fails to remedy the adverse operating effect within a reasonable time, the distributor may electrically disconnect the distributed generation by giving reasonable notice (or without notice when reasonably necessary in the event of an emergency or hazardous situation).

Compare: SR 2007/219 clause 13 Schedule 2
Clause 13(2): amended, on 23 February 2015, by clause 57(2) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

14 Interruptions by distributed generator
(1) This clause applies to any connected distributed generation above 10 kW in total.
(2) The distributed generator must advise the distributor of any planned outages and must make reasonable endeavours to advise the distributor of an event that affects distribution network operations.
(3) The distributed generator must make reasonable endeavours to advise the distributor of the interruption and to co-ordinate with the distributor to minimise the impact of the interruption.

Compare: SR 2007/219 clause 14 Schedule 2

15 Disconnecting distributed generation
(1) Despite clause 10, the distributor may disconnect distributed generation in the following circumstances:
   (a) on receipt of a request from a distributed generator:
   (b) without notice, if a distributed generator has been temporarily electrically disconnected under clause 11(g) and—
      (i) the distributed generator fails to remedy the non-compliance within a reasonable period of time; and
      (ii) there is an ongoing risk to persons or property:
   (c) without notice, if the trader that is recorded in the registry as being responsible for the ICP to which the distributed generation is connected to the distribution network has electrically disconnected the ICP and updated the ICP's status in the registry to "inactive" with the reason of "electrically disconnected – ready for decommissioning":
   (d) on at least 10 business days' notice of intention to disconnect, if—
      (i) the distributed generator has not injected electricity into the distribution network at any time in the preceding 12 months; and
      (ii) the distributed generator has not given written notice to the distributor of the reasons for the non-injection; and
      (iii) the distributor has reasonable grounds for believing that the distributed generator has ceased to operate the distributed generation.

(2) [Revoked]
(3) If a **distributor** disconnects distributed generation under subclause (1) and the **point of connection** is to be decommissioned, the **distributor** must—
   (a) remove all electrical conductors between the distributed generation and the **distributor's lines**;
   (b) advise the **distributed generator** within 2 **business days** of the completion of the work referred to in paragraph (a).

(4) [Revoked]

(5) [Revoked]

Compare: SR 2007/219 clause 15 Schedule 2


Clause 15(1)(b) and (c): substituted, on 23 February 2015, by clause 59(1) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.


Clause 15(4) and (5): revoked, on 23 February 2015, by clause 59(5) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

**Time frame for construction**

15A Distributed generator must construct distributed generation within 18 months of approval

(1) This clause applies if the **distributor** approves the distributed generator's application to connect distributed generation under Part 1, Part 1A, or Part 2 of Schedule 6.1.

(2) The **regulated terms** cease to apply if the distributed generator does not construct the distributed generation within—
   (a) 18 months from the date on which approval was granted; or
   (b) such later date as is agreed by the **distributor** and distributed generator.

(3) The distributed generator must reapply under Schedule 6.1 if—
   (a) the regulated terms no longer apply in accordance with subclause (1); and
   (b) the distributed generator wishes to connect distributed generation to the **distributor's distribution network**.

Cross heading and clause 15A: inserted, on 23 February 2015, by clause 60 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Confidentiality

16 General obligations relating to confidentiality

(1) Each party must preserve the confidentiality of confidential information, and must not directly or indirectly reveal, report, publish, transfer, or disclose the existence of any confidential information, except as permitted in subclause (2).

(2) Each party must only use confidential information for the purposes expressly permitted by these regulated terms.

Compare: SR 2007/219 clause 17 Schedule 2

17 When confidential information can be disclosed

Either party may disclose confidential information in any of the following circumstances:

(a) if the distributed generator and distributor agree in writing to the disclosure of information:

(b) if disclosure is expressly provided for under these regulated terms:

(c) if, at the time of receipt by the party, the confidential information is in the public domain or if, after the time of receipt by either party, the confidential information enters the public domain (except where it does so as a result of a breach by either party of its obligations under this clause or a breach by any other person of that person's obligation of confidence):

(d) if either party is required to disclose confidential information by—

   (i) a statutory or regulatory obligation, body, or authority; or
   (ii) a judicial or arbitration process; or
   (iii) the regulations of a stock exchange upon which the share capital of either party is from time to time listed or dealt in; or
   (iv) this Code:

(e) if the confidential information is released to the officers, employees, directors, agents, or advisors of the party, provided that—

   (i) the information is disseminated only on a need-to-know basis; and
   (ii) recipients of the confidential information have been made fully aware of the party's obligations of confidence in relation to the information; and
   (iii) any copies of the information clearly identify it as confidential information:

(f) if the confidential information is released to a bona fide potential purchaser of the business or any part of the business of a party, subject to that bona fide potential purchaser having signed a confidentiality agreement enforceable by the other party in a form approved by that other party, and that approval may not be unreasonably withheld.

Compare: SR 2007/219 clause 18 Schedule 2
18 Disclosures by employees, agents, etc
To avoid doubt, a party is responsible for any unauthorised disclosure of confidential information made by that party's officers, employees, directors, agents, or advisors.

Compare: SR 2007/219 clause 19 Schedule 2

Pricing

19 Pricing principles
Charges that are payable by the distributed generator or the distributor must be determined in accordance with the pricing principles set out in Schedule 6.4.

Compare: SR 2007/219 clause 20 Schedule 2

Liability

20 General obligations relating to liability
(1) If the distributor or the distributed generator breaches any of the regulated terms (whether by act or omission), that party is liable to the other.

(2) The distributed generator's and the distributor's liability to each other is limited to damages for any direct loss caused by that breach.

(3) This clause and clauses 21 to 25 do not limit the liability of either party to pay all charges and other amounts due under Part 6 of this Code or the regulated terms.

Compare: SR 2007/219 clause 21 Schedule 2
Clause 20(1) and (3): amended, on 23 February 2015, by clause 62 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

21 Exceptions to obligations relating to liability
(1) Neither the distributor nor the distributed generator, nor any of its officers, employees, directors, agents, or advisors, are in any circumstances liable to the other party for—
   (a) any indirect loss, consequential loss (including, but not limited to, incidental or special damages), loss of profit, loss of revenue (except any liability under clause 20(3)), loss of use, loss of opportunity, loss of contract, or loss of goodwill; or
   (b) any loss resulting from the liability of the other party to another person; or
   (c) any loss or damage incurred by the other party if, and to the extent that, this results from any breach of the regulated terms or any negligent action.

(2) The distributor is not liable, except to the extent caused or contributed to by the distributor in circumstances where the distributor was not acting in accordance with Part 6 of this Code (including these regulated terms), for—
   (a) any momentary fluctuations in the voltage or frequency of electricity conveyed to or from the distributed generation's point of connection or nonconformity with harmonic voltage and current levels; or
   (b) any failure to convey electricity to the extent that—
      (i) the failure arises from any act or omission of the distributed generator or other person, excluding the distributor and its officers, employees, directors, agents, or advisors; or
(ii) the failure arises from a reduced injection of electricity into the distribution network; or

(iia) the failure arises from an interruption in the conveyance of electricity in the distribution network, if the interruption was at the request of the system operator or under a nationally or regionally co-ordinated response to an electricity shortage; or

(iii) the failure arises from any defect or abnormal conditions in or about the distributed generator's premises; or

(iv) the distributor was taking any action in accordance with Part 6 of this Code or the regulated terms; or

(v) the distributor was prevented from making necessary repairs (for example, by police at an accident scene).

(3) The distributed generator is not liable for—

(a) a failure to perform an obligation under these regulated terms caused by the distributor's failure to comply with the obligation; or

(b) a failure to perform an obligation under these regulated terms arising from any defect or abnormal conditions in the distribution network.

Compare: SR 2007/219 clause 22 Schedule 2

22 Limits on liability

The maximum total liability of each party, as a result of a breach of the regulated terms, must not in any circumstances exceed, in respect of a single event or series of events arising from the same event or circumstance, the lesser of—

(a) the direct damage suffered or the maximum total liability that the party bringing the claim against the other party has at the time that the event (or, in the case of a series of related events, the first of such events) giving rise to the liability occurred; or

(b) $1,000 per kW of nameplate capacity up to a maximum of $5 million.

Compare: SR 2007/219 clause 23 Schedule 2
Clause 22(b): amended, on 23 February 2015, by clause 64 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

23 Liability clauses do not apply to fraud, wilful breach, and breach of confidentiality

The exceptions in clause 21, and the limits on liability in clause 22, do not apply—

(a) if the distributor or the distributed generator, or any of its officers, employees, directors, agents, or advisors, has acted fraudulently or wilfully in breach of these regulated terms; or

(b) to a breach of confidentiality under clause 16 by either party.

Compare: SR 2007/219 clause 24 Schedule 2
25 Force majeure

(1) A failure by either party to comply with or observe any provisions of these regulated terms (other than payment of any amount due) does not give rise to any cause of action or liability based on default of the provision if—

(a) the failure is caused by—

(i) an event or circumstance occasioned by, or in consequence of, an act of God, being an event or circumstance—

(A) due to natural causes, directly or indirectly and exclusively without human intervention; and

(B) that could not reasonably have been foreseen or, if foreseen, could not reasonably have been resisted; or

(ii) a strike, lockout, other industrial disturbance, act of public enemy, war, blockade, insurrection, riot, epidemic, aircraft, or civil disturbance; or

(iii) the binding order or requirement of a Court, government, local authority, the Rulings Panel, or the Authority, and the failure is not within the reasonable control of the affected party; or

(iv) the partial or entire failure of the injection of electricity into the distribution network; or

(v) any other event or circumstance beyond the control of the party invoking this clause; and

(b) the party could not have prevented such failure by the exercise of the degree of skill, diligence, prudence, and foresight that would reasonably and ordinarily be expected from a skilled and experienced distributor or distributed generator engaged in the same type of undertaking under the same or similar circumstances in New Zealand at the time.

(2) If a party becomes aware of a prospect of a forthcoming force majeure event, it must advise the other party as soon as is reasonably practicable of the particulars of which it is aware.

(3) If a party invokes this clause, it must as soon as is reasonably practicable advise the other party that it is invoking this clause and of the full particulars of the force majeure event relied on.

(4) The party invoking this clause must—

(a) use all reasonable endeavours to overcome or avoid the force majeure event; and

(b) use all reasonable endeavours to mitigate the effects or the consequences of the force majeure event; and

(c) consult with the other party on the performance of the obligations referred to in paragraphs (a) and (b).

(5) Nothing in subclause (4) requires a party to settle a strike, lockout, or other industrial disturbance by acceding, against its judgement, to the demands of opposing parties.

Compare: SR 2007/219 clause 26 Schedule 2

Clause 25(2) and (3): amended, on 23 February 2015, by clause 67(2) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Schedule 6.3
Default dispute resolution process

Contents

1 Application of this schedule
2 Notice of dispute
3 Complaints
4 Application of pricing principles to disputes
5 Orders that Rulings Panel can make

1 Application of this Schedule
This Schedule applies in accordance with clause 6.8.
Compare: SR 2007/219 clause 1 Schedule 3
Clause 1: substituted, on 23 February 2015, by clause 68 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

2 Notice of dispute
(1) A party must give written notice to the other party of the dispute.
(2) The parties must attempt to resolve the dispute with each other in good faith.
(3) If the parties are unable to resolve the dispute, either party may complain in writing to
the Authority.
Compare: SR 2007/219 clause 2 Schedule 3

3 Complaints
(1) A complaint made under clause 2(3) must be treated as if it were a notification given
under regulations made under section 112 of the Act.
(2) The following provisions apply to the complaint:
(a) sections 53-62 of the Act; and
(b) the Electricity Industry (Enforcement) Regulations 2010 except regulations 5, 6, 7, 9, 17, 51 to 75, and subpart 2 of Part 3.
(3) Those provisions apply—
(a) to the dispute that is the subject of the complaint in the same way as those
provisions apply to a notification of an alleged breach of this Code; and
(b) as if references to a participant in those provisions were references to a party
under Part 6 of this Code; and
(c) with any further modifications that the Authority or the Rulings Panel, as the
case may be, considers necessary or desirable for the purpose of applying those
provisions to the complaint.
Compare: SR 2007/219 clause 3 Schedule 3

4 Application of pricing principles to disputes
(1) The Authority and the Rulings Panel must apply the pricing principles set out in
Schedule 6.4 to determine any connection charges payable.
(2) Subclause (1) applies if—
(a) there is a dispute under Part 6 of this Code; and
(b) in the opinion of the Authority or the Rulings Panel it is necessary or desirable to apply subclause (1) in order to resolve the dispute.

Compare: SR 2007/219 clause 4 Schedule 3

5 Orders that Rulings Panel can make
If a complaint is referred to it, the Rulings Panel may make any order, or take any action, that it is able to make or take in accordance with section 54 of the Act.

Compare: SR 2007/219 clause 5 Schedule 3
Schedule 6.4

Pricing principles

1 This Schedule sets out the pricing principles to be applied for the purposes of Part 6 of this Code in accordance with clause 6.9 (which relates to clause 19 of Schedule 6.2 and clause 4 of Schedule 6.3).

Compare: SR 2007/219 clause 1 Schedule 4

2 The pricing principles are as follows:

Charges to be based on recovery of reasonable costs incurred by distributor to connect the distributed generator and to comply with connection and operation standards within the distribution network, and must include consideration of any identifiable avoided or avoidable costs

(a) subject to paragraph (i), connection charges in respect of distributed generation must not exceed the incremental costs of providing connection services to the distributed generation. To avoid doubt, incremental cost is net of—

(i) if the distributed generation is included in a list published by the Authority under clause 2C(1), transmission costs that an efficient distributor would be able to avoid as a result of the electrical connection of the distributed generation at the nameplate capacity specified for that distributed generation in the list; and

(ii) distribution costs that an efficient distributor would be able to avoid as a result of the electrical connection of the distributed generation:

(b) costs that cannot be calculated (eg, avoidable costs) must be estimated with reference to reasonable estimates of how the distributor's capital investment decisions and operating costs would differ, in the future, with and without the generation:

(c) estimated costs may be adjusted ex post. Ex-post adjustment involves calculating, at the end of a period, what the actual costs incurred by the distributor as a result of the distributed generation being electrically connected to the distribution network were, and deducting the costs that would have been incurred had the generation not been electrically connected. In this case, if the costs differ from the costs charged to the distributed generator, the distributor must advise the distributed generator and recover or refund those costs after they are incurred (unless the distributor and the distributed generator agree otherwise):

Capital and operating expenses

(d) if costs include distinct capital expenditure, such as costs for a significant asset replacement or upgrade, the connection charge attributable to the distributed generator's actions or proposals is payable by the distributed generator before
the distributor has committed to incurring those costs. When making reasonable
deveous to facilitate connection, the distributor is not obliged to incur those
costs until that payment has been received:

(e) if incremental costs are negative, the distributed generator is deemed to be
providing network support services to the distributor, and may invoice the
distributor for this service and, in that case, the distributed generator must
comply with all relevant obligations (for example, obligations under Part 6 of this
Code and in respect of tax):

(f) if costs relate to ongoing or periodic operating expenses, such as costs for routine
maintenance, the connection charge attributable to the distributed generator's
actions or proposals may take the form of a periodic charge:

(g) [Revoked]

(h) after the connection of the distributed generation, the distributor may review
the connection charges payable by a distributed generator not more than once in
any 12-month period. Following a review, the distributor must advise the
distributed generator in writing of any change in the connection charges
payable, and the reasons for any change, not less than 3 months before the date
the change is to take effect:

Share of generation-driven costs

(i) if multiple distributed generators are sharing an investment, the portion of costs
payable by any 1 distributed generator—

(i) must be calculated so that the charges paid or payable by each distributed
generator take into account the relative expected peak of each distributed
generator's injected generation; and

(ii) may also have regard to the percentage of assets that will be used by each
distributed generator, the percentage of distribution network capacity
used by each distributed generator, the relative share of expected
maximum combined peak output, and whether the combined peak
generation is coincident with the peak load on the distribution network:

(j) in order to facilitate the calculation of equitable connection charges under
paragraph (i), the distributor must make and retain adequate records of
investments for a period of 60 months, provide the rationale for the investment in
terms of facilitating distributed generation, and indicate the extent to which the
associated costs have been or are to be recovered through generation connection
charges:

Repayment of previously funded investment

(k) if a distributed generator has paid connection charges that include (in part) the
cost of an investment that is subsequently shared by other distributed
generators, the distributor must refund to the distributed generator all
connection charges paid to the distributor under paragraph (i) by other
distributed generators in respect of that investment:
(l) if there are multiple prior distributed generators, a refund to each distributed generator referred to in paragraph (k) must be provided in accordance with the expected peak of that distributed generator's injected generation over a period of time agreed between the distributed generator and the distributor. The refund—

(i) must take into account the relative expected peak of each distributed generator's injected generation; and

(ii) may also have regard to the percentage of assets that will be used by each distributed generator, the percentage of distribution network capacity used by each distributed generator, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the distribution network:

(m) no refund of previous payments from the distributed generator referred to in paragraph (k) is required after a period of 36 months from the initial connection of that distributed generator:

Non-firm connection service

(n) to avoid doubt, nothing in Part 6 of this Code creates any distribution network capacity or property rights in any part of the distribution network unless these are specifically contracted for. Distributors must maintain connection and lines services to distributed generators in accordance with their connection and operation standards.

Compare: SR 2007/219 clause 2 Schedule 4
Heading: amended, on 23 February 2015, by clause 70(1) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 2: amended, on 23 February 2015, by clause 70(2) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 2(a): amended, on 23 February 2015, by clauses 70(3) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 2(c): amended, on 23 February 2015, by clauses 70(4) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 2(d), (f), (h), (j), (k), and (m): amended, on 5 October 2017, by clause 73(3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 2(f): amended, on 23 February 2015, by clauses 70(5) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 2(g): revoked, on 23 February 2015, by clause 70(6) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 2(h): amended, on 23 February 2015, by clauses 70(7) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 2(j): amended, on 23 February 2015, by clauses 70(9) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 2(m): amended, on 23 February 2015, by clauses 70(11) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 2(n): amended, on 23 February 2015, by clauses 70(2) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

2A Transpower to provide reports to Authority in relation to distributed generation
(1) Transpower must, by 15 March 2017 (or such later date as the Authority may allow), provide a report to the Authority that identifies which (if any) distributed generation located in the Lower South Island is required for Transpower to meet the grid reliability standards in the period from 1 April 2017 to 31 March 2020.

(2) Transpower must, by 30 August 2017, provide a report to the Authority that identifies which (if any) distributed generation located in the Lower North Island is required for Transpower to meet the grid reliability standards in the period from 1 April 2017 to 31 March 2020.

(3) Transpower must, by 31 January 2018, provide a report to the Authority that identifies which (if any) distributed generation located in the Upper North Island is required for Transpower to meet the grid reliability standards in the period from 1 April 2017 to 31 March 2020.

(4) Transpower must, by 31 January 2018, provide a report to the Authority that identifies which (if any) distributed generation located in the Upper South Island is required for Transpower to meet the grid reliability standards in the period from 1 April 2017 to 31 March 2020.

(5) In this clause and clause 4,—
(a) Upper North Island is that part of the North Island situated on, or north and west of, a line—
(i) commencing at 38°02'S and 174°42'E; then
(ii) proceeding in a generally north-easterly direction directly to 37°36'S and 175°27'E; then
(iii) proceeding north along the 175°27'E line of longitude; and
(b) Lower North Island is that part of the North Island not referred to in subclause (a); and
(c) Upper South Island is that part of the South Island situated on, or north of, a line passing through 43°30'S and 169°30'E, and 44°40'S and 171°12'E; and
(d) Lower South Island is that part of the South Island not referred to in subclause (c).


2B Authority to review Transpower's reports in relation to distributed generation
(1) The Authority must, as soon as practicable after receiving a report from Transpower under clause 2A,—
(a) approve the report; or
(b) decline to approve the report.

(2) If the Authority declines to approve the report,—
(a) the Authority must, as soon as practicable,—
(i) advise Transpower of its reasons for declining to approve the report; and
(ii) direct Transpower as to how it should amend the report before resubmitting it; and

(b) Transpower must amend the report in accordance with the Authority's direction, and resubmit the report to the Authority,—

(i) for the report provided under clause 2A(1), within 10 business days; and

(ii) for reports provided under clauses 2A(2), (3), or (4), within 20 business days.

(3) The Authority must, as soon as practicable after receiving a resubmitted report from Transpower,—

(a) approve the report; or

(b) decline to approve the report.

(4) Subclause (2) applies to the resubmitted report as if it were the report originally provided under clause 2A.


2C Authority to publish list of distributed generation

(1) The Authority must, after approving a report provided by Transpower under clause 2A, publish a list of distributed generation for the relevant region for the purposes of clause 2(a)(i).

(2) A list published under subclause (1) must include—

(a) only distributed generation that is connected as at 6 December 2016; and

(b) the nameplate capacity of the distributed generation as at 6 December 2016.


3 [Revoked]

Compare: SR 2007/219 clause 3 Schedule 4

Clause 3: revoked, on 23 February 2015, by clause 71 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

4 Delayed application of Electricity Industry Participation Code Amendment (Distributed Generation) 2016

(1) Despite clause 2 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2016,—

(a) until the close of 31 March 2018, Part 6 of this Code applies to the Lower South Island as if the Electricity Industry Participation Code Amendment (Distributed Generation) 2016 had not been made; and

(b) until the close of 30 September 2018, Part 6 of this Code applies to the Lower North Island as if the Electricity Industry Participation Code Amendment (Distributed Generation) 2016 had not been made; and

(c) until the close of 31 March 2019, Part 6 of this Code applies to the Upper North Island as if the Electricity Industry Participation Code Amendment (Distributed Generation) 2016 had not been made; and

(d) until the close of 30 September 2019, Part 6 of this Code applies to the Upper South Island as if the Electricity Industry Participation Code Amendment (Distributed Generation) 2016 had not been made.
(2) In this clause, Upper North Island, Lower North Island, Upper South Island, and Lower South Island have the meanings set out in clause 2A(5).


2. A **distributor** may require the payment of fees for any of the following activities prescribed under Part 6 of this Code to the maximum fee specified in the column opposite that activity:

<table>
<thead>
<tr>
<th>Description of fee</th>
<th>$ (exclusive of GST)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Part 1 of Schedule 6.1 application</strong></td>
<td></td>
</tr>
<tr>
<td>Application fee under clause 2(2)(c)</td>
<td>200</td>
</tr>
<tr>
<td>Fee for observation of testing and inspection under clause 7(5)</td>
<td>60</td>
</tr>
<tr>
<td><strong>Part 1A of Schedule 6.1 application</strong></td>
<td></td>
</tr>
<tr>
<td>Application fee under clause 9B(2)(c)</td>
<td>100</td>
</tr>
<tr>
<td>Fee for inspection under clause 9C(3)</td>
<td>60</td>
</tr>
<tr>
<td>Deficiency fee under clause 9E(4)</td>
<td>80</td>
</tr>
<tr>
<td><strong>Part 2 of Schedule 6.1 application</strong></td>
<td></td>
</tr>
<tr>
<td>Application fee for <strong>distributed generation</strong> with <strong>nameplate capacity</strong> of more than 10 kW but less than 100 kW under clause 11(2)(c)</td>
<td>500</td>
</tr>
<tr>
<td>Application fee for <strong>distributed generation</strong> with <strong>nameplate capacity</strong> of 100 kW or more in total but less than 1 MW under clause 11(2)(c)</td>
<td>1,000</td>
</tr>
<tr>
<td>Application fee for <strong>distributed generation</strong> with <strong>nameplate capacity</strong> of 1 MW or more under clause 11(2)(c)</td>
<td>5,000</td>
</tr>
<tr>
<td>Fee for observation of testing and inspection of <strong>distributed generation</strong></td>
<td>120</td>
</tr>
</tbody>
</table>
### Schedule 6.5

<table>
<thead>
<tr>
<th>Nameplate capacity of more than 10 kW but less than 100 kW under clause 22(5)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Fee for observation of testing and inspection of distributed generation with nameplate capacity of 100 kW or more under clause 22(5)</td>
<td>1,200</td>
</tr>
</tbody>
</table>

Compare: SR 2007/219 Schedule 5
Clause 2: substituted, on 23 February 2015, by clause 73 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
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## Part 7

System operator

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<td>7.12</td>
<td>Authority must publish system operator reports</td>
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### 7.1 Contents of this Part

This Part provides for—

(a) a reasonable and prudent **system operator** standard; and

(a) high level, output focussed performance obligations of the **system operator** in relation to the real time co-ordination and delivery of **common quality** and **dispatch**; and

(b) the functions of the **system operator** in relation to **demand** and supply forecasting, security of supply, and supply emergencies; and

(c) review of the **system operator's** performance under the **Act**, this Code, and the relevant **market operation service provider agreement**.

Clause 7.1(aa): inserted, on 19 May 2016, by clause 7(1) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.

Clause 7.1(a): amended, on 19 May 2016, by clause 7(2) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.
Clause 7.1(b): amended, on 19 May 2016, by clause 7(3) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.
Clause 7.1(c): amended, on 19 May 2016, by clause 7(4) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.

7.1A Reasonable and prudent system operator standard
(1) The system operator must carry out its obligations under this Code with skill, diligence, prudence, foresight, good economic management, and in accordance with recognised international good practice, taking into account—
(a) the circumstances in New Zealand; and
(b) the fact that real-time co-ordination of the power system involves complex judgements and inter-related events.
(2) The system operator does not breach a principal performance obligation or clause 8.5 of this Code if the system operator complies with subclause (1).
Clause 7.1A: inserted, on 19 May 2016, by clause 8 of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.

7.2 Principal performance obligations of the system operator in relation to common quality and dispatch
The obligations in clauses 7.2A to 7.2D are principal performance obligations.

7.2A System operator to maintain frequency
(1) 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; or
(b) a supply and demand imbalance.
(2) Except as provided in this clause and clause 7.2B, the system operator must maintain frequency in the normal band.
(3) The system operator must ensure that the scheduling, pricing, and dispatch tool has the information necessary to schedule a minimum quantity of instantaneous reserve.
(4) Subject to the availability of offers or reserve offers, the system operator must schedule sufficient instantaneous reserve to meet the system operator's obligations in subclauses (5) to (7).
(5) During a contingent event, the system operator must ensure that, for the island in which the contingent event takes place—
(a) frequency remains at or above 48 Hertz; and
(b) frequency returns to or above 49.25 Hertz within 60 seconds after the contingent event.
(6) During an extended contingent event in the North Island, the system operator must ensure that, for that island—
(a) frequency remains at or above 47 Hertz; and
(b) frequency does not drop to or below 47.1 Hertz for longer than 5 seconds; and
(c) frequency does not drop to or below 47.3 Hertz for longer than 20 seconds; and
(d) frequency returns to or above 49.25 Hertz within 60 seconds after the extended contingent event.
(7) During an extended contingent event in the South Island, the system operator must ensure that, for that island—
   (a) frequency remains at or above 45 Hertz; and
   (b) frequency returns to or above 49.25 Hertz within 60 seconds after the extended contingent event.

7.2B System operator to restore frequency if frequency fluctuation occurs
If a frequency fluctuation occurs, the system operator must ensure that frequency is restored to the normal band as soon as reasonably practicable having regard to all circumstances surrounding the frequency fluctuation.

7.2C System operator to manage frequency time error
(1) The system operator must ensure that any deviations from New Zealand standard time in the power system, caused by variations in system frequency, do not exceed 5 seconds.
(2) At least once in each day, the system operator must eliminate from the power system any deviations from New Zealand standard time caused by variations in system frequency.

7.2D System operator to identify and resolve problems
(1) A participant may request that the system operator investigate and resolve a security of supply or reliability problem arising from non-compliance with a standard in clause 4.7, 4.8, or 4.9 of the Connection Code, at any point of connection to the grid.
(2) If the system operator receives a reasonable request under subclause (1), the system operator must, given the assets made available to it at the relevant time—
   (a) identify whether there is a security of supply or reliability problem arising from non-compliance with a standard in clause 4.7, 4.8, or 4.9 of the Connection Code, at any point of connection to the grid; and
   (b) if there is such a problem—
      (i) identify the cause of the problem; and
      (ii) resolve the problem to the extent reasonable and practical.

7.2E System operator to report on frequency fluctuations
(1) By the 10th business day of each month (except by the 20th business day in the month of January), the system operator must report to the Authority the number of frequency fluctuations in each of the following frequency bands, in each island in the previous month:

<table>
<thead>
<tr>
<th>Frequency band (Hertz) (where &quot;x&quot; is the maximum or minimum frequency during a frequency fluctuation)</th>
<th>52.00</th>
<th>&gt; x ≥ 51.25</th>
</tr>
</thead>
<tbody>
<tr>
<td>51.25 &lt; x ≥ 50.50</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
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Part 7

(2) By the 10th business day of each month (except by the 20th business day in the month of January), the system operator must report to the Authority the number of frequency fluctuations in each of the following frequency bands, in the South Island in the previous month:

<table>
<thead>
<tr>
<th>Frequency band (Hertz) (where &quot;x&quot; is the maximum or minimum frequency during a frequency fluctuation)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>55.00 &gt; x ≥ 53.75</td>
<td></td>
</tr>
<tr>
<td>53.75 &gt; x ≥ 52.00</td>
<td></td>
</tr>
<tr>
<td>47.00 &gt; x ≥ 45.00</td>
<td></td>
</tr>
</tbody>
</table>

Compare: Electricity Governance Rules 2003 rules 2 and 3 section II part C
Clauses 7.2A-E: inserted, on 19 May 2016, by clause 10 of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.

7.3 Functions of system operator in relation to security of supply and emergency management

(1) The system operator must—
(a) prepare and publish a security of supply forecasting and information policy that includes a requirement that the system operator—
(i) prepare and publish at least annually a security of supply assessment that contains detailed supply and demand forecasts for at least 5 years, which assists interested parties to assess whether the energy security of supply standard and the capacity security of supply standard set out in subclause (2) are likely to be met; and
(ii) consult with persons that the system operator thinks are representative of the interests of persons likely to be substantially affected by a security of supply assessment prepared under subparagraph (i) before publishing such an assessment; and
(iii) prepare and publish information that assists interested parties to monitor how hydro and thermal generating capacity, transmission assets, primary fuel, and ancillary services are being utilised to manage risks of shortage, including extended dry periods; and
(iv) publish, in relation to the information published under subparagraphs (i) and (iii), sufficient details of the modelling data, assumptions, and
(b) implement and comply with the security of supply forecasting and information policy prepared and published in accordance with paragraph (a).

(2) For the purposes of subclause (1)(a)(i)—
(a) the energy security of supply standard is a winter energy margin of 14-16% for New Zealand and a winter energy margin of 25.5-30% for the South Island; and
(b) the capacity security of supply standard is a winter capacity margin of 630-780 MW for the North Island.

(2A) The Authority may publish a security standards assumptions document.

(2B) Subject to subclauses (2C) and (2D), if the Authority has published a security standards assumptions document under subclause (2A), the system operator must use the assumptions set out in that document in preparing a security of supply assessment under the security of supply forecasting and information policy.

(2C) The system operator may use different assumptions from those in a security standards assumptions document to prepare a security of supply assessment if—
(a) the system operator considers that there are good reasons to use different assumptions; and
(b) the system operator includes in the security of supply assessment—
   (i) a detailed explanation of the assumptions used to prepare the security of supply assessment; and
   (ii) a statement of reasons for using those assumptions instead of the assumptions published by the Authority; and
   (iii) a description of how the security of supply assessment prepared using those assumptions differs from a security of supply assessment prepared using the assumptions set out in the security standards assumptions document.

(2D) Despite subclause (2C), the system operator is not required to include the information referred to in subclause (2C)(b) in a security of supply assessment if the system operator considers that it would have good reason to refuse to supply the information under clause 2.6.

(3) The system operator must—
(a) prepare and publish an emergency management policy that sets out the steps that the system operator must take, and must encourage participants to take, at various stages during an extended emergency such as an extended dry sequence or an extended period of capacity inadequacy; and
(b) include in the emergency management policy the steps that, at various stages in anticipation of and during a gas transmission failure or gas supply failure to generators, the system operator must—
   (i) take as the system operator; and
   (ii) encourage participants to take, including, if appropriate, steps for relevant participants to take in conjunction with gas industry entities; and
   (iii) encourage relevant gas industry entities to take; and
(c) implement and comply with the emergency management policy.
(4) The emergency management policy is not required to include information that is already set out in—
   (a) the system operator rolling outage plan prepared under subpart 1 of Part 9; or
   (b) the policy statement; or
   (c) Technical Code B of Schedule 8.3.

(5) The system operator may depart from the policies set out in an emergency management policy if an EMP departure situation arises and such departure is required to enable the system operator to comply with clause 7.1A(1).

(6) If the system operator makes a departure under subclause (5), the system operator must provide a report to the Authority setting out the circumstances of the EMP departure situation and the actions taken to deal with it. The Authority must publish the report within a reasonable time of its receipt.

Clause 7.3(1)(a): amended, on 19 May 2016, by clause 11(2) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.
Clause 7.3(2A), (2B), (2C) and (2D): inserted, on 3 January 2013, by clause 4(3) of the Electricity Industry Participation (Supply Standards) Code Amendment 2012.
Clause 7.3(3)(a): amended, on 19 May 2016, by clause 11(6)(a) and (b) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.
7.4 Incorporation of security of supply forecasting and information policy and emergency management policy by reference

(1) The security of supply forecasting and information policy and the emergency management policy are incorporated by reference in this Code in accordance with section 32 of the Act.

(2) Subclause (1) is subject to Schedule 1 of the Act, which includes a requirement that the Authority must give notice in the Gazette before an amended or substituted security of supply forecasting and information policy or emergency management policy becomes incorporated by reference in this Code.


7.5 Approval of draft security of supply forecasting and information policy and emergency management policy

(1) The system operator may submit to the Authority for approval a draft security of supply forecasting and information policy or a draft emergency management policy to replace an existing security of supply forecasting and information policy or emergency management policy as the case may be.

(2) [Revoked]

(3) In preparing the draft security of supply forecasting and information policy or the draft emergency management policy, the system operator must—
   (a) consult with persons that the system operator thinks are representative of the interests of persons likely to be substantially affected by the policies; and
   (b) consider submissions made on the policies.

(4) The system operator must provide a copy of each submission received under subclause (3) to the Authority.

(5) The Authority must, as soon as practicable after receiving the draft security of supply forecasting and information policy or the draft emergency management policy, by notice in writing to the system operator,—
   (a) approve the relevant policy; or
   (b) decline to approve the relevant policy.

(6) If the Authority declines to approve the draft security of supply forecasting and information policy or the draft emergency management policy, the Authority must publish the changes that the Authority wishes the system operator to make to the relevant draft policy.

(7) When the Authority publishes the changes that the Authority wishes the system operator to make to the relevant draft policy under subclause (6), the Authority must advise the system operator and interested parties of the date by which submissions on the changes must be received by the Authority.

(8) Each submission on the changes to the draft policy must be made in writing to the Authority and be received on or before the date the Authority advises under subclause (7). The Authority must provide a copy of each submission received to the system operator and must publish the submissions.

(9) The system operator may make its own submission on the changes to the draft policy and the submissions received in relation to the changes. The Authority must publish
the system operator’s submission when it is received.

(10) The Authority must consider the submissions made to it on the changes to the draft policy.

(11) Following the consultation required by subclauses (7) to (10), the Authority may approve the draft policy subject to the changes that the Authority considers appropriate being made by the system operator.


7.6 Variations to security of supply forecasting and information policy and emergency management policy

(1) A participant or the Authority may submit a proposal for a variation to the security of supply forecasting and information policy or the emergency management policy to the system operator.

(2) The system operator must consider a proposed variation to the security of supply forecasting and information policy or the emergency management policy submitted under subclause (1).

(3) The system operator may submit a request for a variation to the security of supply forecasting and information policy or the emergency management policy to the Authority.

(4) Clause 7.5(3) to (11) apply to a request for a variation submitted under subclause (3) as if references to a draft policy were a reference to the requested variation.

(5) The Authority may approve a variation requested under subclause (3) without complying with subclause (4) if—

(a) the Authority considers that it is necessary or desirable in the public interest that the requested variation be made urgently; and

(b) the Authority publishes a notice of the variation and a statement of the reasons why the urgent variation is needed.

(6) Every variation made under subclause (5) expires on the date that is 9 months after the date on which the variation is made.

7.7 System operator and Authority joint development programme

(1) At least annually, the system operator and the Authority must agree a development programme that coordinates and prioritises—

(a) those items in the Authority’s industry development work plan on which the Authority intends to liaise with the system operator; and

(b) the system operator’s capital expenditure plan provided to the Authority under the system operator market operation service provider agreement.

(2) The Authority must publish the programme agreed under subclause (1).

7.8 Review of system operator

(1) The Authority must review the performance of the system operator at least once in
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each year ending 30 June, after the **system operator** submits its self-review under clause 7.11.

(2) The review must concentrate on the **system operator’s** compliance with—
(a) its obligations under this Code and the **Act**; and
(b) the operation of this Code and the **Act**; and
(c) any performance standards agreed between the **system operator** and the **Authority**; and
(d) the provisions of the **system operator’s** market operation service provider **agreement**.

(3) The **Authority** must **publish** a report on the performance of the **system operator** no later than 10 **business days** after the **Authority** completes its review.

### 7.9 Additional matters to be taken into account in system operator review

The **Authority** must take into account the following matters when conducting a review under clause 7.8:

(a) the terms of the **system operator’s** market operation service provider **agreement**:
(b) reports from the **system operator** to the **Authority**, including the **system operator’s** self-review under clause 7.11:
(c) the performance of the **system operator** over time in relation to this Part and Part 8:
(d) the extent to which the acts or omissions of other persons have impacted on the performance of the **system operator** and the nature of the task being monitored:
(e) reports or complaints from any person, and any responses by the **system operator** to such reports or complaints:
(f) the fact that the real time co-ordination of the power system involves a number of complex judgments and inter-related incidents:
(g) any disparity of information between the **Authority** and the **system operator**:
(h) any other matter the **Authority** considers relevant to assess the **system operator’s** performance.

### 7.10 Separation of Transpower roles

(1) **Transpower’s** role as **system operator** under this Code and the **Act** is distinct and separate from any other role or capacity that **Transpower** may have under this Code
and the Act, including as a grid owner or transmission provider.

(2) For this purpose, when assessing an aspect of the performance, or non-performance, of the system operator,—
(a) the assessment must be made on the basis that the system operator had no other role or capacity; and
(b) the system operator must be treated as if it did not have any knowledge or information that may be received or held by Transpower unless Transpower receives or holds that information or knowledge in its capacity as system operator.

(3) Subclause (2) applies, with necessary modifications, to an assessment of an aspect of the performance, or non-performance, of Transpower in any other role or capacity under this Code or the Act.

(4) Transpower must report, in each self-review report provided under this Code, on the extent to which its role as system operator under this Code and the Act has, despite subclauses (1) to (3), been materially affected by—
(a) any other role or capacity that Transpower has under this Code or the Act; or
(b) an agreement.

Compare: SR 2003/374 r 50

7.11 Review of performance of the system operator

(1) No later than 31 August in each year, the system operator must submit to the Authority a review and assessment of its performance in the previous 12 month period ending 30 June.

(2) The self-review must contain such information as the Authority may reasonably require from time to time to enable the Authority to review the system operator’s performance during the period in relation to the following:
(a) the policy statement:
(b) the security of supply forecasting and information policy:
(c) the emergency management policy:
(d) the joint development programme prepared under clause 7.7(1):
(e) the work programmes agreed with the Authority under the system operator's market operation service provider agreement:
(f) the system operator's engagement with participants:
(g) delivery of the system operator's capital and business plans:
(h) the financial and operational performance of the system operator.

(3) [Revoked]

(4) [Revoked]

Compare: Electricity Governance Rules rule 14 section II part C
Clause 7.11(1): amended, on 19 May 2016, by clause 15(1)(a) and (b) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.
Clause 7.11(3) and (4): revoked, on 19 May 2016, by clause 15(3) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.
7.12 Authority must publish system operator reports

(1) The Authority must publish all self-review reports that are received from the system operator and that are required to be provided by the system operator to the Authority under this Code.

(2) The Authority must publish each report within 5 business days after receiving the report.

Compare: SR 2003/374 r 49
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8.1 Contents of this Part
This Part relates to common quality. In particular, this Part concerns the performance obligations of the system operator, the performance obligations of asset owners, arrangements concerning ancillary services, extended reserve, and technical codes.

Compare: Electricity Governance Rules 2003 rule 1 section I part C

8.1A Requirement to provide complete and accurate information
(1) A participant must take all practicable steps to ensure that information that it provides to the extended reserve manager under this Part is—
(a) complete and accurate; and
(b) not misleading or deceptive; and
(c) not likely to mislead or deceive.

(2) If a participant provides information to the extended reserve manager under this Part, and subsequently becomes aware that the information is incomplete, inaccurate,
misleading or deceptive, or likely to mislead or deceive, the participant must provide revised information as soon as practicable.

(3) For the purpose of this clause, information provided by an asset owner to the extended reserve manager is deemed to be accurate if it complies with a data specification published by the extended reserve manager.


Subpart 1—Performance obligations of the system operator

8.2 Contents of this subpart
This subpart provides for—
(a) general performance obligations of the system operator
(b) a policy statement relating to the principal performance obligations of the system operator; and
(c) the review of the policy statement.

Compare: Electricity Governance Rules 2003 rule 1 section II part C

8.3 Recovery of costs from causers of harmonic and voltage non-compliance
(1) If the system operator is able to establish who is causing any departure from the standards referred to in clause 7.2(D), the system operator must endeavour to recover its reasonable identification and testing costs from that person. If the causer is a participant, the participant must pay those costs to the system operator.

(2) If the system operator is unable to recover its reasonable identification and testing costs, or the causer is not able to be identified, then those costs will form part of the system operator's identification costs.

Compare: Electricity Governance Rules 2003 rule 2.3.2 section II part C

Clause 8.3 Heading: amended, on 19 May 2016, by clause 16(1) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.

Clause 8.3(1): amended, on 19 May 2016, by clause 16(2) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.

8.4 System operator may rely on information provided
For the purposes of this Code, the system operator may—
(a) rely on the assets and information about the assets made available to the system operator by asset owners; and
(b) assume that asset owners are complying with the asset owner performance obligations and the technical codes, or complying with a valid dispensation or equivalence arrangement; and
(c) rely on information provided to the system operator by the extended reserve manager.

Compare: Electricity Governance Rules 2003 rule 4 section II part C

Clause 8.4: replaced, on 19 January 2017, by clause 5 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2016.
8.5 Restoration
(1) If an event disrupts the system operator’s ability to comply with the principal performance obligations, the system operator must re-establish normal operation of the power system as soon as possible, given—
   (a) the capability of generation, ancillary services, and extended reserve; and
   (b) the configuration and capacity of the grid; and
   (c) the information made available by asset owners.
(2) When re-establishing normal operation of the power system under subclause (1), the system operator must have regard to the following priorities:
   (a) first, the safety of natural persons:
   (b) second, the avoidance of damage to assets:
   (c) third, the restoration of offtake:
   (d) fourth, conformance with the principal performance obligations:
   (e) fifth, full conformance with the dispatch objective.

Compare: Electricity Governance Rules 2003 rule 5 section II part C

8.6 System operator may contract for higher levels of common quality
Subject to clause 17.29, nothing in this Code prevents the system operator from entering into contracts or arrangements in which levels of quality more stringent than those specified in the principal performance obligations are agreed, if the system operator can identify the incremental costs of those more stringent levels, and can ensure that those incremental costs are paid to the system operator by the persons wishing to enter into that contract or arrangement with the system operator.

Compare: Electricity Governance Rules 2003 rule 6 section II part C

8.7 System operator must not contract contrary to this arrangement
Subject to clauses 8.6 and 17.29, the system operator must not enter into a contract with another person that is inconsistent with the system operator’s obligations under this Code and the technical codes.

Compare: Electricity Governance Rules 2003 rule 7 section II part C

Policy statement

8.8 System operator to comply with policy statement
Subject to clause 8.14, the system operator must comply with the policy statement.

Compare: Electricity Governance Rules 2003 rule 8 section II part C
Clause 8.8: amended, on 19 May 2016, by clause 18 of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.

8.9 [Revoked]

8.10 Incorporation of policy statement by reference

(1) The policy statement is incorporated by reference in this Code in accordance with section 32 of the Act.

(2) Subclause (1) is subject to Schedule 1 of the Act, which includes a requirement that the Authority must give notice in the Gazette before an amended or substituted policy statement becomes incorporated by reference in this Code.

Compare: Electricity Governance Rules 2003 rule 9 section II part C

8.10A Review of policy statement

(1) At least once every 2 years the system operator must—
   (a) review the policy statement; and
   (b) as soon as practicable after completing a review, decide whether or not to propose a change to the policy statement; and
   (c) advise the Authority of its decision.

(2) If the system operator decides to propose a change to the policy statement, the system operator must submit a draft policy statement to the Authority together with the following information:
   (a) an explanation of the proposed change and a statement of the objectives of the proposed change:
   (b) an evaluation of alternative means of achieving the objectives of the proposed change:
   (c) an evaluation of the costs and benefits of the proposed change:
   (d) a list of the persons consulted and a summary of the submissions received.

(3) As part of a review conducted under this clause, the system operator must invite comments from participants.


8.10B System operator decides not to propose change to the policy statement

If the system operator advises the Authority under clause 8.10A(1)(c) that the system operator does not intend to propose a change to the policy statement the system operator must provide the Authority with the following information:
   (a) the findings of the review of the policy statement conducted by the system operator:
   (b) details of any request to amend the policy statement received from a participant or the Authority since the last review:
   (c) the system operator's decision on each such request including, if the system operator declined a requested change, the reasons for declining.

8.10C Authority may require system operator to reconsider

(1) The Authority may require the system operator to reconsider a decision made under clause 8.10A(1)(b) not to propose a change to the policy statement.

(2) If the Authority requires the system operator to reconsider a decision made under subclause 8.10A(1)(b), the Authority must advise the system operator of—
   (a) the Authority’s reasons for requiring the system operator to reconsider; and
   (b) the date, determined after consulting with the system operator, by which the system operator must either confirm its decision or submit a draft policy statement.

(3) The Authority must as soon as practicable publish the advice received from the system operator under clause 8.10A(1)(c) and the advice given by the Authority to the system operator under subclause (2).


8.11 Content of draft policy statement

(1) [Revoked]

(2) [Revoked]

(3) The draft policy statement must include—
   (a) the policies and means that the system operator considers appropriate for the system operator to observe in complying with its principal performance obligations; and
   (b) the policies and means by which scheduling and dispatch are adjusted to meet the dispatch objective, and must include the provision of a dispatch process statement. The dispatch process statement must contain the details of the processes that enable the system operator to meet the dispatch objective, including the methodologies to be used by the system operator for planning to meet the dispatch objective during the period leading up to real time and meeting the dispatch objective in real time; and
   (c) a policy setting out how the system operator will manage any conflict of interest that arises in the performance of its obligations under this Code; and
   (d) a statement of the reasons for adopting the policies and means set out in the policy statement (which statement must be regarded as an explanatory note only and does not form part of the policies itself); and
   (e) a statement of how future policies and means might be formulated and implemented.

Compare: Electricity Governance Rules 2003 rule 10 section II part C

8.11A Changes and variations

(1) The system operator may at any time propose a change to the policy statement by submitting a draft policy statement to the Authority together with the following information:
   (a) an explanation of the proposed change and a statement of the objectives of the proposed change;
   (b) an evaluation of alternative means of achieving the proposed change;
   (c) an evaluation of the costs and benefits of the proposed change.

(2) The Authority or a participant may at any time request that the system operator propose a change to the policy statement under subclause (1).

(3) If the system operator receives a request under subclause (2), it must as soon as practicable—
   (a) decide whether to decline the request, defer the request until the next review date, or submit a draft policy statement to the Authority; and
   (b) publish the decision.

(4) If the system operator declines a request under subclause (3), the Authority may require the system operator to reconsider its decision, giving reasons.


8.12 Consultation on draft policy statement

(1) The Authority must publish the following information as soon as practicable after it receives it:
   (a) a draft policy statement submitted under clause 8.10A and the information required under clause 8.10A(2):
   (b) a draft policy statement submitted under clause 8.11A and the information required under clauses 8.11A(1)(a) to (c).

(2) When the Authority publishes a draft policy statement and information under subclause (1), the Authority must advise participants of the date (which must not be earlier than 10 business days after the date that the Authority publishes the draft policy statement) by which submissions on the changes proposed in the draft policy statement must be received by the Authority.

(3) Each submission on changes proposed in a draft policy statement must be made in writing to the Authority and received on or before the submission expiry date.

(4) The Authority must provide a copy of each submission received to the system operator at the close of business on the submission expiry date and must publish the submissions as soon as practicable.

(5) The system operator may make its own submission on the draft policy statement and the submissions received in relation to it no later than 10 business days after the submission expiry date.
(6) The **Authority** must **publish** the **system operator**’s submission as soon as practicable after it is received.

(7) Following the consultation process required by subclauses (1) to (6), the **Authority** may approve the **draft policy statement** subject to the **system operator** making any changes that the **Authority** considers appropriate.

Compare: Electricity Governance Rules 2003 rule 11 section II part C
Clause 8.12(1), (2), (4) and (6): amended, on 5 October 2017, by clause 85(1) and (2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

8.12A Technical and non-controversial changes

(1) The **system operator** may at any time propose a change to the **policy statement** that it considers is technical and non-controversial by submitting a **draft policy statement** to the **Authority** together with an explanation of the proposed change.

(2) If the **system operator** submits a **draft policy statement** under subclause (1) the **system operator** is not required to provide a statement of the objectives of the proposed change, an evaluation of alternative means of achieving the objectives of the proposed change or an evaluation of costs and benefits of the proposed change.

(3) The **Authority** must, as soon as practicable after receiving a **draft policy statement** and the information required under subclause (1), by notice in writing to the **system operator**—

(a) approve the **draft policy statement** to be incorporated by reference into this Code; or

(b) decline to approve the **draft policy statement**, giving reasons.

(4) If the **Authority** approves the **draft policy statement** it must as soon as practicable—

(a) **publish** notice of its intention to incorporate the **draft policy statement** by reference into this Code; and

(b) include in the notice the **Authority**’s reasons for considering that the changes proposed in the **draft policy statement** are technical and non-controversial; and

(c) invite comment from **participants** on the reasons given in the notice.

(5) After considering any comments made under subclause 4(c) the **Authority** must advise the **system operator** by notice in writing of its decision as to whether to confirm or revoke its approval of the **draft policy statement**, and give reasons for its decision.

(6) The **Authority** must **publish** its decision and reasons as soon as practicable.


8.12B Authority adopts new policy statement

If the **Authority** approves a **draft policy statement** under clause 8.12 or confirms its approval of a **draft policy statement** under clause 8.12A it must—

(a) incorporate the new **policy statement** by reference into this Code in accordance with Schedule 1 of the **Act**; and

(b) **publish** the new **policy statement** and the date on which it takes legal effect.


8.13 [Revoked]
Compare: Electricity Governance Rules 2003 rule 12 section II part C

8.14 Departure from policy statement
(1) The system operator may depart from the policies set out in a policy statement when a system security situation arises and such departure is required for the system operator to comply with clause 7.1A(1).
(2) If the system operator departs from a policy statement under subclause (1), the system operator must provide a report to the Authority setting out the circumstances of the system security situation and the actions taken to deal with it.
(3) The Authority must publish the report within a reasonable time after receiving it.
Compare: Electricity Governance Rules 2003 rule 13 section II part C

System security forecast

8.15 System operator to prepare and review system security forecast
(1) Every 2 years, the system operator must prepare, publish, and provide to the Authority a system security forecast.
(1A) The system security forecast must—
(a) identify risks to the system operator’s ability to meet the principal performance obligations over the ensuing period of not less than 36 months, and indicate how those risks can be managed; and
(b) take into account the capabilities of the grid and connected assets based on information known to, and able to be disclosed by, the system operator.
(2) The date by which the system operator must publish the system security forecast and provide it to the Authority in each year in which the system operator is required to do so, is the date established for that purpose under rule 15 of section II of part C of the rules.
(3) The system operator must review the most recent system security forecast prepared in accordance with subclause (1) at 6 monthly intervals until a new forecast or update is prepared. If, in the reasonable opinion of the system operator, a change has been made to the power system that would materially affect the most recent forecast or update, the system operator must amend the system security forecast, publish it and provide it to the Authority.
Compare: Electricity Governance Rules 2003 rule 15 section II part C

Subpart 2—Asset owner performance obligations and technical standards

8.16 Contents of this subpart
This subpart provides for—
(a) the establishment of performance obligations and technical standards for asset owners to assist the system operator in complying with the principal performance obligations; and
(b) asset owners to obtain an assessment of their assets from the system operator; and
(c) a process for the system operator to approve applications for equivalence arrangements and dispensations (if necessary).
Compare: Electricity Governance Rules 2003 rule 1 section III part C

Asset owner performance obligations and technical standards concerning frequency

8.17 Contribution by injections to overall frequency management
Each generator (while synchronised) and the HVDC owner must at all times ensure that its assets, other than any generating units within an excluded generating station, make the maximum possible injection contribution to maintain frequency within the normal band (and to restore frequency to the normal band). Any such contribution must be assessed against the technical codes.
Compare: Electricity Governance Rules 2003 rule 2.1 section III part C

8.18 Contributions by purchasers to overall frequency management
Each purchaser must limit the magnitude of any instantaneous change in the offtake of electricity and net rate of change in offtake to the levels the system operator reasonably requires. In setting those requirements, the system operator must have regard to the impact of the offtake on the system operator’s ability to comply with the principal performance obligations concerning frequency (as set out in clause 7.2A to 7.2C) and the dispatch objective.
Compare: Electricity Governance Rules 2003 rule 2.2 section III part C

8.19 Contributions to frequency support in under-frequency events
(1) Subject to subclause (3), each generator must at all times ensure that, while electrically connected, its assets, other than any excluded generating stations, contribute to supporting frequency by remaining synchronised, ensuring that each of its generating units can and does, at a minimum, sustain pre-event output—
(a) at all times when the frequency is above 47.5 Hertz; and
(b) for at least 120 seconds when the frequency is 47.5 Hertz; and
(c) for at least 20 seconds when the frequency is 47.3 Hertz; and
(d) for at least 5 seconds when the frequency is 47.1 Hertz; and
(e) for at least 0.1 seconds when the frequency is 47.0 Hertz; and
(f) at any frequencies between those specified in paragraphs (b) to (e) for times derived by linear interpolation.

(2) If the inherent characteristics and design of a generator's generating unit are such that it is reasonably able to operate beyond the above requirements, the generator must declare such capabilities in accordance with clause 2(5) of Technical Code A of Schedule 8.3.

(3) Each South Island generator must ensure that each of its assets, other than excluded generating units, remains synchronised, and can and do, at a minimum, sustain pre-event output—
(a) at all times when the frequency is above 47 Hertz; and
(b) for 30 seconds if the frequency falls below 47 Hertz but not below 45 Hertz.

(4) The HVDC owner must at all times ensure that, while electrically connected, its assets contribute to supporting frequency during an under-frequency event in either island by—
(a) remaining electrically connected to those assets making up the grid in the North Island and South Island while the frequency in both islands remains above 48 Hertz; and
(b) remaining electrically connected to those assets making up the grid in the North Island and South Island while the frequency in both islands remains above 47 Hertz and above 47 Hertz for 90 seconds; and
(c) remaining electrically connected to those assets making up the grid in the North Island and South Island while the frequency in both islands remains above 45 Hertz for 35 seconds, unless the frequency in either island is less than 46.5 Hertz and the frequency is falling at a rate of 7 Hertz per second or greater; and
(d) subject to the level of transfer and the HVDC link configuration at the beginning of the under-frequency event, if the HVDC link itself is not the cause of the under-frequency event, modifying the instantaneous transfer on the HVDC link by up to 250 MW with the objective of limiting the difference between the North Island and South Island frequencies to no greater than 0.2 Hertz.

(5) Each extended reserve provider must provide extended reserve in accordance with Schedule 8.3, Technical Code B.

Compare: Electricity Governance Rules 2003 rule 2.3 section III part C
Clause 8.19(1) and (4): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

8.20 Contributions by grid owners to frequency support
Each grid owner must ensure that its assets are capable of being operated, and operate,
within the frequency targets set out in clause 7.2A.

Compare: Electricity Governance Rules 2003 rule 2.4 section III part C

8.21 Excluded generating stations

(1) For the purposes of clauses 8.17, 8.19, 8.25D, and the provisions in Technical Code A of Schedule 8.3 relating to the obligations of asset owners in respect of frequency, an excluded generating station means a generating station that exports less than 30 MW to a local network or the grid, unless the Authority has issued a direction under clause 8.38 that the generating station must comply with clauses 8.17, 8.19, 8.25A, and 8.25B and the relevant provisions in Technical Code A of Schedule 8.3.

(2) Whether likely to be an excluded generation station or not, a generator who is planning to connect to the grid or a local network a generating unit with rated net maximum capacity equal to or greater than 1 MW must provide the system operator with written advice of its intention to connect together with other information relating to that generating unit in accordance with clause 8.25(4).

Compare: Electricity Governance Rules 2003 rules 2.5 and 2.6 section III part C
Clause 8.21(1): amended, on 24 November 2016, by clause 5(1) and (2) of the Electricity Industry Participation Code Amendment (Generation Fault Ride Through) 2016.

Asset owner performance obligations and technical standards concerning voltage

8.22 Voltage range AOPOs

(1) Each grid owner must ensure that its assets at and in between—
   (a) the high voltage terminals of the grid owner's transformers at each grid injection point and grid exit point; or
   (b) if no transformer exists, the relevant grid injection point or grid exit point—are capable of being operated within the following range of voltages:

<table>
<thead>
<tr>
<th>Nominal grid voltage (kV)</th>
<th>Voltage limits</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Minimum (kV)</td>
</tr>
<tr>
<td>220</td>
<td>198 -10.0%</td>
</tr>
<tr>
<td>110</td>
<td>99  -10.0%</td>
</tr>
<tr>
<td>66</td>
<td>62.7  -5.0%</td>
</tr>
<tr>
<td>50</td>
<td>47.5  -5.0%</td>
</tr>
</tbody>
</table>

(2) Each generator with a point of connection to the grid must at all times ensure that its assets are capable of being operated, and do operate, when the grid is operated within the range of voltages set out in subclause (1).

(3) Each connected asset owner must ensure that its local network is capable of being operated, and does operate, when the grid is operated over the range of voltages set out in subclause (1).
8.23 Voltage support AOPOs

Each generator with a point of connection to the grid must at all times ensure that its assets—

(a) when the voltage at its grid injection point is within the applicable range of nominal voltage, are capable of exporting (over excited) when synchronised and made available for dispatch by the system operator, a minimum net reactive power which is 50% of the maximum continuous MW output power as measured at the following generating unit terminals:

<table>
<thead>
<tr>
<th>Nominal grid voltage (kV)</th>
<th>Voltage range for which reactive power is required</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Minimum (kV)</td>
<td>Maximum (kV)</td>
</tr>
<tr>
<td>220</td>
<td>198 -10.0%</td>
<td>242 10.0%</td>
</tr>
<tr>
<td>110</td>
<td>99 -10.0%</td>
<td>121 10.0%</td>
</tr>
<tr>
<td>66</td>
<td>62.7 -5.0%</td>
<td>69.3 5.0%</td>
</tr>
<tr>
<td>50</td>
<td>47.5 -5.0%</td>
<td>52.5 5.0%</td>
</tr>
<tr>
<td>33</td>
<td>31.35 -5.0%</td>
<td>34.65 5.0%</td>
</tr>
<tr>
<td>22</td>
<td>21.45 -2.5%</td>
<td>22.55 2.5%</td>
</tr>
<tr>
<td>11</td>
<td>10.725 -2.5%</td>
<td>11.275 2.5%</td>
</tr>
</tbody>
</table>

(b) when the voltage at its grid injection point is within the applicable range of nominal voltage, are capable of importing (under excited) when synchronised and made available for dispatch by the system operator, a minimum net reactive power which is 33% of the maximum continuous MW output power as measured at the generating unit terminals as set out below:

<table>
<thead>
<tr>
<th>Nominal grid voltage (kV)</th>
<th>Voltage range for which reactive power is required</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Minimum (kV)</td>
<td>Maximum (kV)</td>
</tr>
<tr>
<td>220</td>
<td>209 -5.0%</td>
<td>242 10.0%</td>
</tr>
<tr>
<td>110</td>
<td>104.5 -5.0%</td>
<td>121 10.0%</td>
</tr>
<tr>
<td>66</td>
<td>62.7 -5.0%</td>
<td>69.3 5.0%</td>
</tr>
<tr>
<td>50</td>
<td>47.5 -5.0%</td>
<td>52.5 5.0%</td>
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</tr>
<tr>
<td>22</td>
<td>21.45 -2.5%</td>
<td>22.55 2.5%</td>
</tr>
<tr>
<td>11</td>
<td>10.725 -2.5%</td>
<td>11.275 2.5%</td>
</tr>
</tbody>
</table>

(c) when synchronised, continuously operate in a manner that supports voltage and voltage stability on the grid in compliance with the technical codes.

Compare: Electricity Governance Rules 2003 rule 3.2 section III part C
8.24 Load shedding obligations to support voltage
(1) If it is not possible for a connected asset owner to comply with subclause (2), the grid owner must, if possible, establish load shedding in block sizes and at voltage levels (and, if automatic systems are established, with relay settings) set out in the technical codes or otherwise as the system operator reasonably requires.
(2) In order to prevent the collapse of the network voltage, each connected asset owner must ensure that, if possible, it has established load shedding in block sizes and at voltage levels (and, if automatic systems are established, with relay settings) in accordance with the technical codes or otherwise as the system operator reasonably requires.

Compare: Electricity Governance Rules 2003 rule 3.3 section III part C

8.25 Other asset owner performance obligations and technical standards
(1) Each grid owner must ensure that the design and configuration of its assets (including its connections to other persons) and associated protection arrangements are consistent with the technical codes and, in the reasonable opinion of the system operator, with maintaining the system operator's ability to comply with the principal performance obligations. In reaching this opinion, the system operator must have regard to the potential impact of the design or configuration of those assets or associated protection arrangements on its compliance with the principal performance obligations and achievement of the dispatch objective.
(2) Each grid owner and each connected asset owner must use reasonable endeavours to ensure that a generator who meets the following criteria provides the system operator with written advice of the existence of its generating unit and the generator's name and address:
(a) the generator is directly connected to the grid owner's grid or directly or indirectly connected to the local network (as the case may be):
(b) the generator has a generating unit with a rated net maximum capacity equal to or greater than 1 MW.
(3) Each asset owner and each purchaser must provide communication facilities that comply with the technical codes or otherwise, as the system operator reasonably requires, which must assist the system operator in planning to comply, and complying, with its principal performance obligations and achieving the dispatch objective.
(4) Each asset owner and each purchaser must provide information that complies with the technical codes or otherwise as the system operator reasonably requests, to assist the system operator in planning to comply, and complying, with its principal performance obligations and achieving the dispatch objective.
(5) If the system operator reasonably considers it necessary to assist the system operator in planning to comply, and complying, with the principal performance obligations and achieving the dispatch objective, the system operator—
(a) may require that an embedded generator provide information regarding the
intended output of each embedded generating station greater than 10 MW in capacity, that must be either—

(i) submitted as an offer in accordance with subpart 1 of Part 13; or

(ii) provided in a form and manner agreed between the system operator and the embedded generator; and

(b) must advise the embedded generator of its requirement at least 20 business days in advance of the requirement coming into effect.

(6) If the system operator reasonably considers it necessary to assist it in planning to comply, and complying, with the principal performance obligations and achieving the dispatch objective, the system operator may apply to the Authority to require an embedded generator to provide information regarding the intended output of a group of embedded generating stations that total greater than 10 MW in capacity and that are connected to the same grid exit point. If the Authority approves the system operator’s request, the information must be provided to the system operator by the relevant embedded generator in a form and manner determined by the Authority.

Compare: Electricity Governance Rules 2003 rule 4.1 to 4.6 section III part C
Clause 8.25(1), (2) and (6): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 8.25(1), (2) and (6): amended, on 5 October 2017, by clause 92(1) and (2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

8.25A Fault ride through

(1) Each generator must ensure that each of its assets, when electrically connected to a network, is capable of remaining stable and electrically connected when the grid’s lowest line-to-line voltage is within the no-trip zone shaded and marked "No-trip zone" in Figure 8.1 (for an asset in the North Island) or Figure 8.2 (for an asset in the South Island) for the period of 6 seconds immediately following the commencement of a zero impedance three-phase short circuit fault, or an unbalanced short circuit fault, on any part of the grid at 110 kV or 220 kV in the island in which the asset is connected.

(2) Each generator must ensure that each of its assets, when electrically connected to a network, is capable of remaining stable and electrically connected when the highest line-to-line voltage at Haywards 220 kV bus (for an asset in the North Island) or Benmore 220 kV bus (for an asset in the South Island) is within the no-trip zone shaded and marked "No-trip zone" in Figure 8.3 for the period of 1 second immediately following the commencement of a trip of the HVDC link.

(3) Whether a generator is complying with subclause (2) must be determined using power system analysis that uses—

(a) study cases provided by the relevant grid owner; and

(b) relevant system assumptions provided by the system operator.

(4) A generator is not required to comply with subclause (1) in respect of an asset in the event of a fault of a type described in subclause (1) if the asset becomes isolated from the grid as a result of the fault.
(5) A generating unit need not comply with subclause (1) to the extent that it is complying with a special protection scheme approved by the system operator.

(6) The absolute grid voltage (per unit) shown on the Y axis of Figure 8.1 and Figure 8.2 is the ratio of grid lowest line-to-line voltage on a line to the nominal operating voltage of the line (that is, 110 kV or 220 kV).

Figure 8.1: North Island no-trip zone during 110 kV or 220 kV faults

Figure 8.2: South Island no-trip zone during 110 kV or 220 kV faults
Figure 8.3: Haywards and Benmore no-trip zone during permanent loss of the HVDC link

8.25B Reactive current and active power output

(1) Each generator must ensure that each of its generating units generates reactive current to oppose the change in its terminal voltage without exceeding the maximum transient reactive current specified in the generator's asset capability statement for the period of 6 seconds immediately following the commencement of a fault on the grid of a type described in clause 8.25A(1).

(2) Each generator must ensure that each of its generating units provides active power output relative to pre-fault active power output at least in proportion to the grid voltage at the grid injection point for the period of 6 seconds immediately following the clearance of a fault on the grid of a type described in clause 8.25A(1).

(3) Subclause (2) does not apply to a wind generating station if there has been a reduction in the intermittent wind power source during the 6 seconds following the commencement of the fault.


8.25C Use of additional equipment

A generator may comply with clause 8.25A in relation to a generating station by—
(a) ensuring that the performance of generating units that comprise the generating station comply; or
(b) installing additional equipment within the generating station; or
(c) a combination of the methods described in paragraphs (a) and (b).


8.25D Application
Clauses 8.25A and 8.25B do not apply—

(a) to a wind generating station when it operates at less than 5% of rated MW; or
(b) to any asset at an excluded generating station.


8.26 Asset owners must co-operate
Each asset owner and each purchaser must co-operate with the system operator as may reasonably be required by the system operator in carrying out its functions.

Compare: Electricity Governance Rules 2003 rule 4.7 section III part C

Compliance

8.27 System operator to monitor compliance
(1) To the extent possible, given the information made available by asset owners, the system operator must monitor, in the manner set out in the policy statement, the ongoing compliance of asset owners with the asset owner performance obligations and the technical codes. To avoid doubt, the system operator has no monitoring obligations under this subpart other than those set out in the policy statement.

(2) The system operator has a discretion to not dispatch an asset or configuration of assets, if it is not satisfied that the assets or configuration of assets comply with the relevant asset owner performance obligations or provisions of the technical codes, or that the asset owner has and is complying with a valid equivalence arrangement or dispensation from the relevant asset owner performance obligations or provisions of the technical codes.

(3) The system operator must immediately advise an asset owner if the system operator has reasonable grounds to believe that the asset owner is not complying with an asset owner performance obligation, equivalence arrangement or dispensation, and that the asset owner—

(a) does not have a valid equivalence arrangement or dispensation from the relevant asset owner performance obligations or provisions of the technical codes: or
(b) is not complying with a valid equivalence arrangement or dispensation from the relevant asset owner performance obligations or provisions of the technical codes.

Compare: Electricity Governance Rules 2003 rule 5 section III part C

8.28 Responsibility for compliance

(1) Each asset owner must comply with the asset owner performance obligations and technical codes at all times and must satisfy the system operator, whenever requested by the system operator acting reasonably, that each of its assets or configuration of assets complies with the asset owner performance obligations and technical codes that apply to that asset or configuration of assets.

(2) If the system operator advises an asset owner under clause 8.27(3), the asset owner must co-operate with the system operator and use reasonable endeavours to restore compliance as soon as practicable.

(3) During a period of commissioning or testing of assets, the asset owner performance obligations and technical codes do not apply to the asset owner in respect of the assets, if—

(a) the obligations that do not apply to the asset owner are specified in the agreed commissioning plan or testing plan; and

(b) during the period of non-compliance the asset owner complies with a commissioning plan or testing plan (as appropriate) agreed with the system operator; and

(c) the period of non-compliance is no longer than the agreed commissioning plan or testing plan; and

(d) subject to subclause (4), if an asset owner during a period of non-compliance meets the requirements of paragraphs (a) to (c), neither the asset owner nor the system operator is liable under this Code in relation to the non-compliance, except that the asset owner is not relieved of liability in the case of a negligent act or omission by the asset owner.

(4) During any period of non-compliance, the non-compliant asset owner must pay the readily identifiable and quantifiable costs associated with its non-compliance, including the costs of the system operator purchasing additional ancillary services required as a consequence of its non-compliance.

Compare: Electricity Governance Rules 2003 rule 6 section III part C
Clause 8.28(2): amended, on 1 November 2018, by clause 12 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018

Equivalence arrangements and dispensations

8.29 Right to apply for approval of equivalence arrangement or grant of dispensation

(1) Subject to subclause (2), if an asset owner cannot comply with an AOPO or a technical code obligation in respect of a particular asset or configuration of assets, being an existing, new or proposed asset, the asset owner may apply for an equivalence arrangement to be approved or dispensation to be granted in accordance with Schedule 8.1.

(2) The system operator may not grant a dispensation in relation to an obligation to provide extended reserve under clause 8.19(5) or Schedule 8.3, Technical Code B, clause 7.
8.30 Approval of equivalence arrangements

The system operator must approve an equivalence arrangement if it has received satisfactory evidence that the asset owner will put in place on the agreed date technical or commercial arrangements that will, in the reasonable opinion of the system operator, achieve compliance with the AOPO or technical code for which the equivalence arrangement is sought, even if the assets or configuration of assets do not strictly comply.

Compare: Electricity Governance Rules 2003 rule 7.2 section III part C

8.31 Grant of dispensations

(1) Subject to subclause (1A), the system operator must grant a dispensation to an asset owner who has or will have assets or a configuration of assets that do not comply with either an AOPO or technical code if the system operator has a reasonable expectation that it can continue to operate the existing system and meet its principal performance obligations and if the system operator can readily quantify the costs on other persons of that dispensation, despite the non-compliance of the assets, but—

(a) if the approval of a dispensation could impose readily identifiable and quantifiable costs on other persons, a condition of the dispensation must be that the asset owner is liable to pay the system operator for those costs, including the costs of the system operator purchasing any other ancillary services required as a consequence of its dispensation; and

(b) the asset owner must acknowledge that the granting of a dispensation does not guarantee that the system operator will dispatch that asset for which the dispensation was granted, as dispatch will only occur in accordance with the dispatch objective; and

(c) if the dispensation is a generating unit dispensation from clause 8.19(1) or (3), the generator must be allocated the following costs in a relevant trading period with respect to paragraph (a) for each of fast instantaneous reserves or sustained instantaneous reserves:

\[ \text{DispCost}_{\text{GENxt}} = 0.5 * Q_{\text{GENxt}} * P_{\text{IRt}} \]

where

\[ \text{DispCost}_{\text{GENxt}} \] is the cost payable by a generator for generating unit x in any trading period t in which a class of instantaneous reserves is procured as a direct result of that generating unit’s dispensation to ensure that the frequency does not fall below 47 Hertz or, in the South Island, below the minimum South Island frequency.
Electricity Industry Participation Code 2010
Part 8

\[ Q_{GENx} \] is the MW amount by which generating unit \( x \) is unable to sustain pre-event output in trading period \( t \) with reference to clause 8.19(1) or (3) (as the case may be) as determined from the capabilities specified in that generating unit’s dispensation (different amounts may be specified with respect to each class of instantaneous reserves).

\[ P_{IRt} \] is the final reserve price for fast instantaneous reserves or sustained instantaneous reserves (as the case may be) in trading period \( t \) in the relevant island.

(1A) If the system operator grants a dispensation from clause 8.25A or clause 8.25B to an asset owner under subclause (1), and the granting of the dispensation could impose readily identifiable and quantifiable costs on any other person, the system operator must not impose a condition on the asset owner in accordance with subclause (1)(a) that has effect earlier than 24 November 2018.

(2) The system operator may impose other reasonable conditions on the grant of a dispensation under subclause (1), including conditions as to duration of the dispensation.

Compare: Electricity Governance Rules 2003 rules 7.3 and 7.4 section III part C
Clause 8.31(1A): inserted, on 24 November 2016, by clause 7(2) of the Electricity Industry Participation Code Amendment (Generation Fault Ride Through) 2016.

8.32 Liability of asset owner pending decision
Pending determination of an asset owner’s application for a dispensation or an equivalence arrangement, if the asset does not comply with the AOPOs or the technical codes, the asset owner is liable for the non-compliance and is responsible for additional costs incurred by the system operator or asset owners as a result of the non-compliance, including the costs of the system operator purchasing other ancillary services as a consequence of the non-compliance.

Compare: Electricity Governance Rules 2003 rule 8 section III part C

8.33 Modification of equivalence arrangement or dispensation
An asset owner may apply to the system operator for a modification to an equivalence arrangement or dispensation, in which case clauses 8.34 to 8.36 and Schedule 8.1 apply.

Compare: Electricity Governance Rules 2003 rule 8.1 section III part C

8.34 Cancellation of equivalence arrangement or dispensation
(1) An asset owner may at any time give written notice to the system operator for an
equivalence arrangement or a dispensation to be cancelled on the grounds that the asset or configuration of assets subject to the equivalence arrangement or dispensation complies with AOPOS or technical codes.

(2) A cancellation takes effect on the date specified in the notice as being the date the system operator accepted the cancellation.

(3) The system operator must record the cancellation in the system operator register no later than 5 days after receiving the notice.

Compare: Electricity Governance Rules 2003 rule 8.2 section III part C

8.35 Revocation of equivalence arrangement and revocation or variation of dispensation

(1) The system operator may revoke approval of an equivalence arrangement or revoke or vary the grant of a dispensation as the system operator reasonably considers appropriate if, at any time after the system operator has approved an equivalence arrangement or granted a dispensation, the system operator is satisfied that 1 or more of the following apply:

(a) the dispensation or equivalence arrangement was approved on information that was false or materially misleading;

(b) a prerequisite of the dispensation or equivalence arrangement has changed:

(c) a condition on which the dispensation or equivalence arrangement was approved has not been complied with:

(d) withdrawal is provided for under the terms of the dispensation granted:

(e) a change to this Code has occurred that affects the dispensation or equivalence arrangement:

(f) a decision has been reconsidered at the direction of the Rulings Panel under clause 8.36(4).

(2) The system operator must not revoke or amend a dispensation or grant a further dispensation or revoke its approval of an equivalence arrangement under subclause (1), unless—

(a) the asset owner to whom the dispensation was granted, or for whom an equivalence arrangement was approved, and any other person who in the opinion of the system operator is likely to have an interest in the matter, is given reasonable notice of the system operator’s intentions and a reasonable opportunity to make submissions to the system operator on the issue; and

(b) the system operator has had regard to the submissions.

Compare: Electricity Governance Rules 2003 rule 8.3 section III part C

8.36 Appeal against decisions

(1) A participant may appeal a decision of the system operator in relation to an application for dispensation or equivalence arrangements on the grounds set out in subclause (3).

(2) An appeal must be made to the Rulings Panel by giving written notice to the Authority specifying the grounds of appeal. A notice must be given no later than 10 business days after publication of the relevant decision in the system operator register under clause 8.
of Schedule 8.1.

(3) For the purposes of subclause (2), an appeal may be made on the grounds that—
(a) the system operator made an error of fact or failed to take into account all relevant information or took into account irrelevant information and such error, failure or irrelevancy was material to the decision; or
(b) the conditions imposed on the dispensation or equivalence arrangement are unjustifiably onerous, unnecessary or impose extra costs if appropriate alternatives exist.

(4) The Rulings Panel, in determining an appeal, must approve the decision of the system operator or direct the system operator to reconsider the decision in full or by reference to specified matters.

(5) Pending the outcome of an appeal, the decision of the system operator in relation to the grant of a dispensation or approval of an equivalence arrangement remains valid and may be relied upon by the relevant asset owner.

Compare: Electricity Governance Rules 2003 rule 8.4 section III part C

8.37 Other provisions relating to equivalence arrangements and dispensations

(1) An asset owner who obtains approval for an equivalence arrangement must comply with its obligations under that arrangement.

(1A) An asset owner who is granted a dispensation must comply with its obligations under that dispensation.

(2) An equivalence arrangement and a dispensation are specific to an asset owner, and no approval of an equivalence arrangement or granting of a dispensation creates a precedent for the approval of other equivalence arrangements or dispensations.

(3) The owner or operator of an asset or configuration of assets must advise the system operator if the owner or operator believes that it is in breach of a condition of its dispensation or equivalence arrangement or that the asset or configuration of assets, including any equivalence arrangement, does not, or is likely not to, comply with the asset owner performance obligations and technical codes.

(4) If an asset owner fails to put in place, maintain and meet all requirements of an approved equivalence arrangement or dispensation, the asset owner is in breach of this Code.

Compare: Electricity Governance Rules 2003 rule 9 section III part C

8.38 Authority may require excluded generating stations to comply with certain clauses

(1) Despite clauses 8.17, 8.19, and 8.25D, the system operator may, at any time, apply to the Authority for the Authority to issue a directive that an excluded generating station asset must comply with clauses 8.17, 8.19, 8.25A, and 8.25B, and the provisions of the technical codes (or parts thereof).

(2) The Authority must issue the directive referred to in subclause (1) if the Authority is satisfied that there is a benefit to the public in obtaining compliance.

(3) If a directive is issued under subclause (2), the owner of the excluded generating
station asset must comply with the directive with effect from the date specified in the directive.

Compare: Electricity Governance Rules 2003 rule 10 section III part C
Clause 8.38(1): amended, on 24 November 2016, by clause 8(1) and (2) of the Electricity Industry Participation Code Amendment (Generation Fault Ride Through) 2016.

Subpart 3—Arrangements concerning ancillary services

8.39 Contents of this subpart
This subpart provides for—
(a) a procurement plan that the system operator must use reasonable endeavours to implement and comply with; and
(b) the review of the procurement plan; and
(c) alternative ancillary service arrangements; and
(d) how ancillary services are to be priced and measured; and
(e) identifying the allocable costs for ancillary services and the regime by which those costs are allocated to affected parties.

Compare: Electricity Governance Rules 2003 rule 1 section IV part C

Procurement plan

8.40 System operator to use reasonable endeavours to implement and comply with procurement plan
The system operator must use reasonable endeavours to both implement and comply with the procurement plan.

Compare: Electricity Governance Rules 2003 rule 2 section IV part C

8.41 [Revoked]

8.42 Incorporation of procurement plan by reference
(1) The procurement plan is incorporated by reference in this Code in accordance with section 32 of the Act.
(2) Subclause (1) is subject to Schedule 1 of the Act, which includes a requirement that the Authority must give notice in the Gazette before an amended or substituted procurement plan becomes incorporated by reference in this Code.

Compare: Electricity Governance Rules 2003 rule 3 section IV part C

8.42A Review of procurement plan
(1) At least once every 2 years the system operator must—
(a) review the procurement plan; and
(b) as soon as practicable after completing the review, decide whether or not to propose a change to the procurement plan; and
(c) advise the Authority of its decision.
(2) If the system operator decides to propose a change to the procurement plan, the system operator must submit a draft procurement plan to the Authority together with the following information:

(a) an explanation of the proposed change and a statement of the objectives of the proposed change;
(b) an evaluation of the costs and benefits of the proposed change;
(c) an evaluation of alternative means of achieving the objectives of the proposed change;
(d) a list of the persons consulted and a summary of the submissions received.

(3) As part of a review conducted under this clause, the system operator must invite comments from participants.


8.42B System operator decides not to amend the procurement plan

If the system operator advises the Authority under clause 8.42A(1)(c) that the system operator does not intend to propose a change to the procurement plan the system operator must provide the Authority with the following information:

(a) the findings of the review of the procurement plan conducted by the system operator;
(b) details of any request to amend the procurement plan received from a participant or the Authority since the last review;
(c) the system operator’s decision on each such request including, if the system operator declined a requested change, the reason for declining.


8.42C Authority may require system operator to reconsider

(1) The Authority may require the system operator to reconsider a decision made under clause 8.42A(1)(b) not to propose a change to the procurement plan.

(2) If the Authority requires the system operator to reconsider a decision made under subclause 8.42A(1)(b) the Authority must advise the system operator of—

(a) the Authority’s reasons for requiring the system operator to reconsider; and
(b) the date, determined after consulting the system operator, by which the system operator must either confirm its decision or submit a draft procurement plan.

(3) The Authority must as soon as practicable publish the advice received from the system operator under clause 8.42A(1)(c) and the advice given by the Authority to the system operator under subclause (2).


8.43 Content of draft procurement plan

The draft procurement plan must, for each ancillary service—
(a) specify the principles that the system operator must apply in making a net purchase quantity assessment, which must include—
   (i) determining the requirements for complying with the principal performance obligations; and
   (ii) determining the requirements for achieving the dispatch objective; and
   (iii) assessing the contribution that compliance by asset owners with the asset owner performance obligations will make towards the system operator’s compliance with the principal performance obligations; and
   (iv) assessing the impact that dispensations and alternative ancillary services arrangements held by asset owners will have on the quantity of ancillary services required to enable the system operator to comply with the principal performance obligations; and

(b) contain a methodology for conducting a net purchase quantity assessment for each relevant ancillary service; and

(c) outline the process that the system operator must use to procure that ancillary service, taking into account that the system operator must use—
   (i) market mechanisms to procure ancillary services wherever technology and transaction costs make this practicable and efficient; and
   (ii) transparent processes that encourage all potential providers to compete to supply ancillary services required to meet common quality standards at the best economic cost; and

(d) specify the administrative costs for that ancillary service as proposed in the draft procurement plan; and

(e) outline the system operator’s technical requirements and key contract terms to support the procurement plan; and

(f) outline the rights and obligations of the system operator in relation to procurement of that ancillary service in circumstances not anticipated by the draft procurement plan, and if the assumptions made by the system operator in the procurement plan cannot be met; and

(g) outline how the system operator will report on progress in implementing the procurement plan.

Compare: Electricity Governance Rules 2003 rule 4 section IV part C

8.43A Changes and variations

(1) The system operator may at any time propose a change to the procurement plan by submitting a draft procurement plan to the Authority together with the following information:
   (a) an explanation of the proposed change and a statement of the objectives of the proposed change:
   (b) an evaluation of alternative means of achieving the objectives of the proposed change:
   (c) an evaluation of the costs and benefits of the proposed change.
(2) The **Authority** or a **participant** may at any time request that the **system operator** propose a change to the **procurement plan** under subclause (1).

(3) If the **system operator** receives a request under subclause (2), it must as soon as practicable—
   (a) decide whether to decline the request, defer the request until the next **review date**, or submit a **draft procurement plan** to the **Authority**; and
   (b) **publish** the decision.

(4) If the **system operator** declines a request under subclause (3) the **Authority** may require the **system operator** to reconsider its decision, giving reasons.

8.44 Consultation on draft procurement plan

(1) The **Authority** must **publish** the following information as soon as practicable after it receives it:
   (a) a **draft procurement plan** submitted under clause 8.42A and the information required under clause 8.42A(2):
   (b) a **draft procurement plan** submitted under clause 8.43A and the information required under clause 8.43A(1)(a) to (c).

(2) When the **Authority** publishes a **draft procurement plan** and information under subclause (1) the **Authority** must advise **participants** of the date (which must not be earlier than 10 **business days** after the date that the **Authority** publishes the **draft procurement plan**) by which submissions on the changes proposed in the **draft procurement plan** must be received by the **Authority**.

(3) Each submission on changes proposed in a **draft procurement plan** must be made in writing to the **Authority** and received on or before the **submission expiry date**.

(4) The **Authority** must provide a copy of each submission received to the **system operator** at the close of business on the **submission expiry date** and must **publish** the submissions as soon as practicable.

(5) The **system operator** may make its own submission on the **draft procurement plan** and the submissions received in relation to it no later than 10 **business days** after the **submission expiry date**.

(6) The **Authority** must **publish** the **system operator**'s submission as soon as practicable after it is received.

(7) Following the consultation process required by subclauses (1) to (6), the **Authority** may approve the **draft procurement plan** subject to the **system operator** making any changes that the **Authority** considers appropriate.
8.44A Technical and non-controversial amendments

(1) The system operator may at any time propose a change to the procurement plan that it considers is technical and non-controversial by submitting a draft procurement plan to the Authority together with an explanation of the proposed change.

(2) If the system operator submits a draft procurement plan under subclause (1) it is not required to provide a statement of the objectives of the proposed change, an evaluation of alternative means of achieving the objectives of the proposed change or an evaluation of the costs and benefits of the proposed change.

(3) The Authority must, as soon as practicable after receiving a draft procurement plan and the information required under subclause (1), by notice in writing to the system operator—
   (a) approve the draft procurement plan to be incorporated by reference into this Code; or
   (b) decline to approve the draft procurement plan, giving reasons.

(4) If the Authority approves the draft procurement plan it must as soon as practicable—
   (a) publish notice of its intention to incorporate the draft procurement plan by reference into this Code; and
   (b) include in the notice the Authority’s reasons for considering that the changes proposed in the draft procurement plan are technical and non-controversial; and
   (c) invite comment from participants on the reasons given in the notice.

(5) After considering any comments made under subclause 4(c) the Authority must advise the system operator by notice in writing of its decision as to whether to confirm or revoke its approval of the draft procurement plan, and give reasons for its decision.

(6) The Authority must publish its decision and reasons as soon as practicable.


8.44B Authority adopts new procurement plan

If the Authority approves a draft procurement plan under clause 8.44 or confirms its approval of a draft procurement plan under clause 8.44A it must—
   (a) incorporate the new procurement plan by reference into this Code in accordance with Schedule 1 of the Act; and
   (b) publish the new procurement plan and the date on which it takes legal effect.


8.45 Contracts with ancillary service agents

(1) The system operator must use reasonable endeavours to implement the procurement plan for each ancillary service by entering into contracts with the ancillary service agents in the manner specified in the procurement plan.

(2) The system operator is the principal in any contract it enters into with an ancillary service agent.

(3) If the system operator has entered into a contract, the system operator must use
reasonable endeavours to ensure that the ancillary service agent complies with its contractual obligations, but the system operator is not otherwise liable in respect of any failure by an ancillary service agent to comply with such obligations.

Compare: Electricity Governance Rules 2003 rule 6 section IV part C

8.45A Methodology to assess net purchase quantity

The system operator must make the net purchase quantity assessment for each relevant ancillary service using the methodology in the procurement plan and publish the results of the assessment as soon as practicable.


8.46 [Revoked]

Compare: Electricity Governance Rules 2003 rule 7 section IV part C

8.47 Departure from procurement plan

(1) The system operator may depart from the processes and arrangements set out in the procurement plan if the system operator reasonably considers it necessary to do so to comply with the principal performance obligations.

(2) When the system operator makes a departure under subclause (1), the system operator must provide a report to the Authority setting out the circumstances of the departure and the actions taken to deal with it.

(3) The Authority must publish the report within a reasonable time after receiving it.

Compare: Electricity Governance Rules 2003 rule 8 section IV part C

Alternative ancillary service arrangements

8.48 Alternative ancillary service arrangements

(1) If an asset owner wishes to have an alternative ancillary service arrangement authorised by the system operator, that asset owner (or, if more than 1 asset owner wishes to have an authorisation, those asset owners jointly) may apply to the system operator to have that arrangement authorised as an alternative ancillary service arrangement using the process set out in Schedule 8.2.

(2) The system operator must authorise the arrangement as an alternative ancillary service arrangement if—

(a) the proposed arrangement complies with the technical requirements for that ancillary service as set out in the current procurement plan; and

(b) the implementation of the proposed arrangement will make the ancillary service available for dispatch by the system operator in substantially the same manner
as if the ancillary service had been procured in accordance with the procurement plan.

(3) As a condition of authorising an alternative ancillary service arrangement under subclause (2), the system operator may do 1 or more of the following:
   (a) require the asset owner to enter into arrangements with the system operator to ensure that the system operator can continue to meet the principal performance obligations;
   (b) specify the date on which the alternative ancillary service arrangement commences;
   (c) impose any other condition it reasonably believes is necessary, including conditions necessary for the system operator to meet its principal performance obligations and conditions necessary for the orderly reconciliation and settlement of ancillary services.

Compare: Electricity Governance Rules 2003 rules 9.1 to 9.3 section IV part C

8.49 Suspension of alternative ancillary service arrangement
(1) An asset owner may at any time give written reasonable notice to the system operator of suspension of the alternative ancillary service arrangement for a period specified in the notice.
(2) The system operator may suspend an alternative ancillary service arrangement in a system security situation.

Compare: Electricity Governance Rules 2003 rule 9.4 section IV part C

8.50 Modification of alternative ancillary service arrangement
An asset owner may apply to the system operator for a modification to an alternative ancillary service arrangement in which case clauses 8.51 to 8.53 and Schedule 8.2 apply.

Compare: Electricity Governance Rules 2003 rule 9.5 section IV part C

8.51 Cancellation of alternative ancillary service arrangement
An asset owner may at any time give reasonable notice in writing to the system operator of cancellation of the alternative ancillary service arrangement, which comes into effect on the date specified in the notice.

Compare: Electricity Governance Rules 2003 rule 9.6 section IV part C

8.52 Revocation of alternative ancillary service arrangements
(1) The system operator may revoke authorisation of the alternative ancillary service arrangement as the system operator reasonably considers appropriate, if at any time after the system operator has authorised an alternative ancillary service arrangement, the system operator is satisfied that 1 or more of the following factors apply:
   (a) the alternative ancillary service arrangement was authorised on information that was false or materially misleading:
   (b) a prerequisite of the alternative ancillary service arrangement has changed:
   (c) a condition upon which the authorisation was granted has not been complied with:
(d) such revocation is provided for under the terms of the authorisation.

(2) Subject to clause 8.49(2), the system operator must not revoke or amend an alternative ancillary service arrangement unless—

(a) the person to whom the authorisation was granted and any other person who, in the opinion of the system operator, is likely to have an interest in the matter, is given reasonable notice of the system operator’s intentions and a reasonable opportunity to make submissions to the system operator; and

(b) the system operator has had regard to those submissions.

Compare: Electricity Governance Rules 2003 rule 9.7 section IV part C

8.53 Appeal of system operator decisions

(1) An applicant may appeal any decision of the system operator in relation to any alternative ancillary service arrangement.

(2) A participant may appeal any decision of the system operator in relation to an alternative ancillary service arrangement on the grounds set out in subclause (4).

(3) An appeal must be commenced with the Rulings Panel by giving written notice to the Authority, specifying the grounds of appeal. A notice must be given within 10 business days of publication of the decision in the system operator register under clause 4 of Schedule 8.2.

(4) For the purpose of subclause (2), an appeal may be made on the grounds that—

(a) the system operator made an error of fact, or failed to take properly into account all relevant information or took into account irrelevant information, and such error, failure or irrelevancy was material to the decision; or

(b) the conditions imposed on the alternative ancillary service arrangement are onerous, unnecessary or impose extra costs if appropriate alternatives exist.

(5) The Rulings Panel, in determining an appeal, must either approve the decision of the system operator or direct the system operator to reconsider the decision in full or by reference to specified matters.

(6) Pending the outcome of an appeal, the decision of the system operator in relation to the authorisation of an alternative ancillary service arrangement remains valid and can be acted upon by the relevant asset owner.

Compare: Electricity Governance Rules 2003 rule 9.8 section IV part C

8.54 Other provisions relating to alternative ancillary service arrangements

(1) The system operator must monitor the performance of alternative ancillary service arrangements in accordance with the procurement plan and the monitoring regimes specified in the respective alternative ancillary service arrangements. If the system operator considers, on reasonable grounds, that an alternative ancillary service arrangement is not being, or likely not to be, complied with, the system operator must immediately advise the asset owner.

(2) An asset owner who obtains an authorisation of an alternative ancillary service arrangement must comply with its obligations under the arrangement. If the system operator advises an asset owner under subclause (1), the asset owner must co-operate with the system operator and must immediately use reasonable endeavours to restore
compliance as soon as possible.

(3) An asset owner who holds an alternative ancillary service arrangement is relieved of an obligation to pay costs for ancillary service in the manner provided for in clauses 8.55 to 8.59 and 8.64 to 8.70 to the extent provided for in the alternative ancillary service arrangement.

(4) The holder of an alternative ancillary service arrangement breaches this Code if ancillary services are not made available to the system operator in accordance with the alternative ancillary service arrangement, or if an alternative ancillary service arrangement fails. From the date a breach of an alternative ancillary service arrangement becomes known, the holder of the alternative ancillary service arrangement must meet its share of the ancillary costs as if the alternative ancillary service arrangement had not been authorised.

Compare: Electricity Governance Rules 2003 rule 10 section IV part C

Subpart 4—Interruptible load

8.54A Contents of this subpart
This subpart provides for the provision of information relating to interruptible load.

8.54B Ancillary service agents to provide information about interruptible load
(1) Each ancillary service agent that contracts for interruptible load in a network must, within 10 business days of entering into the contract, give the following participants the information in subclause (2):
   (a) if the interruptible load is contracted on a local network, the connected asset owner that operates the local network:
   (b) if the interruptible load is contracted on an embedded network, the connected asset owner that operates the local network to which the embedded network is connected:
   (c) if the interruptible load is contracted on the grid, the grid owner that owns or operates the part of the grid on which the interruptible load is contracted.

(2) The information required is—
   (a) a list of the ICPs to which the contract relates; and
   (b) the maximum MW that can be interrupted under the contract; and
   (c) the commencement and expiry dates of the contract.

(3) If an ancillary service agent has given a connected asset owner or grid owner information under subclause (1), the connected asset owner or grid owner may require the ancillary service agent to provide further information about the interruptible load to which the contract relates.

(4) An ancillary service agent must comply with a requirement under subclause (3).
Clause 8.54B: inserted, on 7 August 2014, by clause 9 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.
Clause 8.54B(1) and (3): amended, on 1 February 2016, by clause 11 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

Subpart 5—Extended reserve


8.54C Contents of this subpart
This subpart provides for the procurement of extended reserve.
Clause 8.54C: inserted, on 7 August 2014, by clause 9 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

8.54D System operator to review extended reserve
(1) The system operator must review the technical requirements for extended reserve in accordance with this clause.
(2) The Authority may, at any time, give the system operator principles outlining the Authority's expectations for the objectives of the review.
(3) As part of the review, the system operator must consider any principles given to the system operator by the Authority under subclause (2).
(4) On the basis of the review, the system operator must prepare and publish—
   (a) an extended reserve technical requirements report; and
   (b) an extended reserve technical requirements schedule.
(5) The extended reserve technical requirements report must reflect the system operator's analysis of the technical requirements for extended reserve on which the extended reserve technical requirements schedule is based.
(6) The extended reserve technical requirements schedule must—
   (a) specify the technical specifications for extended reserve that the system operator requires in order to be able to comply with the principal performance obligations; and
   (b) specify requirements for periodic testing that each extended reserve provider will be required to carry out in relation to the relevant assets.
(7) The consultation requirements in Part 1 of Schedule 8.5 apply to the preparation and publication of the extended reserve technical requirements schedule.
Clause 8.54D: inserted, on 7 August 2014, by clause 9 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

8.54E Review of extended reserve technical requirements schedule
(1) The system operator must—
   (a) review the extended reserve technical requirements schedule under this clause; and
   (b) as soon as practicable after completing the review, decide whether to propose a change to the schedule; and
   (c) advise the Authority of its decision.
(2) The review must be conducted so that the system operator advises the Authority of its decision no later than 60 months after the date on which the system operator advised the Authority of its decision on the previous review.

(3) The Authority may direct the system operator to review the extended reserve technical requirements schedule at a time that is sooner than required under subclause (2).

(4) If the system operator decides to propose a change to the extended reserve technical requirements schedule as a result of a review, the system operator must—
(a) prepare and publish—
(i) an extended reserve technical requirements report; and
(ii) an extended reserve technical requirements schedule; and
(b) provide the following additional information when giving a draft of the revised schedule to the Authority under clause 2(2) of Schedule 8.5:
(i) an explanation of the proposed change and a statement of the objectives of the proposed change:
(ii) an evaluation of the costs and benefits of the proposed change:
(iii) an evaluation of alternative means of achieving the objectives of the proposed change.

(5) Clause 8.54D(2), (3) and (5) to (7) applies to each review of the extended reserve technical requirements schedule.

(6) If the system operator advises the Authority that it does not intend to propose a change to the extended reserve technical requirements schedule, the system operator must give the Authority the findings of its review of the schedule.

Clause 8.54E: inserted, on 7 August 2014, by clause 9 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

8.54F Authority may require system operator to reconsider

(1) The Authority may require the system operator to reconsider a decision made under clause 8.54E(1)(c) not to propose a change to the extended reserve technical requirements schedule.

(2) If the Authority requires the system operator to reconsider, the Authority must advise the system operator of—
(a) the Authority's reasons for requiring the system operator to reconsider; and
(b) the date, determined after consulting with the system operator, by which the system operator must—
(i) confirm its decision under clause 8.54E(1)(c); or
(ii) provide a draft of the revised schedule to the Authority under clause 2(2) of Schedule 8.5.

(3) The Authority must as soon as practicable publish the advice received from the system operator under clause 8.54E(1)(c) and any advice given by the Authority to the system operator under subclause (2).

8.54G Preparation and publication of extended reserve selection methodology

(1) The extended reserve manager must prepare and publish an extended reserve selection methodology.

(2) The methodology must specify how the extended reserve manager will procure extended reserve according to the extended reserve technical requirements schedule.

(3) The methodology must—
   (a) be based on the principles specified in clause 8.54H; and
   (b) specify how the methodology applies to each island, including, if appropriate, specifying that the methodology does not apply to an island; and
   (c) identify the asset owners that are required to provide information during an extended reserve selection process; and
   (d) specify the information that the asset owners are required to provide; and
   (e) specify the time frame within which asset owners are required to provide the information; and
   (f) specify the basis on which the extended reserve manager selects asset owners to be extended reserve providers; and
   (g) include default terms and conditions specifying the basis on which extended reserve must be provided, including requirements for periodic testing of assets.

(3A) If the extended reserve manager decides that asset owners will receive payment for providing extended reserve, the methodology must specify how payments are set.

(4) The consultation and approval requirements in Part 2 of Schedule 8.5 apply to the preparation and publication of the extended reserve selection methodology.

8.54H Principles for extended reserve selection methodology

(1) The extended reserve selection methodology must give effect to the principles specified in subclause (2).

(2) The extended reserve selection methodology must—
   (a) reflect a balance of interests between potential extended reserve providers, and between such providers and the system operator; and
   (b) enable extended reserve to be procured cost-effectively, by setting out how to evaluate—
      (i) the expected cost of providing the extended reserve (including capital and operating costs); and
      (ii) in the case of extended reserve that involves the interruption of load, the expected cost of an interruption during an event that calls on extended reserve, taking into account opportunity cost and the performance
characteristics of the relevant load; and
(iii) the likely transaction costs associated with administering extended reserve and in providing extended reserve; and
(c) seek an appropriate balance between certainty in the provision of extended reserve products and flexibility to accommodate changes in circumstances and technologies.


8.54I Review of extended reserve selection methodology
(1) The Authority may direct the extended reserve manager to review the extended reserve selection methodology.
(2) Clause 8.54G applies to each review of the extended reserve selection methodology, except that the extended reserve manager must give a draft of the revised methodology to the Authority and the system operator under clause 5(2) of Schedule 8.5 no later than 40 business days after the date of the direction under subclause (1).

Clause 8.54I: inserted, on 7 August 2014, by clause 9 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

8.54J Extended reserve manager to undertake extended reserve selection process
(1) The extended reserve manager must undertake an extended reserve selection process in accordance with the extended reserve selection methodology when directed to do so by the Authority.
(2) The Authority must make a direction under subclause (1) no later than 60 months after the publication of the current extended reserve procurement schedule.
(3) The Authority may direct the extended reserve manager as to the scope of a selection process.
(4) If the Authority directs the extended reserve manager to undertake a limited selection process under subclause (3), the Authority must give reasons for the direction.
(5) After completing a selection process, the extended reserve manager must prepare and publish an extended reserve procurement schedule.
(6) Subclause (5) does not require the extended reserve manager to publish any information the publication of which would be likely unreasonably to prejudice the commercial position of the person who supplied or who is the subject of the information.
(7) The extended reserve procurement schedule must—
(a) set out the results of the selection process; and
(b) identify the asset owners that are required to be extended reserve providers; and
(c) specify the extended reserve to be provided; and
(d) include information as to how the amounts payable (if any) to each extended reserve provider will be calculated; and
(e) identify asset owners that have not been selected to be extended reserve providers.
(8) The consultation and approval requirements in Part 3 of Schedule 8.5 apply to the preparation and publication of the extended reserve procurement schedule.
(9) The extended reserve manager may undertake consultation additional to that required by Part 3 of Schedule 8.5 if the extended reserve manager considers it necessary to do so.

(10) As soon as practicable after receiving a direction from the Authority under subclause (2), the extended reserve manager must publish an indicative time frame within which the extended reserve manager expects to complete the selection process.

(11) The publication of an extended reserve procurement schedule relating to the provision of extended reserve for only part of an island must be disregarded for the purposes of determining the date by which the Authority must give a direction under subclause (2).

(12) Despite subclause (6), the extended reserve manager must, within 2 business days after publishing the extended reserve procurement schedule under subclause (5), provide a copy of the extended reserve procurement schedule to the clearing manager.

Clause 8.54J inserted, on 7 August 2014, by clause 9 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

8.54K Information required for extended reserve selection process

(1) During an extended reserve selection process, each asset owner identified in the extended reserve selection methodology, other than a generator that is directly connected to the grid, must comply with a request from the extended reserve manager to provide any information described in the methodology.

(2) Each asset owner required to give information to the extended reserve manager, must do so—

(a) within the time frame specified in the extended reserve selection methodology; and

(b) in accordance with the extended reserve selection methodology, data specification and extended reserve manager calendar published by the extended reserve manager.

(3) If the extended reserve manager considers that any information provided by an asset owner is incomplete or insufficient, the extended reserve manager may require that the asset owner provide further information.

(4) An asset owner must comply with a requirement under subclause (3) within the time frame specified by the extended reserve manager.

Clause 8.54K inserted, on 7 August 2014, by clause 9 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.
Clause 8.54K(1) amended, on 19 January 2017, by clause 7(1) of the Electricity Industry Participation Code Amendment (Extended Reserve) 2016.
Clause 8.54K(2) replaced, on 19 January 2017, by clause 7(2) of the Electricity Industry Participation Code Amendment (Extended Reserve) 2016.

8.54L Extended reserve manager to issue extended reserve procurement notices

(1) The extended reserve manager must issue an extended reserve procurement notice to each asset owner specified in the extended reserve procurement schedule.
(2) Each extended reserve procurement notice must—
   (a) specify the information in the extended reserve procurement schedule relating to the asset owner; and
   (b) if an asset owner has been selected to be an extended reserve provider,—
      (i) specify the default terms and conditions (as specified in the extended reserve selection methodology) that apply to the provision of extended reserve by the asset owner; and
      (ii) include information as to how the amounts payable (if any) to each extended reserve provider will be calculated.

(3) The extended reserve manager must give each asset owner its extended reserve procurement notice no later than 5 business days after publishing the extended reserve procurement schedule.

Clause 8.54L: inserted, on 7 August 2014, by clause 9 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

8.54M Asset owners to prepare implementation plans
(1) Each asset owner identified in an extended reserve procurement schedule must prepare an implementation plan specifying how the asset owner will implement the obligations allocated to it.
(2) Each asset owner must give its implementation plan to the system operator for approval no later than 40 business days after receiving its extended reserve procurement notice, or by such later date as may be agreed between the asset owner and the system operator.
(3) Each implementation plan must specify how the asset owner will implement the transition to complying with its obligations (if any) under its most recent extended reserve procurement notice from complying with its obligations (if any) under its previous extended reserve procurement notice.
(4) Each implementation plan must specify 1 or more dates on which payments (if any) to the asset owner will commence or cease for all or part of the provision of extended reserve under the asset owner's extended reserve procurement notice.
(5) Each date specified in an implementation plan under subclause (4) must be the date on which provision of the extended reserve to which the payment (if any) relates will commence or cease, as the case may be.
(6) An asset owner may amend an implementation plan after giving it to the system operator under subclause (2) with the agreement of the system operator.
(7) If the system operator requires that an asset owner make changes to an implementation plan given to the system operator under subclause (2), the asset owner must comply with the requirement.
(8) The system operator must approve an implementation plan given to it by an asset owner under subclause (2) if the plan meets the requirements of this clause.

8.54N Terms and conditions applying to the provision of extended reserve
In the case of an asset owner that has been selected to be an extended reserve provider, the default terms and conditions in the asset owner's extended reserve procurement notice apply to the provision of extended reserve by the asset owner but may be amended by agreement in writing between the asset owner and the system operator.
Clause 8.54N: inserted, on 7 August 2014, by clause 9 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

8.54O System operator to publish and maintain extended reserve schedule
(1) The system operator must publish an extended reserve schedule.
(2) Subclause (1) does not require the system operator to publish any information the publication of which would be likely unreasonably to prejudice the commercial position of the person who supplied or who is the subject of the information.
(3) The extended reserve schedule must specify the obligations of each asset owner identified in the extended reserve procurement schedule, based on information from—
(a) the latest extended reserve procurement schedule; and
(b) each approved implementation plan; and
(c) any amendment to default terms and conditions applying to an extended reserve provider agreed under clause 8.54N; and
(d) any other information held by the system operator that describes the obligations of an extended reserve provider to provide extended reserve.
(4) The system operator must amend the extended reserve schedule to reflect any change to any information described in subclause (3), so that the schedule is kept up to date.
(5) Despite subclause (2), the system operator must, within 2 business days of publishing the extended reserve schedule under subclause (1), provide a copy of the extended reserve schedule to the extended reserve manager.

8.54P System operator to issue statements of extended reserve obligations
(1) The system operator must issue to each asset owner identified in the extended reserve schedule a statement of extended reserve obligations under this clause.
(2) Each statement of extended reserve obligations must specify the obligations of the asset owner to which it relates, as specified in the extended reserve schedule as at the date on which it is issued.
(3) The system operator must issue a statement of extended reserve obligations to an asset owner at each of the following times:
(a) as soon as practicable after the asset owner's implementation plan is approved under clause 8.54M:
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8.54Q System operator to give written notice of dates

(1) The system operator must give written notice to the Authority, the extended reserve manager, and the clearing manager of all dates on which extended reserve providers will provide, or cease to provide, extended reserve, as set out in the extended reserve schedule.

(2) If an amendment to an implementation plan made under clause 8.54M(6) or (7) results in an extended reserve provider providing, or ceasing to provide, any extended reserve on a date that is different from the relevant date specified in the implementation plan, in each case the system operator must—

(a) update the extended reserve schedule with the new date; and

(b) give written notice to the Authority, the extended reserve manager, and the clearing manager of the new date.

Clause 8.54Q: inserted, on 7 August 2014, by clause 9 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.
Clause 8.54Q heading: amended, on 19 January 2017, by clause 10(1) of the Electricity Industry Participation Code Amendment (Extended Reserve) 2016.

8.54R System operator to report to Authority

In its monthly report given to the Authority under clause 3.14, the system operator must include information about any use of extended reserve.

Clause 8.54R: inserted, on 7 August 2014, by clause 9 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

8.54S New connected asset owners and new grid owners to provide information

(1) The purpose of this clause is to require new connected asset owners and new grid owners to provide information so that their obligations under this subpart can be determined.

(2) No later than 20 business days after a connected asset owner commences taking electricity from the grid, it must give the Authority either—
(a) historical records of the quantity of electricity consumed in the connected asset owner’s network or by the connected asset owner; or

(b) if the Authority advises the connected asset owner that it is not satisfied with the records given under paragraph (a), or if there are no such records, a bona fide business plan that permits a realistic estimate to be made of the amount of electricity to be consumed in the connected asset owner’s network or by the connected asset owner.

(3) No later than 20 business days after a grid owner starts to convey electricity on the grid, it must give the Authority either—

(a) historical records of the quantity of electricity conveyed by the grid owner on the grid; or

(b) if the Authority advises the grid owner that it is not satisfied with the records given under paragraph (a), or if there are no such records, a bona fide business plan that permits the Authority to make a realistic estimate of the amount of electricity to be conveyed by the grid owner on the grid.


8.54T Assignment of extended reserve obligations

(1) An extended reserve provider that proposes to assign assets that it uses to provide extended reserve may apply to the Authority by notice in writing for approval to assign its obligations to provide extended reserve that relate to those assets.

(2) The Authority may, on receiving an application under subclause (1),—

(a) approve the assignment; or

(b) approve the assignment with conditions; or

(c) decline to approve the assignment.

(3) Before giving an extended reserve provider approval to assign its obligations under subclause (2), the Authority must consult with the system operator.

(4) If the Authority gives an extended reserve provider approval to assign its obligations under subclause (2), the Authority must give written notice to the system operator.

(5) An assignment of an extended reserve provider's obligations is not effective except as approved by the Authority under subclause (2).


8.54TA Extended reserve manager may rely on information provided

For the purposes of this Code, the extended reserve manager may rely on the information provided to the extended reserve manager by an asset owner.

8.54TB Extended reserve manager to consider new or revised information

(1) If the extended reserve manager receives new or revised information from an asset owner, it must provide that information to the Authority if it considers that the information would change the outcome of the processes specified in clauses 8.54J, 8.54K, or 8.54L.

(2) If the extended reserve manager provides the information to the Authority under subclause (1), the Authority may direct the extended reserve manager to undertake the extended reserve selection process under clause 8.54J again.


8.54TC Extended reserve manager to produce periodic performance report

(1) The extended reserve manager must—
(a) monitor the performance of extended reserve; and
(b) produce a periodic performance report that reports on the outcome of its monitoring of the performance of extended reserve.

(2) The time period to be covered in the periodic performance report must be agreed between the extended reserve manager and the Authority.

(3) The extended reserve manager must provide the periodic performance report to the Authority and the system operator no later than 30 business days after the end of each periodic performance reporting period.

(4) The extended reserve manager must, no later than 5 business days after finalising the periodic performance report, publish a copy of the report that excludes any information that, if published, would be likely unreasonably to prejudice the commercial position of the person who supplied, or who is the subject of, the information.


Information required for transitional purposes


8.54TD Information required for transition

(1) The extended reserve manager and the system operator may request an asset owner, other than a generator directly connected to the grid, to provide any information that the extended reserve manager or the system operator (as the case may be) considers is necessary to transition from the obligations that existed immediately prior to the Electricity Industry Participation Code Amendment (Extended Reserve) 2014 coming into effect, to the obligations specified in that Code amendment.

(2) An asset owner that receives a request under subclause (1) must comply with that request.

(3) If the extended reserve manager or the system operator (as the case may be) considers that information provided by an asset owner in accordance with subclause (2) is incomplete or insufficient, the extended reserve manager or the system operator (as the case may be) may require that the asset owner provide further information.
(4) Each asset owner required to provide information under this clause must do so within the time frame specified in the request.

(5) The extended reserve manager and the system operator may provide the information received from an asset owner under subclause (2) or (3) to each other.


Transitional provisions—extended reserve


8.54TE Transitional provisions for extended reserve

(1) If the system operator took any action before clause 8.54D came into force that, if that clause had been in force at the time of the action, would have contributed to complying with that clause, the action is deemed to have been taken when that clause was in force.

(2) The first implementation plan that an asset owner gives the system operator under clause 8.54M(2) must specify how the asset owner will implement the transition from complying with its obligations (if any) under Schedule 8.3, Technical Code B, clause 7 as it applied before clause 8.54M(2) came into force, to complying with its extended reserve procurement notice.

(3) The first statement of extended reserve obligations that the system operator issues to each asset owner under clause 8.54P must specify the date on which it comes into force.

(4) Despite the revocation of Schedule 8.3, Technical Code A, Appendix B, clause 6, and the replacement of Schedule 8.3, Technical Code B, clause 7 by the Electricity Industry Participation Code Amendment (Extended Reserve) 2014, each North Island distributor that was required to comply with those clauses before 7 August 2014 must continue to comply with those clauses as if the Electricity Industry Participation Code Amendment (Extended Reserve) 2014 had not been made until the earlier of—

(a) 7 August 2024; or
(b) the date on which the first statement of extended reserve obligations issued under clause 8.54P comes into force in respect of the distributor.

(5) Despite the revocation of Schedule 8.3, Technical Code A, Appendix B, clause 7, and the replacement of Schedule 8.3, Technical Code B, clause 7 by the Electricity Industry Participation Code Amendment (Extended Reserve) 2014, each South Island grid owner that was required to comply with those clauses before 7 August 2014 must continue to comply with those clauses as if the Electricity Industry Participation Code Amendment (Extended Reserve) 2014 had not been made until the earlier of—

(a) 7 August 2024; or
(b) the date on which the first statement of extended reserve obligations issued under clause 8.54P comes into force in respect of the grid owner.

(6) However, subclause (5) applies as if Schedule 8.3, Technical Code B, clause 7(6)(d)(ii) was amended from 7 May 2015 by replacing "45.5 Hertz" with "46.5 Hertz".

(7) Clause 8.29(2) does not apply in respect of an application for a dispensation from a South Island grid owner until 7 August 2024.

8.54TF Transitional provisions for change to frequency limit in South Island

(1) No later than 7 February 2015, each South Island grid owner must prepare and give the system operator a plan for complying with Schedule 8.3, Technical Code B, clause 7(6)(d)(ii), as modified by clause 8.54T(6).

(2) The system operator must approve a plan received under subclause (1) subject to any changes that the system operator considers necessary.

(3) A South Island grid owner does not breach Schedule 8.3, Technical Code B, clause 7(6)(d)(ii) if the grid owner complies with a plan approved by the system operator under subclause (2).


Subpart 6—Allocating costs

Heading: inserted, on 24 March 2015, by clause 10 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

8.54U Contents of this subpart

This subpart provides for the allocation of costs relating to ancillary services and extended reserve.

Clause 8.54U: inserted, on 24 March 2015, by clause 10 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

Allocating costs for ancillary services and extended reserve


8.55 Identifying costs associated with ancillary services and extended reserve

(1) The allocable costs for each ancillary service are—

(a) the actual amounts that the ancillary service agents are entitled to receive for that ancillary service under contracts entered into by the system operator in implementing the procurement plan; plus

(b) the actual administrative costs of the system operator (as approved by the Authority) incurred in administering the procurement plan in respect of that ancillary service; less

(c) any readily identifiable and quantifiable costs to be paid by asset owners in respect of that ancillary service as a condition of any dispensations stipulated in accordance with clause 8.31(1)(a); less

(d) any identifiable costs to be paid by any person in respect of that ancillary service, as a condition of any agreement reached by the system operator, in accordance with clause 8.6.

(2) The allocable costs for extended reserve are the actual amounts (if any) that extended reserve providers are entitled to receive for providing extended reserve under the current extended reserve procurement schedule.

Compare: Electricity Governance Rules 2003 rule 11.1 section IV part C
8.56 **Black start costs allocated to grid owner**

The allocable cost of black start must be paid by the registered participants who are grid owners to the system operator in accordance with the process described in clause 8.68. If there are multiple grid owners, those costs must be allocated between them in proportion to their respective ODV valuations.

Compare: Electricity Governance Rules 2003 rule 11.2 section IV part C

8.57 **Over frequency reserve costs allocated to HVDC owner**

The allocable cost of over frequency reserve must be paid by the HVDC owner to the system operator in accordance with the process described in clause 8.68.

Compare: Electricity Governance Rules 2003 rule 11.3 section IV part C

8.58 **Frequency keeping costs are allocated to purchasers**

The allocable cost of frequency keeping must be paid by purchasers to the system operator in accordance with the process in clause 8.68. Those costs must be calculated in accordance with the following formula:

\[
\text{Share}_{PURx} = \frac{F_c \times \max(0, \sum_t (\text{Offtake}_{PURxt} - \text{EFK}_{PURxt}))}{\sum_x \max(0, \sum_t (\text{Offtake}_{PURxt} - \text{EFK}_{PURxt}))}
\]

where

- \(\text{Share}_{PURx}\) is purchaser \(x\)’s share of allocable cost in relation to frequency keeping
- \(F_c\) is the allocable cost of frequency keeping services in the billing period
- \(\text{Offtake}_{PURxt}\) is the total reconciled quantity in kWh for purchaser \(x\) across all grid exit points in trading period \(t\) in the billing period
- \(\text{EFK}_{PURxt}\) is the quantity of any frequency keeping provided under any alternative ancillary service arrangement for frequency keeping authorised by the system operator for purchaser \(x\) in trading period \(t\).

Compare: Electricity Governance Rules 2003 rule 11.4 section IV part C

8.59 **Availability costs allocated to generators and HVDC owner**

The availability costs in a billing period must be allocated separately to persons in the North Island and South Island in accordance with the following formula:

\[
\text{Share}_i = \frac{A_c \times m_i}{M_t}
\]

where
Share\(_t\) is the availability cost allocated to a generator who owns generating unit \(x\) or to the HVDC link for trading period \(t\) for the North Island or South Island as appropriate.

\(A_c\) is the availability cost for the North Island or South Island as appropriate incurred in respect of trading period \(t\).

\[ m_t = \max(0, \text{INJGEN}_{xt} - (h \cdot \text{INJD}) - \text{EIR}_{\text{GEN}_{xt}}) = m_{xt} \text{ for any generating unit} \]
\[ \text{is max}(0, \text{HVDCRisk}_{xt} - (h \cdot \text{INJD}) - \text{EIR}_{\text{HVDC}_{xt}}) = m_{ht} \text{ for the HVDC link} \]

\(M_t\) is \(\sum x m_{xt} + m_{ht}\).

\(h\) is 0.5 MWh/MW.

\(\text{INJGEN}_{xt}\) is the electricity injected (expressed in MWh) by generating unit \(x\) in trading period \(t\) into the North Island or South Island as appropriate.

\(\text{EIR}_{\text{GEN}_{xt}}\) is the quantity of any instantaneous reserve provided under any alternative ancillary service arrangements for instantaneous reserve authorised by the system operator for generating unit \(x\) in trading period \(t\).

\(\text{HVDCRisk}_{xt}\) is the at risk HVDC transfer (expressed in MWh) in trading period \(t\) into the North Island or South Island as appropriate.

\(\text{EIR}_{\text{HVDC}_{xt}}\) is the quantity of any instantaneous reserve provided under any alternative ancillary service arrangement for instantaneous reserve authorised by the system operator for at risk HVDC transfer in trading period \(t\).

\(\text{INJD}\) is 60 MW.

Compare: Electricity Governance Rules 2003 rule 11.5.1 section IV part C

8.60 System operator must investigate causer of under-frequency event

1. The system operator must promptly advise the Authority, every generator, grid owner and any other participant substantially affected by an under-frequency event, that an under-frequency event has occurred.

2. The system operator may, by notice in writing to a participant, require a participant to provide information required by the system operator for the purposes of this clause.

3. A notice given under subclause (2) must specify the information required by the system operator and the date by which the information must be provided (which must not be earlier than 20 business days after the notice is given).

4. A participant who has received a notice under subclause (2) must provide the information required by the system operator by the date specified by the system operator in the notice.

5. Within 40 business days of receiving the information, or such longer period as may be agreed by the Authority, the system operator must provide a report to the Authority that includes the following:
(a) whether, in the system operator's view, the under-frequency event was caused by a generator or grid owner, and if so, the identity of the causer:
(b) the reasons for the system operator's view:
(c) all of the information the system operator considered in reaching its view.

Compare: Electricity Governance Rules 2003 rule 11.5.1A section IV part C
Clause 8.60 Heading: amended, on 19 May 2016, by clause 25(1) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.
Clause 8.60(2): amended, on 19 May 2016, by clause 25(3)(a), (b) and (c) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.
Clause 8.60(3): amended, on 19 May 2016, by clause 25(4)(a) and (b) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.

8.61 Authority to determine causer of under-frequency event

(1) The Authority must determine whether an under-frequency event has been caused by a generator or grid owner and, if so, the identity of the causer.
(2) The Authority must publish a draft determination that states whether the under-frequency event was caused by a generator or grid owner and, if so, the identity of the causer.
(3) The Authority must give reasons for its findings in the draft determination.
(4) The Authority must consult every generator, grid owner and other participant substantially affected by an under-frequency event in relation to the draft determination.
(5) When the Authority publishes the draft determination under subclause (2), the Authority must give notice to generators, grid owners, and other participants substantially affected by the under-frequency event of the closing date for submissions on the draft determination.
(6) The date referred to in subclause (5) must be no earlier than 10 business days after the date of publication of the draft determination.
(7) The Authority must publish submissions received under subclause (4) unless there is good reason for withholding information in a submission.
(8) For the purposes of subclause (7), good reason for withholding information exists if there is good reason for withholding the information under the Official Information Act 1982.
(9) Following the consultation under subclause (4), the Authority must publish a final determination.

Compare: Electricity Governance Rules 2003 rule 11.5.1B section IV part C
Clause 8.61 Heading: amended, on 19 May 2016, by clause 26(1) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.
Clause 8.61(5): amended, on 19 May 2016, by clause 26(4)(a) and (b) of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.
8.62 Disputes regarding Authority determinations

(1) A participant who is substantially affected by a determination may dispute the determination by referring the matter to the Rulings Panel.

(2) A dispute is commenced by giving written notice to the Rulings Panel specifying the grounds of the dispute.

(3) A notice under subclause (2) must be given within 10 business days after the determination is published.

(4) The Authority’s determination is suspended if a dispute is referred to the Rulings Panel within that time.

(5) If a dispute is not referred to the Rulings Panel within that time, the determination is final.

(6) If a dispute is referred to the Rulings Panel, the Authority must provide the Rulings Panel with all information considered by the Authority in making the determination.

Compare: Electricity Governance Rules 2003 rule 11.5.1C section IV part C

8.63 Decision of the Rulings Panel

(1) The Rulings Panel may—
   (a) confirm the determination; or
   (b) amend the determination; or
   (c) substitute its own determination; or
   (d) refer the determination back to the Authority with directions as to the particular matters that require reconsideration or amendment.

(2) The Authority’s determination has effect as confirmed, amended, or substituted by the Rulings Panel from the date of the Rulings Panel’s decision.

(3) The Rulings Panel must give a copy of its decision to the Authority as soon as reasonably practicable.

(4) The Authority must publish the Rulings Panel’s decision as soon as reasonably practicable.

(5) If the Rulings Panel refers the matter back to the Authority, the Authority must have regard to the Rulings Panel’s directions under subclause (1)(d).

Compare: Electricity Governance Rules 2003 rule 11.5.1D section IV part C

8.64 Event costs allocated to event causers

The event charge payable by the causer of an under-frequency event (referred to as “Event e” below) must be calculated in accordance with the following formula:
EC = ECR * (\(\sum_y (\text{INT}_{ye} \text{ for all } y) - \text{INJ}_D\))

where

EC is the event charge payable by the causer

ECR is $1,250 per MW

INJ_D is 60 MW

\(\text{INT}_{ye}\) is the electric power (expressed in MW) lost at point y by reason of Event e (being the net reduction in the injection of electricity (expressed in MW) experienced at point y by reason of Event e) excluding any loss at point y by reason of secondary Event e.

y is a point of connection or the HVDC injection point at which the injection of electricity was interrupted or reduced by reason of Event e.

Compare: Electricity Governance Rules 2003 rule 11.5.2 section IV part C

8.65 Rebates paid for under-frequency events

An event charge that has been paid for an under-frequency event (referred to as “Event e”) under clause 8.64 must be rebated in accordance with the following formula to persons who are allocated availability costs in accordance with clause 8.59:

\[
\text{Rebate}_{xe} = \text{EC}_e * \frac{\text{Z}_{xe}}{\text{Z}_{tote}}
\]

where

\(\text{Rebate}_{xe}\) is the rebate of the event charge paid for Event e to person “\(x\)”, who has been allocated availability costs in accordance with clause 8.59

\(\text{EC}_e\) is the event charge paid for Event e

\(\text{Z}_{xe}\) is the sum of all availability costs paid by \(x\) during the billing period in which Event e occurred and the 2 preceding billing periods

\(\text{Z}_{tote}\) is the sum of all availability costs paid for all trading periods during the billing period in which Event e occurred and the two preceding billing periods.

Compare: Electricity Governance Rules 2003 rule 11.5.3 section IV part C

8.66 Payments and rebates

All costs calculated in accordance with clauses 8.59 and 8.64 are payable by the relevant participants to the system operator, and all event charge rebates calculated in accordance with clause 8.65 are payable by the system operator to the relevant participants, in accordance with clause 8.69.
8.67 Voltage support costs allocated in 3 parts – nominated peak, monthly peak and residual charges

(1) Each connected asset owner must pay the allocable cost of voltage support in each zone to the system operator in accordance with clause 8.68. The costs must be calculated in accordance with this clause.

(2) Each connected asset owner must pay a nominated peak kvar charge calculated in accordance with the following formula:

$$\text{NomCharge}_{xz} = \text{PeakRate}_z \times \sum_j Q_{xjz}$$

where

- $\text{NomCharge}_{xz}$ is the total nominated peak charges for connected asset owner $x$ in zone $z$
- $\text{PeakRate}_z$ is the fixed $$/kvar set annually in advance by system operator for zone $z$
- $Q_{xjz}$ is Nom PeakLINES$_{xjz}$, which is the peak demand in kvar (in zone $z$) nominated to the system operator in advance of, and having effect from, 1 March each year by connected asset owner $x$ at its connected asset owner kvar reference node $j$
- $\sum_j$ is the sum across all connected asset owner kvar reference nodes $j$ of connected asset owner $x$ in zone $z$

(3) Each connected asset owner must pay a monthly peak penalty charge calculated in accordance with the following formula:

$$\text{PeakPenaltyCharge}_{\text{LINE}xz} = \text{PenaltyRate}_z \times \sum_j \text{PenaltyQuantity}_{\text{LINE}xjz}$$

where

- $\text{PeakPenaltyCharge}_{\text{LINE}xz}$ is the total peak penalty charges for connected asset owner $x$ across all connected asset owner kvar reference nodes $j$ for connected asset owner $x$ in zone $z$
- $\text{PenaltyRate}_z$ is the fixed $$/kvar penalty charge for “kvar above nominated kvar” set annually in advance by the system operator in zone $z$
- $\sum_j$ is the sum across all connected asset owner kvar reference nodes $j$ of connected asset owner $x$ in zone $z$
- $\text{PenaltyQuantity}_{\text{LINE}xjz}$ is the “kvar above nominated kvar” quantity for connected asset owner $x$ at its connected asset owner kvar reference node $j$ in zone $z$
(4) For the purpose of calculating the “kvar above nominated kvar” quantity, the kvar taken by the connected asset owner—
(a) includes only kvar demands on weekdays (Monday to Friday but excluding national holidays) between the hours of 0700 to 2100 inclusive; and
(b) includes no more than 2 kvar peaks in any 1 day; and
(c) is the average of the 6 largest kvar peaks for the connected asset owner in each month measured at the connected asset owner kvar reference node j within the zone z,—
and “kvar above nominated kvar” is the difference between the kvar taken by the connected asset owners as determined in accordance with paragraphs (a) to (c) and the nominated kvar specified by the connected asset owner.

(5) Each connected asset owner must pay a residual charge or receive a residual payment calculated in accordance with the following formulae:

\[
\text{Residual}_{\text{ALLz}} = V\text{cost}_z - \text{Nom Charge}_{\text{ALLz}} - \text{PeakPenaltyCharge}_{\text{ALLz}}
\]

\[
\text{Residual}_{\text{LINEallz}} = \text{Residual}_{\text{ALLz}} \times \left( \frac{\sum x_j \text{NomPeak}_x \text{LINE}x_{jz}}{\sum x_j Q_{xj}} \right)
\]

\[
\text{Residual}_{\text{LINE}x_z} = \text{Residual}_{\text{LINEallz}} \times \left( \frac{\text{BillingPeriodOfftake}_{\text{LINE}x_z}}{\text{BillingPeriodOfftake}_{\text{ALLz}}} \right)
\]

where

\(V\text{cost}_z\) is the total allocable costs for voltage support in zone z in the billing period

\(\text{Nom Charge}_{\text{ALLz}}\) is the sum of all \(\text{Nom Charge}_{xz}\) for zone z

\(\text{PeakPenaltyCharge}_{\text{ALLz}}\) is the sum of all connected asset owners’ PeakPenaltyChargeLINExz for zone z

\(\text{Residual}_{\text{ALLz}}\) is the total residual to be recovered from or paid to connected asset owners in zone z

\(\text{Residual}_{\text{LINEallz}}\) is the portion of \(\text{Residual}_{\text{ALLz}}\) to be recovered from or paid to connected asset owners in zone z

\(\text{Residual}_{\text{LINE}x_z}\) is the portion of \(\text{Residual}_{\text{LINEallz}}\) to be recovered from or paid to connected asset owner x in zone z

\(\text{BillingPeriodOfftake}_{\text{LINE}x_z}\) is the sum of metering information for connected asset owner x across all connected asset owner kvar reference nodes in zone z for the billing period for all trading periods

\(\text{BillingPeriodOfftake}_{\text{ALLz}}\) is the sum of metering information for all connected asset owners across all connected asset owner kvar reference nodes in zone z for the billing period for all trading periods.
Electricity Industry Participation Code 2010
Part 8

(6) For the purposes of this clause, a connected asset owner does not include a generator who is supplied electricity for consumption at a point of connection with the grid. Compare: Electricity Governance Rules 2003 rule 11.6 section IV part C

8.67A Extended reserve costs allocated to connected asset owners
If there are allocable costs for extended reserve in a billing period, each connected asset owner, other than a generator that is directly connected to the grid, must pay a charge for extended reserve for the billing period in accordance with the following formula:

Extended reserve charge\(_D\) = \[(\text{TERAC}_{\text{NI}} \times \frac{L_{\text{NI}, D}}{L_{\text{NI}, \text{TOT}}}) + (\text{TERAC}_{\text{SI}} \times \frac{L_{\text{SI}, D}}{L_{\text{SI}, \text{TOT}}})\]

where

Extended reserve charge\(_D\) is the extended reserve charge owing by the connected asset owner for the billing period

\(\text{TERAC}_{\text{NI}}\) is the sum of all payments for extended reserve provided in the North Island for the billing period

\(L_{\text{NI}, D}\) is the connected asset owner’s total offtake (in MWh) at grid exit points in the North Island in the billing period

\(L_{\text{NI}, \text{TOT}}\) is the total offtake (in MWh) by all connected asset owners at grid exit points in the North Island in the billing period

\(\text{TERAC}_{\text{SI}}\) is the sum of all payments for extended reserve provided in the South Island for the billing period

nodes in zone \(z\) for the billing period for all trading periods

\(\Sigma_j\) is the sum across all connected asset owner kvar reference nodes \(j\) for all connected asset owners \(x\) in zone \(z\)

\(\Sigma_j\) is the sum across all connected asset owner kvar reference nodes \(j\) of connected asset owner \(x\) in zone \(z\)

\(Q_{x,j,z}\) is Nom PeakLINES\(_{x,j,z}\), which is the peak demand in kvar (in zone \(z\)) nominated to the system operator in advance of, and having effect from, 1 March each year by connected asset owner \(x\) at its connected asset owner kvar reference node \(j\)
L_{SI, D} \text{ is the connected asset owner’s total offtake (in MWh) at grid exit points in the South Island in the billing period.}

L_{SI, TOT} \text{ is the total offtake (in MWh) by all connected asset owners at grid exit points in the South Island in the billing period.}


8.68 Clearing manager to determine amounts owing

(1) The clearing manager must determine the amount owing to the system operator by each grid owner, purchaser, generator and connected asset owner for ancillary services under clauses 8.55 to 8.67. On behalf of the system operator, the clearing manager must collect those amounts, and any amounts advised by the system operator as owing to it under clauses 8.6 and 8.31(1)(a), by including the relevant amounts in the amounts advised by the clearing manager as owing under Part 14.

(2) To enable the clearing manager to determine those amounts, the system operator must provide to the clearing manager the total allocable cost for each ancillary service and any additional information required to carry out the calculations under clauses 8.55 to 8.67 that is not otherwise provided by the reconciliation manager or the pricing manager under Part 13.

(3) The clearing manager must determine the amount owing by each connected asset owner, other than a generator that is directly connected to the grid, for extended reserve in accordance with clause 8.67A.

(4) The clearing manager must determine the amount owing to each extended reserve provider for the provision of extended reserve in accordance with—
(a) the extended reserve schedule; and
(b) any relevant notice received from the system operator under clause 8.54Q(2).

(5) The clearing manager must collect the amounts determined under subclause (3) and pay the amounts determined under subclause (4) by including the relevant amounts in the invoices issued by the clearing manager under Part 14.

(6) All amounts owing under this clause are subject to the priority order of payments set out in clause 14.56.

Compare: Electricity Governance Rules 2003 rule 11.7 section IV part C
8.69 Clearing manager to determine wash up amounts payable and receivable

(1) The clearing manager must determine the following amounts owing as a result of washups under subpart 6 of Part 14:

(a) the amount owing to the system operator by each grid owner, purchaser, generator and connected asset owner for ancillary services under clauses 8.55 to 8.67:

(b) the amount owing to each grid owner, purchaser, generator and connected asset owner by the system operator for ancillary services under clauses 8.55 to 8.67:

(c) the amount owing by each distributor for extended reserve under clause 8.67A:

(d) the amount owing to each extended reserve provider for extended reserve under clause 8.68.

(2) On behalf of the system operator the clearing manager must collect or pay the amounts owing for ancillary services, and any amounts advised by the system operator as payable to it under clauses 8.6 and 8.31(1)(a) by including the relevant amounts advised by the clearing manager as owing under Part 14.

(3) To enable the clearing manager to determine the amounts payable for ancillary services, the system operator must provide to the clearing manager the allocable cost for each ancillary service and any additional information required to carry out the recalculations under clauses 8.55 to 8.67 that is not otherwise provided by the reconciliation manager or the pricing manager under Part 13.

(4) All amounts owing under this clause are subject to the priority order of payments set out in clause 14.56.

Compare: Electricity Governance Rules 2003 rule 11.9 section IV part C


8.70 System operator pays ancillary service agents

(1) The system operator must pay each ancillary service agent the amounts that each ancillary service agent is entitled to receive for ancillary services under contracts entered into by the system operator in implementing the procurement plan.

(2) The system operator must use the clearing manager as its agent to pay participants.

Compare: Electricity Governance Rules 2003 rule 11.9 section IV part C
Schedule 8.1
cls 8.29 and 8.33
Approval of equivalence arrangement or grant of dispensation

1 Contents of this Schedule
This Schedule sets out the process for an asset owner who wishes to apply for—
(a) approval of an equivalence arrangement; or
(b) the grant of a dispensation.

2 Application and supporting information
Each application for an equivalence arrangement or a dispensation must—
(a) be in writing; and
(b) specify the AOPO or technical code from which approval for an equivalence arrangement or the grant of dispensation is sought; and
(c) provide supporting information for the application, including sufficient information about the actual capability of the asset or configuration of assets; and
(d) describe any remedial action planned to return the asset or configuration of assets to a compliant state; and
(e) specify the required term of the equivalence arrangement or dispensation; and
(f) indicate any information for which confidentiality is sought on the grounds that it would, if disclosed, unreasonably prejudice the commercial position of the person who supplied the information (or of the person who is the subject of that information), or would disclose a trade secret, or on the ground that it is necessary to protect information which is itself subject to an obligation of confidence, and the duration of the requirement for confidentiality.

3 System operator obligations on receipt of application
No later than 5 business days after receiving the application made in accordance with clause 2, the system operator must—
(a) record the name of the asset owner making the application, the date and the subject matter of the application in the system operator register; and
(b) give written notice to the Authority of the application; and
(c) provide the asset owner with an estimate of the likely time that it will take to consider the application and the likely costs associated with processing the application.

4 Rights and obligations while processing applications
(1) The system operator must use reasonable endeavours to process an application for approval of an equivalence arrangement or grant of a dispensation within the timeframe and costs estimated in accordance with clause 3(c).
(2) If the system operator cannot process the application within the timeframe or costs originally estimated, it must give notice of this fact and its amended estimates of timeframe or costs to the asset owner, and clause 5 applies in respect of those costs.

(3) The system operator may require the provision of additional information at any stage during the application process and, provided the system operator’s requirements are reasonable, that information must be provided by the asset owner if the application is to be processed.

(4) The asset owner may withdraw an application at any time, provided that it meets all costs incurred by the system operator as at the date of the withdrawal of the application. If any costs have been paid in advance, those monies outstanding to the credit of the asset owner must immediately be returned to the asset owner.

(5) An applicant may amend an application being considered by the system operator at any time. All amendments must be in writing and submitted to the system operator and take effect from the date of receipt.

Compare: Electricity Governance Rules 2003 clause 4 schedule C1 part C

5 Obligation of asset owner to pay costs

(1) The system operator and the asset owner must agree on the costs involved in processing an application for approval of an equivalence arrangement or grant of a dispensation and the method for payment to the system operator by the asset owner of those costs—

(a) before the system operator proceeds with the application; and

(b) at any time during the processing of the application when either—

(i) the system operator gives written notice to the asset owner that it considers the estimate of the likely timeframe involved in processing the application will exceed the estimate given under clause 3(c) or any revised estimate given under clause 4; or

(ii) an asset owner varies its application and the system operator, acting reasonably, considers this variation will change the cost of processing the application.

(2) The system operator is entitled not to proceed until agreement on costs is reached at any of these stages.

Compare: Electricity Governance Rules 2003 clause 5 schedule C1 part C


6 Special provisions relating to the grant of dispensations

(1) Before granting a dispensation, the system operator must issue a draft decision on the application. The draft decision must be published on the system operator register and must include—

(a) an assessment by the system operator of the technical issues; and

(b) advice from the system operator about any changes required to ancillary services procurement as a result of the proposed dispensation.

(2) If changes are required to the procurement plan, the draft decision must be conditional on the procurement plan being amended appropriately in accordance with clause 8.44.
(3) A participant may make a submission to the system operator on the application that resulted in the publication of the draft decision no later than 10 business days after the draft decision is recorded on the system operator register.

(4) The system operator must—
   (a) consider all submissions; and
   (b) give written notice of its decision on an application to the participant who made the application.

Compare: Electricity Governance Rules 2003 clause 6 schedule C1 part C

7 Decision of the system operator
The system operator must advise all applicants for approval of an equivalence arrangement or grant of a dispensation of—
   (a) its decision as soon as it is made in writing; and
   (b) the reason for its decision.

Compare: Electricity Governance Rules 2003 clause 7 schedule C1 part C

8 Decisions must be recorded
(1) An approval of an equivalence arrangement or grant of a dispensation by the system operator must be recorded in the system operator register.

(2) The approval must state the name of the asset owner, the date, duration and nature of the equivalence arrangement or dispensation, including any conditions.

(3) On request, and at the cost of the person making the request, the system operator must supply all background information in relation to its decision to that person, other than information designated as commercially sensitive by the relevant asset owner.

Compare: Electricity Governance Rules 2003 clause 8 schedule C1 part C
Schedule 8.2  
cls 8.48 and 8.50  
Approval of alternative ancillary service arrangement

1  Process for approval of alternative ancillary service arrangement
(1) An application for an alternative ancillary service arrangement must—
   (a) be in writing; and
   (b) specify the ancillary service for which approval for an alternative ancillary service arrangement is sought; and
   (c) provide supporting information for the application, including sufficient information about the actual capability of the asset or configuration of assets; and
   (d) describe any remedial action planned to return the asset or configuration of assets to a compliant state; and
   (e) specify the required term of the alternative ancillary service arrangement; and
   (f) indicate any information for which confidentiality is sought on the grounds that it would, if disclosed, unreasonably prejudice the commercial position of the person who supplied the information (or the person who is the subject of that information), or would disclose a trade secret, or on the ground that it is necessary to protect information which is itself subject to an obligation of confidence.

(2) No later than 5 business days after receipt of the application under subclause (1), the system operator must—
   (a) record the name of the asset owner making the application, the date and the subject matter of the application in the system operator register; and
   (b) give written notice to the Authority of the application; and
   (c) provide the asset owner with an estimate of the likely time it will take to consider the application and the likely costs associated with processing the application.

(3) The system operator and the asset owner must agree on the costs involved in processing an application for authorisation of an alternative ancillary service arrangement and the method for payment to the system operator by the asset owner of those costs—
   (a) before the system operator proceeds with the application; and
   (b) at any time during the processing of the application, the system operator is entitled not to proceed until agreement is reached if either—
      (i) the system operator gives written notice to the asset owner that it considers the estimate of the likely timeframe and costs involved in processing the application will exceed the estimate given under subclause (2)(c); or
      (ii) an asset owner varies its application and the system operator, acting reasonably, considers this variation will change the costs in processing the application.

Compare: Electricity Governance Rules 2003 clauses 1.1 to 1.3 schedule C2 part C  
Clause 1(2)(b) and (3)(b)(i): amended, on 5 October 2017, by clause 112(1) and (2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
2 Obligations in processing applications
(1) The system operator must use reasonable endeavours to process an application for authorisation of an alternative ancillary service arrangement within the timeframe and costs estimated in accordance with clause 1(2)(c).
(2) If the system operator cannot process an application within the timeframe and costs originally estimated, it must give notice of this fact and its amended estimates of timeframe and costs to the asset owner and the provisions of clause 1(3) must apply in respect of those costs.
(3) The system operator may require the provision of additional information at any stage during the application process and, provided the system operator’s requirements are reasonable, that information must be provided by the asset owner if the application is to be processed.
(4) The asset owner may withdraw an application at any time provided that it meets all costs incurred by the system operator as at the date of withdrawal of the application. If those costs have been paid in advance, those monies outstanding to the credit of the asset owner must immediately be returned to the asset owner.
(5) An applicant may amend an application being considered by the system operator at any time. All amendments must be in writing and submitted to the system operator and must take effect from the date of receipt.
Compare: Electricity Governance Rules 2003 clause 1.4 schedule C2 part C

3 Decision of the system operator
The system operator must advise all applicants for authorisation of an alternative ancillary service arrangement of its decision as soon as it is made in writing, and advise such applicants of the reason for that decision.
Compare: Electricity Governance Rules 2003 clause 1.5 schedule C2 part C

4 Decisions must be recorded
An authorisation of an alternative ancillary service arrangement by the system operator must be recorded in the system operator register. Except for information that the system operator agreed was commercially sensitive, the authorisation must state the name of the asset owner, the date, duration and nature of the alternative ancillary service arrangement, including any conditions. On request, and at the cost of the person making the request, the system operator must supply all background information in relation to its decision to that person, other than information designated as commercially sensitive by the relevant asset owner.
Compare: Electricity Governance Rules 2003 clause 1.6 schedule C2 part C
Schedule 8.3  
Technical codes

Technical Code A – Assets

1 Purpose
The purpose of this technical code is to define obligations for asset owners and technical standards for assets that are supportive of, or more detailed than, those set out in subpart 2 of Part 8, in order to enable the system operator to plan to comply, and to comply, with the principal performance obligations.

Compare: Electricity Governance Rules 2003 clause 1 technical code A schedule C3 part C

2 General requirements
(1) Each asset owner must ensure that—
(a) its assets at grid exit points and at grid injection points, and, in the case of connected asset owners, the assets of any embedded generator connected to it, are identified and referred to by a system number; and
(b) its assets, both in the manner in which they are designed and operated, are capable of being operated, and operate, within the limits stated in the asset capability statement provided by the asset owner for that asset; and
(c) it meets any other reasonable requirements of the system operator, identified during planning studies, which are required for the system operator to plan to comply, or to comply, with its principal performance obligations.

(2) Each asset owner must provide the system operator with an asset capability statement, and any other information reasonably required by the system operator, to allow the system operator to assess compliance of its asset or any configuration of assets with the requirements of the asset owner performance obligations and technical codes at each of the following times:
(a) before the completion of planning for the construction of that asset or configuration of assets;
(b) at, or before, the completion of construction but before the commissioning of that asset or configuration of assets, except that the asset owner must put in place a commissioning plan in accordance with subclauses (6) to (8) to minimise the impact of commissioning tests on the system operator’s ability to comply with its principal performance obligations, and adhere to this plan during commissioning, unless otherwise agreed to by the system operator.

(3) On, or before, completion of commissioning of an asset or configuration of assets, the asset owner must obtain a final assessment in writing from the system operator that the asset or configuration of assets meets the requirements of the asset owner performance obligations and technical codes. This final assessment must be based on the information supplied by the asset owner and, if necessary, the result of system tests at commissioning.

(4) The system operator must give the assessment referred to in subclause (2)(b) within a
reasonable time frame of the request and supply the asset owner with all information that supports its assessment. Any permission granted by the system operator to an asset owner to conduct commissioning of any asset or configuration of assets must permit connection of the asset (or configuration of assets) solely for the purposes of commissioning.

(5) Each asset owner must provide the system operator with an asset capability statement in the form from time to time published by the system operator for each asset that is proposed to be connected, or is connected to, or forms part of the grid. The asset capability statement must—

(a) include all information reasonably requested by the system operator so as to allow the system operator to determine the limitations in the operation of the asset that the system operator needs to know for the safe and efficient operation of the grid; and

(b) include any modelling data for the planning studies, as reasonably requested by the system operator; and

(c) be updated and reissued to the system operator as information and design development progresses through the study, design, manufacture, testing and commissioning phases; and

(d) be complete and up to date before the commissioning of the asset; and

(e) be complete and up to date at all times while the asset is connected to, or forms part of, the grid.

(6) Each asset owner must provide a commissioning plan or test plan in accordance with subclauses (7) or (8) (as the case may be) in the following situations:

(a) when changes are made to assets that alter any of the following at the grid interface:

(i) the single-line diagram:

(ii) a protection system, other than a change to a protection system setting:

(iii) a control system, including a change to a control system setting:

(iv) any rating of assets:

(b) when assets are to be connected to, or are to form part of, the grid:

(c) if it is necessary for an asset owner to perform a system test or other test to ascertain or confirm asset capabilities, and if the commissioning or testing or connection of those assets may affect the system operator’s ability to plan to comply, or to comply with, its principal performance obligations. If an asset owner is unsure whether the commissioning or connection of an asset may impact on the system operator’s ability to plan to comply, and to comply with, the principal performance obligations it must contact the system operator for advice.

(7) The commissioning plan prepared by an asset owner and agreed by the system operator must—

(a) include a timetable containing the sequence of events necessary to connect the assets to the grid and conduct any proposed system test; and

(b) contain the protection and control settings to be applied before the assets are made live (where live has the meaning given to it in the Electricity (Safety)
Regulations 2010); and
(c) contain the procedures for commissioning the plant with minimum risk to personnel and plant and to the ability of the system operator to plan to comply and to comply with its principal performance obligations.

(8) If a test plan is required under subclause (6), it must be prepared by the asset owner in consultation with the system operator. The test plan must contain sufficient information to enable the system operator to plan to comply, and to comply, with the principal performance obligations.

(9) Once assessed by the system operator acting reasonably, the asset owner must follow the commissioning plan or test plan at all times, unless otherwise agreed with the system operator (such agreement must not be unreasonably withheld if compliance with the commissioning plan or testing plan is not practicable and non-compliance does not impact on the system operator's ability to comply with its principal performance obligations or on other asset owners).

3 Requirements for asset information

(1) In accordance with clause 8.25(4), the following information is required by the system operator to assist it to plan to comply, and to comply, with its principal performance obligations:

(a) sufficient information must be exchanged between the system operator and the asset owner to ensure that both fully understand the implications of any changes to the asset capability statement or of any proposed connection of the relevant assets to the grid or to the local network. This information must be exchanged in accordance with a timetable agreed to by the system operator and the asset owner:

(b) if reasonably requested by the system operator, the asset owner must provide sufficient information to the system operator to demonstrate the compliance of the asset owner's assets with the asset owner performance obligations and the technical codes.

(2) Information about an asset, supply or demand of other asset owners must only be disclosed by the system operator—

(a) as expressly provided for in this Code; or

(b) as reasonably required in a grid emergency or to ensure the security of the grid;

or

(c) as required by law; or

(d) otherwise as may be agreed with the relevant asset owners.

(3) Each asset owner must provide the system operator with—

(a) all information reasonably requested by the system operator so as to ensure compliance with clause 8.25(4) and to enable the system operator to assess the
grid interface; and
(b) details of protection systems, including settings, to ensure that the requirements of clause 8.25(4) are met.

(4) Each asset owner must ensure that all supporting information for the operational control of assets is kept up to date.

Compare: Electricity Governance Rules 2003 clause 3 technical code A schedule C3 part C

4 Requirements for grid and grid interface
(1) Each asset owner and grid owner must co-operate with the system operator to ensure that protection systems on both sides of a grid interface, which include main protection systems and back up protection systems, are co-ordinated so that a faulted asset is electrically disconnected by the main protection system first and the other assets are not prematurely electrically disconnected.

(2) A proposed grid interface, including the settings of any associated protection system, must be agreed between the relevant asset owner and the system operator before being implemented.

(3) Each asset owner must ensure that sufficient circuit breakers are provided for its assets so that each of its assets is able to be electrically disconnected from the grid whenever a fault occurs within the asset.

(4) Each asset owner must ensure that it provides protection systems for its assets that are connected to, or form part of, the grid. Each asset owner must also ensure that as a minimum requirement—
(a) such protection systems support the system operator in planning to comply, and complying, with the principal performance obligations and are designed, commissioned and maintained, and settings are applied, to achieve the following performance in a reliable manner:
(i) electrically disconnect any faulted asset in minimum practical time (taking into account selectivity margins and industry best design practice) and minimum disruption to the operation of the grid or other assets:
(ii) be selective when operating, so that the minimum amount of assets are electrically disconnected:
(iii) as far as reasonably practicable, preserve power system stability; and

(b) it provides duplicated main protection systems for each of its assets at voltages of 220 kV a.c. or above, other than busbars; and

(c) it provides, for each of its 220 kV a.c. busbars—
(i) a single main protection system and a back up protection system; or
(ii) if the performance of its back up protection system does not meet the requirements of paragraph (a), a duplicated main protection system; and

(d) it provides duplicated main protection systems for each of its busbars at voltages above 220 kV a.c.; and

(e) it designs, tests and maintains its main protection systems at voltages of 220 kV a.c. or above in accordance with the requirements set out in Appendix A; and
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(f) it provides a circuit breaker failure protection system, that need not be duplicated, for each circuit breaker at voltages of 220 kV a.c. or above. Circuit breaker duplication is not required; and

(g) protection system design for a connection of assets to the grid at lower voltages must be similar to existing design practice in adjacent connections of assets to ensure coordination of protection systems.

5 Specific requirements for generators

(1) Each generator must ensure that—

(a) each of its generating units, and its associated control systems,—
   (i) supports the system operator to plan to comply, and to comply, with the principal performance obligations; and
   (ii) is able to synchronise at a stable frequency within the frequency range stated in the asset capability statement for that asset; and

(b) the rate of change in the output of any of its generating units does not adversely affect the system operator's ability to plan to comply, and to comply, with the principal performance obligations. The rate of change must be adjustable to allow for changes in grid conditions; and

(c) each of its generating units has a speed governor that—
   (i) provides stable performance with adequate damping; and
   (ii) has an adjustable droop over the range of 0% to 7%; and
   (iii) does not adversely affect the operation of the grid because of any of its non-linear characteristics; and

(d) appropriate speed governor settings to be applied before commencing system tests for a generating unit are agreed between the system operator and the generator. The performance of the generating unit is then assessed by measurements from system tests and final settings are then applied to the generating unit before making it ready for service after those final settings are
agreed between the system operator and the generator. An asset owner must not change speed governor settings without system operator approval.

(2) Each generator with a generating unit connected to the grid must—
(a) have an excitation and voltage control system with a voltage set point that is adjustable over the range of voltage set out in clause 8.23 and operates continuously in the voltage control mode when synchronised; and
(b) in order to meet the asset owner performance obligations, ensure that each of its generating units is equipped with either—
(i) a connection transformer with an appropriate range of taps on each transformer together with an on-load tap-changer; or
(ii) assets to give a dynamic performance equivalent to those required by subparagraph (i).

(3) If the output of more than 1 generating unit is controlled by a common control system, the generator must ensure that—
(a) the common control system does not adversely affect the ability of the system operator to plan to comply, and to comply, with the principal performance obligations; and
(b) the combined output from the generating units performs as though it were from 1 generating unit; and
(c) the control system does not degrade the individual performance of any one generating unit.

(4) Each generator and grid owner must ensure that each of its assets is capable of operating under the voltage imbalance conditions stated in clause 4.9 of the Connection Code and, when operated within the limits stated in its asset capability statement, does not—
(a) contribute unbalanced phase currents into the grid; or
(b) aggravate any current imbalance that may occur on the grid.

(5) At some points of connection, a generator must ensure that its generating units have both main protection systems and back-up protection systems for nearby faults on the grid, if the necessity for, and the method of providing, such protection systems is agreed between the system operator and the generator.

6 Specific requirements for connected asset owners
Each connected asset owner must agree with the system operator any temporary or permanent connection of the connected asset owner’s assets if those assets become simultaneously connected to the grid at more than 1 point of connection.
7 Modifications and changes to assets

(1) Assets that have been modified, or are proposed to be modified, are deemed to be new assets for the purposes of this Code and this Technical Code and are subject to the requirements for connection to the grid and the requirements for commissioning assets. For the purposes of this Schedule, the following are considered to be modifications to assets, if the new connection or alteration may affect the capacity of the assets or may affect asset owner performance obligations or technical code requirements:

(a) a new connection of assets to the grid or a local network;
(b) a new connection of assets to form part of the grid;
(c) a new connection of an embedded generator to a local network other than an excluded generator as defined in clause 8.21(1);
(d) an alteration to assets already connected to the grid or, in the case of embedded generator, already connected to a local network.

(2) The asset owner must give written notice to the system operator in a timely manner of any assets that have been decommissioned if the assets affect or could affect the system operator’s ability to comply with its principal performance obligations.

8 Records, tests and inspections

(1) Each asset owner must arrange for, and retain, records for each of its assets to demonstrate that the assets comply with the asset owner performance obligations and this technical code.

(2) In addition to the requirements for commissioning or testing in clause 2(6) to (8), each asset owner must carry out periodic testing—

(a) of its assets in accordance with Appendix B; and
(b) in the case of an asset owner that is an extended reserve provider, of assets specified in its statement of extended reserve obligations in accordance with that statement.

(3) If the system operator advises an asset owner that it reasonably believes that an asset may not comply with an asset owner performance obligation or this technical code, the asset owner must—

(a) as soon as practicable, but no later than 30 days after receiving a written request, advise the system operator of its remedial or test plan for the assets; and
(b) as soon as reasonably practicable undertake any remedial action or testing of its assets in accordance with its plan advised to the system operator in paragraph (a). The system operator may require such testing or remedial action to be undertaken in the presence of a system operator representative.
(4) Each **asset owner** must, at the request of the **system operator**, provide access to records of the performance or testing of an **asset** and access to inspect an **asset**.

Compare: Electricity Governance Rules 2003 clause 8 technical code A schedule C3 part C

9 **Status of system operator approval**
A review and approval by the **system operator** under this Code must not be construed as confirming or endorsing the design or warranting the safety, durability or reliability of an **asset**. Such review or approval does not relieve the **asset owner** from its obligations to continue to meet the requirements of this Code. The **system operator** is not, by reason of any such review or lack of review, responsible for strength, adequacy of design or capacity of an **asset**. In undertaking a review, the **system operator** is not responsible for any consequence of a failure of an **asset** due to inadequate design.

Compare: Electricity Governance Rules 2003 clause 9 technical code A schedule C3 part C
Appendix A: Main protection system requirements

1 General requirements
An asset owner must design, test and maintain all main protection systems at voltages of 220 kV a.c. or above to conform to electricity industry standards and practices as they are reasonably and ordinarily applied by a skilled and experienced asset owner to current installations at voltages of 220 kV a.c. or above in the New Zealand context.

Compare: Electricity Governance Rules 2003 clause 1 appendix A technical code A schedule C3 part C

2 Specific requirements for main protection systems
Main protection systems at voltages of 220 kV a.c. or above must meet the requirements set out below:
(a) either test blocks or both test switches and test terminals must be provided:
(b) the electrical continuity of fused protection circuits, including d.c. and voltage transformer circuits must be supervised:
(c) the electrical continuity of circuit breaker trip circuits must be supervised.

Compare: Electricity Governance Rules 2003 clause 2 appendix A technical code A schedule C3 part C

3 Specific requirements for duplicated main protection systems
Duplicated main protection systems (the 2 components of which are referred to in this appendix as main 1 protection and main 2 protection) at voltages of 220 kV a.c. or above must meet the requirements set out below:
(a) duplicated main protection systems must be designed with sufficient coverage and probability of detection that if any or all parts of 1 main protection system fail, the other main protection system electrically disconnects a faulted asset before a back up protection system initiates the electrical disconnection of other non-faulted assets:
(b) the d.c. supply to duplicated main protection systems must consist of 2 independent station batteries, each with its own charger, supervision, and with a capacity and carry over duty to cover charger failure until repair and restoration. Station batteries may only feed a common primary d.c. busbar provided that the busbar is insulated and isolated from earth:
(c) the d.c. supply to each duplicated main protection system must be independently fused at the primary d.c. busbar:
(d) the manufacturer of main 1 protection must not be the same as the manufacturer of main 2 protection, unless one protection uses different measurement principles from the other:
(e) the current transformer core (or an equivalent instrument) and the cabling associated with that current transformer core or equivalent instrument (as the case may be) used for main 1 protection must be independent from that used for main 2 protection:
(f) if a voltage transformer supply is required for main 1 or main 2 protection—
   (i) the supply must be fused at the voltage transformer; and
   (ii) the supply for main 1 protection must use an independent fuse and cable
from those used for main 2 protection:

(g) main 1 protection must use, in each of the circuit breakers tripped by that main 1 protection, an independent trip coil from that used for main 2 protection:

(h) if protection signalling is used, main 1 protection must use a signal channel over an independent bearer on a different route from that used for main 2 protection:

(i) main 1 protection cabling must be segregated from main 2 protection cabling in a manner that minimises the risk of common mode failure of main 1 and 2 protection and minimises the number of connections in any protection circuit.

Compare: Electricity Governance Rules 2003 clause 3 appendix A technical code A schedule C3 part C Clause 3(a) and (i): amended, on 5 October 2017, by clause 120 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

4 Existing equipment

Despite clauses 1 and 3—

(a) a current transformer commissioned before 31 May 2007 is not required to comply with clause 3(e) until the current transformer is replaced; and

(b) a circuit breaker commissioned before 31 May 2007, if not designed to incorporate a second trip coil, is not required to comply with clause 3(g) until the circuit breaker is replaced; and

(c) cabling commissioned before 31 May 2007, if not designed to be segregated, is not required to comply with the segregation requirements of clause 3(i) until the cabling is replaced.

Appendix B: Routine testing of assets


1 Periodic tests to be carried out

(1) This Appendix sets out periodic tests required for the purposes of clause 8(2) of Technical Code A.

(2) Each asset owner may be legally required, other than under this Code, to carry out additional tests to ensure that their assets are safe and reliable.

(3) For the purposes of this Appendix, generating unit does not include a generating unit for which wind is the primary power source.

Compare: Electricity Governance Rules 2003 clause 1 appendix B technical code A schedule C3 part C
Clause 1: substituted, on 7 August 2014, by clause 18 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

2 Generating unit frequency response

Each generator, other than generators who are owners of excluded generating stations that are not subject to a directive issued by the Authority under clause 8.38, must—

(a) test the trip frequencies and trip time delays of each of its generating units’ analogue over-frequency relays and analogue under-frequency relays at least once every 4 years; and

(b) test the trip frequencies and trip time delays of each of its generating units’ non-self monitoring digital over-frequency relays and non-self monitoring digital under-frequency relays at least once every 4 years; and

(c) test the trip frequencies and trip time delays of each of its generating units’ self monitoring digital over-frequency relays and self monitoring digital under-frequency relays at least once every 10 years; and

(d) based on the tests carried out in accordance with paragraphs (a) to (c), provide a verified set of under-frequency trip settings and time delays to the system operator in an updated asset capability statement within 3 months of the completion date of each such test; and

(e) based on the tests carried out in accordance with paragraphs (a) to (c), provide a verified set of over-frequency trip settings and time delays to the system operator in an updated asset capability statement within 3 months of the completion date of each such test.

Compare: Electricity Governance Rules 2003 clause 2 appendix B technical code A schedule C3 part C

3 Generating unit governor and speed control

Each generator, other than generators who are owners of excluded generating stations that are not subject to a directive issued by the Authority under clause 8.38 must—

(a) test the governor system response of each of its generating units’ mechanical or analogue speed governors at least once every 5 years; and

(b) test the governor system response of each of its generating units’ digital or
electro-hydraulic speed governors at least once every 10 years; and

(c) based on the tests carried out in accordance with paragraphs (a) or (b), provide a verified set of modelling parameters and governor system response data to the system operator in an updated asset capability statement within 3 months of the completion date of each such test, including—

(i) a block diagram showing the mathematical representation of the governor; and

(ii) a block diagram showing the mathematical representation of the turbine dynamics including non-linearity and the applicable fuel source; and

(iii) a parameter list showing gains, time constants and other settings applicable to the block diagrams.

Compare: Electricity Governance Rules 2003 clause 3 appendix B technical code A schedule C3 part C

4 Generating unit transformer voltage control

Each generator with a point of connection to the grid must—

(a) test the operation of each of its generating unit transformers’ on-load tap changer analogue control systems at least once every 4 years; and

(b) test the operation of each of its generating unit transformers’ on-load tap changer digital control systems at least once every 10 years; and

(c) based on the tests carried out in accordance with paragraphs (a) or (b), provide a verified set of control parameters including voltage set points, operating dead bands and response times to the system operator in an updated asset capability statement within 3 months of the completion date of each such test.

Compare: Electricity Governance Rules 2003 clause 4 appendix B technical code A schedule C3 part C

5 Generating unit voltage response and control

Each generator with a point of connection to the grid must—

(a) test the modelling parameters and voltage response of each of its generating units’ analogue excitation systems at least once every 5 years; and

(b) test the modelling parameters and voltage response of each of its generating units’ digital excitation systems at least once every 10 years; and

(c) based on the tests carried out in accordance with paragraphs (a) or (b), provide a verified set of modelling parameters and voltage response data to the system operator in an updated asset capability statement within 3 months of the completion date of each such test, including—

(i) a block diagram showing the mathematical representation of the automatic voltage regulator; and

(ii) a block diagram showing the mathematical representation of the exciter; and

(iii) a parameter list showing gains, time constants and other settings applicable to the block diagrams.

Compare: Electricity Governance Rules 2003 clause 5 appendix B technical code A schedule C3 part C
6 [Revoked]

Compare: Electricity Governance Rules 2003 clause 6 appendix B technical code A schedule C3 part C

7 [Revoked]

Compare: Electricity Governance Rules 2003 clause 7 appendix B technical code A schedule C3 part C

8 Grid owner transformer voltage range

Each grid owner must—
(a) test the operation of each of its transformers’ on-load tap changer analogue control systems at least once every 4 years; and
(b) test the operation of each of its transformers’ on-load tap changer digital control systems at least once every 10 years; and
(c) based on the tests carried out in accordance with paragraphs (a) or (b), provide a verified set of control parameters to the system operator in an updated asset capability statement within 3 months of the completion date of each such test, including voltage set points, operating dead bands and response times.

Compare: Electricity Governance Rules 2003 clause 8 appendix B technical code A schedule C3 part C

9 Grid owner static var compensator transient response and control

Each grid owner must—
(a) test the transient response, steady state response and a.c. disturbance response of each of its static var compensators at least once every 10 years; and
(b) test the operation of each of its static var compensators’ analogue control systems at least once every 4 years; and
(c) test the operation of each of its static var compensators’ digital control systems at least once every 10 years; and
(d) based on the test carried out in accordance with paragraph (a), provide a verified set of modelling parameters, transient response parameters, steady state response parameters, and a.c. disturbance response data to the system operator in an updated asset capability statement within 3 months of the completion date of each such test including—
(i) a block diagram showing the mathematical representation of the static var compensator; and
(ii) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagrams; and
(iii) a detailed functional description of all of the components of the static var compensator and how they interact in each mode of control; and
(iv) step response test results; and
(v) a.c. fault recovery disturbance test results; and
(e) based on tests carried out in accordance with paragraphs (b) or (c), provide a set of control system test results to the system operator in an updated asset capability statement within 3 months of the completion date of each such test.
10 **Grid owner capacitors and reactive power control systems**

Each **grid owner** must—

(a) test the capacitance of each of its capacitors at least once every 8 years; and  
(b) test the operation of each of its reactive power control assets’ analogue **control systems** at least once every 4 years; and 
(c) test the operation of each of its reactive power control assets’ digital **control systems** at least once every 10 years; and  
(d) based on the test carried out in accordance with paragraph (a), provide a set of test results to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test; and

(e) based on tests carried out in accordance with paragraphs (b) or (c), provide a verified set of **control system** test results including voltage set points, operating dead bands and time delays to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test.

Compare: Electricity Governance Rules 2003 clause 9 appendix B technical code A schedule C3 part C

11 **Grid owner synchronous compensators**

Each **grid owner** must—

(a) test each of its synchronous compensators’ analogue and electromechanical excitation systems at least once every 5 years; and   
(b) test each of its synchronous compensators’ digital excitation systems at least once every 10 years; and  
(c) based on the tests carried out in accordance with paragraphs (a) or (b), provide a verified set of modelling parameters and voltage response data to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test including—

(i) a block diagram showing the mathematical representation of the automatic voltage regulator; and 

(ii) a block diagram showing the mathematical representation of the exciter; and 

(iii) a detailed functional description of the excitation system in all modes of control; and  

(iv) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagrams.

Compare: Electricity Governance Rules 2003 clause 11 appendix B technical code A schedule C3 part C

12 **HVDC link frequency control and protection**

The **HVDC owner** must—

(a) test the operation of each of its **HVDC link’s** analogue **control systems** at least once every 4 years; and  
(b) test the operation of each of its **HVDC link’s** digital **control systems** at least once every 10 years; and  
(c) test the operation of each of its **HVDC link’s** analogue protection systems at least
13 Asset owner a.c. protection systems
Each asset owner must—
(a) test the operation of the analogue protection systems on its a.c. assets at least once every 4 years; and
(b) test the operation of the non-self monitoring digital protection systems on its a.c assets at least once every 4 years; and
(c) test the operation of the self monitoring digital protection systems on its a.c. assets at least once every 10 years; and
(d) test the operation of the protection system measuring circuits on its a.c. assets by secondary injection at least once every 4 years; and
(e) test the operation of the protection system trip circuits, including circuit breaker trips, on its a.c. assets at least once every 4 years; and
(f) confirm at least once every 4 years that its protection settings are identified, co-ordinated, applied correctly and meet the requirements of the AOPOs and the technical codes; and
(g) based on tests carried out in accordance with paragraphs (a) to (e), provide a verification to the system operator in an updated asset capability statement that the protection systems meet the requirements of the AOPOs and technical codes within 3 months of the completion date of each such test; and
(h) based on the confirmation carried out in accordance with paragraph (f), provide an
updated asset capability statement to the system operator within 3 months of the completion date of each such confirmation.

Compare: Electricity Governance Rules 2003 clause 13 appendix B technical code A schedule C3 part C

14 Representative testing

(1) Subject to clause 8(3) of Technical Code A, each asset owner may provide the information required under clauses 3(c), 5(c), and 11(c) to the system operator, based on representative modelling parameters and response data instead of based on the tests required under clauses 3(a) and (b), 5(a) and (b), and 11(a) and (b), for any group of identical assets, if each of those assets—
   (a) was manufactured to the same specification; and
   (b) is installed at the same location; and
   (c) is controlled in the same way; and
   (d) has a similar maintenance history.

(2) Each asset owner providing representative modelling parameters and response data to the system operator in accordance with subclause (1) for a group of identical assets must—
   (a) complete a full set of tests in accordance with clauses 3(a) or (b), 5(a) or (b), and 11(a) or (b), as applicable, on an asset that is representative of that group to derive a verified set of modelling parameters and response data; and
   (b) complete sufficient testing on the remaining assets in that group of identical assets in accordance with clauses 3(a) or (b), 5(a) or (b), and 11(a) or (b), as applicable, to verify that the performance of the remaining assets in that group is fully consistent with the modelling parameters and response data derived from the tests carried out on the representative asset; and
   (c) certify to the system operator, that to the best of the asset owner’s information, knowledge and belief, the performance of that group of assets is fully consistent with the representative modelling parameters and response data provided to the system operator for that group of assets.

Compare: Electricity Governance Rules 2003 clause 14 appendix B technical code A schedule C3 part C

15 Transitional provisions

(1) Unless a test interval of less than 60 months is specified in this Appendix, each asset owner must complete the first of each test required in this Appendix no later than 5 June 2013.

(2) A test that is required to be carried out in accordance with this Appendix, but that an asset owner carried out before 5 June 2008, is deemed to be the first test of that type required in this Appendix, if—
   (a) the asset owner has submitted the relevant written test results to the system operator; and
   (b) the system operator has advised the asset owner that the specification of the test is acceptable; and
   (c) the interval between the actual date of the test and the date on which this Code came into force is less than the maximum test interval specified for the
corresponding test in this Appendix.

(3) If a test has been deemed to be the first test in accordance with subclause (2), the date by which the next such test must be carried out must be calculated using the actual date upon which the first test was carried out, not the date upon which it was deemed to have been carried out.

Compare: Electricity Governance Rules 2003 clause 15 appendix B technical code A schedule C3 part C
Technical Code B – Emergencies

1 Purpose and application
The purpose of this technical code is to set out the basis on which the system operator and participants must anticipate and respond to emergency events on the grid that affect the system operator’s ability to plan to comply, and to comply with its principal performance obligations.

Compare: Electricity Governance Rules 2003 clause 1.1 technical code B schedule C3 part C

2 Application
This technical code applies to all asset owners except for excluded generating stations. If the system operator reasonably considers it necessary to assist the system operator in planning to comply and complying with the principal performance obligations, the system operator may require that an excluded generating station comply with some or all of the requirements of this technical code.

Compare: Electricity Governance Rules 2003 clause 1.2 technical code B schedule C3 part C

3 Obligations of all parties
The system operator and all participants must plan individually and, if appropriate, collectively, for a grid emergency, and act quickly and safely during a grid emergency in accordance with this technical code, so that the actual and potential impacts of any grid emergency are minimised.

Compare: Electricity Governance Rules 2003 clause 2 technical code B schedule C3 part C

4 Obligations of the system operator
The system operator must use reasonable endeavours to ensure that—
(a) if necessary, each participant is advised of any independent action required of it if there is a grid emergency; and
(b) facilities to be put in place by grid owners or other asset owners to manually electrically disconnect demand at each point of connection are specified.

Compare: Electricity Governance Rules 2003 clause 3 technical code B schedule C3 part C

5 Formal notices and responses
(1) The system operator must issue a notice either orally or in writing to relevant participants whenever, or as soon as practicable after, any of the following events has occurred:
(a) the ability of the system operator to plan to comply, and to comply, with the principal performance obligations is at risk or is compromised (as set out in the policy statement);
(b) public safety is at risk;
(c) there is a risk of significant damage to assets;
(d) independent action has been taken in accordance with this technical code to
restore the system operator’s principal performance obligations.

(1A) The system operator must issue a notice in writing to all participants whenever, or as soon as practicable after, an island wide instruction to electrically disconnect demand has been issued, amended, or revoked under clause 6.

(1B) For the purposes of subclause (1A), an island wide instruction is when the electrical or geographical region affected by a notice is all of an island.

(1C) The system operator must provide any notice issued under subclause (1A) to the pricing manager by 0730 hours on the following trading day.

(2) The system operator must ensure that a formal notice issued in accordance with subclause (1) or subclause (1A) includes the following:
(a) the electrical or geographical region affected by the notice:
(b) the potential consequences of the situation:
(c) the responses requested of participants:
(d) the start time and end time of the situation to which the notice applies.

(3) The system operator must record the issue of a formal notice, and each participant must record receipt of a formal notice.

(4) If the system operator issues a request in accordance with this technical code to a participant, the participant must use reasonable endeavours to respond to the request.

6 Actions to be taken by the system operator in a grid emergency

(1) If insufficient generation and frequency keeping gives rise to a grid emergency, the system operator may, having regard to the priority below, if practicable, and regardless of whether a formal notice has been issued, do 1 or more of the following:
(a) request that a generator varies its offer and dispatch the generator in accordance with that offer, to ensure there is sufficient generation and frequency keeping:
(b) request that a purchaser or a connected asset owner reduce demand:
(c) require a grid owner to reconfigure the grid:
(d) require the electrical disconnection of demand in accordance with clause 7A:
(e) take any other reasonable action to alleviate the grid emergency.

(2) If insufficient transmission capacity gives rise to a grid emergency, the system operator may, having regard to the priority below, if practicable, and regardless of whether a formal notice has been issued, do 1 or more of the following:
(a) request that a generator varies its offer and dispatch the generator in accordance with that offer, to ensure that the available transmission capacity
within the grid is sufficient to transmit the remaining level of demand:

(b) request that an asset owner restores its assets that are not in service:
(c) request that a purchaser or connected asset owner reduces its demand:
(d) require the electrical disconnection of demand in accordance with clause 7A:
(e) take any other reasonable action to alleviate the grid emergency.

(3) If frequency is outside the normal band and all available injection has been dispatched, the system operator may require the electrical disconnection of demand in accordance with clause 7A in appropriate block sizes until frequency is restored to the normal band.

(4) If any grid voltage reaches the minimum voltage limit set out in the table contained in clause 8.22(1), and is sustained at or below that limit, the system operator may require the electrical disconnection of demand in accordance with clause 7A in appropriate block sizes until the voltage is restored to above the minimum voltage limit.

(5) The system operator may, if an unexpected event occurs giving rise to a grid emergency, take any reasonable action to alleviate the grid emergency.

Compare: Electricity Governance Rules 2003 clause 5 technical code B schedule C3 part C

7 Extended reserve providers to provide extended reserve

(1) Each extended reserve provider must provide extended reserve at all times in accordance with its current statement of extended reserve obligations issued by the system operator under clause 8.54P.

(2) An extended reserve provider must give written notice to the system operator as soon as practicable if the extended reserve provider is unable to comply with subclause (1).

Compare: Electricity Governance Rules 2003 clause 6 technical code B schedule C3 part C
Clause 7(9A) and (9B): inserted, from 3 January 2013 to 2 October 2013, by clause 4(a) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2012.
Clause 7(9A) and (9B): inserted, on 2 October 2013, by clause 4(a) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2013.
Clause 7(9A) and (9B): revoked, on 3 April 2014, by clause 5(a) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2013.


Clause 7(12A) and (12B): revoked, on 3 April 2014, by clause 5(d) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2013.

Clause 7(12A) and (12B): substituted, from 3 January 2013 to 2 October 2013, by clause 4(g) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2012.

Clause 7(12A) and (12B): substituted, on 2 October 2013, by clause 4(g) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2013.

Clause 7(12A) and (12B): revoked on 3 April 2014, by clause 5(g) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2013.


Clause 7(16A) and (16B): inserted, from 3 January 2013 to 2 October 2013, by clause 4(g) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2012.

Clause 7(16A) and (16B): inserted, on 2 October 2013, by clause 4(g) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2013.

Clause 7(16A) and (16B): revoked on 3 April 2014, by clause 5(g) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2013.

7A Emergency load shedding

(1) Each connected asset owner must maintain a process for electrical disconnection of demand for points of connection.

(2) The process must specify the participant that will effect the electrical disconnection of demand.

(3) The connected asset owner must obtain agreement for the process from the system operator and each grid owner.

(4) Each connected asset owner must advise the system operator of the agreed process in addition to any changes to a process previously advised.

(5) If the system operator requires the electrical disconnection of demand under this technical code, the system operator must instruct connected asset owners and grid owners in accordance with the agreed process under subclause (3) to electrically disconnect demand for the relevant point of connection.

(6) If the system operator and a connected asset owner or grid owner have not agreed on a process for electrical disconnection of demand at a point of connection, the system
operator must instruct grid owners to electrically disconnect demand directly at the relevant point of connection.

(7) To the extent practicable, the system operator must use reasonable endeavours when instructing the electrical disconnection of demand to ensure equity between connected asset owners.

(8) Each connected asset owner or grid owner must act as instructed by the system operator operating under clause 6.


7B Obligations of extended reserve providers in relation to automatic under-frequency load shedding

(1) On the operation of extended reserve that is an automatic under-frequency load shedding system, an extended reserve provider—
   (a) must, as soon as practicable, advise the system operator of the operation of the automatic under-frequency load shedding system and, if reasonably required by the system operator to plan to comply, or to comply, with its principal performance obligations, a reasonable estimate of the amount of demand that has been electrically disconnected; and
   (b) may electrically connect demand only when permitted to do so by the system operator; and
   (c) must ensure demand electrically connected under paragraph (b) complies with the obligations in its statement of extended reserve obligations; and
   (d) must report to the system operator if demand is moved between points of connection; and
   (e) may request permission to electrically connect demand from the system operator if no instruction to electrically connect demand is received from the system operator within 15 minutes of the frequency returning to the normal band; and
   (f) may cautiously and gradually electrically connect the demand electrically disconnected through the automatic under-frequency load shedding system if there is a loss of communication with the system operator, 15 minutes after the loss of communication occurred.

(2) An extended reserve provider may electrically connect demand only while frequency is within the normal band and voltage is within the required range.

(3) Each extended reserve provider must immediately cease the electrical connection of demand and, to the extent necessary, electrically disconnect demand, if the frequency drops below the normal band or the voltage moves outside the required range.

(4) As soon as practicable after communications are restored, each extended reserve provider must report to the system operator on the status of electrical connection of load and the status of re-arming the automatic under-frequency load shedding system.
Clause 7B: inserted, on 7 August 2014, by clause 21 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

Clause 7C: Obligations of extended reserve providers in security of supply situations

(1) This clause applies if a direction under clause 9.15 is in force.

(2) The system operator may give notice to 1 or more of the participants specified in subclause (5), specifying modifications to the participant's statement of extended reserve obligations during any 1 or more periods, or in any 1 or more circumstances, specified in the notice.

(3) The system operator must keep a record of each notice given under subclause (2).

(4) When a notice under subclause (2) is in force in relation to a participant, the requirements of the participant's statement of extended reserve obligations are modified for that participant to the extent, and during the periods or in the circumstances (as the case may be), specified in the notice.

(5) The participants to whom the system operator may issue a notice in accordance with subclause (2) are—
   (a) connected asset owners in the North Island; and
   (b) grid owners in the South Island.

(6) The system operator may amend or revoke a notice, or revoke and substitute a new notice.

(7) A notice under subclause (2) expires on the earlier of—
   (a) the date (if any) specified in the notice for its expiry; and
   (b) the revocation or expiry of the direction referred to in subclause (1).

Clause 7C: inserted, on 7 August 2014, by clause 21 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

Clause 8: Obligations of grid owners

(1) A grid owner must use reasonable endeavours to ensure that appropriate assets are installed for the manual electrical disconnection of demand at points of connection.

(2) A grid owner must take independent action as may be required by the system operator in accordance with clause 6(4), to electrically disconnect demand at points of connection when any grid voltage reaches the minimum voltage limit set out in the table contained in clause 8.22(1) and is sustained at or below that level. A grid owner must continue to electrically disconnect demand at points of connection while the voltage remains below that minimum voltage limit, being guided by any arrangements with connected asset owners as advised by the system operator.

Compare: Electricity Governance Rules 2003 clause 7 technical code B schedule C3 part C
Clause 8(1) and (2): amended, on 5 October 2017, by clause 128(1) and (2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
9 Obligations of generators and ancillary service agents to take independent action

The following independent action is required of generators and ancillary service agents during the occurrence of extreme variations of frequency or voltage at the points of connection to which their assets are connected (such extreme levels of frequency or voltage are deemed to constitute a grid emergency and require a fast and independent response from each generator and each ancillary service agent):

(a) when the under-frequency limit is reached and the frequency continues to fall, each generator must use reasonable endeavours to take the following immediate independent action to assist in restoring frequency:
   (i) increase the energy injection from each generating unit that is physically capable of increasing such injection:
   (ii) attempt to restore grid frequency to the normal band by synchronising and loading each generating unit that is not electrically connected but is able to be electrically connected and operated in this manner:
   (iii) re-synchronise and load each generating unit that has tripped and is able to be electrically connected and operated in this manner:
   (iv) report to the system operator as soon as practicable after taking action in accordance with subparagraphs (i) to (iii):

(b) when the over frequency limit is reached and the frequency continues to rise, each generator must use reasonable endeavours to take the following immediate independent action to assist in restoring frequency:
   (i) decrease the energy injection from electrically connected generating units if the generator is physically capable of decreasing such injection:
   (ii) report to the system operator as soon as practicable after taking action in accordance with subparagraph (i):

(c) when either the minimum voltage limit or the maximum voltage limit set out in the table contained in clause 8.22(1) is exceeded at any point of connection, generators and ancillary service agents must use reasonable endeavours to take immediate independent action to return the voltage to, as close as practicable, within such limits. Each generator must use reasonable endeavours to synchronise and, as necessary, load and adjust all available generating units that can assist in restoring the voltage. Ancillary service agents must also use reasonable endeavours to electrically connect to the grid and, as necessary, load all available reactive capability resources, that can assist in restoring the voltage. As soon as practicable after taking such actions, each generator and ancillary service agent must report to the system operator on the action taken to correct voltage:

(d) for a loss of communication with the system operator, lasting at least 5 minutes, each generator must use reasonable endeavours to—
   (i) for synchronised generating units, take independent action to adjust supply to maintain frequency as close as possible to the normal band, and maintain voltage as close as possible either to that previously advised by the system operator, or as can be best established by the generator; and
(ii) **synchronise** available **generating units** to the **grid** if the **generating units** currently **electrically connected** do not have the capacity to control the frequency and voltage as required by paragraph (e)(i); and

(iii) continue to attempt to maintain the frequency and voltage to meet the requirements of paragraph (e)(i); and

(iv) as soon as practicable after communications are restored, report to the **system operator** on the action taken:

(e) for a **loss of communication** with the **system operator** lasting at least 5 minutes, **ancillary service agents** must use reasonable endeavours to—

(i) if on load, take independent action to adjust any real or **reactive power** resources to maintain frequency and voltage as close as possible either to that previously advised by the **system operator** or as can be best established by the **ancillary service agent**; and

(ii) **electrically connect** available **reactive capability** resources to the **grid** if the currently **electrically connected reactive power** resources do not have the capacity to control the voltage above the minimum limit set out in the table contained in clause 8.22(1); and

(iii) continue to attempt to maintain the voltage above the minimum limit set out in the table contained in clause 8.22(1); and

(iv) as soon as practicable after communications are restored, report to the **system operator** on the action taken:

(f) in the event of a failure at the **system operator’s** operational centre that disables the main **dispatch** or communication systems, the **system operator** may temporarily transfer its operational activities to an alternative operational centre, and the **system operator** must arrange for communication facilities to transfer to the new location and must give written notice to **participants** of those arrangements.

Compare: Electricity Governance Rules 2003 clause 8 technical code B schedule C3 part C
Technical Code C – Operational communications

1 Purpose
The purpose of this technical code is to state the minimum requirements for the communications required under this Code between asset owners, except owners of excluded generating stations, and the system operator, in order to assist the system operator to plan to comply, and to comply, with the principal performance obligations. Additional requirements may be set out in other clauses. This technical code does not deal with the content of communications, which is dealt with in each technical code and in Part 13 where relevant.

Compare: Electricity Governance Rules 2003 clause 1.1 technical code C schedule C3 part C

2 Application
This technical code applies to the system operator and to all asset owners except owners of excluded generating stations. If the system operator reasonably considers it necessary to assist the system operator in planning to comply, and complying, with the principal performance obligations, the system operator may require that an excluded generating station comply with some or all of the requirements of this technical code.

Compare: Electricity Governance Rules 2003 clause 1.2 technical code C schedule C3 part C

3 General requirements for operational communications
(1) Each voice or electronic communication between the system operator and an asset owner must be logged by the system operator and the asset owner. Unless otherwise agreed between the system operator and the asset owner, every voice instruction must be repeated back by the person receiving the instruction and confirmed by the person giving the instruction before the instruction is actioned.

(2) The system operator and each asset owner must nominate and advise each other of the preferred points of contact and the alternative points of contact to be used by the system operator and the asset owner. Each asset owner must also nominate and advise the system operator of the person to receive instructions and formal notices as set out in Technical Code B. The preferred points of contact must include those to be used when the system operator instructs the asset owner, when the system operator sends formal notices to the asset owner and when the asset owner contacts the system operator. The alternative points of contact must be used only if the preferred points of contact are not available.

(3) The grid owner and each other asset owner must nominate and advise each other of the preferred points of contact and the alternative points of contact to be used by the grid owner and the other asset owner for the purpose of communications regarding the availability of the grid owner’s data transmission communications. The alternative points of contact must only be used if the preferred points of contact are not available.

Compare: Electricity Governance Rules 2003 clause 2 technical code C schedule C3 part C
4 Specific requirements for voice communication

(1) Each asset owner must have in place a primary means of communicating by voice between the control room of the asset owner and the system operator. The primary means of voice communication must use either—
(a) the grid owner’s speech network; or
(b) a widely available public switched telephone network that operates in real time and in full duplex mode.

(2) Each asset owner must have in place a backup means of communicating by voice between the control room of the asset owner and the system operator. The backup means of voice communication—
(a) must be approved by the system operator (such approval not to be unreasonably withheld); and
(b) may include, but is not limited to, satellite phone or cellular phone; and
(c) may be used only if the primary means of voice communication described in subclause (1) is unavailable or otherwise with the agreement of the system operator.

(3) An asset owner who has a control room with, at any time, operational control of more than 299 MW of injection, offtake, or power flow must have 2 or more backup means of voice communication between the control room of the asset owner and the system operator, each of which must meet the requirements of subclause (2).

Compare: Electricity Governance Rules 2003 clause 3 technical code C schedule C3 part C

5 Specific requirements for transmitting information

(1) Each asset owner must transmit information between its control room and the system operator in writing.

(2) Despite subclause (1), an asset owner may request the system operator to approve an alternative means of transmitting information (such approval not to be unreasonably withheld).

(3) Each asset owner must have in place a backup means of transmitting information. The backup means of transmitting information—
(a) must be approved by the system operator (such approval not to be unreasonably withheld); and
(b) may include, but is not limited to, voice communication or email; and
(c) may only be used if the primary means of transmitting information described in subclause (1) or (2) is unavailable or otherwise with the agreement of the system operator.

Compare: Electricity Governance Rules 2003 clause 4 technical code C schedule C3 part C

Clause 5(2) and (3): amended, on 5 October 2017, by clause 130(3) and (4) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
6 Specific requirements for data transmission communication
(1) Each asset owner (other than a grid owner) must have in place—
   (a) a primary means of transmitting data between the assets of the asset owner and a SCADA remote terminal unit of a grid owner; or
   (b) if approved by the system operator (such approval not to be unreasonably withheld), a primary means of transmitting data between the assets of the asset owner and the system operator.
(2) A grid owner must have in place a primary means of transmitting data between the assets of the grid owner and the system operator.
(3) Each asset owner must have in place a backup means of transmitting data for each type of indication and measurement specified in Appendix A of this technical code. The backup means of data transmission communication—
   (a) must be approved by the system operator (such approval not to be unreasonably withheld); and
   (b) may include, but is not limited to, use of voice communication or document transmission communication; and
   (c) may only be used if the primary means of data transmission communication described in subclause (1) or (2) is unavailable or otherwise with the agreement of the system operator.

Compare: Electricity Governance Rules 2003 clause 5 technical code C schedule C3 part C

7 Availability of primary means of communication
(1) Each asset owner must use reasonable endeavours to ensure that the primary means of communication described in clauses 4(1), 5(1) or (2), and 6(1) or (2) is available continuously.
(2) If the primary means of communication described in clauses 4(1), 5(1) or (2), and 6(1) or (2) is unavailable, an asset owner must use reasonable endeavours to restore availability of the primary means of communication as soon as practicable.

Compare: Electricity Governance Rules 2003 clause 6 technical code C schedule C3 part C

8 Notice of planned outages of primary means of communication
Each asset owner must give written notice to the system operator of any planned outage of a primary means of communication described in clauses 4(1), 5(1) or (2), and 6(1) or (2).

Compare: Electricity Governance Rules 2003 clause 7 technical code C schedule C3 part C

9 Performance requirements for indications and measurements
(1) Each asset owner must provide the relevant indications and measurements shown in Appendix A to the system operator, in accordance with clause 6. The system operator may require the asset owner to provide additional information if, in the reasonable opinion of the system operator, such information is required for the system operator to plan to comply, and to comply, with its principal performance obligations.
(2) The asset owner must use reasonable endeavours to ensure that the accuracy of the measurements it provides to the system operator in accordance with subclause (1) complies with Appendix A.

(3) Each indication and measurement provided in accordance with subclause (1) must be updated at the grid owner’s SCADA remote terminal or the system operator’s interface unit at least once every 8 seconds when provided by the primary means of data transmission communications.

Compare: Electricity Governance Rules 2003 clause 8 technical code C schedule C3 part C
Appendix A: Indications and Measurements
(Clause 9(1)-(3) of Technical Code C)

Table A1: Requirements of generators

Each generator must provide the indications and measurements in Table A1. If net (or gross) measurements are required in Table A1, the use of scaling factors together with the provision of the relevant gross (or net) values is acceptable with the system operator’s approval. Each generator must provide scaling factors to the grid owner so that the grid owner can apply the adjustment at the SCADA server.

<table>
<thead>
<tr>
<th>Indication or measurement</th>
<th>Values required</th>
<th>Accuracy³</th>
</tr>
</thead>
<tbody>
<tr>
<td>Station net MW</td>
<td>Import and export</td>
<td>±2%</td>
</tr>
<tr>
<td>Generating unit gross MW¹</td>
<td>Import and export, for each generating unit</td>
<td>±2%</td>
</tr>
<tr>
<td>Station net Mvar</td>
<td>Import and export</td>
<td>±2%</td>
</tr>
<tr>
<td>Generating unit gross Mvar¹</td>
<td>Import and export, for each generating unit</td>
<td>±2%</td>
</tr>
<tr>
<td>Generating unit circuit breaker status¹</td>
<td>Open /closed /in transition/ indication error²</td>
<td>N/A</td>
</tr>
<tr>
<td>Grid interface circuit breaker status</td>
<td>Open /closed /in transition/ indication error²</td>
<td>N/A</td>
</tr>
<tr>
<td>Grid interface disconnector status</td>
<td>Open /closed /in transition/ indication error</td>
<td>N/A</td>
</tr>
<tr>
<td>Special protection scheme status</td>
<td>Enabled/disabled/summer/winter</td>
<td>N/A</td>
</tr>
<tr>
<td>Maximum output capacity of generating station (for intermittent generators only)</td>
<td>Number of connected generating units × MW capability of each generating unit</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Comparative notes:
- Table A1 amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Table A2: Requirements of grid owners:

Each grid owner must provide the indications and measurements shown in Table A2 in respect of assets connected to, or forming part of, the grid.

<table>
<thead>
<tr>
<th>Indication or measurement</th>
<th>Values required</th>
<th>Accuracy³</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid interface circuit breaker status</td>
<td>Open /closed /in transition/ indication error²</td>
<td>N/A</td>
</tr>
<tr>
<td>Grid interface disconnector status</td>
<td>Open/ closed/ in transition/ closed to earth/ indication error</td>
<td>N/A</td>
</tr>
<tr>
<td>Grid interface auto reclose status</td>
<td>Enabled/disabled/ operated/locked out</td>
<td>N/A</td>
</tr>
<tr>
<td>Grid interface MW</td>
<td>Import and export</td>
<td>±2%</td>
</tr>
<tr>
<td>Indication or measurement</td>
<td>Values required</td>
<td>Accuracy^3</td>
</tr>
<tr>
<td>---------------------------------------------------------------</td>
<td>------------------------------------------------------</td>
<td>------------</td>
</tr>
<tr>
<td><strong>Grid interface</strong> Mvar</td>
<td>Import and export</td>
<td>±2%</td>
</tr>
<tr>
<td>Circuit Amps</td>
<td>Current at each termination point of a circuit</td>
<td>N/A</td>
</tr>
<tr>
<td>Circuit MW</td>
<td>MW at each termination point of a circuit</td>
<td>N/A</td>
</tr>
<tr>
<td>Circuit Mvar</td>
<td>Mvar at each termination point of a circuit</td>
<td>N/A</td>
</tr>
<tr>
<td><strong>Special protection scheme</strong> status</td>
<td>Enabled/disabled/summer/winter</td>
<td>N/A</td>
</tr>
<tr>
<td>Tap positions for <strong>interconnecting transformers</strong> and supply transformers with on-load tap changers</td>
<td>Tap position for all windings including tapped tertiaries</td>
<td>N/A</td>
</tr>
<tr>
<td>Tap positions for <strong>interconnecting transformers</strong> and supply transformers with off-load tap changers^4</td>
<td>Tap position for all windings including tapped tertiaries</td>
<td>N/A</td>
</tr>
<tr>
<td>Reactive plant (eg RPC equipment, capacitor, reactor, condenser) Mvar</td>
<td>Import and export</td>
<td>±2%</td>
</tr>
<tr>
<td>Bus voltage</td>
<td>kV</td>
<td>±2%</td>
</tr>
<tr>
<td><strong>Special protection scheme</strong> status</td>
<td>Enabled/disabled/summer/winter</td>
<td>N/A</td>
</tr>
<tr>
<td>HVDC modulation status</td>
<td>Frequency stabiliser/ spinning reserve sharing/ Haywards frequency control/ AC transient voltage support</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Compare: Electricity Governance Rules 2003 table A2 appendix A technical code C schedule C3 part C
Table A2: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

**Table A3: Requirements of connected asset owners**

Each **connected asset owner** must provide the indications and measurements shown in Table A3 in respect of **assets** connected to, or forming part of, the **grid**.

<table>
<thead>
<tr>
<th>Indication or measurement</th>
<th>Values required</th>
<th>Accuracy^3</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Grid interface circuit breaker</strong> status</td>
<td>Open/ closed/ in transition/ indication error^2</td>
<td>N/A</td>
</tr>
<tr>
<td><strong>Grid interface</strong> disconnector status</td>
<td>Open/ closed/ in transition/ indication error</td>
<td>N/A</td>
</tr>
<tr>
<td><strong>Grid interface</strong> auto reclose status</td>
<td>Enabled/disabled/operated/locked out</td>
<td>N/A</td>
</tr>
<tr>
<td><strong>Special protection scheme</strong> status</td>
<td>Enabled/disabled/summer/winter</td>
<td>N/A</td>
</tr>
<tr>
<td>Reactive plant^5 (eg RPC equipment, capacitor, reactor, condenser) Mvar</td>
<td>Import and export</td>
<td>±2%</td>
</tr>
</tbody>
</table>

Table A3 Heading: amended, on 1 February 2016, by clause 23(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.
Table A3: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Table A3: amended, on 1 February 2016, by clause 23(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

1 Required only if a **generating unit** has a maximum continuous rating of greater than 5 MW.

2 No intentional time delays should be included for **circuit breaker** indications as these are time tagged by the **system operator** to less than 10 ms.

3 If accuracy is measured at the input terminal of the RTU of the **grid owner**, under normal operating conditions at full scale.

4 Indication required within 5 minutes of status change.

5 Required only if reactive plant has a maximum continuous rating of greater than 5 Mvar.

Compare: Electricity Governance Rules 2003 table A3 appendix A technical code C schedule C3 part C
Technical Code D – Co-ordination of outages affecting common quality

1 Purpose
The purpose of this technical code is to set out the obligations of asset owners to give written notice of planned outages of assets that affect common quality, and to set out the obligations of the system operator in relation to outage co-ordination and the provision of timely advice to asset owners on the security implications of notified planned outages.

2 Notice of planned outages
(1) Each asset owner must, in relation to each of its assets, give written notice to the system operator as soon as practicable of all planned outages of such assets if such outages may impact on the system operator’s ability to plan to comply, and to comply, with the principal performance obligations.

(2) If the asset owner is unsure whether an outage of an asset may impact on the system operator’s ability to plan to comply, and to comply, with the principal performance obligations, the asset owner must contact the system operator for advice.

(3) Each asset owner must give written notice to the system operator up to 12 months ahead of planned outages and update the system operator of changes to the planned outages as and when the asset owner becomes aware of them.

3 Assessment of notified planned outages
The system operator must assess all notified planned outages and the extent to which they impact on the system operator’s ability to plan to comply, and to comply with the principal performance obligations.

4 Assets may be requested to remain in service
The system operator may request that an asset owner of assets that are the subject of a notified planned outage keep those assets in service until a more suitable time, if such outage would, in the reasonable opinion of the system operator, adversely affect the system operator’s ability to plan to comply, and to comply, with the principal performance obligations. The system operator may propose a suitable alternative time for the notified planned outage.

5 Asset owners to assist security
(1) An asset owner must endeavour to programme its notified planned outage at a time when there will be no disruption to the system operator’s ability to plan to comply, and...
6 Asset outage programme
The system operator must regularly publish an asset outage programme containing all notified planned outage information provided by the asset owners.
Compare: Electricity Governance Rules 2003 clause 6 technical code D schedule C3 part C

7 Assets may be requested to return to service
The system operator may request an asset owner to terminate a notified planned outage in progress within a pre-arranged period so that assets that are the subject of the notified planned outage can be returned to service to support the system operator in planning to comply, and in complying, with the principal performance obligations.
Compare: Electricity Governance Rules 2003 clause 7 technical code D schedule C3 part C
Schedule 8.4

[Revoked]

Compare: Electricity Governance Rules 2003 schedule C6 part C
Schedule 8.4: revoked, on 19 May 2016, by clause 30 of the Electricity Industry Participation Code Amendment (System Operator and Alignment with Statutory Objective) 2016.
Schedule 8.5

Consultation and approval requirements for extended reserve procurement documents

Part 1

Consultation on extended reserve technical requirements schedule

1 Application of this Part
This Part sets out the consultation requirements that apply to the extended reserve technical requirements schedule.

2 Publication of extended reserve technical requirements schedule
(1) The system operator must prepare a draft of the extended reserve technical requirements schedule.
(2) The system operator must give the draft schedule to the Authority for comment, along with the extended reserve technical requirements report.
(3) The Authority must provide comments on the draft schedule to the system operator as soon as practicable after receiving it.
(4) The system operator must consider the Authority's comments.
(5) After the system operator has considered the Authority's comments, the system operator must—
   (a) consult with persons that the system operator thinks are representative of the interests of persons likely to be substantially affected by the draft schedule; and
   (b) consider submissions made on the draft schedule.
(6) The system operator must give a copy of each submission made to it and a copy of the draft schedule that the system operator proposes to publish to the Authority.
(7) The Authority must provide comments on the draft schedule as soon as practicable after receiving it.
(8) The system operator must consider the Authority's comments.
(9) Following the consultation required by this clause, the system operator must finalise and publish the draft schedule.

3 Technical and non-controversial changes
(1) The system operator may at any time make a change to the extended reserve technical requirements schedule that it considers is technical and non-controversial.
(2) If the system operator makes a change to the extended reserve technical requirements schedule under subclause (1), the system operator is not required to comply with clause 2 of this Schedule.
(3) The system operator must give written notice to the Authority of any changes to the extended reserve technical requirements schedule made under this clause.

Part 2
Consultation on extended reserve selection methodology

4 Application of this Part
This Part sets out the consultation and approval requirements that apply to the extended reserve selection methodology.

5 Preparation of and consultation on extended reserve selection methodology
(1) The extended reserve manager must prepare a draft of the extended reserve selection methodology.
(2) The extended reserve manager must give the draft methodology to the Authority and the system operator for comment, along with one or more worked examples of an extended reserve procurement schedule, created using—
   (a) the draft extended reserve selection methodology; and
   (b) data specified by the system operator.
(3) The Authority and the system operator must provide comments on the draft methodology to the extended reserve manager as soon as practicable after receiving it.
(4) The extended reserve manager must consider the comments provided by the Authority and the system operator.
(5) After the extended reserve manager has considered the comments provided by the Authority and the system operator, the extended reserve manager must—
   (a) consult with persons that the extended reserve manager thinks are representative of the interests of persons likely to be substantially affected by the draft methodology; and
   (b) consider submissions made on the draft methodology.

6 Approval of extended reserve selection methodology
(1) The extended reserve manager must give the Authority and the system operator—
   (a) a copy of each submission made on the draft extended reserve selection methodology; and
   (b) a response to each issue raised in each submission; and
   (c) a copy of the draft methodology that the extended reserve manager proposes to publish.
(2) As soon as practicable, but no later than 15 business days after receiving a copy of the draft methodology, the system operator must—
   (a) give the Authority any comments it wishes to make on the draft methodology; or
   (b) advise the Authority that it does not wish to make any comments.
(3) As soon as practicable after receiving the system operator's comments, or advice that the system operator does not wish to make any comments, the Authority must, by notice in writing to the extended reserve manager and the system operator,—
   (a) approve the draft methodology; or
(b) decline to approve the draft methodology.

(4) If the Authority declines to approve the draft methodology, the Authority must either—

(a) publish the changes that the Authority wishes the extended reserve manager to make to the draft methodology; or

(b) require the extended reserve manager to prepare a new draft methodology.


7 Consultation on proposed changes

(1) When the Authority publishes changes that the Authority wishes the extended reserve manager to make to the draft extended reserve selection methodology under clause 6(4), the Authority must advise the extended reserve manager and interested parties of the date by which submissions on the changes must be made to the Authority.

(2) Each submission on the changes to the draft methodology must be made in writing to the Authority and be received by the date specified by the Authority.

(3) The Authority must—

(a) give a copy of each submission made to the extended reserve manager; and

(b) publish the submissions.

(4) The extended reserve manager may make its own submission on the changes to the draft methodology and the submissions made in relation to the changes.

(5) The Authority must publish the extended reserve manager's submission when it is received.

(6) The Authority must consider the submissions made to it on the changes to the draft methodology and prepare a revised draft methodology incorporating any amendments that the Authority proposes be made to the methodology.

(7) The Authority must give the revised draft methodology prepared under subclause (6) to the system operator, and clause 6(2) applies as if the revised draft methodology was the draft methodology prepared under clause 5.

(8) As soon as practicable after receiving the system operator's comments, or advice that the system operator does not wish to make any comments, the Authority must,—

(a) by notice in writing to the extended reserve manager and the system operator,—

(i) approve the revised draft methodology; or

(ii) amend the revised draft methodology to address any comments received from the system operator, and approve it; or

(b) publish a further revised draft methodology, and advise the extended reserve manager and interested parties of the date by which submissions on the changes must be made to the Authority.

(9) If the Authority publishes a further revised draft methodology under subclause (8)(b), subclauses (2) to (8) apply as if the further revised draft methodology was the revised draft methodology.

8 Technical and non-controversial changes

(1) The extended reserve manager may at any time propose a change to the extended reserve selection methodology that it considers is technical and non-controversial by giving a draft methodology to the Authority together with an explanation of the proposed change.

(2) If the extended reserve manager gives a draft methodology to the Authority under subclause (1) the extended reserve manager is not required to comply with clauses 5 and 6 of this Schedule.

(3) The Authority must give written notice to the system operator of any proposed change to the extended reserve selection methodology that it receives under subclause (1).

(4) The Authority must, as soon as practicable after receiving a draft methodology and the information required by subclause (1), by notice in writing to the extended reserve manager and the system operator—

(a) approve the draft methodology; or

(b) decline to approve the draft methodology, giving reasons.


9 Publication of extended reserve selection methodology

As soon as practicable after the Authority approves the extended reserve selection methodology under clause 6(3)(a), 7(8)(a), or 8(4)(a), the extended reserve manager must publish the methodology.


Part 3

Consultation on extended reserve procurement schedule

10 Application of this Part

This sets out the consultation and approval requirements that apply to the extended reserve procurement schedule.

11 Preparation of and consultation on extended reserve procurement schedule

(1) The extended reserve manager must prepare a draft of the extended reserve procurement schedule.

(2) The extended reserve manager must—

(a) give the draft to the Authority and the system operator for comment; and

(b) if requested, give the Authority or the system operator the information used by the extended reserve manager to prepare the draft.
(3) The Authority and the system operator must provide comments on the draft procurement schedule to the extended reserve manager as soon as practicable after receiving it.

(4) The extended reserve manager must consider the comments provided by the Authority and the system operator.

(5) After the extended reserve manager has considered the comments provided by the Authority and the system operator, the extended reserve manager must—
   (a) consult with persons that the extended reserve manager thinks are representative of the interests of persons likely to be substantially affected by the draft procurement schedule; and
   (b) consider submissions made on the draft procurement schedule.

12 Approval of extended reserve procurement schedule

(1) The extended reserve manager must give the Authority and the system operator—
   (a) a copy of each submission made on the draft extended reserve procurement schedule; and
   (b) a response to each issue raised by each submission; and
   (c) a copy of the draft procurement schedule that the extended reserve manager proposes to publish.

(2) As soon as practicable, but no later than 15 business days after receiving a copy of the draft procurement schedule, the system operator must—
   (a) give the Authority any comments it wishes to make on the draft procurement schedule; or
   (b) advise the Authority that it does not wish to make any comments.

(3) As soon as practicable after receiving the system operator's comments, or advice that the system operator does not wish to make any comments, the Authority must, by notice in writing to the extended reserve manager and the system operator,—
   (a) approve the draft procurement schedule; or
   (b) decline to approve the draft procurement schedule.

(4) If the Authority declines to approve the draft procurement schedule, the Authority must either—
   (a) publish the changes that the Authority wishes the extended reserve manager to make to the draft procurement schedule; or
   (b) require the extended reserve manager to prepare a new draft procurement schedule.


13 Consultation on proposed changes

(1) When the Authority publishes changes that the Authority wishes the extended reserve manager to make to the draft extended reserve procurement schedule under clause 12(4), the Authority must advise the extended reserve manager and interested parties of the date by which submissions on the changes must be made to the Authority.

(2) Each submission on the changes to the draft procurement schedule must be made in
writing to the Authority and be made by the date advised by the Authority.

(3) The Authority must—
(a) give a copy of each submission made to the extended reserve manager; and
(b) publish the submissions.

(4) The extended reserve manager may make its own submission on the changes to the draft procurement schedule and the submissions made in relation to the changes.

(5) The Authority must publish the extended reserve manager's submission when it is received.

(6) The Authority must consider the submissions made to it on the changes to the draft procurement schedule and prepare a revised draft procurement schedule incorporating any amendments that the Authority proposes be made to the schedule.

(7) The Authority must give the revised draft procurement schedule prepared under subclause (6) to the system operator, and clause 12(2) applies as if the revised draft procurement schedule was the draft procurement schedule prepared under clause 11.

(8) As soon as practicable after receiving the system operator's comments, or advice that the system operator does not wish to make any comments, the Authority must,—
(a) by notice in writing to the extended reserve manager and the system operator,—
   (i) approve the revised draft procurement schedule; or
   (ii) amend the revised draft procurement schedule to address any comments received from the system operator, and approve it; or
(b) publish a further revised draft procurement schedule, and advise the extended reserve manager and interested parties of the date by which submissions on the changes must be made to the Authority.

(9) If the Authority publishes a further revised draft procurement schedule under subclause (8)(b), subclauses (2) to (8) apply as if the further revised draft procurement schedule was the revised procurement schedule.

Clause 13(1) and (8)(b): amended, on 19 December 2014, by clause 19(1) of the Electricity Industry Participation Code Amendment (Minor Code Amendments) (No 3) 2014.

14 Publication of extended reserve procurement schedule
As soon as practicable after the Authority approves the extended reserve procurement schedule under clause 12(3)(a) or 13(8)(a), the extended reserve manager must publish the schedule.

Schedule 8.5: inserted, on 7 August 2014, by clause 22 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.
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Part 9
Security of supply

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Subpart 1—Planning for shortage of supply situations

9.1 Purpose

The purpose of this subpart and subpart 2 is to provide for the management and co-ordination of planned outages as an emergency measure during energy shortages.

Compare: SR 2008/252 r 3

System operator rolling outage plan

9.2 System operator must prepare and publish system operator rolling outage plan

(1) The system operator must prepare and publish a system operator rolling outage plan.

(2) Before publishing a system operator rolling outage plan the system operator must submit to the Authority for approval a draft system operator rolling outage plan.

(3) Clause 7.5(3) to (11) applies to the approval of the system operator rolling outage plan by the Authority as if references to the security of supply forecasting and information policy and the emergency management policy were a reference to the system operator rolling outage plan.

Compare: SR 2008/252 r 5

9.3 Incorporation of system operator rolling outage plan by reference

(1) The system operator rolling outage plan is incorporated by reference in this Code in accordance with section 32 of the Act.

(2) Subclause (1) is subject to Schedule 1 of the Act, which includes a requirement that the Authority must give notice in the Gazette before an amended or substituted system operator rolling outage plan becomes incorporated by reference in this Code.

9.4 Contents of system operator rolling outage plan
A system operator rolling outage plan must—
(a) describe events that the system operator predicts will be likely to give rise to the need to make a supply shortage declaration; and
(b) set out thresholds that the system operator will apply in deciding whether to make a supply shortage declaration; and
(c) specify how the system operator intends to determine what directions to give to address the shortage of electricity supply or transmission capacity that gives rise to the declaration; and
(d) identify specified participants, or a class or classes of specified participants, who are required to develop participant rolling outage plans under clauses 9.6 to 9.13; and
(e) specify criteria, methodologies, and principles to be applied in implementing outages, or taking any other action, to be provided for in participant rolling outage plans; and
(f) specify criteria, methodologies, and principles to be applied by any specified participant who does not have an approved participant rolling outage plan in implementing outages, or taking any other action, in accordance with directions given by the system operator under clause 9.15.

Compare: SR 2008/252 r 6

9.5 Amendments and substitutions of system operator rolling outage plans
(1) The system operator may—
(a) amend a system operator rolling outage plan; or
(b) revoke a system operator rolling outage plan and substitute a new plan.
(2) This subpart applies to an amendment to a plan or a substitute plan—
(a) as if the amendment or substitute plan were the original plan; and
(b) with other necessary modifications.
(3) The system operator must not submit an amended or new system operator rolling outage plan to the Authority under clause 9.2(2) unless the system operator has—
(a) consulted with persons that the system operator thinks are representative of the interests of persons likely to be substantially affected by the amended or new plan; and
(b) considered submissions made on the amended or new plan.
(4) Subclause (3) does not apply if the system operator considers that it is necessary or desirable in the public interest that the proposed system operator rolling outage plan be published urgently, and, in this case, the system operator rolling outage plan must state that the plan is published in reliance on this subclause and then, within 6 months of the plan being published, the system operator must—
(a) comply with subclause (3); and
(b) decide whether or not the plan should be amended or revoked and a new plan substituted; and
(c) no later than 10 business days after making that decision, publish the decision; and

(d) if the system operator decides that the plan should be amended or revoked and a new plan substituted, comply with this clause in relation to the proposed amendment or revocation and substitution.

(5) To avoid doubt, a system operator rolling outage plan is not invalid only because the system operator did all or any of the things referred to in subclause (3) before this clause came into force.

Participant rolling outage plans

9.6 System operator must require specified participants to develop participant rolling outage plans

(1) This clause applies when a specified participant is identified under a system operator rolling outage plan as being required to develop a participant rolling outage plan.

(2) The system operator must send notice in writing to that specified participant of that requirement, including—
   (a) specifying the requirements that the participant rolling outage plan must comply with under this Part and the system operator rolling outage plan; and
   (b) specifying a date by which the specified participant must submit that plan to the system operator.

(3) The system operator must send the notice under subclause (2) as soon as practicable after the system operator publishes its system operator rolling outage plan.

9.7 Specified participants must develop participant rolling outage plans

(1) Each specified participant who receives a notice under clause 9.6 must develop its participant rolling outage plan in accordance with the notice.

(2) The specified participant must submit the plan to the system operator by the date specified under clause 9.6(2)(b).

9.8 Contents of participant rolling outage plans

(1) Each participant rolling outage plan must—
   (a) be consistent with the system operator rolling outage plan; and
   (b) comply with the requirements specified in the notice sent under clause 9.6(2)(a); and
   (c) specify the actions that the specified participant will take to achieve, or contribute to achieving, reductions in the consumption of electricity (including any target level of reduction of consumption of electricity in accordance with criteria, methodologies, and principles specified in the system operator rolling
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outage plan) to comply with a direction from the system operator given under clause 9.15.

(2) This clause does not limit clause 9.6(2)(a).
Compare: SR 2008/252 r 8C

9.9 Approval of participant rolling outage plans

(1) The system operator must, as soon as practicable after receiving a participant rolling outage plan, by notice in writing to the specified participant who submitted the plan,—
(a) approve it; or
(b) decline to approve it.

(2) The system operator may decline to approve the plan only if the system operator is not satisfied that the plan complies with clause 9.8.
Compare: SR 2008/252 r 8D

9.10 Revision of participant rolling outage plans

If the system operator declines to approve a participant rolling outage plan,—
(a) the system operator must—
(i) indicate the grounds on which it declines to approve the plan; and
(ii) direct the specified participant to submit a revised plan; and
(b) the specified participant must submit a revised plan to the system operator no later than—
(i) 15 business days after the date on which the specified participant received the direction from the system operator to submit a revised plan; or
(ii) any later date that the system operator may allow in any particular case.

Compare: SR 2008/252 r 8E

9.11 Approval of revised participant rolling outage plans

(1) As soon as practicable after receiving a revised participant rolling outage plan, the system operator must, by notice in writing to the specified participant who submitted the plan,—
(a) approve the plan; or
(b) decline to approve it.

(2) If the system operator declines to approve the revised plan, clause 9.10 applies.
Compare: SR 2008/252 r 8F

9.12 Publishing of participant rolling outage plans

A specified participant must make its participant rolling outage plan available to the public, at no cost, on an Internet site maintained by or on behalf of the specified participant, at all reasonable times, as soon as practicable after it is approved by the system operator.

Compare: SR 2008/252 r 8G
9.13 Specified participants must keep participant rolling outage plans up to date

(1) Each specified participant who has had a participant rolling outage plan approved under clauses 9.6 to 9.12 must—
   (a) keep the plan under review, and (if necessary) amend the plan to take account of any change of circumstances and to ensure that the plan continues to comply with clause 9.8; and
   (b) as soon as practicable after amending the plan, but in any case no later than 20 business days after amending it, submit the plan to the system operator.

(2) Despite subclause (1), not later than 2 years after the date on which a specified participant's participant rolling outage plan was last approved, the specified participant must resubmit the plan to the system operator for approval.

(3) A plan submitted to the system operator under subclause (1)(b) is deemed to be approved by the system operator unless, no later than 20 business days after the system operator receives the plan, the system operator advises the specified participant who submitted the plan, by notice in writing, that it declines to approve the plan.

(4) Clauses 9.9 to 9.12 apply to a plan that is submitted or resubmitted or declined under this clause, except as provided in subclause (3).

Subpart 1A—Urgent temporary grid reconfigurations


9.13A Purpose

The purpose of this subpart is to provide for the urgent temporary removal of interconnection assets from service, or temporary reconfiguration of the grid, in order to improve security of supply.


9.13B Request for urgent temporary grid reconfiguration

(1) The system operator may give notice in writing to Transpower requesting that Transpower temporarily remove 1 or more interconnection assets from service, or temporarily reconfigure the grid, if the system operator considers that—
   (a) exceptional circumstances exist—
      (i) that are likely to lead, for a period of at least 3 weeks, to—
         (A) a shortfall in thermal fuel; or
         (B) a shortfall of hydro inflows; or
         (C) the loss of a large generating asset; and
      (ii) that make it necessary or desirable in the public interest to temporarily remove 1 or more interconnection assets from service or temporarily reconfigure the grid; and
   (b) the removal or reconfiguration would improve security of supply.
(2) A notice given under subclause (1) must specify—
(a) the exceptional circumstances; and
(b) the reasons why temporarily removing assets from service or temporarily reconfiguring the grid would improve security of supply.

(3) No later than 10 business days after giving notice to Transpower, the system operator must give a written report to the Authority setting out the basis on which the system operator requested that Transpower remove 1 or more interconnection assets from service or temporarily reconfigure the grid.

(4) The system operator must ensure that the report given under subclause (3) includes—
(a) the matters specified in subclause (2)(a) and (b); and
(b) sufficient information to demonstrate that in developing its request to Transpower the system operator followed a robust process, including the options the system operator considered and the extent of any analysis and consultation undertaken by the system operator.

(5) The Authority must publish the report.


Subpart 2—Outages in shortage of supply situation

9.14 Supply shortage declaration
(1) The system operator may, after consultation with the Authority, make a supply shortage declaration.

(2) The system operator may make a supply shortage declaration only if there is a shortage of electricity supply or transmission capacity such that the system operator considers—
(a) that the normal operation of the spot market for electricity is, or will soon be, unlikely to facilitate the adjustment of supply and demand necessary to ensure that supply matches demand; and
(b) that, if planned outages are not implemented, unplanned outages are likely.

(2A) For the purposes of subclause (2), the spot market for electricity includes the processes for setting—
(a) real time prices:
(b) forecast prices and forecast reserve prices:
(c) provisional prices and provisional reserve prices:
(d) interim prices and interim reserve prices:
(e) final prices and final reserve prices.

(3) A declaration applies to—
(a) all of New Zealand; or
(b) the regions specified in the declaration.

(4) In making a declaration under subclause (1), the system operator must have regard to the system operator rolling outage plan.

(5) The system operator must publish the declaration as soon as practicable after it is made.
9.15 Power to direct outages in security of supply situation

(1) The system operator may, at any time in the period during which a supply shortage declaration is in force, give a written direction to specified participants to contribute to achieving reductions in the consumption of electricity by implementing outages or taking any other action specified in the direction.

(2) A direction must—
(a) be consistent with the system operator rolling outage plan; and
(b) be given only after consultation with the Authority; and
(c) if the direction requires a specified participant to implement outages, specify the savings targets that the specified participant must achieve.

(3) [Revoked]

(4) The system operator must publish each direction as soon as practicable after it is given.

(5) The system operator may—
(a) amend a direction; or
(b) revoke a direction and, if the system operator considers it appropriate, substitute a new direction.

(6) Subclauses (1) to (4) apply to an amendment to a direction or a substitute direction—
(a) as if the amendment or substitute direction were the original direction; and
(b) with other necessary modifications.

9.16 Specified participants must comply with direction

(1) Each specified participant must comply with a direction given to it by the system operator under clause 9.15.

(2) Each specified participant must, in complying with the direction, apply, to the extent practicable, the criteria, methodologies, and principles specified in the system operator rolling outage plan.

(3) Each specified participant must comply with a direction in accordance with its participant rolling outage plan, if it has a plan that has been approved under subpart 1.

(4) If a specified participant does not have a participant rolling outage plan approved under subpart 1, the specified participant,—
(a) in complying with the direction, must apply, to the extent practicable, the criteria, methodologies, and principles specified in the system operator rolling outage plan; and
(b) as soon as practicable after the direction is given, must provide to the system operator information as to the steps the specified participant will take to comply with the direction (including any steps the specified participant has already taken to comply with the direction).

Compare: SR 2008/252 r 11

9.17 Revocation of supply shortage declaration

(1) The system operator must revoke a supply shortage declaration when it is satisfied that the circumstances that gave rise to the declaration no longer apply.

(2) The system operator must publish the revocation as soon as practicable after it is made.

Compare: SR 2008/252 r 13

Subpart 3—Miscellaneous

9.18 Provision of information

(1) The system operator may, by notice in writing to a participant who the system operator considers may have information relevant to any of the following, require the participant to provide the information to the system operator:

(a) the preparation by the system operator of the system operator rolling outage plan under clauses 9.1 to 9.5; and
(b) the need for a supply shortage declaration; and
(c) the need for a direction requiring outages under clause 9.15; and
(d) the number and extent of outages necessary under a direction; and
(e) monitoring compliance with a direction given under clause 9.15.

(2) Subclause (1) applies only to information that is—

(a) reasonably necessary for the system operator to undertake its functions under this Part or to monitor compliance with a direction regarding outages; and
(b) in that participant's possession or that the participant can obtain without unreasonable difficulty or expense.

(3) The system operator must specify in the notice given under subclause (1) the date by which the participant must provide the information required.

(4) A participant who has received a notice under subclause (1) must provide the information required by the system operator by the date specified by the system operator in the notice.

(5) The system operator may require specified participants to provide to the system operator contact information specified by the system operator that would enable the system operator to communicate with the specified participants.

Compare: SR 2008/252 r 14
Subpart 4—Customer compensation schemes


9.19 Contents of this subpart
This subpart provides a framework under which each retailer must have a customer compensation scheme for all of 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 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.

Requirement for retailers to have customer compensation scheme

9.20 Retailer must have customer compensation scheme
(1) Each retailer who has 1 or more qualifying customers—
(a) must, at all times, have a default customer compensation scheme; and
(b) may, in addition to a default customer compensation scheme, have 1 or more additional customer compensation schemes.

(2) Each of a retailer’s qualifying customers must be covered by the retailer’s default customer compensation scheme, unless the retailer’s qualifying customer has elected to be covered by 1 of the retailer’s additional customer compensation schemes (if any) in accordance with clause 9.27.

(3) A retailer’s customer compensation scheme may cover a customer of the retailer who is not a qualifying customer.

9.21 Qualifying customers
(1) A retailer’s qualifying customer is a person who, at any time during a 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 public conservation period, of 3000 kWh or more.
(2) Despite subclause (1), a person is not a **qualifying customer** if the price of all of the **electricity** provided under the person’s contract with the **retailer** for the supply of **electricity** is determined by reference to the **final price** at a GXP.

(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 **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 a **public conservation period**, when—

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

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


Clause 9.21(4)(a)(i) and (ii): amended, on 5 October 2017, by clause 150(4)(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.


### 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 a **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**.


**Official conservation campaign**

### 9.23 System operator commences official conservation campaign

(1) The **system operator** must commence an **official conservation campaign** for the South Island—
(a) when a comparison of storage in the South Island hydro lakes with the South Island hydro risk curves, as that term is defined in the security of supply forecasting and information policy,—
   (i) shows a risk of shortage for the South Island of 10% or more; and
   (ii) forecasts that the risk of shortage for the South Island will be 10% or more for 1 week or more; or
(b) despite paragraph (a), if it has agreed a date with the Authority for an official conservation campaign to commence for the South Island, on that date.

(2) The system operator must commence an official conservation campaign for New Zealand—
(a) when a comparison of storage in New Zealand’s hydro lakes with the hydro risk curves, as that term is defined in the security of supply forecasting and information policy,—
   (i) shows a risk of shortage for New Zealand of 10% or more; and
   (ii) forecasts that the risk of shortage for New Zealand will be 10% or more for 1 week or more; or
(b) despite paragraph (a), if it has agreed a date with the Authority for an official conservation campaign to commence for New Zealand, on that date.

(3) The system operator must use reasonable endeavours to give each participant and the Authority at least 2 weeks’ notice of an official conservation campaign commencing.

(4) If the system operator has commenced an official conservation campaign, it must—
(a) during the period of the official conservation campaign, regularly review the steps that the system operator must take, and encourage participants to take, under the emergency management policy; and
(b) end the official conservation campaign—
   (i) when a comparison of storage in the hydro lakes with the hydro risk curves, as that term is defined in the security of supply forecasting and information policy, shows a risk of shortage for New Zealand or the South Island (as the case may be) of 8% or less; and
   (ii) despite subparagraph (i), if it has agreed a date with the Authority for an official conservation campaign to end, on that date.

(5) If the system operator and the Authority agree under subclause (1)(b) or (2)(b) that an official conservation campaign will commence, the system operator must publish the reasons for agreeing that the official conservation campaign will commence.

(6) The system operator must, as soon as practicable after ending an official conservation campaign, give notice to each participant and the Authority of the date on which the official conservation campaign ended.

Default customer compensation scheme

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 a 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 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 a 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 a public conservation period.

(2) [Revoked]

(3) For the purposes of this clause—
   (a) compensation includes—
      (i) money:
      (ii) a credit on the qualifying customer’s electricity account with the retailer; and
   (b) the form of the compensation is to be determined by the retailer.

Minimum weekly amount of compensation

9.25 Authority must determine minimum weekly amount

(1) In determining the minimum weekly amount that each retailer must pay to its qualifying customers, the Authority must take into account—
   (a) the estimated value, in dollars/MWh, of the savings that the Authority expects all qualifying customers in the South Island or New Zealand, as the case may be, of all retailers, will achieve during an official conservation campaign; and
   (b) any other factors that the Authority considers relevant.

(2) The Authority must—
   (a) publish the minimum weekly amount; and
   (b) review the minimum weekly amount—
       (i) after each 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.


Additional customer compensation schemes

9.26 Retailer may have additional customer compensation schemes

A retailer may have 1 or more additional customer compensation schemes.


9.27 Qualifying customer may elect to be covered by additional customer compensation scheme

(1) If a retailer has 1 or more additional customer compensation schemes, each of the retailer’s qualifying customers is covered by—
   (a) 1 of the retailer’s additional customer compensation schemes only if the qualifying customer elects to be covered by the additional customer compensation scheme; or
   (b) in the absence of an election, the retailer’s default customer compensation scheme.

(2) Before accepting a qualifying customer’s election, a retailer must ensure that it informs the qualifying customer of—
   (a) the details of the additional customer compensation scheme; and
   (b) the differences between the retailer’s default customer compensation scheme and the additional customer compensation scheme.

(3) A retailer must keep a record of each qualifying customer’s election.

(4) A qualifying customer’s election must not—
9.28 Publishing description of additional customer compensation schemes

A retailer who has 1 or more additional customer compensation schemes must—

(a) publish and keep published a description of its additional customer compensation schemes; and

(b) on request from one of the retailer’s customers, provide a written description of the additional customer compensation schemes.


Certification of compliance


9.29 Each retailer must provide certification

(1) Each retailer must certify to the Authority that—

(a) the retailer’s customer compensation scheme complies with this subpart; and

(b) the retailer has provided compensation to its qualifying customers, to the extent required by this subpart.

(2) The certification provided under subclause (1) must be—

(a) [Revoked]

(b) in the form specified by the Authority; and

(c) signed and dated by a director of the retailer and either—

(i) another director of the retailer; or

(ii) the retailer’s chief financial officer, or a person holding an equivalent position; or

(iii) the retailer’s chief executive officer, or a person holding an equivalent position.

(3) A retailer must provide certifications as follows:

(a) within 7 months of the end of a public conservation period;

(b) within 1 month of receiving a request to do so by the Authority.

(4) [Revoked]


Audit

9.30 Audit of compliance
(1) The Authority may, in its discretion, carry out an audit to determine whether a retailer has complied with this subpart.
(2) If the Authority decides to audit a retailer under subclause (1), the Authority must require the retailer to nominate an appropriate auditor.
(3) The retailer must nominate an auditor within a reasonable timeframe, and the Authority must appoint the nominated auditor.
(4) If the retailer fails to nominate an appropriate auditor within a reasonable timeframe, the Authority may appoint an auditor of its own choice.


9.31 Retailer must provide information to auditor
(1) A retailer subject to an audit under this subpart must, on request from the auditor, provide the auditor with information relating to its compliance with this subpart in the previous 12 months or such other period specified by the auditor.
(2) The retailer must provide the information within 20 business days after receiving a request from the auditor.


9.32 Auditor must provide audit report
(1) The retailer must ensure that the auditor provides the Authority with an audit report on the retailer's compliance with this subpart that has been prepared in accordance with this clause.
(2) The audit report must include any comments from the retailer on any non-compliance found by the auditor if the retailer provided the comments to the auditor within a time specified by the auditor.
(3) [Revoked]
(4) The audit report must not contain any of the information provided by the retailer to the auditor under clause 9.31 unless requested by the Authority.

9.33 Payment of auditor’s costs

(1) If an audit establishes, to the Authority’s reasonable satisfaction, that a retailer has not complied with this subpart (whether or not the Authority appoints an investigator to investigate the alleged breach), the retailer must pay the auditor’s costs.

(2) If the Authority considers that the retailer’s non-compliance is minor or relates to some (but not all) of the clauses in this subpart, the Authority may, in its discretion, determine the proportion of the auditor’s costs that the retailer must pay, and the retailer must pay those costs.

(3) If an audit establishes to the Authority’s reasonable satisfaction that a retailer has complied with this subpart, the Authority must pay the auditor’s costs.

Electricity Industry Participation Code 2010

Part 10
Metering

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This Part provides for—

(a) ensuring the accuracy of the clearing and settlement of electricity trading in the wholesale electricity market by regulating how existing and new metering installations are used to accurately measure and record electricity conveyed; and

(b) the responsibility for ensuring a metering installation is in place; and

(c) the responsibility for ensuring the compliance of metering installations; and

(d) the processes and procedures that apply to testing, calibrating, and certifying metering installations; and

(e) [Revoked]

(f) the processes and procedures that apply to approving ATHs; and

(g) regulating the data use, handling, storage, and transmission processes associated with metering installations and metering data; and

(h) regulating metering installations that are used for electricity trading; and

(i) the processes and procedures relating to the registry and information for the purposes of Part 15; and

(j) related matters, processes, and procedures.

Clause 10.1(e): revoked, on 1 June 2017, by clause 5 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

Subpart 1—Preliminary provisions

10.2 Authority’s discretion and powers

(1) A clause in this Part that gives the Authority a discretion or power—

(a) confers an absolute discretion to the Authority—

(i) taking into account any specific requirements set out in the clause; and

(ii) observing the principles of natural justice; and

(b) to approve an application by a person to carry out an activity under this Part, may be exercised by—

(i) granting the application; or

(ii) declining the application; or

(iii) granting the application with any conditions that the Authority considers appropriate in the circumstances.

(2) The Authority, when exercising a discretion or power under this Part, must act in a timely manner.

(3) The Authority must give an applicant reasons for its decision if the Authority—

(a) declines an application for approval to carry out an activity under this Part; or

(b) grants an application for approval to carry out an activity under this Part with any conditions that the Authority considers appropriate in the circumstances.

(4) Nothing in this Part limits any of the Authority’s rights and obligations under the Act.


Clause 10.2(1), (2) and (3): amended, on 5 October 2017, by clause 157(2) and (3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
10.3 Use of contractors

(1) A participant may perform its obligations and exercise its rights under this Part by using a contractor.

(2) A participant who uses a contractor to perform the participant’s obligation under this Part—
   (a) remains responsible and liable for, and is not released from, the obligation, or any other obligation under this Part; and
   (b) cannot assert that it is not responsible or liable for the obligation on the ground that the contractor—
       (i) has done or not done something; or
       (ii) has failed to meet a relevant standard; and
   (c) must ensure that the contractor has at least the specified level of skill, expertise, experience, or qualification that the participant would be required to have if it were performing the obligation itself.

(3) If a participant is a party to a contract or arrangement containing a provision, or part of a provision, which is inconsistent with this Part, the provision, or part of the provision, has no effect.

10.4 Participant obligations

(1) If this Part provides that a participant must obtain a consumer’s consent, approval, or authorisation, the participant must, if relevant, ensure that the consent, approval, or authorisation extends, for the full term of the contract or arrangement in relation to which the consent, approval, or authorisation is given, to any participant who may be expected to rely on that consent, approval, or authorisation to remain in compliance with this Part.

(2) If a participant (participant A) incorrectly populates the registry, causing another participant (participant B) to breach an obligation under this Code, and participant B relies, in good faith, on the incorrect information in the registry, participant B has not breached its obligation.

(3) A participant must comply with all applicable enactments.

(4) A participant is, unless it is specified otherwise in this Part, responsible for all costs of its compliance with this Part.

(5) A reference in this Part to a participant knowing, or being or becoming aware of, a fact, includes reference to when a participant should have, in the circumstances, known, or been or become aware of, the fact.


10.5 References to timing

(1) If an event is described in this Part as taking place on, or an obligation becoming effective from, a date, it takes place on, or becomes effective from, the beginning of the first trading period on the date, unless specified otherwise.

(2) If a time period is expressed in this Part as—
   (a) commencing on a date, it commences at the beginning of the first trading period on the date, unless specified otherwise:
10.6 Participant to provide accurate information

(1) A participant must take all practicable steps to ensure that information that it provides under this Part is—
   (a) complete and accurate;
   (b) not misleading or deceptive;
   (c) not likely to mislead or deceive.

(2) If a participant becomes aware that the information the participant provided under this Part does not comply with subclause (1)(a) to (c), even if the participant has taken all practicable steps to ensure that the information complies, the participant must, except if clause 10.43 applies, as soon as practicable provide such further information, or corrected information, as is necessary to ensure that the information complies with subclause (1)(a) to (c).

Clause 10.6(2); substituted, on 19 December 2014, by clause 20 of the Electricity Industry Participation Code Amendment (Minor Code Amendments) (No 3) 2014.

10.7 Access to premises in which metering installation located

(1) In this clause, access to a metering installation—
   (a) means physical access to the premises in which the metering installation is located; but
   (b) does not include access to the following, which are dealt with in Schedule 10.6:
       (i) raw meter data from the metering installation; and
       (ii) the metering installation itself and its metering components.

(2) A reconciliation participant must, upon receiving a request from 1 of the following parties, arrange access to a metering installation for which it is responsible:
   (a) the Authority:
   (b) an ATH:
   (c) an auditor:
   (d) a metering equipment provider:
   (e) a gaining metering equipment provider.

(3) A party listed in subclause (2) may only request access to the metering installation for the purposes of exercising the party’s rights and performing the party’s obligations under this Code or any relevant regulations in relation to 1 or more of the following:
   (a) the party’s audit functions:
   (b) the party’s administration functions:
   (c) the party’s testing functions:
   (d) the provision of metering components.

(4) A reconciliation participant who is required to give a party listed in subclause (2) access to a metering installation must use its best endeavours to do so—
   (a) in accordance with the authorisation, and any conditions or restrictions contained in the authorisation, referred to in subclause (5); and
   (b) subject to and to the extent allowed by the authorisation, in a manner and within a timeframe which are appropriate in the circumstances, to enable the party to
exercise the party’s rights, or perform the party’s obligations, that are dependent, either directly or indirectly, on access being given.

(5) If the reconciliation participant referred to in subclause (2) is a trader responsible for an ICP that—
   (a) has a consumer, the trader must have obtained the authorisation from the consumer to access the metering installation before arranging access; or
   (b) does not have a consumer, the trader must arrange for access to the metering installation.

(6) The reconciliation participant must arrange for the party listed in subclause (2) to be provided with any necessary facilities, codes, keys, or other means to enable the party to obtain access to the metering installation by the most practicable means.


10.8 Requirements for information to be recorded, given, produced, or received
(1) In this Part, a participant who must record, give, produce, or receive information, must do so in accordance with 1 or more of the following requirements published or notified by the Authority:
   (a) requirements providing for particular electronic technology:
   (b) requirements providing for the use of a particular kind of data storage device:
   (c) requirements providing for the use of a particular kind of electronic communication.

(2) Subpart 3 of Part 4 of the Contract and Commercial Law Act 2017 does not, because of section 218(2)(a) of that Act, apply to this Part.

(3) The Authority must act reasonably when determining the requirements referred to in subclause (1).

Clause 10.8(2): amended, on 1 November 2018, by clause 20(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

10.9 Demarcation of responsibility between metering equipment provider and reconciliation participant
(1) The demarcation of the responsibility of a metering equipment provider under this Part and a reconciliation participant under Part 15, is at the services access interface.

(2) A metering equipment provider is responsible for providing and maintaining the services access interface.

(3) The services access interface for a metering installation is—
   (a) determined by the ATH certifying the metering installation under clause 10 of Schedule 10.4; and
   (b) recorded in the metering installation certification report under clause 10 of Schedule 10.4.

10.10 Standards used
In this Part a reference to compliance with a standard, including an AS/NZS or IEC standard, is a reference to—
   (a) the version of the standard existing as at 29 August 2013; or
   (b) any amendment to or replacement of the standard incorporated by the Authority
in accordance with section 32 of the Act; or
(c) any equivalent standard incorporated by the Authority in accordance with section 32 of the Act.


Metering installations

10.11 Categories of metering installation
(1) An ATH must, before it certifies a metering installation, determine the category of the metering installation by reference to the characteristics of the metering installation, in accordance with clauses 5 and 6 of Schedule 10.7.
(2) A metering installation used solely for unmetered load is category 0.
(3) The category of each metering installation, other than a category 0 metering installation, is for all purposes of this Part—
(a) determined by the ATH certifying the metering installation under clauses 5 and 6 of Schedule 10.7; and
(b) recorded in the metering installation certification report under clause 8(4) of Schedule 10.7.

10.12 Interference with metering installation
A participant must not directly or indirectly interfere with a metering installation for which it is not the metering equipment provider, unless—
(a) it is instructed or permitted to do so by the metering equipment provider responsible for the metering installation; or
(b) the participant has an arrangement with the trader responsible for the metering installation as the gaining metering equipment provider who will be responsible for the metering installation.

10.13 Electricity conveyed
(1) A participant must use the quantity of electricity measured by a metering installation for a point of connection as the raw meter data for the quantity of electricity conveyed through the point of connection.
(2) Subclause (1) does not apply to electricity that is—
(a) estimated in accordance with this Code; or
(b) supplied by an embedded generator who has given notice to the reconciliation manager under clause 15.13.
(3) A metering equipment provider must, for each point of connection at which it is the metering equipment provider, ensure that all electricity conveyed through the point of connection is measured by a metering installation or metering installations, in accordance with this Part.
(4) Despite subclause (3), a metering equipment provider is not required to measure electricity conveyed through a point of connection if the electricity is—
(a) unmetered load; or
(b) supplied by an embedded generator who has given notice to the
reconciliation manager under clause 15.13.

Unmetered load

10.14 Unmetered load

(1) This clause applies to a retailer who is recorded in the registry as being responsible for an ICP.

(2) A retailer—
(a) must quantify any unmetered load at the ICP in accordance with Parts 11 and 15; and
(b) may, subject to subclause (3), only treat load as unmetered load if it reasonably expects, in any rolling 12 month period, the load to be not greater than—
(i) 3,000 kWh; or
(ii) 6,000 kWh if the load is predictable load of a type approved and published by the Authority.

(3) Subclause (2)(b) does not apply to distributed unmetered load managed in accordance with Part 15.

(4) If the load during a rolling 12 month period exceeds the applicable limit under subclause (2)(b), the retailer breaches this clause from the date on which the limit was, or was calculated or estimated to have been, first exceeded.

(5) A retailer described in subclause (4) must—
(a) as soon as reasonably practicable, but no later than 20 business days after the limit was calculated or estimated to have been first exceeded, commence corrective measures to ensure that it complies with this Part; and
(b) within 20 business days of commencing the corrective measures referred to in paragraph (a), complete the corrective measures so that it complies with this Part; and
(c) as soon as reasonably practicable, but no later than 10 business days after it becomes aware of the limit having been calculated or estimated to have been first exceeded, advise each participant who is, or would reasonably be expected to be, affected, of—
(i) the date on which the limit was calculated or estimated to have been first exceeded; and
(ii) the details of the corrective measures that the retailer proposes to take, has taken, or is taking, to reduce the unmetered load.


Metering data

10.15 Security of metering data

(1) This clause applies to—
(a) a participant who has the right to collect, obtain, use, or store metering data; and 
(b) the Authority.

(2) A person to whom this clause applies must take security measures, as are reasonable in the circumstances, to protect metering data against loss or unauthorised access, use, modification, or disclosure.

(3) Subclause (2) is subject to—
(a) the person's obligations under any other enactment; and 
(b) the person being otherwise compelled by law; and 
(c) any applicable material that the Authority incorporates into this Code under section 32(3) of the Act.

### 10.16 Metering data exchange timing and formats

(1) A participant (other than a market operation service provider) must, if it is under an obligation to provide metering data under this Part, provide the metering data to the relevant person—
   (a) in the absence of any timeframe specified in this Code, within a reasonable timeframe specified by the Authority; and 
   (b) in the format the Authority specifies to participants from time to time.

(2) The Authority must provide reasonable notice of any changes to the format the Authority specifies under subclause (1)(b).

(3) Despite subclause (1)(b), a participant may provide the metering data in an alternative format if it has an arrangement with the recipient to use the alternative format.

(4) Despite subclause (3), the participant must be able to comply with any format requirements the Authority specifies under subclause (1)(b), within 1 business day of ceasing to have an arrangement with the recipient under subclause (3).

(5) Despite using an alternative format under subclause (3), a participant must still comply with all other obligations in this Code.

Clause 10.16(1)(a) amended, on 1 November 2018, by clause 22(a) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.
Clause 10.16(1)(b) amended, on 1 November 2018, by clause 22(b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.
Clause 10.16(2) amended, on 1 November 2018, by clause 22(c) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

### Audits

10.17 [Revoked]

10.17A Metering equipment providers and ATHs to arrange for regular audits

Each metering equipment provider and each ATH must arrange to be audited regularly in accordance with Part 16A in respect of the metering equipment provider's or ATH's obligations under this Part.


10.17B Authority and participant requested audits

(1) The Authority may at any time carry out, or appoint an auditor to carry out, an audit of a participant in respect of the participant's obligations under this Part.

(2) If a participant considers that another participant may not have complied with this Part, the participant may request that the Authority carry out, or appoint an auditor to carry out, an audit of the other participant.

(3) Part 16A applies to an audit carried out under this clause.

Clause 10.17B: inserted, on 1 June 2017, by clause 7 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

Subpart 2—Ongoing obligations

Metering equipment providers

10.18 Category 1 metering installations and higher categories of metering installations must have metering equipment provider

(1) A participant who is responsible under Part 15 for providing submission information to the reconciliation manager for a point of connection must ensure that, for each metering installation for the point of connection used for an activity regulated under this Code, there is a metering equipment provider.

(2) A participant must not use, and must not permit any person to use, a category 1 metering installation, or higher category of metering installation, for a point of connection for an activity regulated under this Code unless, at the time of such use, there is a metering equipment provider for the metering installation.

(3) Despite subclauses (1) and (2), a point of connection at which all electricity conveyed is unmetered load—

(a) does not require a metering equipment provider; and

(b) may be used for an activity regulated under this Code.

(4) If there is more than 1 metering installation for a point of connection, the metering equipment provider for each metering installation must be the same participant.

10.19 Metering equipment provider

(1) The metering equipment provider for each existing category 1 metering installation, or higher category of metering installation, being used on 29 August 2013 for an activity regulated under this Code, for a point of connection—

(a) that is an ICP and not also an NSP, is the participant, or a consumer, who is identified in the registry as being the primary metering contact at 2400 hours on 28 August 2013;

(b) that is an NSP and not also a point of connection to the grid—

(i) is the participant who owns the meter for the point of connection:
(ii) if there is more than 1 meter for the point of connection, is the participant who is appointed by the meter owners for the point of connection, or failing agreement, appointed by the Authority:

(c) to the grid, is the participant responsible for metering as set out in the NSP table on the Authority’s website at 2400 hours on 28 August 2013.

(2) The metering equipment provider for each category 1 metering installation, or higher category of metering installation for a point of connection, other than a metering installation referred to in subclause (1),—

(a) that is an ICP and not also an NSP, is the person recorded in the registry as accepting responsibility as the metering equipment provider under clause 1(1)(a)(ii) of Schedule 11.4:

(b) that is an NSP and not also a point of connection to the grid, is—

(i) the network owner referred to in clause 10.25(2)(a)(i); or

(ii) if a person has contracted with the network owner under clause 10.25(2)(a)(ii), that person:

(c) that is a point of connection to the grid, is—

(i) the participant referred to in clause 10.26(7)(b); or

(ii) if a person has contracted with the participant responsible for providing a metering installation under clause 10.26(7)(b), that person.


10.20 Obligations of metering equipment provider

A metering equipment provider must—

(a) [Revoked]

(b) comply with all of its obligations in this Code including the obligations under Schedules 10.6, 10.7, and 10.8.

Clause 10.20(a): revoked, on 1 June 2017, by clause 8 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

10.21 When metering equipment provider’s obligations come into effect

(1) The obligations under this Part of a person who assumes responsibility, or is appointed to be responsible, as the metering equipment provider, under clauses 10.19(2) or 10.22, for a metering installation, commence,—

(a) for an ICP that is not also an NSP, on the date that is recorded in the registry as being the date on which the metering installation equipment was installed; or

(b) for an NSP, on the effective date set out in the NSP table on the Authority’s website.

(2) Despite subclause (1), if a person fails to become the metering equipment provider due solely to an administrative failure or similar reason, the Authority may determine
the date that the person becomes the metering equipment provider.

10.22 Change of metering equipment provider
(1) The metering equipment provider for a metering installation may change only if the participant responsible for ensuring there is a metering installation under clause 10.24, 10.25, or 10.26 enters into an arrangement with another person to become the metering equipment provider for the metering installation and—
(a) in the case of a metering installation for an ICP that is not also an NSP—
(i) the trader for the metering installation records the name of the gaining metering equipment provider in the registry in accordance with Part 11; and
(ii) the gaining metering equipment provider records in the registry that it accepts becoming the metering equipment provider (including the effective date from which the gaining metering equipment provider assumes its responsibility as metering equipment provider for the metering installation) in accordance with Part 11; or
(b) in the case of a metering installation for an NSP, the participant responsible for the provision of the metering installation under clause 10.25 advises the reconciliation manager of the gaining metering equipment provider.
(2) The gaining metering equipment provider must, within 20 business days of assuming responsibility for a metering installation, pay the losing metering equipment provider the proportion of the costs described in subclause (3).
(3) The costs payable under subclause (2) are those directly and solely attributable to the certification tests and calibration tests of the metering installation or any of its metering components from the period beginning on the date the gaining metering equipment provider assumes responsibility for the metering installation, for the remainder of the certification validity period for the metering installation or the metering component.
Clause 10.22(1)(a)(i) and (ii): amended, on 5 October 2017, by clause 161(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

10.23 Termination of metering equipment provider responsibility
(1) Subject to subclause (2), a metering equipment provider’s obligations under this Part for a metering installation terminate only when—
(a) for an ICP that is not also an NSP, the metering equipment provider changes under clause 10.22(1)(a), in which case the metering equipment provider’s obligations terminate from the date on which the gaining metering equipment provider assumes responsibility, set out in clause 10.21(1)(a); or
(b) for an NSP, the metering equipment provider changes under clause 10.22(1)(b), in which case the metering equipment provider’s obligations terminate from the date on which the gaining metering equipment provider assumes responsibility, set out in clause 10.21(1)(b); or
(c) the metering installation is no longer required for the purposes of Part 15 and the
point of connection for the metering installation has been decommissioned; or
(d) the ICP for the metering installation is converted to be used solely for unmetered load in accordance with this Code.

(2) Despite subclause (1), a metering equipment provider must either—
(a) comply with its continuing obligations, including record keeping obligations, which—
(i) are expressed in this Part as having minimum time periods, until that period expires; or
(ii) by their nature extend beyond the date or event referred to in subclause (1); or
(b) before its obligations terminate under subclause (1), enter into an arrangement with a participant to assume its obligations referred to in paragraph (a).

10.23A Decommissioning of metering installation at ICP

(1) If a metering installation at an ICP is to be decommissioned, but the ICP is not being decommissioned, the metering equipment provider that is responsible for decommissioning the metering installation must,—
(a) if the metering equipment provider is responsible for interrogating the metering installation—
(i) arrange for a final interrogation to take place before the metering installation is decommissioned; and
(ii) provide the raw meter data from the interrogation to the trader that is recorded in the registry as being responsible for the ICP; or
(b) if another participant is responsible for interrogating the metering installation, advise the other participant not less than 3 business days before the decommissioning—
(i) of the date and time of the decommissioning; and
(ii) that the participant must carry out a final interrogation.

(2) To avoid doubt, if a metering installation at an ICP is to be decommissioned because the ICP is being decommissioned—
(a) the metering equipment provider is not responsible for arranging a final interrogation of the metering installation; and
(b) the trader that is recorded in the registry as being responsible for the ICP must arrange for a final interrogation of the metering installation under clause 11.18(3).


Responsibility for ensuring there are metering installations

10.24 Responsibility for ensuring there is metering installation for ICP that is not also NSP

A trader must, for each electrically connected ICP that is not also an NSP, and for which it is recorded in the registry as being responsible, ensure that—
(a) there is 1 or more metering installations; and
(b) all electricity conveyed is quantified in accordance with this Code; and
(c) it does not use subtraction to determine submission information for the purposes
10.25 Responsibility for ensuring there is metering installation for NSP that is not point of connection to grid

(1) A distributor must, for each NSP that is not a point of connection to the grid, and for which it is recorded in the NSP table on the Authority’s website as being responsible, ensure that—
   (a) there is 1 or more metering installations; and
   (b) all electricity conveyed is quantified in accordance with this Code:

(2) A distributor must, if it proposes the creation of a new NSP that is not a point of connection to the grid,—
   (a) for each metering installation for the NSP, either—
      (i) assume responsibility for being the metering equipment provider; or
      (ii) contract with a person who, in that contract, assumes responsibility for being the metering equipment provider; and
   (b) no later than 20 business days after assuming responsibility or entering into the contract under paragraph (a), advise the reconciliation manager of—
      (i) the reconciliation participant for the NSP; and
      (ii) the participant identifier of the metering equipment provider for the metering installation; and
   (c) no later than 20 business days after the date of certification of each metering installation, advise the reconciliation manager of the certification expiry date of the metering installation.

(3) In relation to an NSP of the type described in subclause (1), a distributor must, no later than 20 business days after a metering installation for such an NSP is recertified, advise the reconciliation manager of the following:
   (a) the reconciliation participant for the NSP:
   (b) the participant identifier of the metering equipment provider for the metering installation:
   (c) the certification expiry date of the metering installation.

10.26 Responsibility for ensuring there is metering installation for point of connection to grid

(1) A grid owner must, for each GXP which connects to its grid, ensure that there is 1 or more certified metering installations for the GXP.
(2) An asset owner must, for each GIP which connects to the grid, ensure that there is 1 or more certified metering installations for the GIP.

(3) A participant who proposes to connect to the grid at a new point of connection must take all practicable steps and use its best endeavours to agree with the grid owner and any other affected participants, on which participant will provide the metering installation for the proposed new point of connection.

(4) If the participants cannot agree, within 60 business days of the grid owner first being advised of the proposed new point of connection to the grid, on the participant to be responsible for providing the metering installation,—
   (a) any affected participant may advise the Authority—
      (i) that agreement has not been reached; and
      (ii) of the identity of all affected participants; and
      (iii) of the reasons (if and to the extent known) that agreement was not reached; and
   (b) the Authority must determine which participant must provide the metering installation; and
   (c) the Authority must advise—
      (i) the relevant participant of its responsibility to provide the metering installation; and
      (ii) the participant intending to connect to the grid of its determination; and
      (iii) the grid owner of its determination.

(5) When determining which participant is responsible for providing the metering installation, the Authority must, unless it is satisfied that there is good reason not to do so, do so on the basis that—
   (a) the grid owner is responsible if the Authority anticipates that the point of connection is a GXP; and
   (b) the participant connecting assets to the grid at the point of connection is responsible if the Authority anticipates that the point of connection is a GIP.

(6) The participant responsible for providing the metering installation (unless the participant is a grid owner) must also, for each proposed new metering installation for a point of connection to the grid,—
   (a) provide a copy of the metering installation design to the grid owner before ordering equipment; and
   (b) provide the grid owner with at least 3 months to review and comment on the metering installation design; and
   (c) respond, within 3 business days of receipt, to any request from the grid owner for additional details or required changes to the metering installation; and
   (d) ensure that any reasonable changes to the metering installation or the metering installation configuration requested by the grid owner are carried out.

(7) The participant responsible for providing the metering installation must—
   (a) advise the reconciliation manager of the certification expiry date of the metering installation no later than 10 business days after certification of the metering installation; and
   (b) assume responsibility for being the metering equipment provider for the metering installation or contract with a person to assume responsibility for being the metering equipment provider for the metering installation; and
(c) advise the **reconciliation manager** of the **participant identifier** of the **metering equipment provider** under paragraph (b) by no later than **20 business days** after,—

(i) if it is appointed under a contract, entering into the contract under paragraph (b); or

(ii) if it assumes responsibility for being the **metering equipment provider**, other than under a contract, assuming responsibility.

(8) The **participant** responsible for providing the **metering installation** (unless the **participant** is a **grid owner**) must, in the case of a proposed modification to an existing **metering installation** under clause 19 of Schedule 10.7—

(a) provide a copy of the **metering installation** design to the **grid owner** before ordering equipment or carrying out the modification to the **metering installation** design; and

(b) provide the **grid owner** with at least **3 months** to review and comment on the **metering installation** design; and

(c) respond, within **3 business days** of receipt, to any request from the **grid owner** for additional details or required changes to the **metering installation** or its configuration; and

(d) ensure that any reasonable changes to the **metering installation** or the **metering installation** configuration requested by the **grid owner** are carried out.

(9) If the **grid owner** considers, acting reasonably, that a proposed new **metering installation**, or a proposed change to an existing **metering installation**, or its configuration, requires subtraction or a **loss compensation** or **error compensation** process to determine **submission information** for the purposes of Part 15, the **grid owner** must, unless an **error compensation** process is to be applied to the **metering installation** that is already within the applicable accuracy tolerances set out in Table 1 of Schedule 10.1—

(a) provide all relevant details to the **Authority**, in the **prescribed form**, at least **20 business days** before—

(i) the proposed date for installing the **metering installation**; or

(ii) the proposed date for changing the **metering installation** or **metering installation**’s configuration; and

(b) respond, within **3 business days** of receipt, to any request from the **Authority** for additional details; and

(c) ensure that any reasonable changes to the **metering installation** or its configuration requested by the **Authority** are carried out.

(10) A **metering equipment provider** must ensure that the quantity of **electricity** conveyed through a **point of connection** to the **grid** for which there is a **metering installation** for which it is responsible is measured using a **half-hour metering installation**.

(11) If a **metering installation** for a **point of connection** to the **grid** is **recertified**, the **participant** responsible for providing the **metering installation** must, within **10 business days** of the date of **recertification**, advise the **reconciliation manager** of the **metering installation**’s new **certification** expiry date.

Clause 10.26(2): amended, on 29 August 2013, by clause 16(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).

Clause 10.27 Change in responsibility for ensuring metering installation for point of connection to grid

(1) If a participant considers, on the basis of historical metering data, that there has been a change in the overall net flow of electricity at a point of connection to the grid over any 12 month period, the participant who is responsible for ensuring there is a metering installation may initiate the process under clauses 10.26(3) to 10.26(5) with all necessary amendments, in order to change the participant responsible for providing the metering installation.

(2) If the participant who is responsible for ensuring there is a metering installation changes under subclause (1), the responsibility for providing submission information to the reconciliation manager under Part 15 changes.

Connecting and electrically connecting points of connection

Heading: amended, on 29 August 2013, by clause 17(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).

Clause 10.28 [Revoked]

Clause 10.28(2)(a), (2)(b) and (3): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 10.29 When grid owner may connect point of connection to grid

(1A) Only a grid owner may connect a point of connection to the grid.

(1) Despite subclause (1A), a grid owner must not connect a point of connection to the grid unless it has—
(a) ensured that the processes described in clause 10.26 have been carried out; and
(b) requested, in the prescribed form, not less than 20 business days before the proposed connection date, authorisation from the Authority, to connect the point of connection; and
(c) obtained the authorisation referred to in paragraph (b) from the Authority.

(2) The grid owner must, within 5 business days of connecting a point of connection to the grid, advise the reconciliation manager of—
(a) the point of connection that has been connected; and
(b) the connection date.

Heading: amended, on 5 October 2017, by clause 166(1) of the Electricity Industry Participation Code Amendment
10.29A When grid owner may temporarily electrically connect point of connection to grid

(1) Subject to clause 10.33, only a grid owner may temporarily electrically connect a point of connection to the grid.

(2) A grid owner may temporarily electrically connect a point of connection to the grid that is to be quantified with a category 1 metering installation, or higher category of metering installation, only if a metering equipment provider requests that the grid owner temporarily electrically connect the point of connection to the grid for the purposes of—

(a) certifying a metering installation at the point of connection to the grid; or
(b) maintaining, repairing, testing, or commissioning a metering installation at the point of connection to the grid.

(3) Despite subclause (2), a metering equipment provider must not request that a grid owner temporarily electrically connect a point of connection to the grid unless—

(a) the grid owner responsible for the point of connection has authorised the metering equipment provider to do so; and
(b) the metering equipment provider has an arrangement with that grid owner to provide metering services.


10.30 When distributor or embedded network owner may connect NSP that is not point of connection to grid

(1A) Only a distributor that initiates, under Part 11, the creation of an NSP on the distributor's network that is not a point of connection to the grid may connect the NSP to—

(a) an embedded network, if the embedded network owner has agreed to the connection; or
(b) a local network, if the local network owner has agreed to the connection.

(1B) Only an embedded network owner that initiates, under Part 11, the creation of an NSP on its embedded network—

(a) may connect the NSP to another embedded network; but
(b) can only do so if the other embedded network owner has agreed to the connection.

(1) Despite subclause (1A), a distributor must not connect an NSP on its network that is not a point of connection to the grid unless requested to do so by the reconciliation participant responsible for ensuring there is a metering installation for the point of connection.
A distributor must, within 5 business days of connecting an NSP, advise the reconciliation manager of the following:

(a) the NSP that has been connected; and
(b) the connection date; and
(c) the participant identifier of the metering equipment provider for each metering installation for the NSP; and
(d) the certification expiry date of each metering installation for the NSP.

Clause 10.30: substituted, on 29 August 2013, by clause 19 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).

10.30A When distributor may temporarily electrically connect NSP that is not point of connection to grid

(1) Subject to clause 10.33, only a distributor that initiates, under Part 11, the creation of an NSP on the distributor's network that is not a point of connection to the grid may temporarily electrically connect the NSP to—
(a) an embedded network, if the embedded network owner has agreed to the temporary electrical connection; or
(b) a local network, if the local network owner has agreed to the temporary electrical connection.

(2) Subject to clause 10.33, only an embedded network owner that initiates, under Part 11, the creation of an NSP on its embedded network—
(a) may temporarily electrically connect the NSP to another embedded network; but
(b) can only do so if the other embedded network owner has agreed to the temporary electrical connection.

(3) A distributor may only temporarily electrically connect an NSP that is not a point of connection to the grid if a metering equipment provider requests that the distributor temporarily electrically connect the NSP for the purposes of—
(a) certifying a metering installation at the NSP; or
(b) maintaining, repairing, testing, or commissioning a metering installation at the NSP.

(4) Despite subclause (3), a metering equipment provider must not request that a distributor temporarily electrically connect an NSP that is not a point of connection to the grid unless—
(a) the reconciliation participant responsible for the NSP authorises the metering equipment provider to do so; and
(b) the metering equipment provider has an arrangement with that reconciliation participant to provide metering services.


10.31 When distributor may connect ICP that is not NSP

(1) Only a distributor may, on its network, connect an ICP that is not an NSP.
(2) Despite subclause (1), a distributor must not connect an ICP that is not an NSP unless—
   (a) the trader trading at the ICP has requested the connection; or
   (b) in the following circumstances:
      (i) there is only shared unmetered load at the ICP; and
      (ii) in accordance with clause 11.14, the distributor has—
          (A) assigned the shared unmetered load; and
          (B) advised each trader, that is responsible under clause 11.18(1) for the ICPs across which the unmetered load is shared, of that assignment.

Clause 10.31: substituted, on 29 August 2013, by clause 20 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).
Clause 10.31(a): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

10.31AWhen distributor may temporarily electrically connect ICP that is not NSP
(1) Subject to clause 10.33, only a distributor may, on its network, temporarily electrically connect an ICP that is not an NSP.

(2) A distributor may only temporarily electrically connect an ICP that is not an NSP—
   (a) if a metering equipment provider requests that the distributor temporarily electrically connect the ICP for the purposes of—
      (i) certifying a metering installation at the ICP; or
      (ii) maintaining, repairing, testing, or commissioning a metering installation at the ICP; or
   (b) in the following circumstances:
      (i) there is only shared unmetered load at the ICP; and
      (ii) in accordance with clause 11.14, the distributor has—
          (A) assigned the shared unmetered load; and
          (B) advised each trader, that is responsible under clause 11.18(1) for the ICPs across which the unmetered load is shared, of that assignment; and
          (iii) the distributor has advised those traders of the distributor's intention to temporarily electrically connect the ICP.

(3) Despite subclause (2)(a), a metering equipment provider must not request that a distributor temporarily electrically connect an ICP that is not an NSP unless—
   (a) the trader responsible for the ICP has authorised the metering equipment provider to do so; and
   (b) the metering equipment provider has an arrangement with that trader to provide metering services.

(4) Despite subclause (2)(b), the distributor need not advise the traders of the distributor's intention to temporarily electrically connect the ICP if—
   (a) advising all traders would impose a material cost on the distributor; and
(b) in the distributor's reasonable opinion, advising the traders would not result in any material benefit to any of the traders.


10.31B When distributor may electrically connect ICP that is not NSP

(1) A distributor may electrically connect an ICP that is not an NSP only if—

(a) there is only shared unmetered load at the ICP; and

(b) in accordance with clause 11.14, the distributor has—

(i) assigned the shared unmetered load; and

(ii) advised each trader, that is responsible under clause 11.18(1) for the ICPs across which the unmetered load is shared, of that assignment; and

(c) the distributor has advised those traders of the distributor's intention to electrically connect the ICP.

(2) Despite subclause (1)(b), the distributor need not advise the traders of the distributor's intention to electrically connect the ICP if—

(a) the distributor is doing so following a maintenance outage; and

(b) advising all traders would impose a material cost on the distributor; and

(c) in the distributor's reasonable opinion, advising the traders would not result in any material benefit to any of the traders.


10.32 Reconciliation participant requesting connection of point of connection

For the purposes of clauses 10.30(1) and 10.31(2), a reconciliation participant must only request the connection of a point of connection if the reconciliation participant—

(a) accepts responsibility for the reconciliation participant's obligations in this Part and Parts 11 and 15 for the point of connection; and

(b) has an arrangement with a metering equipment provider to provide 1 or more metering installations for the point of connection.

Clause 10.32 Heading: amended, on 29 August 2013, by clause 21(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).


Clause 10.32: amended, on 29 August 2013, by clause 21(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).


10.33 When reconciliation participant may temporarily electrically connect point of connection

(1) A reconciliation participant may temporarily electrically connect a point of connection, or authorise a metering equipment provider to temporarily electrically connect a point of connection under subclause (2), only if—
(aa) for an NSP that is a point of connection to the grid, the grid owner has approved—
   
   (i) the reconciliation participant temporarily electrically connecting the point of connection; or
   
   (ii) the reconciliation participant authorising the temporary electrical connection of the point of connection:

(ab) for an NSP that is not a point of connection to the grid, the distributor that gave notice to the reconciliation manager under clause 25 of Schedule 11.1 has approved—
   
   (i) the reconciliation participant temporarily electrically connecting the point of connection; or
   
   (ii) the reconciliation participant authorising the temporary electrical connection of the point of connection:

(a) for a point of connection that is an ICP, but which is not an NSP,—

   (i) the reconciliation participant is recorded in the registry as the trader responsible for the ICP; and
   
   (ii) if the ICP has metered load, 1 or more certified metering installations are in place at the ICP in accordance with this Part; and
   
   (iii) if the ICP has not previously been electrically connected, the owner of the network to which the point of connection is connected has given written approval of the temporary electrical connection.

(b) [Revoked]

(c) [Revoked]

(2) A reconciliation participant described in subclause (1) may authorise a metering equipment provider, with which the reconciliation participant has an arrangement, to request the temporary electrical connection of a point of connection only for the purposes of—

   (a) certifying a metering installation at the point of connection; or
   
   (b) maintaining, repairing, testing, or commissioning a metering installation at the point of connection.

(3) [Revoked]

(4) [Revoked]

Clause 10.33(1)(b) and (c): revoked, on 1 November 2018, by clause 27(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

10.33A When reconciliation participant may electrically connect point of connection

(1) A reconciliation participant may electrically connect a point of connection, or authorise the electrical connection of a point of connection, only if—

(aa) for an NSP that is a point of connection to the grid, the grid owner has approved—

(i) the reconciliation participant electrically connecting the point of connection; or

(ii) the reconciliation participant authorising the electrical connection of the point of connection:

(ab) for an NSP that is not a point of connection to the grid, the distributor that gave notice to the reconciliation manager under clause 25 of Schedule 11.1 has approved—

(i) the reconciliation participant electrically connecting the point of connection; or

(ii) the reconciliation participant authorising the electrical connection of the point of connection:

(a) for a point of connection that is an ICP, but which is not an NSP,—

(i) the reconciliation participant is recorded in the registry as the trader responsible for the ICP; and

(ii) if the ICP has metered load, 1 or more certified metering installations are in place at the ICP in accordance with this Part; and

(iii) if the ICP has not previously been electrically connected, the owner of the network to which the point of connection is connected has given written approval of the electrical connection.

(b) [Revoked]

(c) [Revoked]

(2) Further to subclause (1), a reconciliation participant described in subclause (1)(a)(i)—

(a) may authorise the electrical connection of an ICP if—

(i) a metering installation is in place at the ICP; and

(ii) the metering installation is operational but not certified; and

(iii) the reconciliation participant arranges for the certification of the metering installation to be completed within 5 business days of the ICP being electrically connected:

(b) may electrically connect an ICP if the point of connection is solely for unmetered load.

(3) A reconciliation participant must not authorise the electrical connection of a point of connection in either of the following circumstances:

(a) a distributor has electrically disconnected the point of connection for safety reasons, and has not subsequently approved the electrical connection of the point of connection:

(b) electrically connecting the point of connection would breach the Electricity (Safety) Regulations 2010.

(4) No participant may electrically connect a point of connection, or authorise the electrical connection of a point of connection, other than—
25 1 November 2018

(a) a reconciliation participant in the circumstances described in subclauses (1), (2), or (3):

(b) a distributor in the circumstances described in clause 10.31B(1).


Clause 10.33A(1)(aa) and (ab): inserted, on 1 November 2018, by clause 28(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.


Clause 10.33A(1)(b) and (c): revoked, on 1 November 2018, by clause 28(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.


General metering installation requirements

10.34 Installation and modification of metering installations

(1) This clause applies to a metering equipment provider that proposes to install or modify a metering installation at a point of connection other than a point of connection to the grid.

(2) The metering equipment provider must consult with the distributor and the trader for the point of connection on the matters specified in subclause (2A), before—

(a) finalising the design of a metering installation for the point of connection; or

(b) modifying the design of a metering installation installed at the point of connection.

(2A) The matters referred to in subclause (2) are the metering installation’s—

(a) required functionality; and

(b) terms of use; and

(c) required interface format; and

(d) integration of the ripple receiver and the meter; and

(e) functionality for controllable load.

(3) Each participant involved in the consultation referred to in subclause (2) must—

(a) use its best endeavours to reach agreement; and

(b) act reasonably and in good faith.

(4) If the participants referred to in subclause (2) cannot agree, within 20 business days of the distributor first being advised of the proposed new or modified metering installation, on the metering installation’s requirements set out in subclause (2A)(a) to (e)—

(a) an affected participant may refer the matter to the Authority under clause 10.50 by advising the Authority—

(i) that agreement has not been reached; and

(ii) of the identity of all affected participants; and

(iii) the reasons (if and to the extent known) why agreement was not reached; and

(b) the Authority—

(i) may, at its discretion, determine the metering installation requirements; and

(ii) must, if it determines the metering installation requirements, —
(A) do so in accordance with clause 10.50(4); and
(B) advise each affected participant of the determination it has made

Clause 10.34(1) and (2): substituted, on 1 February 2016, by clause 28(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

10.35 Physical location of metering installations

(1) A reconciliation participant responsible for ensuring there is a category 1 metering installation or category 2 metering installation must ensure that the metering installation is located as physically close to a point of connection as practical in the circumstances.

(2) A reconciliation participant responsible for ensuring there is a category 3 or higher metering installation must,—
   (a) if practical in the circumstances, ensure that the metering installation is located at a point of connection; or
   (b) if it is not practical in the circumstances to locate the metering installation at the point of connection, calculate the quantity of electricity conveyed through the point of connection using a loss compensation process approved by the certifying ATH.

(3) If a calculation is carried out under subclause (2)(b), the certifying ATH must record in the metering installation certification report—
   (a) the details of the calculation; and
   (b) any assumption used; and
   (c) any measurement used.

(4) This clause does not apply to an existing metering installation that is in place on 29 August 2013.


10.36 Reconciliation participant to have arrangement with metering equipment provider

A reconciliation participant must, before accepting responsibility to be the reconciliation participant for a point of connection, enter into an arrangement with a metering equipment provider—

(a) for the reconciliation participant to provide the metering equipment provider with physical access to the metering installation for the point of connection and the premises at which it is situated; and
(b) arranging for the electrical disconnection of the point of connection, if required by the metering equipment provider to enable the metering equipment provider to comply with its obligations under this Part; and
(c) for the metering equipment provider to provide the reconciliation participant with access at the services access interface to the metering data from the
metering installation for the point of connection, in accordance with an authorisation from—
(i) in the case of an ICP, the consumer; or
(ii) in the case of an NSP, the network owner.

Active and reactive energy metering

10.37 Active and reactive measuring and recording requirements
(1) A metering equipment provider must ensure that each half-hour metering installation that is a category 3 metering installation, or higher category of metering installation, certified after 29 August 2013, measures and separately records, in accordance with this Part,—
(a) if the measuring and recording requirement is for consumption only—
   (i) import active energy; and
   (ii) import reactive energy; and
   (iii) export reactive energy; or
(b) if the measuring and recording requirement is for consumption and generation, or generation only—
   (i) import active energy; and
   (ii) export active energy; and
   (iii) import reactive energy; and
   (iv) export reactive energy.
(1A) A metering equipment provider must ensure that each half-hour metering installation that is a category 2 metering installation, certified after 29 August 2013, is capable of measuring and recording—
(a) import active energy; and
(b) export active energy; and
(c) import reactive energy; and
(d) export reactive energy.
(1B) A metering equipment provider must ensure that each half-hour metering installation that is a category 2 metering installation, certified after 29 August 2013, measures and separately records, in accordance with this Part,—
(a) if the measuring and recording requirement is for consumption only, import active energy; or
(b) if the measuring and recording requirement is for consumption and generation, or generation only—
   (i) import active energy; and
   (ii) export active energy.
(2) Despite subclauses (1)(a) and (1B)—
(a) each metering installation, for a point of connection to the grid, certified after 29 August 2013, must measure and separately record—
   (i) import active energy; and
   (ii) export active energy; and
(iii) import reactive energy; and
(iv) export reactive energy; and

(b) the accuracy of each local service metering installation for electricity used in and by a grid substation must be within the applicable accuracy tolerances set out in Table 1 of Schedule 10.1.

Clause 10.37(1A) and (1B): inserted, on 1 February 2016, by clause 29(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

Certification of metering installations

10.38 Certification of metering installations

A metering equipment provider must—

(a) obtain and maintain certification in accordance with this Part—
   (i) for each metering installation for which it is responsible; and
   (ii) for each metering component in a metering installation for which it is responsible; and

(b) ensure that any tests required for certification under paragraph (a) are conducted in accordance with this Code including the obligations under Schedule 10.7 or 10.8 (whichever is applicable) by an ATH contracted by the metering equipment provider.

Metering infrastructure

10.39 Responsibility for metering infrastructure integration

(1) A metering equipment provider must ensure that—
   (a) for each metering installation for which it is responsible, an appropriately designed metering infrastructure is in place; and
   (b) in each metering installation for which it is responsible,—
      (i) each metering component is compatible with, and will not cause any interference with the operation of, any other metering component in the metering installation; and
      (ii) collectively, all metering components integrate to provide a functioning system; and
   (c) each metering installation for which it is responsible is correctly and accurately integrated within the associated metering infrastructure.

(2) Subclause (1) does not apply to an electrically disconnected metering installation for an ICP.


Approved test houses and ATHs

10.40 General requirements for approval as ATH
(1) A person wishing to be approved as an ATH, or an ATH wishing to renew its approval, must apply to the Authority—
   (a) at least 2 months before the intended effective date of the approval or renewal; and
   (b) in writing; and
   (c) in the prescribed form; and
   (d) in accordance with Schedule 10.3.

(2) A person making an application must satisfy the Authority (providing, where appropriate, suitable evidence) that the person—
   (a) has the facilities and procedures to reliably meet, for the requested term of the approval, the minimum requirements of this Code for the class or classes of ATH for which it is seeking approval; and
   (b) has had an audit under Part 16A; and
   (c) is a fit and proper person for approval.

(3) Any approved test house operated solely by an ATH is, for all purposes of this Code and the Act, deemed to be approved in accordance with the procedures in the Code.


10.41 Requirements applying to ATHs
An ATH must, when carrying out activities under this Part,—
   (a) only carry out activities for which it has been approved by the Authority; and
   (b) exercise a degree of skill, diligence, prudence, foresight, and economic management, taking into account the technological complexity of the metering components and metering installations being tested—
      (i) determined by reference to good industry practice; and
      (ii) that would reasonably be expected from a skilled and experienced ATH engaged in the management and operation of an approved test house; and
   (c) comply with all applicable safety, employment, environmental, and other enactments; and
   (d) exercise any discretion given to it under this Part by—
      (i) taking into account the relevant circumstances of the particular instance; and
      (ii) acting professionally; and
   (e) record the manner in which it carried out its activities and its reasons for carrying the activities out in that manner.

10.42 ATH’s functions and ongoing obligations
(1) An ATH must comply with this Code including Schedules 10.4, 10.7, and 10.8.
(2) An ATH must, if this Part requires an ATH to complete a function or activity before a metering installation is certified, complete the function or activity as part of the process undertaken to obtain certification for the metering installation.

   Metering installations that are inaccurate, defective, or not fit for purpose

10.43 Metering installations that are inaccurate, defective, or not fit for purpose to be
investigated

(1) For the purposes of this clause and clauses 10.44 to 10.48, a metering installation is—
(a) accurate, if it is within the applicable accuracy tolerances set out in Table 1 of Schedule 10.1;
(b) inaccurate, if it is outside the applicable accuracy tolerances set out in Table 1 of Schedule 10.1.

(2) A participant must comply with this clause and clauses 10.44 to 10.48 if—
(a) in the case of a metering equipment provider, it is advised under subclause (3)(a); or
(b) it becomes aware of an event or circumstance that leads it to believe a metering installation is or could be—
   (i) inaccurate; or
   (ii) defective; or
   (iii) not fit for purpose.

(3) A participant referred to in subclause (2)(b), other than the metering equipment provider responsible for the metering installation, must—
(a) advise the metering equipment provider responsible for the metering installation that it has become aware of an event or circumstance that leads it to believe the metering installation is or could be—
   (i) inaccurate; or
   (ii) defective; or
   (iii) not fit for purpose; and
(b) include, with the advice (if and to the extent they are known), all relevant details.

(4) A metering equipment provider must, if it is advised under subclause (3)(a), or becomes aware as referred to in subclause (2)(b), within the period set out in subclause (5),—
(a) investigate—
   (i) if it is advised under subclause (3)(a), the event or circumstance that it is advised of; or
   (ii) if it becomes aware as referred to in subclause (2)(b), the event or circumstance that leads it to believe the metering installation is or could be—
      (A) inaccurate; or
      (B) defective; or
      (C) not fit for purpose; and
(b) complete, or arrange the completion of, a report that contains details of the metering equipment provider’s investigation, its conclusion, and the reasons for its conclusion; and
(c) provide the report to all affected participants.

(5) The time period for the purposes of subclause (4) is as soon as reasonably practicable, but no later than—
(a) 20 business days after becoming aware of the event or circumstance, for a category 1 metering installation;
(b) 10 business days after becoming aware of the event or circumstance, for a
10.44 Metering installations that are inaccurate, defective, or not fit for purpose to be tested

(1) A metering equipment provider must, if a report provided under clause 10.43(4)(c) demonstrates that a metering installation for which it is responsible is inaccurate, defective, or not fit for purpose—
   (a) arrange testing of the metering installation by an ATH; and
   (b) arrange the provision of a statement of situation referred to in clause 10.46 by the ATH.

(2) If the report demonstrates that a metering installation is accurate, not defective, and fit for purpose, a participant who believes that the metering installation is inaccurate, defective, or not fit for purpose, may require testing of the metering installation by—
   (a) advising the metering equipment provider responsible for the metering installation, within 5 business days of receiving the report, of—
      (i) its reasons for requiring testing; and
      (ii) the scope of the testing required; and
   (b) using its best endeavours to agree with the metering equipment provider on an ATH who will test the metering installation and provide a statement of situation under subclause (1).

(3) A metering equipment provider who has been advised under subclause (2)(a) that a participant believes that a metering installation, for which the metering equipment provider is responsible, requires testing, must arrange for an ATH—
   (a) to test the metering installation; and
   (b) to provide the metering equipment provider with a statement of situation under subclause (1)(b) within 5 business days of—
      (i) becoming aware that a metering installation for which it is responsible may be inaccurate, defective, or not fit for purpose under subclause (1); or
      (ii) reaching an agreement with the participant under subclause (2)(b).

(4) If the metering equipment provider and the participant requesting the test under subclause (2) cannot, within 5 business days of the metering equipment provider being advised under subclause (2)(a), agree on an ATH, either participant may advise the Authority, including the reasons, if and to the extent known, why agreement was not reached.

(5) The Authority must, within 5 business days of being advised under subclause (4), advise the metering equipment provider of the ATH that it must instruct to carry out the testing and to provide a statement of situation under subclause (1)(b).

(6) The metering equipment provider must instruct the ATH referred to in subclause (5) within 5 business days of being advised by the Authority.

(7) The metering equipment provider must ensure that the ATH, as soon as practicable after being contracted under subclause (1) or subclause (5), carries out the required testing and delivers the statement of situation to the metering equipment provider.
(8) Despite anything else in this Code, a participant is in breach of this Code from when the tests carried out by an ATH under this clause demonstrate that a metering installation is—
   (a) inaccurate; or
   (b) defective; or
   (c) not fit for purpose.

10.45 Investigation and testing costs
The ATH’s costs incurred by the metering equipment provider under clause 10.44 must be borne by—
   (a) the metering equipment provider, if the investigation or test demonstrates that the metering installation is—
      (i) defective; or
      (ii) inaccurate; or
      (iii) not fit for purpose; or
   (b) the participant who required that the metering installation be investigated or tested, if the investigation or test demonstrates that the metering installation is—
      (i) not defective; and
      (ii) accurate; and
      (iii) fit for purpose.

10.46 Statement of situation
(1) A statement of situation provided by an ATH under clause 10.44(1)(b) must include—
   (a) details of the tests carried out; and
   (b) results of the tests carried out; and
   (c) full details of what was found; and
   (d) conclusions of whether the metering installation is—
      (i) accurate:
      (ii) defective:
      (iii) fit for purpose; and
   (e) the reasons for the conclusions in paragraph (d); and
   (f) an assessment of the risk to the completeness and accuracy of the raw meter data; and
   (g) the details of any remedial action proposed or undertaken; and
   (h) any correction factors to apply to raw meter data to ensure that the volume information is accurate; and
   (i) the period over which the correction factor must be applied to the raw meter data.
(2) A metering equipment provider must, within 3 business days of receiving the statement of situation, provide copies of it—
   (a) to the relevant affected participants for all metering installations; and
   (b) to the Authority—
      (i) for all category 3 and above metering installations; and
(ii) if requested by the Authority, for each category 1 metering installation and each category 2 metering installation.


10.47 Correction of defects and inaccuracies in metering installation

An ATH must, when taking action to remedy an inaccuracy or defect within a metering installation, ensure that records of any modifications that are carried out to the metering installation are kept for each metering component of the metering installation in the metering records and in a manner reasonable in the circumstances to ensure that further investigation can be carried out.

10.48 Correction of defects and inaccuracies in raw meter data

(1) A participant may, within 40 business days of receiving a statement of situation under clause 10.46(2), advise the metering equipment provider of any questions, or requests for clarification, it has in relation to the corrections needed to the raw meter data from the metering installation.

(2) A metering equipment provider must, within 10 business days of being advised under subclause (1), respond in detail to the questions or requests for clarification.

(3) A metering equipment provider must, within 10 business days of being advised under subclause (1), advise the reconciliation participant responsible for providing submission information for the point of connection, of the correction factors referred to in clause 10.46(1)(h) and the period referred to clause 10.46(1)(i).

(4) The reconciliation participant must apply the correction factors advised under subclause (3), for the period advised under subclause (3), to the raw meter data to obtain more accurate information as required under clause 15.12.

NSP table

10.49 NSP table

(1) The Authority must publish an NSP table.

(2) The reconciliation manager must advise the Authority of any change to the information contained in the NSP table within 1 business day of becoming aware of such change.

(3) The Authority must update the NSP table within 2 business days of being advised by the reconciliation manager under subclause (2).

Clause 10.49(2) and (3): amended, on 5 October 2017, by clause 179(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

Dispute resolution
10.50 Dispute resolution

(1) A participant must, in good faith, use its best endeavours to resolve any dispute with any other person about a matter dealt with in this Part.

(2) A participant may refer any dispute or failure to reach agreement within the required timeframe in this Part to the Authority for determination.

(3) A complaint may, if it is not resolved under subclause (1), or by determination of the Authority under subclause (2), be referred to the Rulings Panel in accordance with subpart 4 of Part 2 of the Act and the regulations, by the Authority or a participant.

(4) When determining a dispute, or failure to reach agreement, under subclause (2), the Authority must do so in a way that—
   (a) is consultative with the parties involved; and
   (b) encourages the parties, where possible, to work together on matters that are agreed; and
   (c) takes into account the costs to be borne by, and the benefits that would accrue to, the participants involved; and
   (d) maximises the use of informal means to resolve the dispute or conclude an agreement.

(5) The existence of a dispute or failure to reach agreement does not excuse a participant from complying with this Code.

(6) A participant’s obligations in this clause are subject to the Act and the regulations.

Transitional provisions

10.51 Transitional provisions

(1) In this clause—
   (a) Part 10 means Part 10 of the Code that was effective prior to 29 August 2013; and
   (b) reference to a COP means a code of practice under Part 10.

(2) The intent of this clause is—
   (a) as far as practicable, to preserve the effect of Part 10, prior to 29 August 2013; and
   (b) to clarify that a breach of Part 10 will subsist as a breach of the Code, despite the coming into force of this Part; and
   (c) to clarify that disputes and complaints about breaches under Part 10 must be resolved under this Part, and to provide the procedure to ensure that will happen; and
   (d) to clarify that certain exemptions, authorisations, and code of practice variations under Part 10 will remain in force in accordance with their terms, as if they had been made under this Part; and
   (e) to clarify the effect of certain contractual arrangements after this Part comes into force; and
   (f) to clarify the effect of a participant being in compliance with certain of the provisions in Part 10, after this Part comes into force.

(3) A certification, as at 28 August 2013, of—
   (a) a metering installation—
(i) as a category 1 metering installation that had interim certification under Part 10, continues under this Part until 1 April 2015; and
(ii) as a category 6 metering installation, continues as a category 5 metering installation and otherwise in accordance with the terms of the certification; and
(iii) as any other category, continues under this Part in accordance with the terms of the certification; and

(b) a metering component continues under this Part in accordance with the terms of the certification.

(4) An audit that was carried out under the Code by an auditor, that was completed, immediately prior to 29 August 2013, continues to have the effect and status of an audit under this Part.

(5) The following persons certified and approved by the Electricity Commission or the Authority, under the Code, immediately prior to 29 August 2013, remain, for all purposes of this Part, certified and approved by the Authority, in accordance with the terms and scope of the relevant certification and approval as if such certification and approval had been issued under this Part:

(a) an auditor; and
(b) an approved test house, which will be approved as an ATH under this Part.

(6) The following continue in effect despite anything else in, or the coming into force of, this Part, to the extent that they relate to or concern the same, or similar, obligations under this Part, and will apply to a participant’s obligations under or compliance with, the relevant obligation under this Part:

(a) an approval for an alternative quality management system previously issued under clauses 4(4) and 6(12) of COP 10.2:
(b) an approval for an alternative standard previously issued under clause 3(4) of COP 10.2 and clause 2 of COP 10.2 and 10.3:
(c) a variation under clause 3(15) or 4(7) to 4(9) of COP 10.3:
(d) a temporary certification under clause 9(17) of COP 10.3:
(e) an alternative standard that an approved test house has used in the certification of a metering installation under clause 2 of COP 10.3 and clause 2 of COP 10.4:
(f) a variation approved by the market administrator under COP 10.5:
(g) a statistical sampling process under clause 5(18) of COP 10.3:
(h) an exemption under section 11 of the Act.

(7) An ATH must, if it has certified a metering installation using an alternative standard referred to in subclause (6)(e), in accordance with Part 10, advise the Authority of that alternative standard within 3 business days of 29 August 2013.

(8) The following continue in effect, despite anything else in, or the coming into force of, this Part, to the extent that they relate to or concern the same, or similar, obligations under this Part, and apply to a participant’s obligations under or compliance with, the relevant obligation under this Part:

(a) calibration intervals referred to in clause 6(1) of COP 10.2; and
(b) the maximum intervals between inspections referred to in clause 9(2) of COP 10.3, provided that if the date by which the next inspection would, under this Part,
be later, then such later date will apply.

(9) Despite anything else in, or the coming into force of, this Part—
   (a) clause 10.4 and clauses 10.12 to 10.15 of Part 10 continue to apply insofar as they relate to all raw meter data interrogated and processed under Part 10, on which submission information is based that is still subject to the reconciliation process under Part 15, until the reconciliation process for the submission information has been concluded in accordance with Part 15; and
   (b) clauses 10.7(b) and (c) of Part 10 continue to apply in relation to all raw meter data recorded before 29 August 2013; and
   (c) an approved test house’s obligations under clauses 5(16) and 5(17) of COP 10.2 and clause 4(12) of COP 10.3 will continue in accordance with their terms in relation to all records created before 29 August 2013.

(10) If a participant is a party to an arrangement, assignment, or contract (including an agency agreement) previously entered into under clauses 10.2, 10.3, or 10.6 of Part 10 in relation to a participant’s responsibilities under Part 10 and a provision in that arrangement, assignment, or contract is inconsistent with this Part, the provision ceases to be effective from 29 August 2013, but this is without prejudice to any existing disputes under such arrangements, assignments, or contracts, that must be resolved between the relevant persons concerned in accordance with the arrangement, assignment, or contract as if it remained effective.

(11) Despite anything else in, or the coming into force of, this Part—
   (a) any dispute concerning a metering installation, metering data, raw meter data, and all related matters that were in existence immediately before 29 August 2013,—
      (i) remain in existence; and
      (ii) may be resolved under clause 10.50; and
   (b) any breaches or alleged breaches of Part 10, and investigations of rule breaches or alleged rule breaches under Part 10, are unaffected and must be concluded as if the relevant provisions alleged to have been breached, under Part 10, and the relevant Part 10 definitions remain in force; and
   (c) any rule breaches or alleged rule breaches described in paragraph (b) will be dealt with by the Authority and the Rulings Panel under clause 10.50 and the Act.

(12) Despite anything else in, or the coming into force of, this Part, subclause (13) applies to a participant who was immediately prior to 29 August 2013 responsible under Part 10 for—
   (a) measuring the quantity of electricity at any metering installation; or
   (b) estimating the quantity of unmetered load.

(13) A participant described in subclause (12), who is responsible for volume information which has not, at 29 August 2013, been submitted to the reconciliation manager in accordance with Part 15 must complete the submission of the volume information to the reconciliation manager in accordance with Part 10, as if that Part remained effective.

(14) Despite anything else in, or the coming into force of, this Part, a participant who is responsible for a metering installation under Part 10, immediately prior to 29 August
2013 must remain in compliance with—

(a) clauses 10.7(b) and 10.7(c) of Part 10, in respect of raw meter data kept before 29 August 2013, and does not breach any of the corresponding obligations in this Part, provided that the participant keeps the raw meter data in compliance with clauses 10.7(b) and 10.7(c) of Part 10; and

(b) clause 10 of COP 10.3, in respect of records kept before 29 August 2013, and does not breach any of the corresponding obligations in this Part, provided that the participant keeps the records in compliance with rule 10 of COP 10.3.

(15) The following procedures commenced before, but not completed by, 29 August 2013 are not valid unless they are completed in compliance with this Part:

(a) metering installation tests; and

(b) audits of an approved test house under Part 10 (which must be completed as an audit of an ATH under this Part).

(16) The obligations of a metering equipment provider expressed in this Part as applying in relation to arranging certification of a metering installation or a metering component after 29 August 2013 do not apply to—

(a) a metering installation referred to in subclause (3)(a);

(b) a metering component referred to in subclause 3(b).


### Schedule 10.1 Tables

**Table 1: Metering installation characteristics and associated requirements**

<table>
<thead>
<tr>
<th>Metering installation category</th>
<th>Primary voltage (V)</th>
<th>Primary current (I)</th>
<th>Measuring transformers</th>
<th>Metering installation certification type</th>
<th>Accuracy tolerances</th>
<th>Selected component metering installation minimum IEC class (more accurate components may be used)</th>
<th>Maximum metering installation certification and inspection validity period</th>
<th>Maximum sample inspection and recertification period</th>
<th>Inspection period</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>V &lt; 1kV</td>
<td>I ≤ 160A</td>
<td>None</td>
<td>NHH or HHR</td>
<td>± 2.5%</td>
<td>0.6%</td>
<td>180 months</td>
<td>84 months</td>
<td>120 months ± 6 months</td>
</tr>
<tr>
<td>2</td>
<td>V &lt; 1kV</td>
<td>I ≤ 500A</td>
<td>CT</td>
<td>NHH or HHR</td>
<td>± 2.5%</td>
<td>0.6%</td>
<td>120 months</td>
<td>N/A</td>
<td>120 months ± 6 months</td>
</tr>
<tr>
<td>3</td>
<td>V &lt; 1kV</td>
<td>500A &lt; I ≤ 1200A</td>
<td>CT</td>
<td>HHR only</td>
<td>± 1.25%</td>
<td>0.3%</td>
<td>120 months</td>
<td>N/A</td>
<td>60 months ± 3 months</td>
</tr>
<tr>
<td></td>
<td>1kV ≤ V ≤ 11kV</td>
<td>I ≤ 100A</td>
<td>VT &amp; CT</td>
<td>HHR only</td>
<td>± 1.25%</td>
<td>0.3%</td>
<td></td>
<td>N/A</td>
<td></td>
</tr>
<tr>
<td></td>
<td>11kV &lt; V ≤ 22kV</td>
<td>I ≤ 50A</td>
<td>VT &amp; CT</td>
<td>HHR only</td>
<td>± 1.25%</td>
<td>0.3%</td>
<td></td>
<td>N/A</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>V &lt; 1kV</td>
<td>I &gt; 1200A</td>
<td>CT</td>
<td>HHR only</td>
<td>± 1.25%</td>
<td>0.3%</td>
<td>60 months</td>
<td>N/A</td>
<td>30 months ± 3 months</td>
</tr>
<tr>
<td></td>
<td>1kV ≤ V ≤ 6.6kV</td>
<td>100A &lt; I ≤ 400A</td>
<td>VT &amp; CT</td>
<td>HHR only</td>
<td>± 1.25%</td>
<td>0.3%</td>
<td></td>
<td>N/A</td>
<td></td>
</tr>
<tr>
<td></td>
<td>6.6kV &lt; V ≤ 11kV</td>
<td>100A &lt; I ≤ 200A</td>
<td>VT &amp; CT</td>
<td>HHR only</td>
<td>± 1.25%</td>
<td>0.3%</td>
<td></td>
<td>N/A</td>
<td></td>
</tr>
<tr>
<td></td>
<td>11kV &lt; V ≤ 22kV</td>
<td>50A &lt; I ≤ 100A</td>
<td>VT &amp; CT</td>
<td>HHR only</td>
<td>± 0.75%</td>
<td>0.2%</td>
<td>36 months</td>
<td>N/A</td>
<td>18 months ± 1 month</td>
</tr>
</tbody>
</table>
Table 2: Maximum certification validity periods for the purposes of clause 1(2) of Schedule 10.8

<table>
<thead>
<tr>
<th>Metering installation category</th>
<th>Class 0.2 meter (months)</th>
<th>Class 0.5 meter (months)</th>
<th>Class 1.0 meter (months)</th>
<th>Class 2.0 meter (months)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>180</td>
<td>180</td>
<td>180</td>
<td>180</td>
</tr>
<tr>
<td>2</td>
<td>120</td>
<td>120</td>
<td>120</td>
<td>120</td>
</tr>
<tr>
<td>3 where V&lt;1kV</td>
<td>120</td>
<td>120</td>
<td>120</td>
<td>N/A</td>
</tr>
<tr>
<td>3 where V≥1kV</td>
<td>120</td>
<td>120</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>4</td>
<td>60</td>
<td>60</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>5</td>
<td>36</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>
### Table 3: Selected component certification and comparative recertification minimum test requirements

<table>
<thead>
<tr>
<th>Event</th>
<th>Design</th>
<th>Measuring transformer</th>
<th>Meter</th>
<th>Primary injection to meter</th>
<th>Prevailing load</th>
<th>Data storage device</th>
<th>Software security and communication equipment</th>
<th>Control device</th>
<th>Wiring check</th>
<th>Component certification check</th>
<th>Review of compensation factors</th>
<th>Raw meter data output</th>
<th>Supply polarity</th>
<th>Register advance</th>
<th>Installation or component configuration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial certification category 1</td>
<td>M</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Initial certification categories 2 and 3</td>
<td>M</td>
<td></td>
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<tr>
<td>Recertification of category 1 if the meter is not replaced and recertification of categories 2 and 3</td>
<td>M</td>
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<tr>
<td>Recertification category 1 where meter is replaced with a certified meter</td>
<td>M</td>
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<tr>
<td>Meter change including internal data storage devices</td>
<td>M</td>
<td>M</td>
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</tr>
<tr>
<td>Metrology change either onsite or remote</td>
<td>M</td>
<td>M</td>
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<tr>
<td>External data storage device change</td>
<td>M</td>
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<tr>
<td>Measuring transformer change or ratio change</td>
<td>M</td>
<td>M</td>
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<tr>
<td>Control device change</td>
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<tr>
<td>Additional equipment (eg wiring)</td>
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<td>M</td>
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<td>M</td>
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<td>M</td>
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</tbody>
</table>

Key: M = mandatory, MI = mandatory if the control device is integral with the meter.

Table 3: row 3 amended, on 19 December 2014, by clause 21 of the Electricity Industry Participation Code Amendment (Minor Code Amendments) (No 3) 2014.
## Table 4: Fully calibrated certification minimum test requirements

<table>
<thead>
<tr>
<th>Event</th>
<th>Design</th>
<th>Measuring transformer</th>
<th>Meter</th>
<th>Primary injection to meter</th>
<th>Prevailing load</th>
<th>Data storage device</th>
<th>Software security and communication equipment</th>
<th>Control device check</th>
<th>Wiring check</th>
<th>Component certification check</th>
<th>Review of compensation factors</th>
<th>Raw meter data output</th>
<th>Supply polarity</th>
<th>Register advance</th>
<th>Installation or component configuration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial certification</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>T</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
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<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
</tr>
<tr>
<td>Recertification</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
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<tr>
<td>Meter change including internal data storage device</td>
<td>M</td>
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<tr>
<td>Metrology change either onsite or remote</td>
<td>M</td>
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<tr>
<td>External data storage device change</td>
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<tr>
<td>Measuring transformer change or ratio change</td>
<td>M</td>
<td>M</td>
<td>T</td>
<td>M</td>
<td>M</td>
<td>M</td>
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<tr>
<td>Control device change</td>
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<tr>
<td>Additional equipment (eg wiring)</td>
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</tr>
<tr>
<td>Initial certification</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>T</td>
<td>M</td>
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<td>Recertification</td>
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<td>M</td>
</tr>
</tbody>
</table>

Key: M = mandatory, T = mandatory if test method and test equipment permit, MI = mandatory if the control device is integral with the meter.
Table 5: Standards for metering components

<table>
<thead>
<tr>
<th>Meter and data storage device standards</th>
<th>Standards</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity metering equipment (AC) – Part 1: General requirements, tests and test conditions (classes 0.5, 1 and 2)</td>
<td>EN 50470-1</td>
</tr>
<tr>
<td>Electricity metering equipment (AC) – Part 2: Particular requirements – Electromechanical meters for active energy (classes 1 and 2)</td>
<td>EN 50470-2</td>
</tr>
<tr>
<td>Electricity metering equipment (AC) – Part 3: Particular requirements – Static meters for active energy (classes 0.5, 1 and 2)</td>
<td>EN 50470-3</td>
</tr>
<tr>
<td>Electricity metering equipment (AC) – Particular requirements – Part 11: Electromechanical meters for active energy (classes 0.5, 1 and 2)</td>
<td>IEC 62053-11</td>
</tr>
<tr>
<td>Electricity metering equipment (AC) – Particular requirements – Part 21: Static meters for active energy (classes 1 and 2)</td>
<td>IEC 62053-21</td>
</tr>
<tr>
<td>Electricity metering equipment (AC) – Particular requirements – Part 22: Static meters for active energy (classes 0.2 S and 0.5 S)</td>
<td>IEC 62053-22</td>
</tr>
<tr>
<td>Electricity metering equipment (AC) – Particular requirements – Part 23: Static meters for reactive energy (classes 2 and 3)</td>
<td>IEC 62053-23</td>
</tr>
<tr>
<td>Electricity metering equipment (AC) – Particular requirements – Part 61: Power consumption and voltage requirements</td>
<td>IEC 62053-61</td>
</tr>
<tr>
<td>Electricity metering equipment (AC) – General requirements, tests and test conditions – Part 11: Metering equipment</td>
<td>IEC 62052-11</td>
</tr>
</tbody>
</table>

Measuring transformer standards

| Instrument transformers – Part 1: Current transformers | IEC 60044-1 |
| Instrument transformers – Part 2: Inductive voltage transformers | IEC 60044-2 |
| Instrument transformers – Part 3: Combined transformers | IEC 60044-3 |
| Instrument transformers – Part 5: Capacitor voltage transformers | IEC 60044-5 |
| Coupling capacitors and capacitor dividers | IEC 60358 |
| Instrument transformers – Part 7: Electronic voltage transformers | IEC 60044-7 |
| Instrument transformers – Part 8: Electronic current transformers | IEC 60044-8 |

Other standards

| Electricity metering equipment (AC) – Tariff and load control – Part 11: Particular requirements for electronic ripple control receivers | IEC 62054-11 |
| Electricity metering equipment (AC) – Tariff and load control – Part 21: Particular requirements for time switches | IEC 62054-21 |

### Table 6: Standards of accuracy and overall uncertainty for active and reactive meter calibration and testing

<table>
<thead>
<tr>
<th>Value of Current %</th>
<th>Power Factor</th>
<th>Maximum Overall Uncertainty %</th>
<th>Percentage Error Limits of Meter, Including Uncertainty</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Class of meter 2.0 and 2.0S</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5 to 120</td>
<td>1</td>
<td>±0.4</td>
<td>±1.9</td>
</tr>
<tr>
<td>10 to 120</td>
<td>0.5 lagging</td>
<td>±0.6</td>
<td>±1.9</td>
</tr>
<tr>
<td>10 to 120</td>
<td>0.8 leading</td>
<td>±0.6</td>
<td>±1.9</td>
</tr>
<tr>
<td><strong>Class of meter 1.0 and 1.0S</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5 to 120</td>
<td>1</td>
<td>±0.2</td>
<td>±0.9</td>
</tr>
<tr>
<td>10 to 120</td>
<td>0.5 lagging</td>
<td>±0.25</td>
<td>±0.9</td>
</tr>
<tr>
<td>10 to 120</td>
<td>0.8 leading</td>
<td>±0.25</td>
<td>±0.9</td>
</tr>
<tr>
<td><strong>Class of meter 0.5 and 0.5S</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5 to 120</td>
<td>1</td>
<td>±0.1</td>
<td>±0.5</td>
</tr>
<tr>
<td>10 to 120</td>
<td>0.5 lagging</td>
<td>±0.12</td>
<td>±0.6</td>
</tr>
<tr>
<td>10 to 120</td>
<td>0.8 leading</td>
<td>±0.12</td>
<td>±0.6</td>
</tr>
<tr>
<td><strong>Class of meter 0.2S</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5 to 120</td>
<td>1</td>
<td>±0.06</td>
<td>±0.2</td>
</tr>
<tr>
<td>10 to 120</td>
<td>0.5 lagging</td>
<td>±0.09</td>
<td>±0.3</td>
</tr>
<tr>
<td>10 to 120</td>
<td>0.8 leading</td>
<td>±0.09</td>
<td>±0.3</td>
</tr>
<tr>
<td><strong>Class of meter 3.0 reactive</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>20 to 120</td>
<td>Zero</td>
<td>±1.0</td>
<td>±3.0</td>
</tr>
<tr>
<td>20 to 120</td>
<td>0.8 leading</td>
<td>±1.5</td>
<td>±3.5</td>
</tr>
<tr>
<td>20 to 120</td>
<td>0.8 lagging</td>
<td>±1.5</td>
<td>±3.5</td>
</tr>
<tr>
<td><strong>Class of meter 2.0 reactive</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>20 to 120</td>
<td>Zero</td>
<td>±0.5</td>
<td>±2.0</td>
</tr>
<tr>
<td>20 to 120</td>
<td>0.8 leading</td>
<td>±1.0</td>
<td>±2.5</td>
</tr>
<tr>
<td>20 to 120</td>
<td>0.8 lagging</td>
<td>±1.0</td>
<td>±2.5</td>
</tr>
</tbody>
</table>
### Table 7: Voltage, current, and phase displacement parameters for polyphase meters

<table>
<thead>
<tr>
<th>Polyphase meters</th>
<th>Class of meter</th>
<th>0.2 and 0.5</th>
<th>1.0</th>
<th>2.0</th>
<th>3.0</th>
</tr>
</thead>
<tbody>
<tr>
<td>Each of the voltages between line and neutral or between any 2 lines will not differ from the average corresponding voltage by more than:</td>
<td>±0.1%</td>
<td>±1.0%</td>
<td>±1.0%</td>
<td>±1.0%</td>
<td></td>
</tr>
<tr>
<td>Each of the currents in the conductors will not differ from the average current by more than:</td>
<td>±1.0%</td>
<td>±2.0%</td>
<td>±2.0%</td>
<td>±2.0%</td>
<td></td>
</tr>
<tr>
<td>The phase displacements of each of these currents from the corresponding line-to-neutral voltage, irrespective of the power factor, will not differ from each other by more than:</td>
<td>2°</td>
<td>2°</td>
<td>2°</td>
<td>2°</td>
<td></td>
</tr>
</tbody>
</table>

Table 8: Required minimum sample size for category 1 metering installation inspections required under clause 45(2)(c) of Schedule 10.7

<table>
<thead>
<tr>
<th>Number of metering installations identified</th>
<th>Minimum sample size</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>2-8</td>
<td>2</td>
</tr>
<tr>
<td>9-15</td>
<td>3</td>
</tr>
<tr>
<td>16-25</td>
<td>5</td>
</tr>
<tr>
<td>26-50</td>
<td>8</td>
</tr>
<tr>
<td>51-90</td>
<td>13</td>
</tr>
<tr>
<td>91-150</td>
<td>20</td>
</tr>
<tr>
<td>151-280</td>
<td>32</td>
</tr>
<tr>
<td>281-500</td>
<td>50</td>
</tr>
<tr>
<td>501-1200</td>
<td>80</td>
</tr>
<tr>
<td>1201-3200</td>
<td>125</td>
</tr>
<tr>
<td>3201-10,000</td>
<td>200</td>
</tr>
<tr>
<td>10,001-35,000</td>
<td>315</td>
</tr>
<tr>
<td>35,001-150,000</td>
<td>500</td>
</tr>
<tr>
<td>150,001+</td>
<td>800</td>
</tr>
</tbody>
</table>
Schedule 10.2

[Revoked]

Schedule 10.2: revoked, on 1 June 2017, by clause 10 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Schedule 10.3

ATHs – approval, expiry, cancellation, and renewal of approval

1 Applications for approval and renewal of approval

(1) A person wishing to be approved as an ATH, or an ATH wishing to renew its approval, must apply, in the prescribed form, to the Authority at least 2 months before the intended effective date of the approval or renewal.

(2) An applicant must—
   (a) include in its application—
       (i) the final audit report obtained under Part 16A, together with its responses to the report; and
       (ii) a copy of any quality management certificates it holds; and
       (iii) a copy of its most recent quality management audit report; and
       (iv) the class of ATH for which it is seeking approval; and
       (v) the functions under clauses 3(2) and 4(2) for which it is seeking approval; and
       (vi) the calibration expiry date of each of its working standards and reference standards; and
   (b) provide promptly any other information or documentation the Authority may reasonably request.

(3) The Authority must, within 2 months of receiving an application, advise the applicant of—
   (a) the approval of the application, if the applicant satisfies the Authority that it has met the requirements set out in clause 10.40; or
   (b) the declination of the application, providing reasons, if the Authority considers that—
       (i) the information supplied by the applicant is incomplete or unsatisfactory; or
       (ii) the applicant otherwise fails to demonstrate that it would be, and would remain for the period and functions for which the application is made, compliant with the requirements set out in clause 10.40.

(4) If an application is approved, the Authority must issue a certificate of approval specifying the—
   (a) period of the term of approval, which must not exceed 12 months from the date of approval; and
   (b) functions that the applicant has been approved to carry out; and
   (c) [Revoked]
   (d) date of approval.

Clause 1(4)(c): revoked, on 1 June 2017, by clause 11(2) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
2 \[Revoked\]
Clause 2: revoked, on 1 June 2017, by clause 12 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

3 Approval of class A ATHs

(1) An applicant applying for approval, or renewal of approval, as a class A ATH must, as part of its application, confirm that—
   (a) it holds and complies with AS/NZS ISO 17025 accreditation, for at least the requested term of the approval; and
   (b) the scope of its AS/NZS ISO 17025 accreditation covers the activities that it undertakes, or proposes to undertake; and
   (c) it complies, and will be likely to continue to comply during the requested term of the approval, with any requirements of its ISO accreditation; and
   (d) if it proposes to carry out field work—
      (i) it is certified to the relevant AS/NZS ISO 9001:2008 or AS/NZS ISO 9001:2016 and will remain certified during the requested term of the approval; and
      (ii) the scope of its AS/NZS ISO 17025 accreditation has been extended to cover the carrying out of the field work.

(2) The Authority may approve an applicant to be, or renew an applicant’s approval as, a class A ATH to carry out 1 or more of the following functions:
   (a) calibration of—
      (i) working standards:
      (ii) metering components (other than a calibration referred to in paragraph (c)):
      (iii) metering installations:
   (b) issuing calibration reports:
   (c) calibration of metering components onsite:
   (d) installation and modification of metering installations:
   (e) installation and modification of metering components:
   (f) certification of all categories of metering installations under this Code, and issuing of certification reports:
   (g) testing of metering installations under clause 10.44 and production of statements of situation under clause 10.46:
   (h) inspection of metering installations.

(3) A class A ATH may only carry out 1 or more of the functions listed in subclause (2), subject to—
   (a) the current scope of its approval under subclause (2); and
   (b) any limitations that may be specified in the class A ATH’s AS/NZS ISO 17025 accreditation or the relevant AS/NZS ISO 9001:2008 or AS/NZS ISO 9001:2016 certification.

(4) The Authority may decline an application for approval as a class A ATH even if the applicant—
   (a) has obtained the necessary ISO accreditation or certification; or
(b) has obtained or satisfied any other pre-requisite to approval.
Clause 3(1)(d)(i) and 3(3)(b) amended, on 1 June 2017, by clause 13 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

4 Approval of class B ATHs

(1) An applicant applying for approval, or renewal of approval, as a class B ATH must, as part of its application to the Authority, confirm that—
(a) it holds and complies with AS/NZS ISO 9001:2008 or AS/NZS ISO 9001:2016 certification for at least the requested term of the approval; and
(b) the scope of its AS/NZS ISO 9001:2008 or AS/NZS ISO 9001:2016 certification covers the activities that it undertakes, or proposes to undertake; and
(c) it will develop and at all times during the requested term of the approval maintain a conflict of interest policy in compliance with AS/NZS ISO 17025.

(2) The Authority may approve an applicant to be, or renew an applicant’s approval as, a class B ATH to carry out 1 or more of the following functions:
(a) calibration of class 0.5 meters, class 1 meters and class 2 meters, and class 0.5 current transformers and class 1.0 current transformers, provided that the calibrations are carried out under their approved quality certification and in accordance with this Part, and included within the ATH audit for approval:
(b) installation and modification of metering installations:
(c) installation and modification of metering components:
(d) calibration of metering components onsite:
(e) certification, using the selected component certification method, of—
(i) category 1 metering installations:
(ii) category 2 metering installations:
(iii) category 3 metering installations with a primary voltage of less than 1kV:
(f) certification, using the fully calibrated certification method, of—
(i) category 1 metering installations:
(ii) category 2 metering installations:
(iii) category 3 metering installations with a primary voltage of less than 1kV:
(g) certification, using the comparative recertification method, of category 2 metering installations:
(h) issuing of certification reports in respect of certifications of metering installations under paragraphs (e) to (g):
(i) inspection of—
(i) category 1 metering installations:
(ii) category 2 metering installations:
(iii) category 3 metering installations with a primary voltage of less than 1kV.

(3) A class B ATH may only carry out 1 or more of the functions listed in subclause (2), subject to—
(a) the current scope of its approval under subclause (2); and
(b) any limitations that may be specified in the relevant AS/NZS ISO 9001:2008 or AS/NZS ISO 9001:2016 certification.
(4) The Authority may decline an application for approval as a class B ATH even if the applicant—
(a) has obtained the necessary ISO certification; or
(b) has obtained or satisfied any other pre-requisite to approval.
Clause 4(1)(a) and (b) amended, on 1 June 2017, by clause 14 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Clause 4(3)(b) amended, on 1 June 2017, by clause 14 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

(2) Subclause (1) is subject to Schedule 1 of the Act, which includes a requirement that the Authority must give notice in the Gazette before an amended AS/NZS ISO 9001:2008 or AS/NZS ISO 9001:2016 becomes incorporated by reference in this Code.
Clause 4A inserted, on 1 June 2017, by clause 15 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

5 Expiry and cancellation of approval
(1) If the Authority believes that an ATH is or was in breach of this Part the Authority may cancel the approval of the ATH with immediate effect by advising the ATH.
(2) An ATH must not, at any time after the expiry or cancellation of its approval, display or use its certificate of approval.

6 Changes that affect approval
(1) If an ATH intends to make a material change to any of its facilities, processes, or procedures, or the scope of the ATH’s ISO accreditation is reduced during the term of its approval, the ATH must, at least 5 business days before the change is to take place or reduction in scope is effected,—
(a) advise the Authority of all relevant details of the change or reduction in scope; and
(b) in the case of a material change, submit to the Authority an audit report confirming that, after the change has come into effect, the ATH will continue to meet the requirements under clause 10.40(2)(a).
(2) An ATH’s approval is automatically cancelled from the date of the change or reduction in scope under subclause (1), if the ATH fails to advise the Authority under subclause (1)(a).
(3) The Authority may, if it is advised by an ATH under subclause (1), either—
(a) cancel an ATH’s approval from the date that the Authority advises the ATH that the Authority is not satisfied that the ATH will continue to meet the requirements under clause 10.40(2)(a) after the change or reduction in scope has come into effect; or
(b) revise the scope of the ATH’s approval.

7 Notice of cancellation, expiry, or revision of scope of ATH approval

(1) The Authority must give written notice to all metering equipment providers if—
   (a) an ATH’s approval expires and the Authority does not renew it;
   (b) the Authority cancels an ATH’s approval under clause 5:
   (c) an ATH’s approval is cancelled under clause 6(2) or 6(3)(a):
   (d) the scope of an ATH’s approval has been revised under clause 6(3)(b).

(2) The Authority must include with the notice under subclause (1) the date on which the approval expired or was cancelled, or the scope of the approval was revised.

(3) A metering equipment provider given notice under subclause (1) must treat all metering installations certified by the ATH during the period during which it was not validly approved, or was performing activities outside its scope of approval, as being defective from the date of which the Authority gave notice under subclause (2) and follow the procedures set out in clauses 10.43 to 10.48.

(4) Despite subclause (3), the Authority may give a metering equipment provider written notice that the metering equipment provider must treat a metering installation certified by the ATH as being defective and follow the procedures set out in clauses 10.43 to 10.48.


8 Register of ATHs

(1) The Authority must, keep, maintain, and publish a register of approved ATHs.

(2) The Authority must remove an ATH’s details from the register if the ATH’s approval—
   (a) expires and the Authority does not renew it; or
   (b) is cancelled.
Schedule 10.4
ATH ongoing functions and obligations

1 Accommodation and environment
An ATH must, for each approved test house that it operates,—
(a) maintain a list of personnel who are authorised to access and use its laboratory and storage facilities; and
(b) restrict access to its laboratory and storage facilities to—
(i) the personnel specified under paragraph (a); and
(ii) the Authority; and
(iii) an auditor conducting an audit; and
(iv) any other person who is, at all times, directly supervised by a member of personnel specified under paragraph (a); and
(c) restrict access to its metering records to—
(i) the relevant metering equipment provider:
(ii) the Authority:
(iii) an auditor conducting an audit:
(iv) the relevant metering component owner; and
(d) ensure that the environment in which its activities are undertaken does not, or could not reasonably be expected to, invalidate test results or adversely affect the required accuracy of measurement; and
(e) monitor and record the environmental conditions within its approved test house’s laboratory and storage facilities; and
(f) comply with the specific requirements of the applicable standard listed in Table 5 of Schedule 10.1 for the calibrations or tests being carried out.


2 Equipment
(1) An ATH must, at all times, ensure that—
(a) it has access to all items of equipment required for the performance of the calibrations and tests it is approved to undertake under this Part; and
(b) each item of equipment it uses is maintained in accordance with the manufacturer’s recommendations and this Code (but if there is any inconsistency or contradiction between the manufacturer’s recommendations and this Code, this Code takes precedence); and
(c) it maintains records about each item of its equipment, including—
(i) details of—
(A) maintenance history; and
(B) the ATH’s maintenance programme; and
(ii) calibration reports, including before and after adjustment results; and
(iii) in-service checks; and
(iv) a history of any damage, malfunction, modification, or repair.
(2) A class B ATH must have and maintain procedures for the purchase of test equipment and associated consumables.

3 Reference standards and working standards

(1) An ATH must not use a reference standard or working standard for any activity regulated under this Part unless—

(a) in the case of—

(i) a reference standard, the reference standard has been calibrated by an approved calibration laboratory; or

(ii) a working standard, the working standard has been calibrated by an approved calibration laboratory or a class A ATH; and

(b) the current calibration report for the reference standard or working standard confirms that it—

(i) performs within the manufacturer’s accuracy specifications; and

(ii) has been calibrated under subclause (2) at an interval not exceeding the calibration intervals set out in the following table.

Table 1: Calibration intervals

<table>
<thead>
<tr>
<th>Standard</th>
<th>Initial calibration interval (months beginning from the date of the first calibration)</th>
<th>Maximum calibration interval (months beginning from the date of the current calibration report)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference standard or working standard (other than a working standard used for on-site calibration)</td>
<td>Measuring transformers</td>
<td>36</td>
</tr>
<tr>
<td>Comparator bridges</td>
<td></td>
<td>36</td>
</tr>
<tr>
<td>Meters</td>
<td></td>
<td>12</td>
</tr>
<tr>
<td>Power factor, voltage and current meters</td>
<td></td>
<td>12</td>
</tr>
<tr>
<td>Working standard used for on-site calibration</td>
<td>All</td>
<td>2</td>
</tr>
</tbody>
</table>

(2) An ATH must ensure that a reference standard or working standard is calibrated—

(a) for the first time, within the applicable initial calibration interval set out in Table 1 of subclause (1); and

(b) for each subsequent calibration, within the applicable maximum calibration interval set out in Table 1 of subclause (1).
(3) A class A ATH must ensure that—
(a) in all cases of calibration of its reference standards, the uncertainties given in the reference standard calibration report are sufficiently small so that the overall uncertainty in the measurements used to test a metering installation does not exceed one third of the maximum permitted error set out in Table 1 of Schedule 10.1 for the category of metering installation that the reference standard will be used to calibrate; and
(b) it does not use a working standard on a system operating at a voltage of 33kV or above between active conductors, unless the working standard has been calibrated by an approved calibration laboratory; and
(c) it does not use a reference standard, other than a standard measuring transformer, unless it is maintained at the appropriate reference conditions set out in the reference standard’s current calibration report.

(4) If appropriate reference conditions under subclause (3)(c) cannot be achieved, the class A ATH must calculate and apply adjustments in accordance with the processes and procedures under subclause (5) so that the reference standard achieves the errors and uncertainties set out in the reference standard’s current calibration report.

(5) An ATH must develop and maintain processes and procedures for calculating and applying adjustments to a reference standard’s errors and uncertainties to compensate for deviations from the reference conditions contained in the reference standard’s current calibration report.

(6) An ATH must retain a copy of the current calibration report for each of its reference standards and working standards.

4 Metering component testing systems
An ATH may use a complete calibrated metering component testing system (also known as a test bench) as an alternative to a separately calibrated working standard only if—
(a) the ATH calibrates the complete calibrated metering component testing system under clause 3 as if it was a working standard; and
(b) before completing the calibration report, the ATH carries out a testing system accuracy test, using approved reference standards.

5 Calibration errors
(1) For the purposes of this clause, a reference standard or working standard has a calibration error if it is performing outside of the manufacturer’s accuracy specifications.

(2) An ATH must not use a reference standard or working standard for calibration, if it believes, or should reasonably be expected in the circumstances to believe, that the reference standard or working standard has a calibration error.

(3) An ATH must, as soon as reasonably practicable, but no more than 3 months after becoming aware of a calibration error—
(a) investigate the error; and
(b) ensure the cause of the error is recorded in a **calibration report**; and  
(c) if the investigation indicates that the **reference standard** or **working standard**  
performs outside the manufacturer’s accuracy specifications, advise each **ATH**  
that has used any equipment that was **calibrated** using the **reference standard** or  
**working standard** since the previous **calibration**, of the error.  

(4) An **ATH** must, if a **reference standard** or a **working standard** has a **calibration**  
error,—  

(a) treat each **metering installation** that it has **calibrated** using the **reference  
standard** or **working standard** as outside the applicable accuracy tolerances set  
out in Table 1 of Schedule 10.1; and  
(b) comply with clause 10.43.  

(5) For the purposes of this clause, a **working standard** includes a complete **calibrated  
metering component** testing system referred to in clause 4.  

6 **Measurement traceability**  
An **ATH** must document, maintain, and comply with, a system that ensures, whenever it  
undertakes a **calibration** test or measurement,—  

(a) it keeps sufficient records to enable the **ATH** to replicate the test or measurement  
in every respect should the need arise; and  
(b) the results of the measurements are **traceable**.  

*Requirements for calibration of metering components*  

7 **Calibration methods**  
(1) An **ATH** must, before it **certifies** a **metering installation** or **metering component**,  
ensure that 1 of the following persons has **calibrated** the **metering components** under  
this Part:  

(a) an **approved calibration laboratory**; or  
(b) an **ATH** with the appropriate approval under Schedule 10.3.  

(2) An **ATH** must, before it **certifies** a **metering component**, ensure that the **metering  
component** is **calibrated** or **adjusted** under—  

(a) the appropriate physical and electrical reference conditions detailed in the  
standard listed in Table 5 of Schedule 10.1; or  
(b) conditions which permit the **ATH** to calculate the results and their **uncertainty** at  
the reference conditions detailed in the standard listed in Table 5 of Schedule 10.1.  

(3) A **class B ATH** must, when **calibrating** a **metering component**,—  

(a) follow all relevant requirements of NZ/AS ISO 17025 for **calibration**; and  
(b) only use the relevant methodologies that have been **audited** in the **class B ATH**’s  
most recent **audit** for approval.  

(4) If an **ATH calibrates** a **metering component**, it must ensure that the individual test  
points that it uses are—  

(a) no less than the minimum set out in the standards listed in Table 5 of Schedule  
10.1; or
(b) sufficient and appropriate in the circumstances to ensure that the calibration allows calculation of the metering installation error as set out in clause 22 of Schedule 10.7.

(5) An ATH must, when calibrating a metering component,—
   (a) if necessary, adjust and document the error compensation; and
   (b) ensure that any adjustment carried out under paragraph (a) is appropriate to achieve an error as close as practicable to zero; and
   (c) ensure that the uncertainty of measurement during the calibration of the metering component does not exceed one third of the maximum permitted error in the relevant standard listed in Table 5 of Schedule 10.1; and
   (d) if the metering component is intended for a metering installation which is to be certified using the selected component certification method, ensure that the ATH records the errors of a current transformer from 5% to 120% of rated primary current.

(6) An ATH must ensure that—
   (a) it has documented instructions on the use and operation of all relevant equipment it uses for calibration; and
   (b) it has documented calibration procedures that it must make available to, and ensure are followed by, its staff carrying out the calibration; and
   (c) its calibration procedures are aligned with the standards listed in Table 5 of Schedule 10.1.

(7) An ATH—
   (a) may select a test point other than those specified in the relevant standard listed in Table 5 of Schedule 10.1, or at a lower burden than specified in the standard; but
   (b) must, if it does this, document its reasons for the selection of these test points in the calibration report.

8 Compensation factors
An ATH must, if it is approved to certify metering installations, have a documented process for determining compensation factors.

9 Seals
An ATH must have a documented system for applying seals to a metering installation, that—
   (a) meets the requirements of clause 47 of Schedule 10.7; and
   (b) is appropriate in the circumstances to ensure—
      (i) the ATH’s ability to monitor the metering installation’s continued integrity; and
      (ii) the relevant metering equipment provider is alerted as soon as practicable to any unauthorised access to the metering installation.

10 Services access interface
An ATH must, when preparing a metering installation certification report,
determine, and record in the certification report, the services access interface.

11 Certification and calibration reports
(1) An ATH must, for each metering installation that it certifies, produce a certification report in accordance with Schedule 10.7.
(2) An ATH must, for each metering component—
   (a) that it calibrates, produce a calibration report in accordance with Schedule 10.8; and
   (b) that it certifies, produce a certification report in accordance with Schedule 10.8.

12 ATH record keeping and documentation
(1) An ATH must ensure it documents and maintains a record system for all records, certificates, and reports for any activity regulated under this Part.
(2) An ATH must ensure that—
   (a) all its records, certificates, and reports are stored securely; and
   (b) each of its test records for a metering installation is identified by a unique identifier; and
   (c) all of its records, certificates, and reports are sufficiently detailed to enable verification of all aspects of all tests it carries out, including the following:
      (i) test conditions; and
      (ii) specific test equipment used; and
      (iii) personnel carrying out the tests.

13 Retention of ATH records
An ATH must, for each activity regulated under this Part in relation to a metering installation and metering component that it certifies and a metering component that it calibrates, retain, for at least 48 months after the date of decommissioning the metering installation or removal of a metering component,—
   (a) all of its records, certificates, and reports; and
   (b) all certification reports produced by the ATH.

14 Making available of ATH records
An ATH must, within 5 business days of creating a record, certificate, or report for a metering installation that it certifies,—
   (a) send, in electronic form or such other form as may be agreed between the parties, a copy of the record, certificate, or report to the metering equipment provider responsible for the metering installation; and
   (b) ensure that the metering equipment provider receives the record, certificate, or report.

15 ATH organisation and management
(1) An ATH must ensure that—
   (a) it has managerial staff who, unless otherwise permitted in the relevant approval,
all have the authority and resources needed to discharge their duties; and
(b) the responsibilities, authority, and functional relationships of all its personnel are
fully and accurately specified and recorded in the ATH’s records.

(2) An ATH must appoint—
(a) a technical manager (however named) with overall responsibility for technical
operations, who must have appropriate engineering qualifications and experience
in the operation of an approved test house; and
(b) a quality manager (however named), with responsibility for the quality
management certification and the implementation of the quality management
system.

(3) An ATH must ensure that all staff who perform or supervise work or activities
regulated under this Part are technically competent, experienced, qualified, and trained
for the functions they perform.

16 Quality management system
An ATH must establish, document, implement, maintain, and comply with a quality
management system which records its processes and procedures to ensure compliance
with this Part.

17 Field work
A class A ATH must, if it arranges for another person to carry out field work, ensure
that person is certified to the relevant AS/NZS ISO 9001:2008 or AS/NZS
ISO 9001:2016 at all times while the person carries out the work.
Clause 17 amended, on 1 June 2017, by clause 16 of the Electricity Industry Participation Code Amendment
(Requirements and Processes for Audits) 2016.
Schedule 10.5

[Revoked]
Schedule 10.5: revoked, on 1 June 2017, by clause 17 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
1 Metering equipment provider must provide access to raw meter data

(1) A metering equipment provider must, within 10 business days of receiving a request from a trader with whom it has an arrangement to access raw meter data from a metering installation for which the metering equipment provider is responsible, give remote or onsite access at the services access interface to the trader to collect, obtain, and use raw meter data from the metering installation.

(2) A metering equipment provider may, if it receives a request from a person with whom it has an arrangement, other than a trader under subclause (1), to access raw meter data from a metering installation for which the metering equipment provider is responsible, give remote or onsite access at the services access interface to the person to collect, obtain, and use raw meter data from the metering installation.

(3) A metering equipment provider must only give access to a trader under subclause (1), or a person under subclause (2), if the trader or person has entered into a contract to collect, obtain, and use the raw meter data, with the consumer whose electricity is measured or estimated, or whose load is controlled at the metering installation.

(4) A metering equipment provider must, within 10 business days of receiving a request from 1 of the following parties, give the party access to raw meter data from a metering installation for which it is responsible:
   (a) a relevant reconciliation participant with whom it has an arrangement, other than a trader:
   (b) the Authority:
   (c) an ATH:
   (d) an auditor.

(5) A party listed in subclause (4) may only request access to raw meter data for the purposes of exercising the party’s rights and performing the party’s obligations under this Code or any relevant regulations in relation to 1 or more of the following:
   (a) the party’s audit functions:
   (b) the party’s administration functions:
   (c) the party’s testing functions:
   (d) the provision of submission information to the reconciliation manager.

(6) The metering equipment provider must provide a trader under subclause (1) or a party under subclause (4) with—
   (a) the raw meter data; or
   (b) any necessary facilities, codes, keys, or other means to enable the trader or party to access the raw meter data by the most practicable means.

(7) The metering equipment provider must, when complying with subclause (6), or when providing access to a person under subclause (2), use appropriate procedures to ensure that—
   (a) the raw meter data is received only by—
      (i) the trader, person, or party; or
Electricity Industry Participation Code 2010
Schedule 10.6

(2) Restrictions on use of raw meter data

(1) A metering equipment provider must not give a trader under clause 1(1), a person under clause 1(2), or a party under clause 1(3), access to raw meter data from a metering installation for which it is responsible, if to do so would, or would reasonably be expected to,—

(a) breach any regulatory or legal requirement; or
(b) prejudice the maintenance and monitoring of this Code, including the prevention, investigation, and detection of Code breaches and the right to a fair hearing before the Authority or the Rulings Panel; or
(c) result in the metering equipment provider breaching an obligation of confidentiality; or
(d) interfere with the privacy of a natural person; or
(e) create an improper gain or improper advantage for any participant or person; or
(f) commercially disadvantage the metering equipment provider or any other participant or person, in a material manner; or
(g) prejudice the future supply of raw meter data that is required by a market operation service provider to perform an obligation under this Code.

(2) A metering equipment provider must not limit or restrict a person’s or party’s right to access information from a metering installation for which the metering equipment provider is responsible, if the right of access is provided for in this Part.

3 Metering equipment provider must provide access to metering installation

(1) A metering equipment provider must, within 10 business days of receiving a request from 1 of the following parties, arrange physical access to each metering component in a metering installation for which it is responsible:

(a) a relevant reconciliation participant with whom it has an arrangement, other than a trader:
(b) the Authority:
(c) an ATH:
(d) an auditor:
(2) A party listed in subclause (1) may only request physical access to a metering component in the metering installation for the purposes of exercising the party’s rights and performing the party’s obligations under this Code or any relevant regulations in relation to 1 or more of the following:
   (a) the party’s audit functions;
   (b) the party’s administration functions;
   (c) the party’s testing functions;
   (d) the provision of metering components.

(3) The metering equipment provider must arrange for a party under subclause (1) to be provided with any necessary facilities, codes, keys, or other means to enable the party to obtain physical access to all metering components in the metering installation by the most practicable means.

(4) In complying with subclause (3), the metering equipment provider must use appropriate procedures to ensure that—
   (a) the security of the metering installation is maintained; and
   (b) physical access to the metering installation under subclause (1) is limited to only the physical access required for the purposes of exercising the party’s rights and performing the party’s obligations under this Code or any relevant regulations in relation to the party’s audit, administration, and testing functions.

(5) If a party referred to in subclause (1) requires urgent physical access to a metering installation, it must advise the relevant metering equipment provider, giving all relevant particulars of the physical access required and the reason for the urgency, and the metering equipment provider must use its best endeavours to arrange physical access in accordance with the requested urgency.


4 Metering equipment provider record keeping and documentation

(1) A metering equipment provider must—
   (a) for each metering installation for which it is responsible, keep accurate and complete records as specified in Table 1 of Schedule 11.4; and
   (b) for each metering installation for which it is responsible other than an interim certified metering installation, keep accurate and complete records of—
      (i) the certification expiry date of each metering component in the metering installation; and
      (ii) all equipment used in relation to the metering installation, including serial numbers and details of the equipment's manufacturer; and
      (iii) the manufacturer’s, or if different the most recent, test certificate for each metering component in the metering installation; and
      (iv) the metering installation category for the metering installation; and
      (v) all certification reports and calibration reports showing dates tested, tests carried out, and test results for all metering components in the metering installation; and
      (vi) the contractor who installed each metering component in the metering installation.
installation; and
(vii) the certification sticker, or equivalent details, for each metering component that is certified under Schedule 10.8 in the metering installation; and
(viii) seal identification information under clause 47 of Schedule 10.7 relating to the metering installation; and
(ix) any applicable compensation factors; and
(x) the owner of each metering component within the metering installation; and
(xi) any applications installed within each metering component within the metering installation; and
(xii) the signed inspection report under clause 44 of Schedule 10.7, confirming that the metering installation continues to comply with the requirements of this Part.

(2) A metering equipment provider must, within 10 business days of receiving a request from a participant for a signed inspection report prepared under clause 44 of Schedule 10.7, make a copy of the report available to the participant.

(3) A metering equipment provider must retain metering records relating to—
(a) a metering component in a metering installation for which it is or was responsible, for at least 48 months after the metering component is removed from the metering installation, even if—
(i) the metering installation is subsequently decommissioned; or
(ii) the metering equipment provider ceases to be responsible for the metering installation; and
(b) a metering installation for which it is responsible, for at least 48 months after the date on which—
(i) the metering installation is decommissioned; or
(ii) the metering equipment provider ceases to be responsible for the metering installation.


5 Metering equipment provider to provide access to metering records
(1) A gaining metering equipment provider may request that a losing metering equipment provider provide it with access to metering records required for the gaining metering equipment provider to exercise its rights and perform its obligations under this Code or any relevant regulations in relation to its respective auditing, administration, and testing functions.

(2) The losing metering equipment provider must, within 10 business days of receiving a request under subclause (1), provide the gaining metering equipment provider with—
(a) the metering records; or
(b) any necessary facilities, codes, keys, or other means to enable the gaining metering equipment provider to obtain access to the metering records by the most practicable means.

(3) In complying with subclause (2), the losing metering equipment provider must use
appropriate procedures to ensure that—

(a) the metering records are received only by the gaining metering equipment provider or its contractor; and

(b) the security of the metering records is maintained; and

(c) it only provides access to the specific metering records required for the purposes of the gaining metering equipment provider exercising its rights and performing its obligations under this Code or any relevant regulations in relation to its auditing, administration, and testing functions.


6 Provision of metering records when ATH recertifying metering installation

(1) This clause applies if—

(a) a metering equipment provider contracts with an ATH to recertify a metering installation for which the metering equipment provider is responsible; and

(b) the ATH did not perform the previous certification of the metering installation.

(2) If this clause applies, the metering equipment provider must, no later than 10 business days after the effective date of the contract, provide the ATH with a copy of all relevant metering records.

7 Metering equipment provider must use participant identifier

(1) A metering equipment provider must—

(a) ensure that it has a unique participant identifier for its activities as metering equipment provider under this Code; and

(b) use its participant identifier, if required under this Code, to correctly identify its information.

(2) A metering equipment provider must apply to the Authority in the prescribed form for a participant identifier at least 5 business days before the metering equipment provider requires the participant identifier.

(3) The Authority may change a metering equipment provider’s participant identifier.

(4) If the Authority changes a metering equipment provider’s participant identifier—

(a) it must advise the metering equipment provider of the date on which the change takes effect at least 3 months before the date; and

(b) the new participant identifier becomes effective from the date advised under paragraph (a).

8 Electronic interrogation of metering installation

(1) This clause applies when raw meter data can only be obtained from a metering equipment provider’s back office.

(2) A metering equipment provider must—

(a) ensure that the interrogation cycle for each metering installation that it electronically interrogates does not exceed the maximum interrogation cycle in the registry; and

(b) interrogate a metering installation for which it is responsible at least once in each maximum interrogation cycle in the registry; and
(c) when electronically *interrogating a metering installation*, ensure that the *interrogation* and processing system electronically monitors and corrects its internal clocks against a time source with a verifiable standard, at a frequency sufficient, and no longer than 1 week, to ensure the internal clock is accurate, when carrying out an *interrogation*, to within ±5 seconds of—

(i) New Zealand standard time; or

(ii) New Zealand daylight time.

(3) A *metering equipment provider* must, for each *metering installation* for which it is responsible, record in the *interrogation* and processing system logs, the time, the date, and the extent of any change in the internal clock setting in the *metering installation*.

(4) A *metering equipment provider* must ensure that a *data storage device* in a *metering installation* for which it is responsible for *interrogating* does not exceed the maximum time error set out in Table 1 of subclause (5).

(5) A *metering equipment provider* must, when *interrogating a metering installation*,—

(a) compare the time on the internal clock of the *data storage device* with the time on the *interrogation* and processing system clock; and

(b) calculate the time error for the *data storage device*; and

(c) if the time error calculated under paragraph (b) is equal to or less than the applicable time error set out in Table 1, correct the clock of the *data storage device*; and

(d) if the time error calculated under paragraph (b) is greater than the applicable time error set out in Table 1,—

(i) correct the clock of the *data storage device*; and

(ii) compare the time of the clock with the time of the *interrogation* and processing system clock; and

(iii) advise the affected *reconciliation participant* for the *point of connection*, within 5 business days of correcting the clock, of any affected raw meter data; and

(iv) comply with the requirements of clause 10.43; and

(e) download the *event log*; and

(f) check the *event log* for evidence of malfunctioning or tampering and if this is detected, carry out the appropriate requirements of this Part.

### Table 1: Maximum permitted time errors

<table>
<thead>
<tr>
<th>Metering installation category</th>
<th>Half-hour metering installations (seconds)</th>
<th>Non half-hour metering installations (seconds)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>±30</td>
<td>±60</td>
</tr>
<tr>
<td>2</td>
<td>±10</td>
<td>±60</td>
</tr>
<tr>
<td>3</td>
<td>±10</td>
<td>NA</td>
</tr>
<tr>
<td>4</td>
<td>±10</td>
<td>NA</td>
</tr>
<tr>
<td>5</td>
<td>±5</td>
<td>NA</td>
</tr>
</tbody>
</table>
(6) The **metering equipment provider** must, when **interrogating** a **metering installation**, ensure that all **raw meter data** downloaded as part of the **interrogation**, and used for submitting information for the purposes of Part 15, is archived—
(a) for no less than 48 months after the **interrogation** date; and
(b) in a form that cannot be modified without an audit trail being created; and
(c) in a form that is secure and prevents access by any unauthorised person; and
(d) in a form that is accessible to authorised personnel.

(7) A **metering equipment provider** must, when **interrogating** a **metering installation**,—
(a) ensure that for all **metering information**, an **interrogation log** is generated by the **interrogation software** to record details of each **interrogation**; and
(b) review the **event log** either manually or by an automated **software** function which flags exceptions and—
   (i) take appropriate action where problems are apparent; and
   (ii) pass relevant **event log** entries to the **reconciliation participant** for the **metering installation**; and
(c) ensure that the **interrogation log** forms part of the **interrogation audit trail** and contains the following as a minimum:
   (i) the date of **interrogation**; and
   (ii) the time of commencement of **interrogation**; and
   (iii) the operator of the **interrogation system identification** (where available); and
   (iv) the unique identifier of the **data storage device** being **interrogated**; and
   (v) any clock errors outside the range specified in Table 1 of subclause (5); and
   (vi) the method of **interrogation**; and
   (vii) the identifier of the reading device used for **interrogation** (if applicable).

(8) Subclause (9) applies when—
(a) a **metering equipment provider** interrogates a **half-hour metering installation** which is a **category 1 metering installation** or a **category 2 metering installation**; and
(b) the **certifying ATH** confirmed, as a part of the **metering installation’s** most recent **certification**, that the **metering equipment provider’s back office** processes include, for each **interrogation cycle**, a comparison of the difference in the increment of the **meter registers** to the **half-hour metering raw meter data**.

(9) When this subclause applies, the **metering equipment provider** must ensure that each electronic **interrogation** of the **metering installation** that retrieves **half hour metering information** compares that information against the increment of the **metering installation’s accumulating meter registers**.


9 **Contracting with ATH**

A **metering equipment provider** must, when contracting with an **ATH** in relation to the required activities for the **certification of a metering installation** for which it is responsible, ensure that an **ATH contracted to perform work under this Part has the**
appropriate scope of approval for such work.
Metering installation requirements

Metering installation general requirements

1 Maintenance and repair of metering installations
(1) A metering equipment provider must comply with subclause (2)—
   (a) for each metering installation for which it is responsible; and
   (b) for each metering component in a metering installation for which it is responsible.

(2) A metering equipment provider must ensure that—
   (a) it carries out regular maintenance, including battery monitoring and replacement,
       in accordance with the applicable requirements in the metering records; and
   (b) it carries out all necessary repairs; and
   (c) if it is not possible to repair a metering installation or metering component so that it complies with the applicable requirements in this Part, it is—
      (i) replaced with a metering installation or metering component that complies with the applicable requirements in this Part; or
      (ii) in the case of a metering installation, decommissioned; and
   (d) it documents in the metering records all maintenance, repairs, or replacements it carries out at the time it carries out the maintenance, repairs, or replacement.

2 Design reports for metering installations
(1) A metering equipment provider must obtain a design report under this clause for—
   (a) a proposed new metering installation for which it will be responsible, before it installs the metering installation; and
   (b) a modification to an existing metering installation for which it is responsible before the modification commences.

(2) The metering equipment provider must ensure that a design report is prepared by a person with an appropriate level of skill, expertise, experience, and qualification.

(3) The metering equipment provider must ensure that a design report includes—
   (a) a schematic drawing of the metering installation for use by an ATH; and
   (b) details of the configuration scheme that programmable metering components are to include; and
   (c) confirmation that the configuration scheme has been approved by an approved test laboratory; and
   (d) the maximum interrogation cycle specified in clause 36(4); and
   (e) any compensation factor arrangements; and
   (f) the method of certification required under this Part to be used for the metering installation; and
   (g) the name and signature of the person who prepared the design report and the date.
on which it was signed.

(4) The metering equipment provider must provide the design report to the certifying ATH before the ATH installs or modifies—
(a) the metering installation; or
(b) a metering component in the metering installation.

3 ATH design report obligations

(1) A certifying ATH must, before it certifies a new or modified metering installation, check and approve, in writing, the design report provided under clause 2 (including the configuration scheme and the schematic drawing), to ensure that the proposed new or modified metering installation—
(a) will function correctly; and
(b) will provide the required accuracy and raw meter data; and
(c) complies with this Part.

(2) The certifying ATH must, within 10 business days of the date on which it certifies the metering installation—
(a) update the design report with any changes to the metering installation design; and
(b) provide a copy of the updated design report to the metering equipment provider responsible for the metering installation.

4 Metering equipment provider obligations

(1) A metering equipment provider must, for each metering installation for which it is responsible,—
(a) ensure that the sum of the measured error and uncertainty does not exceed the maximum permitted error set out in Table 1 of Schedule 10.1 for the category of the metering installation; and
(b) ensure that the design of the metering installation, including its data storage device and interrogation system, will ensure that the sum of the measured error and the smallest possible increment of the energy value of the raw meter data obtained from the metering installation does not exceed the maximum permitted error set out in Table 1 of Schedule 10.1 for the category of the metering installation; and
(c) comply with the requirements applying to the metering equipment provider in the design report provided under clause 2; and
(d) ensure that the metering installation complies with—
   (i) the design report provided under clause 2; and
   (ii) this Part.

(2) A metering equipment provider must ensure that, for each metering installation for which it is responsible for an ICP that is not also an NSP,—
(a) the metering installation configuration does not use subtraction to determine submission information used for the purposes of Part 15; and
(b) which is a category 3 or higher metering installation, is a half-hour metering installation.
(3) A metering equipment provider must ensure that, for each metering installation for which it is responsible for an NSP that is not a point of connection to the grid,—
(a) the metering installation configuration does not use subtraction to determine submission information used for the purposes of Part 15; and
(b) it is a half-hour metering installation.

(4) A metering equipment provider must, for each metering installation for which it is responsible, ensure that it is appropriate having regard to the physical and electrical characteristics of the point of connection.

Determination of metering installation categories

5 Determination of metering installation category
An ATH must, before it certifies a metering installation, determine the category of the metering installation in accordance with the following:
(a) subject to clause 6, if the metering installation incorporates a current transformer, its category must be determined according to the primary current rating of the current transformer and the connected voltage set out in Table 1 of Schedule 10.1:
(b) if the metering installation does not incorporate a current transformer and the quantity of electricity conveyed is measured by a meter, it must be category 1.


6 Determination of metering installation incorporating current transformer to be lower category
(1) An ATH may, when determining the category of a metering installation under clause 5(a), determine under subclause (2) that the category is lower than would otherwise be the case under clause 5(a), only in 1 of the following circumstances:
(a) if a protection device, including a fuse or a circuit breaker, is installed that limits the maximum current of the metering installation; or
(b) if the metering equipment provider, acting reasonably on the basis of historical metering data, believes that the maximum current to be conveyed through the point of connection will, at all times during the intended certification period, be lower than the current setting of the protection device for the category for which the metering installation—
(i) is certified; or
(ii) is required to be certified by this Code; or
(c) if the metering installation uses less than 0.5 GWh in any 12 month period; or
(d) if the metering equipment provider, acting reasonably on the basis of historical metering data, believes that the metering installation (including, for example, a metering installation for an emergency fire pump or flood pump) will use less than 0.5 GWh in any 12 month period.

(2) If an ATH determines the category of a metering installation under—
(a) subclause (1)(a), the ATH must, when certifying the metering installation,
determine the category of the **metering installation** by reference to the maximum current setting of the protection device. The **ATH** must, when doing so—

(i) confirm the suitability and operational condition of the protection device; and

(ii) record, in the **metering records**, the rating and setting of the protection device; and

(iii) seal the protection device under clause 47; and

(iv) apply, if practicable, a warning tag to the seal under clause 47(6):

(b) subclause (1)(b), the **ATH** may, only if it considers it appropriate in the circumstances, at the request of the **metering equipment provider**, determine the **metering installation** category according to the **metering installation**’s expected maximum current. If the **ATH** determines the category of a **metering installation** under this clause, then—

(i) the **metering equipment provider** responsible for the **metering installation** must, each month, obtain a report from the **participant interrogating** the **metering installation**, detailing the maximum current conveyed through the **point of connection** for the prior month. For the purposes of this subparagraph, the **metering equipment provider** must determine the maximum current from **raw meter data** from the **metering installation** by either calculation from the kVA by **trading period** if available, or from a maximum current indicator if fitted in the **metering installation**; and

(ii) if the **metering equipment provider** does not receive the report in any month, or the report demonstrates that the maximum current conveyed through the **point of connection**, at any time during the previous month, exceeded the maximum permitted current for the **metering installation** category as **certified, certification** for the **metering installation** is automatically cancelled from the date on which the **metering equipment provider** should have received the report, or the date on which the **metering equipment provider** received the report:

(c) subclause (1)(c) or subclause (1)(d),—

(i) if the primary voltage is—

   (A) less than 1kV, the **ATH** must determine the **metering installation** as category 2; or

   (B) greater than or equal to 1kV, the **ATH** must determine the **metering installation** as category 3; and

(ii) the **metering equipment provider** responsible for the **metering installation** must, each month during the **certification** period, obtain a report from the **participant interrogating** the **metering installation** detailing the total kWh consumption of the **metering installation** for the prior 12 months:

(d) subclause (1)(d), if the **metering equipment provider** does not receive the report in any month, or the report identifies that the **electricity** conveyed through the **point of connection** exceeded 0.5 GWh during the previous 12 month period, the
certification for the metering installation is automatically cancelled from the date on which the metering equipment provider should have received the report, or the date on which the metering equipment provider received the report.

(3) The ATH must, before it determines a metering installation to be a lower category under this clause, visit the site of the metering installation to ensure that the installation is suitable for the metering installation to be determined to be a lower category.

(4) If an ATH determines a metering installation to be a lower category under this clause the metering installation certification report must include all information required to demonstrate, as at the certification date, compliance with this clause.


Clause 6(2)(c): amended, on 29 August 2013, by clause 30(3) and (4) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).


Certification of metering installation

7 Method of certification

(1) An ATH must, when certifying a metering installation, only use—

(a) the selected component certification method under clause 11, if the metering installation is a category 1 metering installation, a category 2 metering installation or a category 3 metering installation; or

(b) the fully calibrated certification method under clause 13.

(2) Despite subclause (1), an ATH may recertify—

(a) a category 1 metering installation using statistical sampling under clause 16; or

(b) a category 2 metering installation using the approved comparative recertification method under clause 12.

(3) If an ATH uses statistical sampling under subclause (2)(a), it must use the applicable method described in subclause (1)(a) and (1)(b) to certify each metering installation in the sample.

8 Metering installation certification requirements

(1) An ATH must not certify a metering installation unless the metering installation complies with this Part.

(2) An ATH must, when certifying a metering installation,—

(a) prepare a certification report for the metering installation; and

(b) specify in the certification report whether the metering installation is either—

(i) half hour; or

(ii) non half hour; and

(c) determine the services access interface for the metering installation under clause 10 of Schedule 10.4 and record it in the metering installation certification report; and
(d) ensure that each metering component in the metering installation functions correctly.

(3) An ATH may only certify a metering installation as category 3 or higher if the metering installation incorporates a half hour meter or half hour data storage device to quantify the electricity conveyed.

(4) An ATH must, when preparing a metering installation certification report, record the category of the metering installation.


8A ATH amends certification reports

(1) Subject to subclause (2), an ATH may amend a certification report for a metering installation prepared under this Schedule, or a certification report for a metering component prepared under Schedule 10.8, if—
   (a) the ATH prepared the certification report; and
   (b) the ATH—
      (i) receives, or becomes aware of, new information relevant to the certification; or
      (ii) becomes aware of a change to the metering installation or metering component, other than a change that affects the accuracy of the metering installation or metering component; and
   (c) the new information or change would have caused the ATH to reach a different conclusion in its certification report.

(2) An amendment under subclause (1) must not—
   (a) change the category of the metering installation:
   (b) extend the expiry date in the certification report:
   (c) change a calibration report in the certification report.

(3) If an ATH amends a certification report under subclause (1)—
   (a) the ATH must advise the relevant metering equipment provider of the changes to the certification report; and
   (b) the metering equipment provider must, upon being advised under paragraph (a), update the registry in accordance with Part 11.

(4) Despite anything else in this Part, if an ATH amends a certification report under this clause, the certification of the metering installation or metering component remains valid to the extent of the amendment.


9 Certification tests

(1) An ATH, when carrying out a test set out in Table 3 or 4 of Schedule 10.1,—
   (a) to carry out a prevailing load test on a metering installation or metering component, must do so by using a working standard connected to the metering installation:
   (b) to carry out an installation or component configuration test on a metering installation or metering component, must ensure that the actual configuration scheme is the same as the scheme for the metering installation or metering
component recorded in the design report:

(c) to carry out a raw meter data output test for a category 1 metering installation or category 2 metering installation, must do so by applying a measured increase in load and measuring—
   (i) the increment of the sum of the meter registers; or
   (ii) the accumulation of pulses resulting from the increase in load:

(d) to carry out a raw meter data output test for a half-hour metering installation which is a category 1 metering installation or for a half-hour metering installation which is a category 2 metering installation, must either—
   (i) compare the output from a working standard to the raw meter data from the metering installation for a minimum of 1 trading period; or
   (ii) confirm that the metering equipment provider’s back office processes include a comparison of the difference in the increment of the meter registers to the half-hour metering raw meter data, if the raw meter data is to be used for the purposes of Part 15:

(e) to carry out a raw meter data output test for a category 3 or higher half-hour metering installation, must compare the output of a working standard to the raw meter data from the metering installation for a minimum of 1 trading period:

(f) to carry out a raw meter data output test for a non-half-hour metering installation which is a category 2 metering installation, must do so by comparing the output of a working standard to the increment of the sum of the meter registers.

(1A) If an ATH performs a raw meter data output test under subclause (1)(c) or subclause (1)(d), for a metering installation that will be certified for remote meter reading, the ATH must—
   (a) obtain the raw meter data from the back office system where the raw meter data is held; or
   (b) ensure that the metering equipment provider responsible for the metering installation has a process to validate a meter reading taken at the time of the metering installation certification with a meter reading from the metering equipment provider’s back office system.

(2) If an ATH performs a test under subclause (1) that requires a comparison between 2 quantities, the ATH must not certify the metering installation unless the metering installation passes the test.

(3) For the purposes of subclause (2), a metering installation passes if the test demonstrates that the difference between the 2 quantities is within the applicable accuracy tolerances set out in Table 1 of Schedule 10.1.
10 Test results
(1) An ATH must, before it certifies a metering installation or any of a metering installation’s metering components, review the relevant test results for each of the metering installation’s metering components to ensure that—
(a) the metering component passed all the tests; and
(b) the metering installation meets the requirements for certification.
(2) If the ATH considers that the test results show that the requirements in this Part for certification of the metering installation are not met, it must—
(a) within 5 business days of reviewing the tests, advise the relevant metering equipment provider providing detailed reasons; and
(b) not certify the metering installation.

11 Selected component certification of metering installation
(1) This clause applies only when an ATH uses the selected component certification method.
(2) An ATH may use the selected component certification method to certify a metering installation only for the categories of metering installation for which the stated requirements are set out in Table 1 of Schedule 10.1.
(3) An ATH must only use the selected component certification method to certify a metering installation—
(a) by carrying out the tests set out in Table 3 of Schedule 10.1; and
(b) if an ATH or an approved test laboratory or an approved calibration laboratory has calibrated each of the following metering components in the metering installation in accordance with clause 1(1)(a)(ii) or 1(1)(b) of Schedule 10.8:
   (i) meter;
   (ii) measuring transformer; and
(c) if each data storage device in the metering installation has been certified in accordance with clause 5 of Schedule 10.8.
(4) An ATH must, before it uses the selected component certification method,—
(a) check the design report of the metering installation to—
   (i) confirm the metering installation functions in accordance with the design report; and
   (ii) ensure the metering installation complies with this Part; and
(b) ensure that each metering component in the metering installation is used only in a permitted combination as set out in Table 1 of Schedule 10.1; and
(c) check and confirm that the metering installation is correctly wired in accordance with all applicable requirements and enactments; and
(d) ensure that each metering component in the metering installation is fit for purpose.
(5) An ATH must, when it certifies a metering installation under this clause, ensure that the metering installation certification report includes confirmation that the ATH has—
(a) checked the design report of the metering installation to—
(i) confirm the **metering installation** functions in accordance with the design report; and

(ii) ensure the **metering installation** complies with this Part; and

(b) ensured that each **metering component** in the **metering installation** has been **calibrated** and **certified** as required in this Part; and

(c) ensured that the **metering installation** has passed the relevant tests and checks set out in Table 3 of Schedule 10.1; and

(d) checked and confirmed that the **metering installation** is correctly wired in accordance with all applicable requirements and enactments; and

(e) carried out any tests and checks required to confirm the integrity of the **metering installation** and recorded these and their results in the **metering installation certification report**.

(6) An **ATH** must, when it certifies a **metering installation** under this clause, include in the **metering installation certification report**—

(a) any **compensation factors** that must be applied; and

(b) how the **compensation factors** must be applied under clause 2 of Schedule 15.3.


12 Comparative recertification

(1) This clause only applies when an **ATH** uses the **comparative recertification** method.

(2) An **ATH** may only use the **comparative recertification** method to **recertify** a **category 2 metering installation** in accordance with this Part if—

(a) the **certification** of the current transformers in the **metering installation** expires before the **meter certification** expiry date; and

(b) each of the following **metering components** in the **metering installation** has been **certified** in accordance with Schedule 10.8:

(i) **data storage device**:

(ii) **meter**.

(3) An **ATH** must, when **recertifying** a **category 2 metering installation** under this clause, ensure that—

(a) the **metering installation** has passed the tests set out in Table 3 of Schedule 10.1, using a **working standard** connected to the **metering installation**; and

(b) the current measurement sensor connected around the cables or bus-bars adjacent to the **metering installation** is sufficiently accurate so that the sum of the measured **metering installation** accuracy, the **uncertainty** of the **metering installation**, and the **uncertainty** of the current measurement sensor does not exceed the maximum permitted error set out in Table 1 of Schedule 10.1 for the **category of the metering installation**; and

(c) the overall **metering installation** accuracy meets the requirements of Table 1 of
Schedule 10.1.

(4) An **ATH** must, before it uses the **comparative recertification** method—
(a) check the design report of the **metering installation** to—
   (i) confirm the **metering installation** functions in accordance with the design report; and
   (ii) ensure the **metering installation** complies with this Part; and
(b) check and confirm that the **metering installation** is correctly wired in accordance with all applicable requirements and enactments; and
(c) carry out any tests and checks required to confirm the integrity of the **metering installation** and record these and their results in the **metering installation certification report**.

(5) An **ATH** must, for each **metering installation** it **certifies** under this clause,—
(a) prepare a **certification report**; and
(b) ensure that each **metering component** in the **metering installation** is fit for purpose.

13 **Fully calibrated metering installation certification**

(1) This clause only applies when an **ATH** uses the **fully calibrated certification** method.

(2) An **ATH** may only use the **fully calibrated certification** method to **certify** a **category 1 metering installation**, or higher category of **metering installation**.

(3) An **ATH** must use the **fully calibrated certification** method to **certify** a **metering installation**—
(a) by carrying out the tests set out in Table 4 of Schedule 10.1; and
(b) only if each of the following **metering components** in the **metering installation** has been **certified** in accordance with Schedule 10.8:
   (i) **data storage device**;
   (ii) **meter**;
   (iii) **measuring transformer**.

(4) An **ATH** must ensure that each **metering component** in a **metering installation** which is **certified** under this clause has a current **certification report** that—
(a) complies with the requirements of this Part; and
(b) if the **metering component** is a **calibrated metering component**, includes a **calibration report** that—
   (i) confirms that the **metering component** complies with the requirements of its accuracy class set out in Table 1 of Schedule 10.1; and
   (ii) includes the **certification date** of the **metering component**.

(5) An **ATH** must, when preparing a **metering installation certification report** under this clause, include confirmation that the **ATH** has—
(a) checked the design report of the **metering installation** to—
   (i) confirm the **metering installation** functions in accordance with the design report; and
   (ii) ensure the **metering installation** complies with this Part; and
(b) ensured that each **metering component** in the **metering installation** has been **calibrated** and **certified** as required in this Part; and
(c) ensured that the relevant tests and checks set out in Table 4 of Schedule 10.1 have been passed; and
(d) checked and confirmed that the metering installation is correctly wired in accordance with all applicable requirements and enactments; and
(e) carried out any tests and checks required to confirm the integrity of the metering installation.

(6) An ATH must, when it certifies a metering installation under this clause, include in the metering installation certification report—
   (a) any compensation factors that must be applied; and
   (b) how the compensation factors must be applied under clause 2 of Schedule 15.3.

(7) An ATH must, before it certifies a metering installation under this clause, ensure that the ATH uses the manufacturer’s meter class accuracy, and not the meter’s actual tested accuracy, to determine whether the metering installation is within the relevant maximum permitted error set out in Table 1 of Schedule 10.1.

14 Insufficient load for metering installation certification tests

(1) This clause only applies if there is insufficient electricity conveyed through a point of connection to allow an ATH to complete a prevailing load test for a metering installation that is being certified as a half-hour metering installation.

(2) When this clause applies, the ATH must, when certifying the metering installation, ensure that—
   (a) it performs an additional integrity check of the metering installation wiring, and records the results of this check in the certification report; and
   (b) it records in the certification report that the metering installation is certified under this clause.

(3) A metering equipment provider must, for each metering installation for which it is responsible, and that is certified under this clause, obtain and monitor raw meter data from the metering installation at least once each month during the period of certification to determine if load during the month is sufficient for a prevailing load test to be completed.

(4) Despite subclause (1), the metering equipment provider must, if raw meter data obtained under subclause (3) demonstrates, at any time, that there is sufficient electricity conveyed through the point of connection for a prevailing load test to be completed, ensure that the certifying ATH makes a subsequent visit to the metering installation as soon as practicable, but no later than 20 business days after the metering equipment provider has obtained the raw meter data, to carry out and complete the tests set out in Table 4 of Schedule 10.1.

(5) The certifying ATH must, if the tests referred to in subclause (4) demonstrate that the metering installation performs within the relevant maximum permitted error set out in Table 1 of Schedule 10.1,—
   (a) update the metering installation certification report, within 5 business days of completing the tests, to include the results of the tests carried out; and
   (b) leave the original metering installation certification expiry date unchanged.

(6) If the tests referred to in subclause (4) demonstrate that the metering installation does
not perform within the relevant maximum permitted error set out in Table 1 of Schedule 10.1—

(a) the metering installation certification is automatically cancelled from the date of the tests; and

(b) the certifying ATH must advise the metering equipment provider of the cancellation within 1 business day of carrying out the tests; and

(c) the metering equipment provider must follow the procedure set out in clauses 10.43 to 10.48.


15 Recertification programme

(1) A metering equipment provider must have a recertification programme for all metering installations for which it is responsible to ensure that each metering installation is recertified prior to the expiry date of its then current certification if the metering installation is not decommissioned.

(2) Subclause (1) does not apply to an electrically disconnected metering installation for an ICP.


Statistical sampling recertification

16 Recertification of group of category 1 metering installations by statistical sampling

(1) A metering equipment provider may arrange for an ATH to recertify a group of category 1 metering installations for which the metering equipment provider is responsible using a statistical sampling process set out in subclause (2).

(2) To recertify a group of category 1 metering installations, an ATH must—

(a) select a sample from the group, using a statistical sampling process—

(i) prescribed in AS/NZS 1284; or

(ii) that is approved and published by the Authority; and

(aa) use the pass/fail criteria in AS/NZS 1284 to evaluate whether the group meets the recertification requirements of this Part; and

(b) recertify each metering component in the metering installation in the sample using—

(i) the fully calibrated certification method; or

(ii) the selected component certification method; and

(c) advise the metering equipment provider as soon as reasonably practicable, if the group—

(i) meets the recertification requirements of this Part; or

(ii) fails to meet the recertification requirements of this Part.

(3) An ATH must, when selecting a sample from the group under subclause (2)(a),—

(a) document the process it follows and any assumptions it makes; and

(b) keep records in accordance with clause 13 of Schedule 10.4, of—
(i) each step in the process; and
(ii) each metering installation in the sample; and
(iii) each metering installation in the group that is recertified using this process.

(4) The recertification of a metering installation in the group—
(a) commences from the date of the advice referred to in subclause (2)(c)(i) if the sample meets the recertification requirements of this Part:
(b) is automatically cancelled from the date of the advice referred to in subclause (2)(c)(ii) if the sample fails to meet the recertification requirements of this Part.

(5) The metering equipment provider must, upon being advised under subclause (2)(c), update the registry in accordance with Part 11.

(6) Despite clause 41(1), an ATH who recertifies a group of metering installations using a statistical sampling process is not required to apply a certification sticker to a metering installation in the group that was not part of the sample.

Clause 16(2)(aa): inserted, on 29 August 2013, by clause 35(3) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).
Clause 16(2)(b): substituted, on 29 August 2013, by clause 35(4) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).

Certification validity periods

17 Determination of expiry dates for certification of metering components and metering installations

(1) An ATH must, when certifying a metering installation,—
(a) determine, in accordance with this clause, the date on which the metering installation’s certification will expire; and
(b) record the expiry date in the metering installation certification report.

(2) The expiry date for a metering installation’s certification is the earliest of—
(a) the date falling after the date of its commissioning by the number of months equivalent to the maximum metering installation certification validity period for the relevant category of metering installation, as set out in Table 1 of Schedule 10.1; and
(b) the earliest certification expiry date of a metering component in the metering installation; and
(c) a date determined by the ATH taking into account—
(i) the condition of each metering component in the metering installation; and
(ii) all relevant circumstances relating to the metering installation.

(3) Despite subclause (2), the expiry date for each metering installation in a group of metering installations recertified under clause 16, that does not form a part of the sample, is the earliest expiry date of the metering installations in the sample.

18 Interim certified metering installations
A metering equipment provider must ensure that each interim certified metering installation on 28 August 2013 is certified under this Part by no later than 1 April 2015.


19 Modification of metering installations

(1) If a metering installation is modified, the certification of the metering installation is automatically cancelled with effect from—
(a) the date the modification began; or
(b) if the metering equipment provider responsible for the metering installation does not know the date in subclause (a), the date on which the metering equipment provider became aware of, or would reasonably have been expected to have become aware of, the modification.

(2) For the purposes of this clause, a modification of a metering installation includes, any 1 or more of the following:
(a) any change to the software, ROM, or firmware in the metering installation that may affect the operation of the metrology layer unless the change is made under subclause (3);
(b) installation, removal, repair, or modification, of a metering component in the metering installation, other than the temporary connection of testing or monitoring equipment by using a test facility;
(c) any change to the burdening of a measuring transformer in the metering installation, unless changed under clause 31(6);
(d) reconfiguration of any wiring (but not straight replacement of wiring in a category 1 metering installation);
(e) relocation of a metering component in the metering installation or the metering installation enclosure:
(f) any interference with the metering installation that affects the accuracy of the metering installation.

(2A) For the purposes of subclause (1), and despite subclause (2), a modification of a metering installation does not include the replacement of a modem in the metering installation by the ATH that is responsible for certifying the metering installation.

(3) Despite subclauses (1) and (2)(a), the certification of a metering installation is not cancelled if—
(a) an approved test laboratory has tested and confirmed under clause 39 that the integrity of the measurement and logging of a data storage device in the metering installation would be unaffected by the change; and
(b) the change does not, or would not be considered by the ATH who most recently certified the metering installation to, affect—
(i) the accuracy of the raw meter data obtained from the metering installation; or
(ii) the accuracy of the metrology layer of the metering installation; or
(iii) a compensation factor programmed into any metering component in the metering installation; and
(c) the ATH who most recently certified the metering installation approves, in advance, the process of changing the software, ROM, or firmware in the metering installation; and

(d) the change is carried out in accordance with a documented methodology that has been audited under this Part; and

(e) the metering equipment provider responsible for the metering installation records in the metering records the details of the change, including the time and date; and

(f) any change of the metering installation’s parameters does not affect the metrology layer; and

(g) [Revoked]

(h) clause 8A(1) applies.

(3A) Despite subclauses (1) and (2)(b), the certification of a metering installation is not cancelled if—

(aa) a control device that does not switch meter registers has malfunctioned and been replaced with a certified control device; and

(a) the replacement control device has the same characteristics as the control device it replaces and—

(i) is certified in accordance with this Part; and

(ii) will not adversely affect the operation of any other metering components or connections to those metering components; and

(iii) is likely to receive control signals, as required by clause 34; and

(iv) is correctly connected and programmed; and

(b) the metering equipment provider responsible for the metering installation has in place—

(i) an appropriate agreement with the approved test house that is responsible for the certification of the metering installation, to record the replacement in its metering installation certification records; and

(ii) appropriate procedures for ensuring that replacements are carried out only by persons authorised by the metering equipment provider; and

(c) the metering equipment provider updates—

(i) the metering records with the details of the replacement, including the date; and

(ii) the registry metering records.

(3B) In setting a procedure under subclause (3A)(b)(ii), a metering equipment provider must ensure that, within 10 business days of the replacement occurring, the person carrying out the replacement provides the notice and metering records for the replaced control device and the replacement control device to—

(a) the metering equipment provider; and

(b) the approved test house that is responsible for the certification of the metering installation.

(4) Despite subclause (2)(c), the certification of a metering installation continues if—

(a) there is a minor repositioning of 1 of the following in a category 1 metering installation which does not involve disconnection of wiring:
(i) the meter in the existing metering installation enclosure; or
(ii) the existing metering installation enclosure; or

(b) the relocation does not cause, directly or indirectly, the metering installation to be—
(i) outside the applicable accuracy tolerances set out in Table 1 of Schedule 10.1; or
(ii) defective; or
(iii) not fit for purpose.

(5) If a metering component that must be certified under this Part and which is in an interim certified metering installation is modified, or replaced with a metering component that is not certified under Schedule 10.8, the interim certified metering installation's certification is automatically cancelled from the date of the modification or replacement.

(6) Despite subclause (5), if an ATH modifies an interim certified metering installation by replacing a metering component that must be certified under this Part with an equivalent certified metering component, the interim certified metering installation's certification is not cancelled.

(7) A replacement metering component under subclauses (5) or (6) must comply with this Code.

20 Cancellation of certification of metering installations

(1) The certification of a metering installation is automatically cancelled on the date on which any 1 of the following events takes place:

(a) the metering installation is modified otherwise than under clause 19(3), 19(3A), or 19(6):
(b) the metering installation is classed as outside the applicable accuracy tolerances set out in Table 1 of Schedule 10.1, defective, or not fit for purpose under—
(i) this Part; or
(ii) any audit:
(c) an ATH advises the metering equipment provider responsible for the metering installation of—

(i) a reference standard or working standard used to certify the metering installation not being compliant with this Part when it was used to certify the metering installation; or

(ii) the failure of a group of meters in the statistical sampling recertification process for the metering installation; or

(iii) the failure of a certification test for the metering installation:

(d) the manufacturer of a metering component in the metering installation determines that the metering component does not comply with the standards to which the metering component was tested:

(e) an inspection of the metering installation, that is required under this Part, is not carried out in accordance with the relevant clauses of this Part:

(f) if the metering installation has been determined to be a lower category under clause 6 and the maximum current conveyed through the metering installation at any time exceeds the current rating of its metering installation category as set out in Table 1 of Schedule 10.1:

(g) the metering installation—

(i) is certified under clause 14 and sufficient load is available for full certification testing; and

(ii) has not been retested under clause 14(4):

(h) a control device in the metering installation certification is, and remains for a period of at least 10 business days, bridged out under clause 35(1):

(i) the metering equipment provider responsible for the metering installation is advised by an ATH under clause 48(6)(b) that a seal has been removed or broken and the accuracy and continued integrity of the metering installation has been affected.

(2) A metering equipment provider must, within 10 business days of becoming aware that 1 of the events in subclause (1) has occurred in relation to a metering installation for which it is responsible, update the metering installation’s certification expiry date in the registry.


Accuracy and error calculation

21 Metering installation accuracy

An ATH must not certify a metering installation if the metering installation exceeds the maximum permitted error for the relevant metering installation category set out in Table 1 of Schedule 10.1, after the application of any external compensation factors.

22 Error Calculation

(1) An ATH must, before it certifies a metering installation under clauses 12 or 13, calculate the error of the metering installation in accordance with the following:
(a) the ATH must calculate the percentage error of the metering installation using appropriate mathematical methods, taking account of—
   (i) all sources of measurement error; and
   (ii) the estimated total quantity of electricity to be conveyed through the metering installation over the next 12 months; and
(b) the error calculation must include uncertainty in measurement; and
(c) for the purposes of paragraph (b), the ATH must calculate uncertainty at a 95% level of confidence and in compliance with JCGM 100:2008.

(2) The ATH must not certify the metering installation if—
   (a) the uncertainty for the metering installation is greater than the relevant maximum site uncertainty set out in Table 1 of Schedule 10.1; and
   (b) the sum of the measured error and the uncertainty of the metering installation is greater than the relevant maximum permitted error set out in Table 1 of Schedule 10.1.

(3) The ATH must record the calculation under subclause (1)(a) in the metering installation certification report.

23 Time keeping requirements
A metering equipment provider must, if a time keeping device that is not remotely monitored and corrected controls the switching of a meter register in a metering installation for which it is responsible, ensure that the time keeping device—
   (a) has a time keeping error of not greater than an average of 2 seconds per day over a period of 12 months; and
   (b) is monitored and corrected at least once every 12 months.

24 Compensation factors
(1) An ATH must, before it certifies a metering installation that requires a compensation factor to adjust raw meter data—
   (a) advise the metering equipment provider responsible for the metering installation of the compensation factor; and
   (b) ensure that the compensation factor to be applied to raw meter data external to the metering installation can only be applied as follows:
      (i) for ratio compensation, on a category 1 metering installation, or higher category of metering installation; or
      (ii) for error compensation, on a metering installation that quantifies electricity conveyed through a point of connection to the grid; or
      (iii) for loss compensation, only on a category 3 or higher metering installation.
(2) An ATH must, when it prepares a certification report for a metering installation that requires a compensation factor, record the methodology, assumptions, measurements, calculation, and details of—
   (a) each compensation factor that is included within the internal configuration of the metering installation; and
   (b) each compensation factor that must be applied to the raw meter data.
(3) A metering equipment provider must, for a metering installation in relation to which a compensation factor must be applied,—
(a) if the metering installation is for a point of connection that is an NSP, advise the reconciliation participant responsible for the metering installation of the compensation factor within 10 business days of the date on which the metering installation is certified; or
(b) in all other cases, update the compensation factor recorded in the registry in accordance with Part 11.


*Installation of metering components in metering installations*

25 Installation of metering components

(1) An ATH must, before it certifies a metering installation, ensure that installation of—
(a) measuring transformers, and associated burden if required, test facilities, potential fuses, and switchboard wiring, was carried out by—
(i) a suitably qualified person (for example by a switchboard manufacturer); or
(ii) an ATH; and
(b) each metering component in the metering installation, other than a metering component referred to in paragraph (a), is carried out by an ATH.

(2) An ATH must, before it certifies a metering installation, ensure that each metering component in the metering installation has been installed in accordance with the design report under clause 2.

26 Requirements for metering installation incorporating meter

(1) A metering equipment provider must ensure that each meter in a metering installation for which it is responsible is certified in accordance with this Part.

(2) An ATH must, unless clause 43(2) applies, before it certifies a metering installation incorporating a meter, if the meter had previously been used in another metering installation, ensure that the meter has been recalibrated since it was removed from the previous metering installation, by—
(a) an approved calibration laboratory; or
(b) an ATH.

(3) The ATH must, before it certifies a metering installation incorporating a meter, document in the metering records—
(a) any regular maintenance required for the meter in accordance with the manufacturer’s recommendations; and
(b) any maintenance that has been carried out on the meter (for example battery monitoring and replacement).

(4) An ATH must, before it certifies a metering installation incorporating a meter, record in the metering installation certification report, the maximum interrogation cycle for the metering installation.

(5) The maximum interrogation cycle for a metering installation referred to in subclause (4) is the period of memory availability given the meter configuration.
(6) Subclause (4) does not apply to a metering installation incorporating both a meter and a data storage device (see clause 36 of Schedule 10.7).


27 Meter certification expiry date

(1) An ATH must, before it certifies a metering installation incorporating a meter, determine the meter certification expiry date for each meter in the metering installation in accordance with this clause.

(2) The meter certification expiry date must be the earliest end date of the following periods, calculated from the date of commissioning of the metering installation:
   (a) the maximum metering installation certification validity period set out in Table 1 of Schedule 10.1 for the relevant category of metering installation; or
   (b) the maximum meter certification validity period set out in Table 2 of Schedule 10.1 for the relevant class of meter for the metering installation; or
   (c) the certification period specified in the meter certification report.

(3) Despite subclause (2), the meter certification expiry date for a meter that has been certified and subsequently installed in, but then removed from, a category 1 metering installation, remains the meter certification expiry date determined for that meter when it was installed in the category 1 metering installation.

(4) Despite subclauses (2) and (3), if an electromechanical meter is not installed in a metering installation within 24 months of the date of the meter's certification report, the meter must be recertified before it is installed.

(5) The ATH must record the certification expiry date for each meter in a metering installation in—
   (a) the metering installation certification report; and
   (b) the meter certification report.


28 Requirements for metering installation incorporating measuring transformer

(1) A metering equipment provider must ensure that each measuring transformer in a metering installation for which it is responsible is certified in accordance with this Part.

(2) An ATH must, before it certifies a metering installation which includes a measuring transformer that had previously been used in another metering installation, ensure that the measuring transformer has been recalibrated, since it was removed from the previous metering installation, by—
   (a) an approved calibration laboratory; or
   (b) an ATH.

(3) The ATH must, before it certifies a metering installation incorporating a measuring transformer, document in the metering records—
   (a) any regular maintenance required for the measuring transformer in accordance with the manufacturer's recommendations; and
(b) any maintenance that has been carried out on the measuring transformer.

(4) An ATH must, before it certifies a metering installation incorporating a measuring transformer,—

(a) ensure that—

(i) the measuring transformer is connected to a meter through a test facility that has provision for isolation; and

(ii) the test facility and the provision for isolation are installed as physically close to the meter as practicable in the circumstances; and

(b) using the fully calibrated certification method, ensure that the ATH uses the measuring transformer’s actual accuracy (rather than class accuracy) when calculating the maximum permitted error for the relevant metering installation category set out in Table 1 of Schedule 10.1; and

(c) carry out primary injection tests on the measuring transformer if it considers it is appropriate in the circumstances; and

(d) ensure that the measuring transformer is—

(i) mounted securely; and

(ii) if practicable, in an enclosure that is sealed in accordance with clause 47 against unauthorised access; and

(e) ensure that any voltage supply from a voltage transformer to a meter, or other equipment in the metering installation, is protected by appropriately rated fuses or circuit breakers dedicated to the supply; and

(f) ensure that all fuses and circuit breakers are sealed or located in sealed enclosures under clause 47; and

(g) ensure that, if an enclosure also contains fuses or circuit breakers supplying other circuits, those supplying metering circuits are individually sealed; and

(h) ensure that if the measuring transformer’s secondary circuit in the metering installation is earthed, it is earthed at no more than 1 point; and

(i) ensure that the total burden (magnitude and phase angle, where appropriate) on the measuring transformer does not exceed—

(i) its name plate rating; or

(ii) an alternative rating lower than the name plate rating, if specified in the metering installation design report.

(5) Despite subclause (4)(d)(ii), if access to the enclosure is required by a person other than an employee or subcontractor of an ATH, the ATH may use alternative sealing arrangements (for example, terminal studs drilled so that sealing wire can be passed through the holes to secure the connections, or the use of sealing paint applied to terminal screws).


29 Measuring transformer certification expiry date

(1) An ATH must, before it certifies a metering installation incorporating a measuring transformer, determine the measuring transformer certification expiry date for each measuring transformer in the metering installation in accordance with this clause.
(2) The measuring transformer certification expiry date must be no later than the last day of the measuring transformer certification validity period specified in the measuring transformer certification report, after the date of commissioning.

(3) The ATH must record the measuring transformer certification expiry date for each measuring transformer in a metering installation in—
   (a) the certification report for the metering installation; and
   (b) the certification report for the measuring transformer.

30 Other equipment using measuring transformer

(1) A metering equipment provider must not permit a measuring transformer, in a metering installation for which it is responsible, to be connected to equipment used at any time for a purpose other than metering, unless it is not practical for the equipment to have a separate measuring transformer.

(2) An ATH must, before it certifies a metering installation incorporating a measuring transformer used by—
   (a) another metering installation, ensure, where voltage transformers are connected to more than 1 meter, that—
      (i) the meters are included in the metering installation being certified; and
      (ii) appropriate fuses or circuit breakers are provided to protect the metering circuit from short circuits or overloads affecting the other meter;
   (b) equipment referred to in subclause (1), ensure that—
      (i) the accuracy of the metering installation remains within the maximum permitted error for the relevant metering installation category set out in Table 1 of Schedule 10.1; and
      (ii) the metering installation certification report confirms that the accuracy of the metering installation remains within the maximum permitted error for the relevant metering installation set out in Table 1 of Schedule 10.1; and
      (iii) any wiring between the equipment and any part of the metering installation has no intermediate joints; and
      (iv) the equipment referred to in subclause (1) is labelled appropriately, including with any restrictions regarding being electrically disconnected; and
      (v) the connection details of the equipment referred to in subclause (1) are recorded in the metering installation design report; and
      (vi) appropriate fuses or circuit breakers are provided to protect the voltage transformer and metering circuit from short circuits or overloads affecting the other equipment; and
      (vii) the wiring referred to in subparagraph (iii) is certified as part of the metering installation.

(3) [Revoked]


31 Measuring transformer burden and compensation requirements

(1) An ATH may certify a metering installation for a point of connection to the grid that includes error compensation factors as an alternative to the use of burden resistors, only if the ATH is satisfied the error compensation factors will provide a more accurate result than the use of burden resistors.

(2) A metering equipment provider must ensure that a change to, or addition of, a measuring transformer burden or compensation factor related to a measuring transformer, in a metering installation for which it is responsible, is only carried out by:
   (a) the ATH who most recently certified the metering installation; or
   (b) if the metering installation is for a point of connection to the grid, a suitably qualified person approved by both—
      (i) the metering equipment provider responsible for the metering installation; and
      (ii) the ATH who most recently certified the metering installation.

(3) An ATH must, before it may add or change any burden or compensation factor detailed in the design report referred to in clause 2,—
   (a) obtain the approval of the metering equipment provider responsible for the metering installation, which may be withheld in the metering equipment provider’s absolute discretion; and
   (b) if it obtains the approval referred to in paragraph (a), record in the metering records the reason for the proposed addition or change.

(4) A metering equipment provider must, before it may approve the addition of, or change to, the burden or compensation factor of a measuring transformer in a metering installation for which it is responsible, consult with the ATH who carried out the most recent certification of the metering installation.

(5) If the metering equipment provider approves the addition of, or change to, the burden or compensation factor under subclause (4), it must ensure that the metering installation, other than a metering installation for a point of connection to the grid, is recertified by an ATH for the addition of or change to the burden or compensation factor before the addition or change becomes effective.

(6) Despite subclause (3)(a), an ATH may change the burden on a voltage transformer, without obtaining the approval of the metering equipment provider, if the ATH confirms in the certification report that the difference between the new burden and the burden at the time of the most recent metering installation certification is—
   (a) less than or equal to one thirtieth of the rating, in VA, of the voltage transformer if the voltage transformer is rated at less than 30 VA; or
   (b) no greater than 1 VA, if the voltage transformer is rated at equal to or greater than 30 VA.

(7) An ATH must, before it certifies a measuring transformer, if the in-service burden is less than the lowest burden test point specified in a standard set out in Table 5 of Schedule 10.1,—
(a) install burdening resistors to increase the in-service burden to be equal to or greater than the lowest test point specified in the standard; or

(b) confirm that—

(i) a class A ATH has confirmed by calibration that the accuracy of the measuring transformer will not be adversely affected by the in-service burden being less than the lowest burden test point specified in the standard; or

(ii) the measuring transformer's manufacturer has confirmed that the accuracy of the metering transformer will not be adversely affected by the in-service burden being less than the lowest burden test point specified in the standard.

Clause 31(7): substituted, on 29 August 2013, by clause 41 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).

32 Alternative certification requirements for metering installation incorporating measuring transformer

(1) An ATH may, if it cannot comply with the requirements of clause 2 of Schedule 10.8 due solely to its inability to obtain physical access to test an installed measuring transformer in a metering installation, certify the metering installation for a period not exceeding 24 months, if—

(a) the measuring transformer has not previously been certified under this clause; and

(b) the ATH is satisfied, having made due enquiry, that the metering installation will comply with the applicable accuracy requirements as set out in Table 1 of Schedule 10.1; and

(c) the ATH has advised the metering equipment provider responsible for the metering installation that this clause applies; and

(d) the metering equipment provider has updated the metering installation's certification in the registry.

(2) The metering equipment provider must, if a metering installation for which it is responsible has been certified under subclause (1),—

(a) by no later than 10 business days after the date of certification of the metering installation, advise the Authority in the prescribed form of—

(i) all relevant details of the metering installation; and

(ii) the reason or reasons why the ATH could not obtain physical access to the measuring transformer; and

(iii) the reason or reasons why the accuracy of the metering installation cannot be outside of the applicable accuracy requirements set out in Table 1 of Schedule 10.1; and

(iv) the metering installation certification expiry date; and

(b) respond, within 5 business days, to any requests from the Authority for additional information; and
(c) ensure that all of the details are recorded in the metering installation certification report.

(3) If an ATH certifies a metering installation under subclause (1), the metering equipment provider responsible for the metering installation must take all steps to ensure that the metering installation is certified, before the metering installation certification expiry date referred to in subclause (2)(a)(iv), in accordance with all other applicable requirements of this Part.

(4) If the Authority subsequently determines that the ATH could have obtained physical access to test an installed measuring transformer in the metering installation, the metering installation is deemed to be defective and the metering equipment provider responsible for the metering installation must comply with clauses 10.43 to 10.48. Clause 32(1)(d), (2) and (4): amended, on 5 October 2017, by clause 191 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

33 Requirements for metering installation incorporating control device

(1A) A reconciliation participant that is responsible for a point of connection must advise the metering equipment provider responsible for the metering installation at the point of connection if a control device in the metering installation is to be used by the reconciliation participant for any purpose under Part 15 to do either of the following:

(a) control a load:

(b) switch meter registers.

(1) A reconciliation participant must ensure that a control device is certified under this Part by an ATH before the reconciliation participant uses any raw meter data that depends on the operation of the control device, for any purpose under Part 15.

(2) An ATH must, before it certifies a metering installation incorporating a control device that must be certified under subclause (1),—

(a) determine the control device certification expiry date for each control device contained in the metering installation as being the same as the metering installation certification expiry date; and

(b) record the expiry date, for each control device, in the metering installation certification report; and

(c) if the metering installation contains a control device that had previously been used in another metering installation, ensure that the control device has been certified in accordance with Schedule 10.8 after it was removed from the other metering installation; and

(d) ensure that the metering installation certification report includes confirmation that—

(i) the control device complies with any applicable standards listed in Table 5 of Schedule 10.1; and

(ii) the control device is fit for purpose; and

(e) check that the control device is—

(i) likely to receive control signals, as required under clause 34; and

(ii) correctly connected; and

(iii) correctly programmed.
34 Control device reliability requirements

(1) An ATH must, before it certifies a metering installation incorporating a control device that is required to be certified under clause 33, determine, in consultation with the relevant distributor if appropriate, if the likelihood of the control device not receiving control signals would affect the accuracy or completeness of the information for the purposes of Part 15.

(2) A control signal provider, if it is a participant, must respond in a timely manner to any requests from the ATH referred to in subclause (1).

(3) The ATH must, if it determines under subclause (1) that the likelihood of the control device not receiving control signals would affect the accuracy or completeness of the information for the purposes of Part 15, advise the metering equipment provider responsible for the metering installation of its determination, including all relevant details, within 3 business days of making its determination.

(4) If subclause (3) applies—

(a) the ATH may certify the metering installation excluding the control device; and

(b) the ATH must not certify the control device.

(5) The metering equipment provider must, as soon as reasonably practicable, and at least within 3 business days after being advised under subclause (3), advise the following parties of the ATH's determination, including all relevant details:

(a) the reconciliation participant for the point of connection for the metering installation; and

(b) the control signal provider.


35 Control device bridged out

(1) A participant must, within 10 business days of bridging out a control device, or becoming aware of a control device being bridged out, advise the following persons:

(a) the reconciliation participant for the point of connection for the metering installation; and

(b) the metering equipment provider responsible for the metering installation incorporating the control device.

(2) A metering installation incorporating a control device referred to in subclause (1) is defective for the purposes of clause 10.43 if it is used for the purposes of providing information for the purposes of Part 15.

36 Requirements for metering installation incorporating data storage device

(1) A metering equipment provider must ensure that each data storage device incorporated in a metering installation for which it is responsible, is certified in accordance with this Part.
(2) An ATH must, before it certifies a metering installation incorporating a data storage device that had previously been used in another metering installation, ensure that the data storage device has been recalibrated since it was removed from the previous metering installation, by—
   (a) an approved calibration laboratory; or
   (b) an approved test laboratory; or
   (c) an ATH.

(3) An ATH must, before it certifies a metering installation incorporating a data storage device (including a metering installation incorporating both a meter and a data storage device), record in the metering installation certification report, the maximum interrogation cycle for the data storage device.

(4) The maximum interrogation cycle for a metering installation incorporating a data storage device is the shortest of the following periods:
   (a) the period of inherent data loss protection for the metering installation; and
   (b) the period of memory availability given the data storage device configuration; and
   (c) the longest period in which the accumulated drift of a data storage device clock is expected to remain in compliance with the maximum time error set out in Table 1 of clause 2 of Schedule 15.2 for the category of the metering installation.


37 Data storage device certification expiry date

(1) An ATH must, before it certifies a metering installation incorporating a data storage device—
   (a) determine, in accordance with this clause, the data storage device certification expiry date for each data storage device contained in the metering installation; and
   (b) record the expiry date in the metering installation certification report.

(2) The data storage device certification expiry date must—
   (a) for a data storage device that is integral to a meter, be no later than the meter certification expiry date; or
   (b) for a data storage device that is not integral to a meter, be no later than the earlier of—
      (i) the date falling the number of days equivalent to the data storage device certification validity period specified in the data storage device certification report, after the commissioning date; and
      (ii) the meter certification expiry date.

(3) The ATH must record the data storage device certification expiry date for a data storage device in a metering installation in—
   (a) the certification report for the metering installation; and
   (b) the certification report for the data storage device.
38 Requirements for certification of metering installation incorporating data storage device

(1) An ATH must, before it certifies a metering installation, ensure that each data storage device in the metering installation—
   (a) is installed so that onsite interrogation is possible without the need to interfere with seals; and
   (b) has a dedicated power supply unless the data storage device is integrated with another metering component.

(2) An ATH must, before it certifies a metering installation,—
   (a) ensure that each data storage device in the metering installation—
      (i) is compatible with each other metering component of the metering installation; and
      (ii) is suitable for the electrical and environmental site conditions in which it is installed; and
      (iii) has been certified under Schedule 10.8; and
      (iv) has appropriate electrical separation between all of its outputs and inputs, and all of its outputs and inputs are rated for purpose; and (v) has no outputs that will interfere with the operation of the metering installation; and
      (vi) records periods of data identifiable or deducible by both date and time on interrogation; and
   (b) check and confirm in the metering installation certification report that each data storage device in the metering installation—
      (i) has memory capacity and functionality that is suitable for the proposed functions of the data storage device specified in the design report for the metering installation; and
      (ii) has availability of memory for a period that is suitable for the proposed functions as set out in the design report for the metering installation, and for a minimum continuous period of 15 days.

(3) An ATH must, before it certifies a metering installation incorporating a data storage device, document in the metering records—
   (a) any regular maintenance required for the data storage device in accordance with the manufacturer's recommendations; and
   (b) any maintenance that has been carried out on the data storage device (for example battery monitoring and replacement).


39 Changes to data storage device software, ROM, or firmware

(1) A metering equipment provider must, if it proposes to change the software, ROM, or firmware of a data storage device installed in a metering installation for which it is responsible, ensure that, before the change is carried out, an approved test laboratory—
   (a) tests and confirms that the integrity of the measurement and logging of the data
storage device would be unaffected by the proposed change; and
(b) documents the methodology and conditions necessary to implement the proposed change; and
(c) advises the ATH that certified the metering installation of any change that would, or would be likely to, affect the accuracy of the data storage device.

(2) A metering equipment provider must, when implementing a proposed change described in subclause (1),—
(a) carry out the change in accordance with the documented methodology and conditions referred to in subclause (1)(b); and
(b) keep a list of data storage devices to which the change was made; and
(c) update the metering records for each metering installation referred to in subclause (1) with details of the change and the methodology referred to in subclause (1)(b).

40 Communication equipment requirements
A metering equipment provider must ensure that the use of its communication equipment complies with the compatibility and connection requirements of any communication network operator to whose communication network the metering equipment provider has communication equipment connected.

41 Certification stickers
(1) An ATH must, except as provided for in clause 16(6) and subclause (4), if it has certified a metering installation under this Part, confirm the certification by attaching a metering installation certification sticker as physically close as practicable to (including, if practicable, on) the meter while maintaining reasonable visibility of the certification sticker and the meter.

(2) An ATH attaching a metering installation certification sticker must ensure that it shows—
(a) the name of the ATH who certified the metering installation; and
(b) the most recent certification date of the metering installation; and
(c) the metering installation category for which the metering installation has been certified; and
(d) the ICP identifier for the metering installation; and
(e) the certification number for the metering installation; and
(f) any other information that the Authority may, from time to time, specify by giving reasonable notice.

(3) An ATH must, when certifying a metering installation that includes a metering component that does not have a certification sticker attached—
(a) obtain the metering component certification sticker required under clause 8 of Schedule 10.8; and
(b) attach it next to the metering installation certification sticker.

(4) Despite subclauses (1) and (3)(b), the ATH must, if attaching a metering installation certification sticker as required under subclause (1) is not practicable,—
(a) devise and use an alternative means of documenting, providing, and maintaining
information in a manner at least equivalent in its effect to that required under subclause (1); and
(b) keep any metering component certification sticker with the information referred to in paragraph (a).


42 Enclosures
An ATH must, before it certifies a metering installation, ensure that, if a metering component in the metering installation is housed in a separate enclosure from the meter enclosure, the enclosure is—
(a) appropriate to the environment in which it is located; and
(b) has a warning label attached stating that the enclosure houses a metering component.

Certification of metering components

43 Metering components must be certified
(1) An ATH must, before it certifies a metering installation, ensure that each metering component that is required to be certified under this Part and which is in the metering installation—
(a) is certified by an ATH in accordance with this Part; and
(b) since certification, has been appropriately stored and not used.

(2) Despite subclause (1) and clause 26(2), an ATH may certify a category 1 metering installation that contains a meter which has been removed from another category 1 metering installation (the "previous metering installation") if the ATH—
(a) is satisfied that external factors have not affected the accuracy of the meter; and
(b) has confirmed that it has been no more than 12 months since the meter was installed in the previous metering installation; and
(c) has confirmed that the meter was calibrated or recalibrated before being installed in the previous metering installation and after being removed from any other metering installation in which the meter was previously installed.


Inspection requirements

44 General inspection requirements
(1) An ATH must, when carrying out an inspection of a metering installation,—
(a) check and confirm that the data storage device in the metering installation operates in accordance with the requirements of this Part; and
(b) check and confirm that the expected remaining lifetime of each battery in the metering installation will be reasonably likely to meet or exceed the metering installation certification expiry date; and

(c) ensure that no modifications under clause 19 have been made to the metering installation without the change having been documented and certification requirements satisfied; and

(d) visually inspect all seals, enclosures, metering components, and wiring of the metering installation for evidence of damage, deterioration, or tampering; and

(e) ensure that the metering installation and its metering components carry appropriate certification stickers in accordance with clause 41; and

(f) in the case of a category 1 metering installation incorporating a data storage device, check and confirm there is no difference between the volume of electricity recorded by the master accumulation register of a data storage device, and the sum of the meter registers.

(2) An ATH must, for each inspection of a metering installation that it carries out, prepare an inspection report that details—

(a) the checks that were carried out; and

(b) the results of the checks; and

(c) the metering installation certification expiry date; and

(d) the serial numbers of each metering component in the metering installation; and

(e) any instances of non-compliance with this Part, and the actions taken to remedy such a breach; and

(f) the name and signature of the person who carried out the inspection and the date on which it was signed.

(3) The ATH must, within 10 business days of carrying out the inspection, provide the inspection report to the metering equipment provider who is responsible for the metering installation.

(4) If an ATH has not performed an inspection of a metering installation, other than an interim certified metering installation, within the specified timeframe under clauses 45(1) or 46(1), the certification of the metering installation is automatically cancelled on the date by which the metering installation was required to have been inspected.

(5) A metering equipment provider must, within 20 business days of receiving the inspection report,—

(a) undertake a comparison of—

(i) the information recorded under subclauses (2)(c) and (d); and

(ii) the information in its own records; and

(b) investigate and correct any discrepancies found under paragraph (a); and

(c) update the registry with the relevant changes.


45 Category 1 metering installation inspection requirements

(1) A metering equipment provider must ensure that—

(a) each category 1 metering installation for which it is responsible, other than an
interim certified metering installation, has been inspected by an ATH within the period set out in Table 1 of Schedule 10.1 starting from the date of the metering installation’s most recent certification; or
(b) for each 12 month period commencing 1 January and ending 31 December, a sample, selected under subclause (2), of the category 1 metering installations for which it is responsible has been inspected by an ATH within the period set out in Table 1 of Schedule 10.1 starting from the date of the earliest certification date of a metering installation in the group.

(2) A metering equipment provider must, for the purposes of subclause (1)(b), select a sample by—
(a) producing a list of all ICP identifiers of each category 1 metering installation for which it is responsible, other than interim certified metering installations; and
(b) removing from the list of ICP identifiers, any ICP identifier for a metering installation that has been certified or inspected in the 84 months prior to the date on which the list was produced; and
(c) identifying the applicable required minimum sample size set out in Table 8 of Schedule 10.1, based on the number of metering installations identified in the list of ICP identifiers in produced in accordance with paragraphs (a) and (b); and
(d) randomly selecting a sample, of the size required under paragraph (c), from the list produced in accordance with paragraphs (a) and (b).

(3) A metering equipment provider must, before it carries out inspections under subclause (1)(b),—
(a) submit a documented process for randomly selecting a sample to the Authority at least 2 months before the first date on which it proposes to carry out the inspections; and
(b) provide promptly any other information or documentation the Authority may reasonably request.

(4) The Authority must, within 2 months of receiving the documented process under subclause (3), advise the metering equipment provider that the documented process—
(a) has been approved; or
(b) has not been approved, providing reasons.

(5) A metering equipment provider must not inspect a sample under this clause unless the Authority has approved the documented process.

(6) A metering equipment provider must, for each inspection of a category 1 metering installation conducted under subclause (1)(b), keep records that detail—
(a) any defects identified that have affected the accuracy or integrity of the raw meter data recorded by the metering installation; and
(b) any discrepancies identified under clause 44(5)(b); and
(c) relevant characteristics, sufficient to enable reporting that identifies any correlations or relationships between inaccuracy and characteristics (for example the meter make, model, and network area, for each metering installation); and
(d) the procedure used, and the lists generated, to select a sample under subclause (2).

(7) A metering equipment provider must, if it believes that a metering installation that
an ATH has inspected under this clause is or could be outside the applicable accuracy tolerances set out in Table 1 of Schedule 10.1, defective, or not fit for purpose,—
   (a) comply with clause 10.43;
   (b) arrange for an ATH to recertify the metering installation under this Schedule, if the metering installation is found to be—
      (i) outside the applicable accuracy tolerances set out in Table 1 of Schedule 10.1; or
      (ii) defective; or
      (iii) not fit for purpose.

(8) A metering equipment provider must, by 1 April in each year, provide to the Authority a report in the prescribed form that states whether the metering equipment provider has, for the previous 1 January to 31 December period, arranged for an ATH to inspect each category 1 metering installation for which it is responsible—
   (a) under subclause (1)(a), in which case the report must also include, for the period—
      (i) a list showing the ICP identifier for each ICP which has a metering installation that was due for inspection, the dates by which the metering installation was due for inspection, and the date on which it was inspected; and
      (ii) a summary of the instances of non-compliance of each category 1 metering installation inspected; and
      (iii) the detailed records required under subclauses (6)(a) and (6)(b); or
   (b) under subclause (1)(b), in which case the report must also include, for the period—
      (i) the number of metering installations identified under subclause (2)(a) to (2)(c); and
      (ii) a summary of the instances of non-compliance of each category 1 metering installation inspected; and
      (iii) the detailed records required under subclauses (6)(a) and (6)(b).

(9) The Authority may, if it considers that the report provided under subclause (8) indicates that there is a statistically significant number of metering installations in the sample which are outside the applicable accuracy tolerances set out in Table 1 of Schedule 10.1, defective, or not fit for purpose, despite subclause (1)(b), advise the metering equipment provider that it must select another sample in accordance with subclause (2) and comply with the applicable requirements of this clause in respect of the sample.

(10) The metering equipment provider must select the additional sample under subclause (9), carry out the required inspections and report to the Authority under subclause (8), within 40 business days of being advised by the Authority under subclause (9).

46 Category 2 metering installation or higher category of metering installation inspection requirements

(1) A metering equipment provider must ensure that each category 2 metering installation, or higher category of metering installation, for which it is responsible is inspected by an ATH at least once within the applicable period set out in Table 1 of Schedule 10.1 starting from the date of the metering installation’s most recent certification.

(2) An ATH must, when conducting an inspection of a category 2 metering installation, or higher category of metering installation, and in addition to complying with clause 44, conduct the following checks:
   (a) a visual inspection of each metering component in the metering installation for damage, tampering, or defect; and
   (b) if the current transformer can be safely accessed, check the position of the current transformer tap to ensure it is still appropriate for the expected maximum current for the metering installation; and
   (c) check for the presence of appropriate voltages at the metering installation; and
   (d) check the voltage circuit alarms and fault indicators.

Sealing

47 Sealing requirements

(1) For the purposes of this clause and clause 48, a reference to something being sealed includes being contained in a sealed enclosure.

(2) An ATH must, before it certifies a metering installation, ensure that each metering component in the metering installation that could reasonably be expected to affect the accuracy or reliability of the metering installation, is sealed.

(3) An ATH must, before leaving a metering installation unattended, ensure that each part and connection of a data storage device that is contained in, or attached to, the metering installation is sealed.

(4) Subclause (3) does not apply to a port for on-site reading that is not capable of carrying out any other function.

(5) An ATH must, before it certifies a metering installation, ensure that the main switch cover is sealed if the main switch—
   (a) is on the supply side of the metering installation; and
   (b) has provision for sealing.

(6) An ATH must, when applying a seal to a metering component in an enclosure, attach a label in a prominent position inside the enclosure, warning—
   (a) of the presence of a sealed metering component in the enclosure; and
   (b) that care must be taken not to disturb the connections to the metering component.

(7) An ATH must use a sealing system that enables the following information to be determined:
   (a) the ATH who affixed the seal; and
(b) the person (or the sealing tool) who applied the seal; and
(c) when the seal was applied.

48 Removal or breakage of seals
(1) Despite clause 10.12, a participant who removes or breaks a seal without authorisation of the metering equipment provider responsible for the metering installation must, within 10 business days of removing or breaking the seal,—
(a) advise the metering equipment provider of—
   (i) the removal or breakage; and
   (ii) the reason for the removal or breakage; and
(b) reimburse the metering equipment provider for the cost of reinstating the seal and recertification if required by the metering equipment provider.
(2) A participant who is required under subclause (1)(b) to reimburse the cost of reinstating and recertifying a seal, must do so within 10 business days of the metering equipment provider advising the participant of the cost.
(3) A participant who becomes aware that another person has removed or broken a seal, must, within 3 business days of becoming aware, advise the metering equipment provider who is responsible for the metering installation.
(4) A metering equipment provider must, if it is advised under subclauses (1) or (3)—
(a) use all reasonable endeavours to ascertain—
   (i) who removed or broke the seal; and
   (ii) the reason for the removal or breakage; and
(b) arrange for an ATH to carry out, as soon as practicable, an inspection of the removal or breakage, and to determine any work required to remedy the removal or breakage.
(5) A metering equipment provider must make the arrangements required under subclause (4)(b) within—
(a) 3 business days of being advised under subclauses (1) or (3), if the metering installation is category 3 or higher; or
(b) 10 business days of being advised under subclauses (1) or (3), if the metering installation is a category 2 metering installation; or
(c) 20 business days of being advised under subclauses (1) or (3), if the metering installation is a category 1 metering installation.
(6) An ATH must, when investigating an unauthorised removal or breakage under subclause (4)(b), assess the accuracy and continued integrity of the metering installation and—
(a) if, in its opinion, the accuracy and continued integrity is unaffected, replace the removed or broken seals; or
(b) if, in its opinion, the accuracy and continued integrity is affected, replace the removed or broken seal and advise the metering equipment provider under clause 10.43.
(7) If subclause (6)(b) applies, the certification of the metering installation is automatically cancelled from the date on which a participant became aware, or should have become aware, of the removed or broken seal.
Schedule 10.8 cl 10.20, 10.38 and 10.42

Metering component requirements

Meters

1   Meter certification requirements

(1) An ATH must, before it certifies a meter, ensure that—

   (a) an approved test laboratory has—

      (i) conducted type-testing that the ATH considers appropriate for the model and version of meter; and

      (ii) produced a type-test certificate that—

           (A) confirms the meter’s technical characteristics; and

           (B) confirms the range of environmental conditions within which the meter has been proven accurate and reliable; and

           (C) confirms that the meter performs the functions for which it was designed; and

           (D) confirms that the meter complies with the requirements of this Part; and

           (E) records the tests undertaken by the approved test laboratory and the reasons why the ATH considers that they are appropriate; and

   (b) the meter has a current calibration report issued by an approved calibration laboratory or an ATH approved to carry out calibration under Schedule 10.3; and

   (c) the meter calibration report—

      (i) confirms that the meter complies with the standards listed in Table 5 of Schedule 10.1; and

      (ii) records any tests the ATH has performed to confirm compliance under subparagraph (i) and the results of those tests; and

      (iii) confirms that the meter has passed the tests; and

      (iv) records any recommendations on error compensation; and

      (v) includes any manufacturer’s calibration test reports; and

   (d) it produces a meter certification report that includes—

      (i) the date on which it certified the meter; and

      (ii) the certification validity period for the meter for each category of metering installation that the meter may be used in; and

      (iii) the maintenance requirements for the meter; and

      (iv) the meter calibration report; and

      (v) whether the certification was based on batch test certificates; and

      (vi) if the certification was based on batch test certificates, confirmation that the manufacturer’s batch testing facility is, in the ATH’s opinion, of an acceptable standard; and

   (e) the percentage values of current set out in Table 6 or Table 7 of Schedule 10.1, as applicable, are relative to the meter’s base or rated current (I_b or I_n) as
appropriate, and this current is selected at a level appropriate for the metering installation in which the meter is to be installed.

(2) The certification validity period referred to in subclause (1)(d)(ii) must not be greater than the maximum certification validity period set out in Table 2 of Schedule 10.1 for the relevant class of meter.


Measuring transformers

2 Measuring transformer certification requirements

(1) An ATH must, before it certifies a measuring transformer,—
(a) ensure, by testing, that a current calibration report sets out the measuring transformer's errors at a range of primary values at their rated burdens; and
(b) that is a multi-tap current transformer, carry out the calibration tests and only certify the transformer for the ratios that have been calibrated if the test is passed; and
(c) if the in-service burden is lower than a test point specified in a standard listed in Table 5 of Schedule 10.1, confirm the accuracy of the measuring transformer at the in-service burden by—
(i) obtaining confirmation of accuracies at the in-service burden from the measuring transformer's manufacturer; or
(ii) if the primary voltage of the measuring transformer is greater than 1kV, a class A ATH calibrating the measuring transformer at the in-service burden; and
(d) determine the measuring transformer certification validity period under clause 3(c)(ii).

(2) An ATH must, before it certifies an epoxy insulated current transformer, ensure that the certification tests allow for, and the metering installation certification report shows, the current transformer’s age, temperature, and batch.


3 Measuring transformer certification report

An ATH must, before it certifies a measuring transformer, ensure that—
(a) the measuring transformer has a current calibration report issued by an approved calibration laboratory or an ATH approved to carry out calibration under Schedule 10.3; and
(b) the measuring transformer calibration report—
(i) confirms that the measuring transformer complies with the standards listed in Table 5 of Schedule 10.1; and
(ii) records any tests the ATH has performed to confirm compliance under subparagraph (i) and the results of those tests; and
(iii) confirms that the measuring transformer has passed the tests; and
(iv) records any recommendations made by the ATH on error compensation; and
(v) includes any manufacturer’s calibration test reports; and
(c) it produces a measuring transformer certification report that includes—
(i) the date on which it certified the measuring transformer; and
(ii) the certification validity period for the measuring transformer which must be no more than 120 months; and
(iii) the measuring transformer calibration report; and
(iv) whether the certification was based on batch test certificates; and
(v) if the certification was based on batch test certificates, confirmation that the manufacturer’s batch testing facility is, in the ATH’s opinion, of an acceptable standard; and
(d) it confirms that it has inspected the manufacturer’s test certificates, and carried out any additional tests it considers necessary, to satisfy itself that the measuring transformer meets the accuracy requirements of this Part.


4 Control device certification report
(1) An ATH must, before it certifies a new control device, produce a certification report that—
(a) confirms that the control device complies with the applicable standards listed in Table 5 of Schedule 10.1; and
(b) includes the details and results of any test that the ATH has carried out to confirm compliance under paragraph (a); and
(c) confirms that the control device has passed such tests.
(2) An ATH must, before it certifies an existing installed control device, produce a certification report that—
(a) confirms that the control device is fit for purpose; and
(b) confirms the control device certification validity period that the ATH considers appropriate, which must be no more than 180 months.

Clause 4: substituted, on 29 August 2013, by clause 47 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).

5 Data storage device certification requirements
(1) An ATH must, before it certifies a data storage device used for storing information that is used for the purposes of Part 15, ensure that—
(a) an approved test laboratory has—
(i) conducted type-testing that the ATH considers appropriate for the model and version of data storage device; and

(ii) produced a type-test certificate that—
   (A) confirms the data storage device’s technical characteristics; and
   (B) confirms the range of environmental conditions within which the data storage device has been proven accurate and reliable; and
   (C) confirms that the data storage device performs the functions for which it was designed; and
   (D) confirms that the data storage device complies with this Part; and
   (E) records the tests undertaken by the approved test laboratory to confirm compliance under sub-subparagraph (D) and the reasons why the ATH considers that they are appropriate; and

(b) it produces a certification report that—
   (i) confirms the data storage device complies with the applicable standards listed in Table 5 of Schedule 10.1; and
   (ii) records the tests the ATH has performed to confirm compliance with subparagraph (i) and the results of those tests; and
   (iii) confirms that the data storage device has passed the tests; and
   (iv) includes the date on which it certified the data storage device; and
   (v) includes the certification validity period for the data storage device for each category of metering installation in which the data storage device may be used; and
   (vi) records the maintenance requirements for the data storage device; and
   (vii) confirms that each period of data is identifiable or deducible by both date and time on interrogation; and
   (viii) confirms that the time and date of the following event conditions are recorded in an event log:
      (A) a loss of the power supply to the data storage device; and
      (B) critical internal alarms such as memory integrity checking, battery low, battery failed, and tampering; and
      (C) phase failure to the meter, if the data storage device is integral to the meter; and
      (D) any software configuration changes; and
      (E) results of time setting comparisons and corrections; and
      (F) the transition from, and to, New Zealand daylight time, if the data storage device operates in New Zealand daylight time; and
   (ix) confirms that the data storage device has the available memory capacity required by the type-test; and
   (x) confirms that the data storage device has the functionality—
      (A) to validate instructions from an interrogation system; and
      (B) for time comparisons and corrections, in response to a valid instruction; and
   (xi) confirms that all information logged is referenced to New Zealand Standard Time or New Zealand daylight time; and
(xii) confirms that the **data storage device** has data loss protection providing a continued clock and memory operation for a continuous period of at least 15 days when the power supply to the **data storage device** is lost.

(2) The **data storage device certification** validity period referred to in subclause (1)(b)(v) must be—
   (a) no more than 180 months, if the **data storage device** is a discrete **metering component**; or
   (b) the same as the **meter certification** validity period, if the **data storage device** is integral to the **meter**.

(3) Despite subclause (1)(b)(ix), the memory capacity of the **data storage device** must not be less than 15 days.

(4) For the purposes of subclause (1), a new version of the **data storage device** includes any change to the specification, hardware, or metrology **software** of the **data storage device**.

### Wiring

6 **Wiring**

(1) An **ATH** must, before it **certifies** a **metering installation**, ensure that all wiring in the **metering installation** is—
   (a) suitable for the environment in which the **metering installation** is located; and
   (b) fit for purpose; and
   (c) securely fastened; and
   (d) compliant with all applicable requirements and enactments.

(2) An **ATH** must, before it **certifies** a **metering installation**, ensure that the wiring between **metering components** in the **metering installation**—
   (a) is run as directly as practicable; and
   (b) is appropriately sized and protected; and
   (c) does not, to the extent practicable, include intermediate joints for any **measuring transformer** circuits; and
   (d) subject to subclause (4), includes conductors that are clearly and permanently identified, by the use of any 1 or more of the following:
      (i) colour coding:
      (ii) marker ferrules:
      (iii) conductor numbering.

(3) For the purposes of subclause (2)(c), if it is not practicable to exclude intermediate joints for any **measuring transformer** circuits, the **ATH** must ensure that the intermediate joints are—
   (a) sealed or in a sealed enclosure; and
   (b) located in a secure position; and
   (c) recorded in the **metering installation certification report**.

(4) The **ATH** must, if the wiring is in a **metering installation** and does not comply with subclause (2)(d)—
   (a) ensure, by testing, that the wiring has been correctly installed; and
(b) record the nature of the test or the tests, and the results of the test or tests, in the metering installation certification report.

**Fuses and circuit breakers**

7 **Fuses and circuit breakers**

An ATH must, before it certifies a metering installation, ensure that all fuses and circuit breakers that are part of the metering installation are—

(a) appropriately rated for the electrical duty and discrimination required; and

(b) clearly labelled and—

(i) sealed; or

(ii) located in sealed enclosures.

**Certification stickers**

8 **Metering component certification stickers**

(1) An ATH must, when certifying a metering component under this Part, confirm the certification by attaching a metering component certification sticker to the metering component or, if not practicable, provide the sticker with the metering component.

(2) An ATH referred to in subclause (1) must ensure that a metering component certification sticker shows—

(a) the name of the metering component owner (if available); and

(b) if the metering component is a meter or a measuring transformer, the name of the ATH or the approved calibration laboratory who calibrated the metering component; and

(c) the name of the ATH who certified the metering component; and

(d) the date on which the metering component was certified; and

(e) the initials or other unique identifier of the person who carried out the certification of the metering component.

(3) An ATH must ensure that a certification sticker is—

(a) made of weather-proof material; and

(b) permanently attached; and

(c) filled out using permanent markings.

**Onsite calibration and certification**

9 **Onsite calibration and certification**

(1) A certifying ATH may only calibrate a metering component onsite—

(a) in the metering component’s normal working environment; and

(b) by—

(i) measuring the influence of all onsite variables and including their estimated effects in the uncertainty calculation; and

(ii) ensuring that—

(A) the effects of any departures from the reference conditions specified in the relevant standards listed in Table 5 of Schedule 10.1 can
accurately and reliably be calculated; and

(B) the metering installation, in which the metering component is incorporated, is within the applicable accuracy tolerances set out in Table 1 of Schedule 10.1 after taking into account all known influences including temperature and temperature co-efficient measurements.

(2) If an ATH calibrates a metering component onsite using manual methods, computers, or automated equipment for the capture, processing, manipulation, recording, reporting, storage, or retrieval of calibration data, it must ensure that its computer software—

(a) is documented in the ATH’s procedures; and

(b) can manipulate the variables that affect the performance of the metering component in a manner that will produce results that would correctly indicate the level of compliance of the metering component with this Code.

(3) An ATH who certifies a metering component onsite must include in the metering component certification report confirmation that—

(a) it has calculated the uncertainty of measurement taking into account all environmental factors for both the metering component being calibrated and the working standards; and

(b) the calculation of the uncertainty referred to in paragraph (a) comprises all uncertainties in the chain of calibration; and

(c) the ATH has used a calibration procedure to calibrate the metering component that—

(i) was included in the ATH’s most recent audit; and

(ii) is appropriate for onsite calibration; and

(iii) includes the methodologies, calculations, and assumptions used by the ATH in determining the uncertainty; and

(d) the ATH believes the methodologies, calculations, and assumptions are appropriate, including reasons for that belief.
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Part 11
Registry information management

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11.1 Contents of this Part
This Part—
(a) provides for the management of information in the registry; and
(b) prescribes a process for switching ICPs between traders; and
(c) prescribes a process for a distributor to change the record in the registry of an ICP so that the ICP is recorded as being usually connected to an NSP in the distributor’s network; and

(d) prescribes a process for switching responsibility for metering installations for ICPs between metering equipment providers; and

(e) prescribes a process for dealing with trader events of default; and

(f) requires retailers to give consumers information about their own consumption of electricity; and

(g) requires retailers to give information about their generally available retail tariff plans to any person on request.

Compare: Electricity Governance Rules 2003 rule 1 part E
Clause 11.1(a) and (c): amended, on 5 October 2017, by clause 194 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

11.2 Requirement to provide complete and accurate information

(1) A participant must take all practicable steps to ensure that information that the participant is required to provide to any person under this Part is—

(a) complete and accurate; and

(b) not misleading or deceptive; and

(c) not likely to mislead or deceive.

(2) If a participant becomes aware that the information the participant provided under this Part does not comply with subclause (1)(a) to (c), even if the participant has taken all practicable steps to ensure that the information complies, the participant must, as soon as practicable, provide such further information as is necessary to ensure that the information complies with subclause (1)(a) to (c).

Compare: Electricity Governance Rules 2003 rule 1A part E

11.2A Use of contractors

(1) A participant may perform its obligations and exercise its rights under this Part by using a contractor.

(2) A participant who uses a contractor to perform the participant’s obligation under this Part—
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(a) remains responsible and liable for, and is not released from the obligation or any other obligation under this Part; and
(b) cannot assert that it is not responsible or liable for the obligation on the ground that the contractor—
   (i) has done or not done something; or
   (ii) has failed to meet a relevant standard; and
(c) must ensure that the contractor has at least the specified level of skill, expertise, experience, or qualification that the participant would be required to have if it were performing the obligation itself.

(3) If a participant is a party to a contract or arrangement containing a provision, or part of a provision, which is inconsistent with this Part, the provision, or part of the provision, has no effect.


11.3 Certain points of connection must have ICP identifiers

(1) This clause applies to the following:
   (a) a trader who has agreed to purchase electricity from an embedded generator or sell electricity to a consumer:
   (b) an embedded generator who sells electricity directly to the clearing manager:
   (c) a direct purchaser connected to a local network or an embedded network:
   (d) an embedded network owner in relation to a point of connection on an embedded network that is settled by differencing:
   (e) a network owner in relation to a shared unmetered load point of connection to the network owner’s network:
   (f) a network owner in relation to a point of connection between the network owner’s network and an embedded network.

(2) A participant to whom this clause applies must, before the participant assumes responsibility for a point of connection described in subclause (3) on a local network or embedded network, obtain an ICP identifier for the point of connection.

(3) The points of connection for which ICP identifiers must be obtained under subclause (2) are points of connection at which any of the following occurs:
   (a) a consumer purchases electricity from a trader:
   (b) a trader purchases electricity from an embedded generator:
   (c) a direct purchaser purchases electricity from the clearing manager:
   (d) an embedded generator sells electricity directly to the clearing manager:
   (e) a network is settled by differencing:
   (f) there is a distributor status ICP—
      (i) at the point of connection between an embedded network and the distributor’s network; or
      (ii) at the point of connection of shared unmetered load.

Compare: Electricity Governance Rules 2003 rule 2 part E
11.4 Distributors must create ICP identifiers for ICPs

(1) Each distributor must create an ICP identifier in accordance with clause 1 of Schedule 11.1 for each ICP on each network for which the distributor is responsible.

(2) A distributor must create an ICP identifier for the point of connection at which an embedded network connects to the distributor’s network in accordance with subclause (1).

(3) An ICP identifier for an ICP may not be changed.

Compare: Electricity Governance Rules 2003 rule 3 part E

11.5 Participants may request that distributors create ICP identifiers for ICPs

(1) A participant to whom clause 11.3 applies may request that a distributor create an ICP identifier for an ICP on a network for which the distributor is responsible.

(2) A participant may make a request under subclause (1) only if the participant has an arrangement with the distributor for line function services in accordance with clause 11.16.

(3) A distributor to whom a request is made must, within 3 business days of receiving the request, create a new ICP identifier for each ICP to which the request relates in accordance with clause 1 of Schedule 11.1, or advise the participant of the distributor’s reasons for not complying with the request.

Compare: Electricity Governance Rules 2003 rule 4 part E


11.6 ICP status

The participant specified in clause 12 of Schedule 11.1 must manage the status of an ICP in accordance with clause 12 of Schedule 11.1.

Compare: Electricity Governance Rules 2003 rule 5 part E

11.7 Provision of ICP information

(1) A distributor whose network includes 1 or more ICPs must provide information about each of those ICPs to the registry manager in accordance with Schedule 11.1.

(2) A trader must provide information about each ICP at which the trader trades electricity to the registry manager in accordance with Schedule 11.1.

Compare: Electricity Governance Rules 2003 rule 6 part E


11.8 Provision of and changes to ICP information and NSP information by participants

(1) This clause applies if—

(a) an NSP is to be created or decommissioned; or

(b) 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”).
(2) The participant specified in clause 25(3) of Schedule 11.1 must give the notice required by clause 25(1) of Schedule 11.1.

(3) A distributor to whom subclause (1)(b) applies must comply with clause 25(2) of Schedule 11.1.

(4) The participants specified in clauses 25 to 27 of Schedule 11.1 must comply with those clauses.

(5) If a network owner acquires all or part of an existing network, the network owner must give the notice required by clause 29 of Schedule 11.1.

Compare: Electricity Governance Rules 2003 rule 8 part E
Clause 11.8(1)(a) and (b): amended, on 5 October 2017, by clause 197 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

11.8A Metering equipment providers to provide registry metering records to registry manager

(1) A metering equipment provider must, for each metering installation described in subclause (2) for which it is responsible,—
   (a) provide to the registry manager the registry metering records for the metering installation in the prescribed form; and
   (b) update the registry metering records in accordance with Schedule 11.4.

(2) Subclause (1) applies to a metering installation that is—
   (a) a category 1 metering installation, or higher category of metering installation; and
   (b) for an ICP that is not also an NSP.

Clause 11.8A: inserted, on 29 August 2013, by clause 8 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

11.8B Metering equipment providers to arrange for regular audits

Each metering equipment provider must arrange to be audited regularly in accordance with Part 16A in respect of the metering equipment provider’s obligations under this Part.

Clause 11.8B: inserted, on 29 August 2013, by clause 8 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.
Clause 11.8B: replaced, on 1 June 2017, by clause 18 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

11.9 [Revoked]

Compare: Electricity Governance Rules 2003 rule 8 part E
Clause 11.9: revoked, on 29 August 2013, by clause 9 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

11.10 Distributors to arrange for regular audits

Each distributor must arrange to be audited regularly in accordance with Part 16A in respect of the distributor’s obligations under this Part.

Compare: Electricity Governance Rules 2003 rule 10 part E
Clause 11.10(1A): inserted, on 29 August 2013, by clause 5(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.
Clause 11.10: replaced, on 1 June 2017, by clause 19 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

11.11 Authority and participant requested audits

(1) The Authority may at any time carry out, or appoint an auditor to carry out, an audit of a participant in respect of the participant's obligations under this Part.

(2) If a participant considers that another participant may not have complied with this Part, the participant may request that the Authority carry out, or appoint an auditor to carry out, an audit of the other participant.

(3) Part 16A applies to an audit carried out under this clause.

Compare: Electricity Governance Rules 2003 rule 10A part E
Clause 11.11: replaced, on 1 June 2017, by clause 20 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

11.12 [Revoked]

Compare: Electricity Governance Rules 2003 rule 10B part E

11.13 [Revoked]

Compare: Electricity Governance Rules 2003 rule 10C part E

11.14 Process for maintaining shared unmetered load

(1) This clause applies if shared unmetered load is connected to a distributor’s network.

(2) The distributor must give written notice to the registry manager, and each trader responsible under clause 11.18(1) for the ICPs across which the unmetered load is shared, of the ICP identifiers of those ICPs.

(3) A trader who receives written notice under subclause (2) must give written notice to the distributor if it wishes to add an ICP to or omit an ICP from the ICPs across which the unmetered load is shared.

(4) A distributor who receives written notice under subclause (3) must give written notice to the registry manager and each trader responsible for any of the ICPs across which the unmetered load is shared, of the addition or omission of the ICP.

(5) If a distributor becomes aware of a change to the capacity of an ICP across which the unmetered load is shared or that an ICP across which the unmetered load is shared is decommissioned, it must give written notice to all traders who receive written notice under subclause (2) of the change or decommissioning as soon as practicable after the change or decommissioning.

(6) A trader who receives written notice under subclause (5) must, as soon as practicable after receiving the written notice, adjust the unmetered load information for each ICP for which it is responsible, so that the unmetered load is shared equally across each of those ICPs.
(7) A trader must take responsibility for shared unmetered load assigned to an ICP for which the trader becomes responsible as a result of a switch in accordance with this Part.
(8) A trader must not relinquish responsibility for shared unmetered load assigned to an ICP if there would then be no ICPs left across which the load could be shared.
(9) A trader who changes the status of an ICP across which the unmetered load is shared to inactive in accordance with clause 19 of Schedule 11.1 is not required to give written notice to the distributor of the change under subclause (3). The amount of electricity attributable to that ICP becomes UFE.

A trader must take responsibility for shared unmetered load assigned to an ICP for which the trader becomes responsible as a result of a switch in accordance with this Part.

A trader must not relinquish responsibility for shared unmetered load assigned to an ICP if there would then be no ICPs left across which the load could be shared.

A trader who changes the status of an ICP across which the unmetered load is shared to inactive in accordance with clause 19 of Schedule 11.1 is not required to give written notice to the distributor of the change under subclause (3). The amount of electricity attributable to that ICP becomes UFE.

11.15 Process for customer or embedded generator switching
(1) This clause applies if a trader (“the gaining trader”) has an arrangement with a customer or embedded generator to—
(a) commence trading electricity with the customer or embedded generator at an ICP at which another trader (“the losing trader”) trades electricity with the customer or embedded generator; or
(b) assume responsibility under clause 11.18(1) for such an ICP.
(2) The gaining trader and the losing trader must comply with Schedule 11.3.

11.15AA Trader may elect to have switch saving protection
(1) A trader that buys electricity from the clearing manager may elect to have switch saving protection by giving written notice to the Authority.
(2) The Authority must publish the name of each trader that has elected to have switch saving protection as soon as practicable after receiving the written notice from the trader.
(3) A trader’s switch saving protection comes into effect on the day after the day on which the Authority publishes the trader’s election.

11.15AB Switch saving protection
(1) This clause applies if a trader (the "protected trader") has switch saving protection.
(2) If the protected trader enters into an arrangement with a customer of another trader (the "losing trader") to commence trading electricity with the customer, the losing trader must comply with subclause (4).
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(3) If a trader enters into an arrangement with a customer of a protected trader to commence trading electricity with the customer, the protected trader must comply with subclause (4).

(4) A losing trader referred to in subclause (2) or a protected trader referred to in subclause (3) must not, by any means, initiate contact with the customer to attempt to persuade the customer to terminate the arrangement referred to in subclause (2) or subclause (3) (as the case may be) during the period specified in subclause (5), including by—
   (a) making a counter-offer to the customer; or
   (b) offering an enticement to the customer.

(5) The period starts on the day on which the trader receives notice of the switch request under clause 22(a) of Schedule 11.3, and ends on the event date for the switch.

Clause 11.15AB: inserted, on 12 January 2015, by clause 4 of the Electricity Industry Participation Code Amendment (Switch Saving Protection) 2014.

11.15AC Trader may communicate with customers for certain purposes

Clause 11.15AB(4) does not prohibit a trader from—
   (a) contacting a customer to advise the customer of any termination fees that the customer is required to pay as a result of the customer ceasing to trade with the trader; or
   (b) contacting a customer regarding administrative matters, including—
      (i) any fees the customer owes the trader:
      (ii) the customer’s final meter reading:
      (iii) how the trader will return any keys it holds on the customer’s behalf:
      (iv) the effect of the customer ceasing to buy electricity from the trader on other contracts between the customer and the trader, for example, for the supply of gas; or
   (c) providing a factual response to a question asked by a customer; or
   (d) making a counter-offer or offering an enticement to a customer who has invited the trader to attempt to persuade the customer to terminate the arrangement referred to in clause 11.15AB(2) or (3); or
   (e) offering an enticement to a customer as part of a general marketing campaign.

Clause 11.15AC: inserted, on 12 January 2015, by clause 4 of the Electricity Industry Participation Code Amendment (Switch Saving Protection) 2014.

11.15AD Cancellation of switch saving protection

(1) A trader that has elected to have switch saving protection may cancel its switch saving protection by giving written notice to the Authority.

(2) However,—
   (a) a trader may not cancel its switch saving protection earlier than 12 months after the date on which the switch saving protection came into effect; and
   (b) a trader that has cancelled its switch saving protection may not elect to have switch saving protection earlier than 12 months after the date on which the trader cancelled its switch saving protection.

Clause 11.15AD: inserted, on 12 January 2015, by clause 4 of the Electricity Industry Participation Code Amendment (Switch Saving Protection) 2014.
11.15A Application of Schedule 11.4
The following parties must comply with Schedule 11.4:
(a) a trader that gives written notice to the registry manager of the gaining metering equipment provider responsible for each metering installation for an ICP:
(b) the registry manager:
(c) the gaining metering equipment provider.
Clause 11.15A(a) and (b): amended, on 5 October 2017, by clause 201 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

11.15B Trader contracts with customers to permit assignment by Authority
(1) Each trader must at all times ensure that the terms of each contract under which a customer of the trader purchases electricity from the trader permit—
(a) the Authority to assign the rights and obligations of the trader under the contract to another trader if the trader commits an event of default under paragraph (a) or (b) or (f) or (h) of clause 14.41(1); and
(b) the terms of the assigned contract to be amended on such an assignment to—
(i) the standard terms that the recipient trader would normally have offered to the customer immediately before the event of default occurred; or
(ii) such other terms that are more advantageous to the customer than the standard terms, as the recipient trader and the Authority agree; and
(c) the terms of the assigned contract to be amended on such an assignment to include a minimum term in respect of which the customer must pay an amount for cancelling the contract before the expiry of the minimum term; and
(d) the trader to provide information about the customer to the Authority and for the Authority to provide the information to another trader if required under Schedule 11.5; and
(e) the trader to assign the rights and obligations of the trader to another trader.
(2) The terms specified in subclause (1) must—
(a) be expressed to be for the benefit of the Authority for the purposes of subpart 1 of Part 2 of the Contract and Commercial Law Act 2017; and
(b) not be able to be amended without the consent of the Authority.
(3) [Revoked]
Heading clause 11.15B: amended, on 28 February 2015, by clause 6(1) of the Electricity Industry Participation Code Amendment (Trader Default) 2014.
11.15C Process for trader events of default

(1) This clause applies if the Authority is satisfied that a trader has committed an event of default under paragraph (a) or (b) or (f) or (h) of clause 14.41.

(2) The Authority and each participant must comply with Schedule 11.5.

(3) This clause ceases to apply, and the Authority and each participant must cease to comply with Schedule 11.5, if the Authority is advised under clause 14.41(2), 14.43(3B), or 14.43(4A) that the relevant participant considers that the event of default has been remedied.

11.16Trader to ensure arrangements for line function services and metering

Before providing the registry manager with information in accordance with clause 11.7(2) or clause 11.18(4), a trader must—

(a) ensure that it, or its customer, has made any necessary arrangements for the provision of line function services in relation to the ICP; and

(b) have entered into an arrangement with a metering equipment provider to be responsible for each metering installation for the ICP.

11.17 Connecting ICP that is not also NSP

(1A) A distributor must, when connecting an ICP that is not also an NSP, follow the connection process set out in clause 10.31.

(1) A distributor must not connect an ICP across which unmetered load is shared unless a trader is recorded in the registry as accepting responsibility for the shared unmetered load.
(2) A **distributor** must not connect an **ICP** of any other kind unless a **trader** is recorded in the **registry** as accepting responsibility for the **ICP**.

(3) Subclause (2) does not apply to an **ICP** that is—

(a) the **point of connection** between a **network** and an **embedded network**; or

(b) the **point of connection** of **shared unmetered load**.

Compare: Electricity Governance Rules 2003 rule 17 part E
Clause 11.17(1A): inserted, on 29 August 2013, by clause 12 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.
Clause 11.17(1A): substituted, on 29 August 2013, by clause 5 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011 Amendment 2013 (No 2).
Clause 11.17(1A), (1) and (2): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 11.17(1A), (1) and (2): amended, on 5 October 2017, by clause 204(2) and (3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

11.18 Trader responsibility for ICP

(1) If a **trader** is recorded in the **registry** as accepting responsibility for an **ICP** that is not also an **NSP**, the **trader** is responsible for all obligations in this Part that—

(a) apply to **traders**; and

(b) relate to an **ICP** that is not also an **NSP**.

(2) A **trader** ceases to be responsible for obligations in this Part relating to an **ICP** that is not also an **NSP** if—

(a) another **trader** is recorded in the **registry** as being responsible for the **ICP**; or

(b) the **ICP** is **decommissioned** in accordance with clause 20 of Schedule 11.1.

(3) If an **ICP** is to be **decommissioned**, the **trader** who is responsible for the **ICP** must—

(a) arrange for a final **interrogation** to take place before or on removal of the **meter**; and

(b) advise the **metering equipment provider** responsible for each **metering installation** for the **ICP** that it is to be **decommissioned**.

(4) A **trader** who is responsible for an **ICP**, other than an **ICP** at which there is only **unmetered load**, must ensure that a **metering equipment provider** is recorded in the **registry** as being responsible for each **metering installation** for the **ICP**.

(5) The **trader** must not trade at an **ICP** if a **metering equipment provider** is not recorded in the **registry** as being responsible for each **metering installation** for the **ICP**, unless the **trader** trades only **unmetered load** at that **ICP**.

Compare: Electricity Governance Rules 2003 rule 17 part E

11.18A Registry manager to advise metering equipment providers

The **registry manager** must, within 1 **business day** of being advised by a **trader** of a **metering equipment provider's participant identifier** for an **ICP** identifier, —
(a) if there is not already a metering equipment provider assigned to the ICP identifier, advise the gaining metering equipment provider that the registry manager has been advised that it is the gaining metering equipment provider for each metering installation for the ICP; or

(b) if there is a losing metering equipment provider, advise both the gaining metering equipment provider and the losing metering equipment provider of the advice.


11.18B Metering equipment provider responsibility for metering installation for ICP

(1) This clause applies to a metering equipment provider who assumes responsibility, or is appointed to be responsible, as the metering equipment provider for an ICP.

(2) The obligations under this Part, of a metering equipment provider to whom this clause applies,—

(a) commence at the same time as the metering equipment provider's obligations under clause 10.21(1):

(b) terminate when the metering equipment provider's obligations under Part 10 terminate under clause 10.23.

(3) [Revoked]

Clause 11.18B: inserted, on 29 August 2013, by clause 13 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

Clause 11.18B(3): revoked, on 1 November 2018, by clause 41 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018

11.19 Authority to specify timeframes and formats of information

(1) Subject to subclause (3), subclause (2) applies if a participant is required to provide information under this Part, but this Code does not specify any 1 or more of the following:

(a) the time by which, or the period within which, the information must be provided:

(b) the format in which the information must be provided:

(c) the method by which the information must be provided.

(2) The participant must provide the information in accordance with requirements as to those matters specified by the Authority.

(3) Unless otherwise specified in this Part, information or notices that must be provided under this Part by the registry manager or to the registry manager, must be provided using the registry.

Compare: Electricity Governance Rules 2003 rule 20 part E


11.20 Registry must be available between 0730 and 1930 each day
(1) The registry manager must ensure that the registry is available to receive and provide information under this Part between 0730 hours and 1930 hours each day.
(2) Information provided to the registry manager after 1930 hours is deemed to be provided at 0730 the next day.

Compare: Electricity Governance Rules 2003 rule 21 part E

11.21 Confirmation of receipt of data
(1) Information provided to the registry manager is deemed, for the purposes of this Part, not to have been received until the registry manager has confirmed receipt in accordance with this clause.
(2) The registry manager must confirm receipt of information received by it in accordance with this Part within 4 hours of the information being provided to it.
(3) In determining whether the registry manager has confirmed receipt within the time specified in subclause (2), no account is to be taken of any period during which the registry is not required to be available under clause 11.20.
(4) If the participant providing the information does not receive confirmation that the registry manager has received the participant's information, the participant must contact the registry manager to check whether the registry manager has received the information.
(5) If the registry manager has not received the information, the participant must re-send the information. This process must be repeated until the registry manager has confirmed receipt of the information in accordance with this clause.

Compare: Electricity Governance Rules 2003 rules 22.1 and 22.2 part E
Clause 11.21(1), (2), (4) and (5): amended, on 5 October 2017, by clause 208(1) and (3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

11.22 Registry manager must maintain register of information
(1) The registry manager must maintain a register of information received by it and updated in accordance with this Code.
(2) The registry manager must ensure that a complete audit trail exists for all information received by it in accordance with this Code.

Compare: Electricity Governance Rules 2003 rule 22.3 part E

11.23 Reports from registry manager
By 1600 hours on the 6th business day of each reconciliation period, the registry manager must publish a report containing the following information:
(a) the number of ICPs in the registry at the end of the immediately preceding consumption period:
(b) the number of notifications received by the registry manager in accordance with clause 2 of Schedule 11.3 during the previous reconciliation period:
(c) such other information as may be agreed from time to time between the registry manager and the Authority.

11.24 Registry manager delivers reports to specific participants

The registry manager must deliver the reports specified in clauses 11.25 to 11.27 in the manner specified in those clauses.

11.25 Reports to clearing manager, system operator or reconciliation manager

(1) The clearing manager, or the system operator, or the reconciliation manager may request in writing, no later than 5 business days before the last day of the month before the 1st month for which the report is requested, a report that includes any or all of the following information:
   (a) all active NSPs connected to a local network during the immediately preceding 14 calendar months:
   (b) all active NSPs connected to a network for which a trader is, and has over the immediately preceding 14 calendar months been, responsible:
   (c) the dates on which each trader’s responsibility under this Code at an NSP commenced and ceased.

(2) The system operator may at any time request, in writing, a report that sets out every switch made under clauses 2, 9 or 14 of Schedule 11.3, the effect of which is that a trader has commenced trading at an NSP or a trader has ceased trading at an NSP.

(3) A request made under subclauses (1) or (2) may—
   (a) be a one-off request; or
   (b) specify a frequency over a particular period; or
   (c) specify a frequency over an indefinite period until terminated by the requesting person.

(4) If the request is received by the time specified in this clause, the registry manager must provide the report by 1000 hours on the 1st business day of the month following the month in which the request was made, or if the request for the report specifies a later date, by the later date.

(5) The person who requested the report may vary any of the details set out in the request, by giving notice to the registry manager of the relevant details in writing by no later
than 5 business days before the last day of the month before the 1st month for which the person requests the variation.

(6) The registry manager must comply with a request made in accordance with subclause (5) by 1000 hours on the 1st business day of the month following the month in which the request was made.

Compare: Electricity Governance Rules 2003 rule 24.1 part E
Clause 11.25(1)(a) and (b): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 11.25(1), (4), (5) and (6): amended, on 5 October 2017, by clause 212(2) to (4) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

11.26 Reports to reconciliation manager

By 1600 hours on the 4th business day of each calendar month, in respect of the immediately preceding consumption period, and by 1600 hours on the 13th business day of each calendar month in respect of the immediately preceding 14 consumption periods, the registry manager must deliver the following reports to the reconciliation manager:

(a) a report identifying the number of ICP days per NSP, differentiated by half-hour metering type or non half-hour metering type (for the purpose of this clause, half-hour metering type on the registry must be reported as half hour, and all other metering types must be reported as non half hour) attributable to each trader for those NSPs that are recorded on the registry as consuming electricity at any time during, as the case may be, that consumption period or any of those consumption periods:

(b) a report detailing the loss factor values for each loss category code recorded in the registry in respect of all trading periods:

(c) a report detailing the balancing area to which each NSP belongs recorded in the registry in respect of all trading periods (including any changes during that month):

(d) a report detailing the half hour ICP identifiers and the NSPs to which they are assigned for each individual trader (including any changes during that month):

(e) a report that sets out every switch made under clauses 2, 9 or 14 of Schedule 11.3, the effect of which is that a trader has commenced trading at an NSP or a trader has ceased trading at an NSP.

Compare: Electricity Governance Rules 2003 rule 24.2 part E
Clause 11.26: amended, on 5 October 2017, by clause 213(2) and (3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

11.27 Reports to Authority

By 1600 hours on the 1st business day of each calendar month, the registry manager must deliver to the Authority a report summarising the number of events—

(a) that a participant has not notified to the registry manager within the timeframes specified in this Part; and
(b) of which the registry manager is aware, despite the participant not having notified the registry manager.

Compare: Electricity Governance Rules 2003 rule 24.3 part E

11.28 Access to registry

(1) A participant may apply to the Authority to have access to information held in the registry.

(2) If the Authority grants a participant’s application, the Authority must specify terms and conditions under which the Authority grants access to the information.

(2A) The participant must comply with the terms and conditions specified by the Authority under subclause (2).

(3) The registry manager must provide to the participant access to information held in the registry in accordance with those terms and conditions.

(4) If the Authority grants a participant access to information in the registry, and the participant requests a report, the registry manager must provide the report to the participant within 4 hours of receiving the request.

(5) In determining whether the registry manager has provided the report within the time specified in subclause (4), no account is to be taken of any period during which the registry is not required to be available under clause 11.20.

Compare: Electricity Governance Rules 2003 rule 25 part E
Clause 11.28(1), (2), (3) and (5): amended, on 5 October 2017, by clause 215(1) to (3) and (5) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 11.28(2A): inserted, on 29 August 2013, by clause 14(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

11.29 Registry information change

If a change to registry information is provided in accordance with clause 11.7, the registry manager must, within 1 business day of receiving the information, advise affected participants of the change.

Compare: Electricity Governance Rules 2003 rule 26 part E

11.30 Use of ICP identifier on invoices

Each trader must ensure that the relevant ICP identifier is printed on every invoice or associated document relating to the sale of electricity rendered by the trader, and that the ICP identifier is clearly labelled "ICP" on the invoice.

Compare: Electricity Governance Rules 2003 rule 27 part E
11.31 Customer and embedded generator queries

(1) If a trader receives a request from a customer of the trader or a person authorised by a customer of the trader for the customer’s ICP identifier, the trader must provide that information no later than 3 business days after receiving the request.

(2) If a distributor receives a request from a customer or embedded generator whose ICP is connected to the distributor’s network for the customer’s or embedded generator’s ICP identifier, or a person authorised by such a customer or embedded generator, the distributor must provide that information no later than 3 business days after receiving the request.

Compare: Electricity Governance Rules 2003 rule 28 part E

11.32 Reliance on registry

A participant does not breach this Code just because the participant does something relying on an incorrect record in the registry.

Compare: Electricity Governance Rules 2003 rule 29 part E

Access by consumers to information about their own electricity consumption

Cross Heading: inserted, on 1 February 2016, by clause 5 of the Electricity Industry Participation Code Amendment (Access to Retail Data) 2014.

11.32A Retailers must give information about consumer electricity consumption

(1) Each retailer must, if requested by a consumer with whom the retailer has a contract to supply electricity, or with whom the retailer has had such a contract in the last 24 months, give the consumer any of the information specified in subclause (2) that the consumer requests.

(2) The information referred to in subclause (1) is information relating to any period in the 24 months preceding the request—

(a) about the consumer’s consumption of electricity relating to each ICP at which the retailer supplied electricity to the consumer; and

(b) used by the retailer to—

(i) calculate the amount of electricity consumed by the consumer at each ICP; or

(ii) provide any service to the consumer.


11.32B Requests for information

(1) A retailer to which a request is made must give the information to the consumer no later than 5 business days after the date on which the request is made.
(2) In responding to a request, the retailer must comply with the procedures, and any relevant EIEP, published by the Authority under clause 11.32F.

(3) A retailer must not charge a fee for responding to a request, but if 4 requests in respect of a consumer's information have been made in a 12 month period, the retailer may impose a reasonable charge for further requests in that 12 month period.

Clause 11.32B: inserted, on 1 February 2016, by clause 5 of the Electricity Industry Participation Code Amendment (Access to Retail Data) 2014.

11.32C Retailers must give written notice to consumers of availability of information

Each retailer must give written notice to each consumer with whom it has a contract to supply electricity of the consumer's ability to make a request to the retailer under clause 11.32B, so that the consumer is given written notice at least once in each year.

Clause 11.32C: inserted, on 1 February 2016, by clause 5 of the Electricity Industry Participation Code Amendment (Access to Retail Data) 2014.

11.32D Information security

A retailer that receives a request for information under clause 11.32B—

(a) must not give access to that information unless it is satisfied as to the identity of the consumer making the request; and

(b) must ensure, by the adoption of appropriate procedures, that any information intended for a consumer is received—

(i) only by the consumer; or

(ii) where the request is made by an agent of the consumer, only by the consumer or the consumer's agent.


11.32E Agents

If a consumer authorises an agent to request information under clause 11.32B, a retailer must treat a request from the agent as if it were a request from the consumer, if the agent has the written authority of the consumer to obtain the information or is otherwise properly authorised by that consumer to obtain the information.

Clause 11.32E: inserted, on 1 February 2016, by clause 5 of the Electricity Industry Participation Code Amendment (Access to Retail Data) 2014.

11.32F Authority to publish procedures for responding to requests for consumption information

(1) The Authority must—

(a) publish, and keep published, procedures under which a retailer must respond to a request from a consumer under clause 11.32B; and
(b) prescribe 1 or more **EIEPs** with which a **retailer** must comply when responding to such a request.

(1A) The **Authority** must publish an **EIEP** it prescribes under subclause (1).

(2) The procedures **published** by the **Authority** must specify the manner in which information must be given to **consumers**.

(3) Each **EIEP** prescribed by the **Authority** must specify 1 or more formats in which information must be given to **consumers**.

(4) Before the **Authority** prescribes an **EIEP** under subclause (1), or amends an **EIEP** that it has prescribed under subclause (1), it must consult with the **participants** that the **Authority** considers are likely to be affected by the **EIEP**.

(5) The **Authority** need not comply with subclause (4) if it proposes to amend an **EIEP** prescribed under subclause (1) if the **Authority** is satisfied that—

(a) the nature of the amendment is technical and non-controversial; or

(b) there has been adequate prior consultation so that the **Authority** has considered all relevant views.

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11.32G Retailers must provide information about generally available retail tariff plans

(1) If any person asks a **retailer** to provide information about 1 or more of the **retailer's** current **generally available retail tariff plans**, the **retailer** must give the requested information to the person no later than 5 **business days** after receiving the request.

(2) If the person requests that information be provided under subclause (1) in a manner or format that differs from the manner or format the **retailer** typically uses to provide such information, the **retailer** may impose a reasonable charge for providing the information in the manner or format requested.

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11.33 Authority may direct registry to be suspended **[Expired]**


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11.34 Registry manager, distributors, and traders not required to comply with obligations when registry suspended **[Expired]**

11.35 Registry manager and traders not required to comply with specified provisions after registry resumes operation [Expired]


11.36 Clauses to expire [Expired]

Schedule 11.1 cl 11.7

Creation and management of ICPs, ICP identifiers and NSPs

ICPs and ICP identifiers

1 ICP identifiers
(1) A distributor must create an ICP identifier for each ICP on each network for which the distributor is responsible in accordance with the following format:

```
yyyyyyyyyyyyxxccc
```

where

- **yyyyyyyyyy** is a numerical sequence provided by the distributor
- **xx** is a code assigned by the Authority to the issuing distributor that ensures the ICP is unique
- **ccc** is a checksum generated according to the algorithm provided by the Authority.

(2) The ICP identifier must be used by a participant in all communications with the registry manager to identify—
   (a) the point at which a trader is deemed to convey electricity to a consumer or from an embedded generating station; and
   (b) the point of connection between an embedded network and its parent network, or the point of connection between a shared unmetered load and its network.

(3) Despite any clause to the contrary, only the obligations in this clause and clauses 2, 6 and 7(1)(a) to (e), (l) and (m) apply if an ICP identifier is used to identify a—
   (a) point of connection between an embedded network and its parent network; or
   (b) point of connection between shared unmetered load and its network.

(4) If an ICP identifier is used in the management of the status of the ICP, the obligations in clauses 13, 16 and 20 also apply.

Compare: Electricity Governance Rules 2003 clause 1.1 schedule E1

2 Address
(1) Each ICP identifier must have a location address that allows the ICP to be readily located.

(2) Despite subclause (1), the address of an ICP identifier for distributed unmetered load may be the location of the distributed unmetered load database.

Compare: Electricity Governance Rules 2003 clause 1.2 schedule E1
3 **Electrically disconnecting**
Each ICP created after 7 October 2002 must be able to be *electrically disconnected* without *electrically disconnecting* another ICP, except for the following ICPs:

(a) an ICP that is the **point of connection** between a **network** and an **embedded network**;
(b) an ICP that represents the consumption calculated by the difference between the total consumption for the **embedded network** and all other ICPs on the **embedded network**.

4 **Authority may grant dispensation**
The **Authority** may, by giving written notice, grant a dispensation from the requirements of clause 3 for an ICP that cannot be *electrically disconnected* without *electrically disconnecting* another ICP.

5 **Electrical load**
The electrical load associated with an ICP is deemed to be supplied through 1 network **supply point** only.

6 **Loss category**
An ICP must have a single **loss category** code that is referenced in such a way as to identify the associated **loss factors**.

7 **Provision of ICP information to the registry manager**


(1) A distributor must, for each ICP on the distributor's **network**, provide the following information to the **registry manager**:

(a) the location address of the **ICP identifier**;
(b) subject to subclause (4), the **NSP identifier** of the NSP to which the ICP is usually connected:
(c) the **installation type** code assigned to the ICP:
(d) the **reconciliation type** code assigned to the ICP:
(e) the loss category code and loss factors for each loss category code assigned to the ICP:

(f) if the ICP connects the distributor's network to an embedded generating station that has a capacity of 10 MW or more, the information required by subclause (6), in accordance with subclause (7):

(g) the price category code assigned to the ICP, which may be a placeholder price category code only if the distributor is unable to assign the actual price category code because the capacity or volume information required to assign the actual price category code cannot be determined before electricity is traded at the ICP:

(h) if the price category code assigned under paragraph (g) requires one or more values for the capacity of the ICP, the chargeable capacity of the ICP, as follows:

(i) if the chargeable capacity cannot be determined before electricity is traded at the ICP, a placeholder chargeable capacity:

(ii) if the capacity value or values can be determined for a billing period from the metering information collected for that billing period, no chargeable capacity:

(iia) if there is more than one capacity value at the ICP, and one or more, but not all, of those capacity values can be determined for a billing period from the metering information collected for that billing period—

(A) no capacity value recorded in the registry field for the chargeable capacity; and

(B) either the term "POA" or all other capacity values, recorded in the registry field in which the distributor installation details are also recorded:

(iib) if there is more than one capacity value at the ICP, and none of those capacity values can be determined for a billing period from the metering information collected for that billing period—

(A) the annual capacity value recorded in the registry field for the chargeable capacity; and

(B) either the term "POA" or all other capacity values, recorded in the registry field in which the distributor installation details are also recorded:

(iii) in any other case, the actual chargeable capacity:

(i) the distributor installation details of the ICP determined by the price category code assigned to the ICP (if any), which may be placeholder distributor installation details only if the distributor is unable to assign the actual distributor installation details because the capacity or volume information required to assign the actual distributor installation details cannot be determined before electricity is traded at the ICP:

(j) the participant identifier of the first trader who has entered into an arrangement with a customer or an embedded generator to sell or purchase electricity at the ICP (only if the information is provided by the first trader):

(k) the status of the ICP determined in accordance with clauses 12 to 20:

(l) designation of the ICP as "Dedicated" if the ICP is located in a balancing area that has more than 1 NSP located within it, and—
(i) the ICP will be supplied only from the NSP with the NSP identifier provided under paragraph (b); or
(ii) the ICP is a point of connection between a network and an embedded network:

(m) if unmetered load, other than distributed unmetered load, is associated with the ICP, the type and capacity in kW of the unmetered load (if the distributor knows that information):
(n) if shared unmetered load is associated with the ICP, a list of the ICP identifiers of the ICPs that are associated with the unmetered load:
(o) if the ICP connects the distributor’s network to distributed generation,—
   (i) the nameplate capacity of the distributed generation; and
   (ii) the generation fuel type of the distributed generation:
(p) the date on which the ICP is initially electrically connected.

(1A) For the purposes of subclause (1)(h), if the price category assigned to the ICP requires information additional to chargeable capacity to unambiguously define the line charges, the additional information may be contained in the distributor installation details field of the registry.

(2) The distributor must provide the information specified in subclauses (1)(a) to (1)(o) to the registry manager as soon as practicable after the ICP identifier for the ICP to which the information relates is created, and before electricity is traded at the ICP.

(2A) The distributor must provide the information specified in subclause (1)(p) to the registry manager no later than 10 business days after the date on which the ICP is initially electrically connected.

(2B) Despite subclause (2A), the distributor is not required to provide the information specified in subclause (1)(p) if the date on which the ICP is initially electrically connected is earlier than 29 August 2013.

(3) The distributor must provide the following information to the registry manager no later than 10 business days after the trading of electricity at the ICP commences:
   (a) the actual price category code assigned to the ICP:
   (b) the actual chargeable capacity of the ICP determined by the price category code assigned to the ICP (if any):
   (c) the actual distributor installation details of the ICP determined by the price category code assigned to the ICP (if any).

(4) If a distributor cannot identify the NSP that is connected to an ICP, the distributor must nominate the NSP that the distributor thinks is most likely to be connected to the ICP, taking into account the flow of electricity within the distributor’s network.

(5) An ICP is deemed to be connected to the NSP nominated by the distributor under subclause (1)(b).

(6) If a distributor assigns a loss category code to an ICP on the distributor’s network that connects the distributor’s network to an embedded generating station that has a capacity of 10 MW or more—
   (a) the loss category code assigned to the ICP must be unique and must not be assigned to any other ICP on the distributor’s network; and
(b) the distributor must provide the following information to the reconciliation manager:

(i) the unique loss category code assigned to the ICP;
(ii) the ICP identifier of the ICP;
(iii) the NSP identifier of the NSP to which the ICP is connected;
(iv) the plant name of the embedded generating station.

(7) The distributor must provide the information in subclause (6) no later than 5 business days before the distributor assigns the loss category code.

(8) A distributor may provide the registry manager with global positioning system coordinates for each ICP on the distributor’s network.

(9) If a distributor provides the global positioning system coordinates of an ICP to the registry manager under subclause (8), it must provide the coordinates—

(a) as New Zealand Transverse Mercator 2000 (NZTM2000) coordinates as defined in Land Information New Zealand’s LINZS25002 standard (Standard for New Zealand Geodetic Datum 2000 Projections); or

(b) in a format specified by the Authority.

Compare: Electricity Governance Rules 2003 clause 2 schedule E1


Clause 7(1), (2), (2A), (3), (8) and (9): amended, on 5 October 2017, by clause 225(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.


Clause 7(1)(h): substituted, on 29 August 2013, by clause 7(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.


Clause 7(1)(o) and (p): inserted, on 29 August 2013, by clause 5(1) of the Electricity Industry Participation (Additional Registry Fields) Code Amendment 2012.

Clause 7(1)(p), (2A) and (2B): amended, on 5 October 2017, by clause 225(4) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

Clause 7(1A): inserted, on 29 August 2013, by clause 7(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.


Clause 7(2A) and (2B): inserted, on 29 August 2013, by clause 5(3) of the Electricity Industry Participation (Additional Registry Fields) Code Amendment 2012.


Clause 7(8) and (9): inserted, on 29 August 2013, by clause 5(4) of the Electricity Industry Participation (Additional Registry Fields) Code Amendment 2012.

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;

(b) 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

(ii) 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.

(3) A distributor is not required to give written notice of a change of information provided in accordance with clause 7(1)(b) if the change is for less than 14 days.

(4) If a change of information provided in accordance with clause 7(1)(b) is for more than 14 days, subclause (2) applies as if the change had taken effect on the 15th day after the change takes effect.

Compare: Electricity Governance Rules 2003 clause 2A schedule E1

9 Traders to provide ICP information to registry manager

(1) Each trader must provide the following information to the registry manager for each ICP for which it is recorded in the registry as having responsibility:

(a) the participant identifier of the trader;

(b) the profile code of each profile at that ICP approved by the Authority in accordance with clause 13 of Schedule 15.5;

(c) the participant identifier of the metering equipment provider for each category 1 metering installation, or higher category metering installation, for the ICP;

(d) [Revoked]

(e) [Revoked]

(ea) the type of submission information that the trader will provide to the reconciliation manager for the ICP:
Electricity Industry Participation Code 2010
Schedule 11.1

(f) if the settlement type UNM is assigned to the ICP—
   (i) if the load is profiled through an engineering profile in accordance with profile class 2.1, the code ENG; or
   (ii) in all other cases, the daily average unmetered load in kWh at the ICP:
   (g) the type and capacity of the unmetered load at the ICP (if any):
       (i) [Revoked]
       (ii) [Revoked]
   (j) the status of the ICP determined in accordance with clauses 12 to 20.
   (k) except as provided in subclause (1A), the relevant business classification code applicable to the customer at the ICP, in accordance with business classification codes published by the Authority.

(1A) A trader must not provide the information specified in subclause (1)(k) if—
   (a) the ICP exists for the purpose of reconciling embedded network residual load; or
   (b) the ICP has "Distributor" status as specified in clause 16.

(2) The trader must provide the information specified in subclause (1)(a) to subclause (1)(j) to the registry manager no later than 5 business days after the trader commences trading at the ICP to which the information relates.

(3) The trader must provide the information specified in subclause (1)(k) to the registry manager no later than 20 business days after the trader commences trading at the ICP to which the information relates.

Compare: Electricity Governance Rules 2003 clause 3 schedule E1
Clause 9(1)(h) and (i): revoked, on 29 August 2013, by clause 8(7) and (8) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.
Clause 9(1A): inserted, on 29 August 2013, by clause 8(9) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.
Clause 9(2) and (3): amended, on 5 October 2017, by clause 227(3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
10 Traders to change ICP information provided to registry manager

(1) If information about an ICP provided to the registry manager in accordance with clause 9 changes, the trader who trades at the ICP must give written notice to the registry manager of the change.

(2) The trader must give the notice no later than 5 business days after the change.

(3) Despite subclause (2), if the trader is not able to give the notice within the timeframe specified in subclause (2) because of the implementation of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, the trader may give the notice up to 20 business days after the change.

(4) Subclause (3) and this subclause expire 20 business days after the date on which the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011 comes into force.

11 Correction of errors in the registry

(1) By 0900 hours on the 1st business day of each reconciliation period, the registry manager must provide to each participant who is required to submit submission information, the following:

(a) a list of the ICPs at which the participant is recorded on the registry as trading during each consumption period being revised in the reconciliation period;

(b) all information associated with the participant’s participant identifier, including the profiles for each ICP.

(2) If there is an error in the information provided under subclause (1), the participant must change the information in the registry as soon as practicable after becoming aware of the error.

12 Management of ICP status by distributors and traders

The status of an ICP, as recorded on the registry, must be managed by distributors and traders in accordance with clauses 13 to 20.

Management of ICP status

Compare: Electricity Governance Rules 2003 clause 3A schedule E1
Clause 10(2) and (3): amended, on 5 October 2017, by clause 228(3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 10(3) and (4): inserted, on 29 August 2013, by clause 9 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013 and expire on 26 September 2013.

Compare: Electricity Governance Rules 2003 clause 3B schedule E1

Compare: Electricity Governance Rules 2003 clause 4 schedule E1
13 “New” status
The ICP status of “New” must be managed by the relevant distributor and indicates that—
(a) the associated electrical installations are in the construction phase; and
(b) the ICP is not ready for the trader to authorise the electrical connection of the ICP.

Compare: Electricity Governance Rules 2003 clause 4.1 schedule E1

14 “Ready” status
(1) The ICP status of “Ready” must be managed by the relevant distributor and indicates that—
(a) the associated electrical installations are ready for connecting to the electricity supply; or
(b) the ICP is ready for the trader to authorise the electrical connection of the ICP.

(2) Before an ICP is given the "Ready" status, the relevant distributor must—
(a) identify the trader that has taken responsibility for the ICP; and
(b) ensure that the ICP has a single price category code.

Compare: Electricity Governance Rules 2003 clauses 4.2 and 4.3 schedule E1

15 "New" or "Ready" status for 24 months or more
(1) Subclause (2) applies if—
(a) an ICP has had the status of "New" for 24 months or more; or
(b) an ICP has had the status of "Ready" for 24 months or more.

(2) The distributor must—
(a) ask the trader who intends to trade at the ICP whether the ICP should continue to have that status; and
(b) decommission the ICP if the trader advises that the ICP should not continue to have that status.

Compare: Electricity Governance Rules 2003 clause 4.3A schedule E1
16  “Distributor” status
(1) The ICP status of “Distributor” must be managed by the relevant distributor and indicates that the ICP record represents a shared unmetered load installation or the point of connection between an embedded network and its parent network.
(2) A trader cannot change the status of an ICP record with the ICP status of “Distributor”.

Compare: Electricity Governance Rules 2003 clause 4.4 schedule E1

17  “Active” status
(1) The ICP status of “Active” must be managed by the relevant trader and indicates that—
  (a) the associated electrical installations are electrically connected; and
  (b) a trader must provide information related to the ICP, in accordance with Part 15, to the reconciliation manager for the purpose of compiling reconciliation information.
(2) Before an ICP is given the “Active” status, the trader must ensure that—
  (a) the ICP has only 1 embedded generator, direct purchaser, or customer of a retailer; and
  (b) the electricity consumed is quantified by a metering installation or a method of calculation approved by the Authority.

Compare: Electricity Governance Rules 2003 clauses 4.5 and 4.6 schedule E1

18  [Revoked]

Compare: Electricity Governance Rules 2003 clause 4.6A schedule E1

19  “Inactive” status
The ICP status of “Inactive” must be managed by the relevant trader and indicates that—
  (a) the ICP is electrically disconnected; or
  (b) submission information related to the ICP is not required by the reconciliation manager for the purpose of compiling reconciliation information.

Compare: Electricity Governance Rules 2003 clause 4.7 schedule E1
Clause 19(a): substituted, on 29 August 2013, by clause 20 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.
20  “Decommissioned” status
(1) The ICP status of “Decommissioned” must be managed by the relevant distributor and indicates that the ICP is permanently removed from future switching and reconciliation processes.
(2) Decommissioning occurs when—
   (a) electrical installations associated with the ICP are physically removed; or
   (b) there is a change in the allocation of electrical loads between ICPs with the effect of making the ICP obsolete; or
   (c) in the case of a distributor-only ICP for an embedded network, the embedded network no longer exists.

Compare: Electricity Governance Rules 2003 clause 4.8 schedule E1

Updating registry standing information

21  Updating table of loss category codes
(1) Each distributor must keep up to date the table in the registry of the loss category codes that may be assigned to ICPs on each distributor’s network, by entering in the table any new loss category codes that may be assigned to an ICP on the distributor’s network.
(2) Each entry in the table must specify the date on which each loss category code takes effect.
(3) The date that a loss category code takes effect must not be earlier than 2 months after the date on which the loss category code is entered in the table.
(4) A loss category code takes effect on the specified date.
(5) To avoid doubt, subclause (3) does not apply to the creation of an ICP or to the transfer of an ICP from 1 distributor's network to another distributor's network.

Compare: Electricity Governance Rules 2003 clause 5 schedule E1

22  Updating loss factors for loss category codes
(1) A distributor must enter loss factors in the registry for each loss category code entered on the table in the registry under clause 21.
(2) A distributor must ensure that—
   (a) each loss category code has no more than 2 loss factors in a calendar month; and
   (b) each loss factor covers a range of trading periods within that month so that all trading periods have a single applicable loss factor.
(3) A distributor who wishes to replace an existing loss factor on the table in the registry must enter the replaced loss factor on the table in the registry.
(4) Each entry in the table must specify the date on which the replaced loss factor takes effect.
(5) The date that a loss factor takes effect must not be earlier than 2 months after the date on which the loss factor is entered in the table.
(6) A replaced loss factor takes effect on the specified date.
(7) To avoid doubt, subclause (5) does not apply to the creation of an ICP or to the transfer of an ICP from one distributor's network to another distributor's network.

(8) The registry manager must publish an updated schedule of all loss category codes and the loss factors for each loss category code no later than one business day after receiving notice of a change.

Compare: Electricity Governance Rules 2003 clause 5A schedule E1

23 Updating table of price category codes

(1) Each distributor must keep up to date the table in the registry of the price category codes that may be assigned to ICPs on each distributor’s network, by entering in the table any new price category codes that may be assigned to an ICP on the distributor’s network.

(2) Each entry in the table must specify the date on which each price category code takes effect.

(3) The date that a price category code takes effect must not be earlier than two months after the date on which the price category code is entered in the table.

(4) A price category code takes effect on the specified date.

(5) To avoid doubt, subclause (3) does not apply to the creation of an ICP or to the transfer of an ICP from one distributor's network to another distributor's network.

Compare: Electricity Governance Rules 2003 clause 6 schedule E1

24 Balancing area information

(1) A distributor must give written notice to the reconciliation manager of the establishment of a balancing area associated with an NSP supplying the distributor’s network, in accordance with clause 26.

(2) A distributor must give written notice to the reconciliation manager of any change to the information provided under subclause (1).

(3) The notice must—

(a) specify the date and trading period from which the change takes effect; and

(b) be given no later than three business days after the change takes effect.

(4) The reconciliation manager must give written notice to the registry manager of any change to balancing areas within one business day after receiving the notice.

(5) The registry manager must publish an updated schedule of the mapping between NSPs and balancing areas within one business day after receiving the notice.

(6) The schedule must specify the date and trading period from which the change took effect.

Compare: Electricity Governance Rules 2003 clause 7 schedule E1
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.

Compare: Electricity Governance Rules 2003 clause 8 schedule E1
Clause 25(1), (2), (3) and (4): amended, on 5 October 2017, by clause 238(1) to (6) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
(3) If a participant gives notice under clause 25(1) of the creation of an NSP, the distributor on whose network the NSP is located must give the reconciliation manager the following information:
   (a) if the NSP is to be located in a new balancing area to be created—
       (i) all relevant details necessary for the balancing area to be created; and
       (ii) notice that the NSP to be created is to be assigned to the new balancing area; and
   (b) in every other case, notice of the balancing area in which the NSP is located.

(4) If a participant gives notice under clause 25(1) or (2) of a creation or transfer that relates to an NSP between a network and an embedded network, the distributor who owns the embedded network must give written notice to the reconciliation manager of the following:
   (a) the network on which the NSP will be located after the creation or transfer:
   (b) the ICP identifier for the ICP that connects the network and the embedded network:
   (c) the date on which the creation or transfer will take effect.

(5) The distributor must give the notice at least 1 month before the creation or transfer.

Compare: Electricity Governance Rules 2003 clause 9 schedule E1
Clause 26(2): amended, on 5 October 2017, by clause 239(2) and (3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 26(2)(a) and (b): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

27 Information to be provided if ICPs become NSPs

(1) If a transfer for which notice is given under clause 25 results in an ICP becoming an NSP at which an embedded network connects to a network, or in an ICP becoming an NSP that is an interconnection point, the distributor who owns the network on which the NSP will be located after the change must give written notice to any trader trading at the ICP of the transfer.

(2) The distributor must give the notice at least 1 month before the transfer.

Compare: Electricity Governance Rules 2003 clause 10 schedule E1

28 Reconciliation manager to allocate new identifiers

The reconciliation manager must, within 1 business day of receiving notice under clause 25(1) or (2), allocate a unique NSP identifier to each point of connection or
**interconnection point** to which the notice relates in accordance with the following format:

bbbqqqz nnnn

where

<table>
<thead>
<tr>
<th>bbbqqqz</th>
<th>is, in the case of a local network, the code for the GXP or GIP or, in the case of an embedded network or the point of connection between 2 local networks, the code for the point of connection to its parent network</th>
</tr>
</thead>
<tbody>
<tr>
<td>bbb</td>
<td>is a combination of 3 alpha characters that form a unique location identifier</td>
</tr>
<tr>
<td>qqq</td>
<td>is the voltage in kV of the supply bus</td>
</tr>
<tr>
<td>z</td>
<td>is a numeral allocated to distinguish it from any other supply bus of the same voltage at the same location</td>
</tr>
<tr>
<td>nnnn</td>
<td>is a participant identifier for the network owner who from time to time owns the network being supplied.</td>
</tr>
</tbody>
</table>

Compare: Electricity Governance Rules 2003 clause 11 schedule E1

**29 Obligations concerning change in network owner**

(1) If a network owner acquires all or part of an existing network, the network owner must give written notice to the following of the acquisition:

(a) the previous network owner:
(b) the reconciliation manager:
(c) the Authority:
(d) every reconciliation participant who trades at an ICP connected to the network or part of the network acquired.

(2) The network owner must give the notice at least 1 month before the acquisition.

(3) The notice must specify—

(a) the ICP identifiers for which the network owner’s participant identifier must be amended to reflect the acquisition of the network or part of the network by the network owner; and
(b) the effective date of the acquisition.

(4) A network owner who acquires all or part of an existing network must comply with Schedule 11.2.

Compare: Electricity Governance Rules 2003 clause 12 schedule E1


Clause 29(2): amended, on 5 October 2017, by clause 242(2) and (3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.


30 **Reconciliation manager to advise registry manager**

(1) The **reconciliation manager** must—

(a) advise the **registry manager** of any new or deleted **NSP identifier** no later than 1 **business day** after receiving notice of its creation or deletion; and

(b) advise the **registry manager** of any changes to supporting **NSP information** provided by a **distributor** in accordance with clause 26(4) no later than 1 **business day** after receiving the notice.

(2) The **registry manager** must **publish** an updated schedule of all **NSP identifiers** and supporting information within 1 **business day** of receiving notice in accordance with subclause (1).

Compare: Electricity Governance Rules 2003 clause 13 schedule E1


Schedule 11.2

Transfer of ICPs between distributors' networks

1 This Schedule applies if a distributor (the applicant 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 applicant distributor's network (a "transfer").

Compare: Electricity Governance Rules 2003 clause 1 schedule E1A
Clause 1: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

2 The applicant distributor must give written notice to the Authority of the transfer.

Compare: Electricity Governance Rules 2003 clause 2 schedule E1A

3 The notice must be in the prescribed form.

Compare: Electricity Governance Rules 2003 clause 3 schedule E1A

4 The notice must be given no later than 3 business days before the transfer takes effect.

Compare: Electricity Governance Rules 2003 clause 4 schedule E1A

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.

Compare: Electricity Governance Rules 2003 clause 5 schedule E1A

6 If a notice relates to an embedded network, it must relate to every ICP on the embedded network.

Compare: Electricity Governance Rules 2003 clause 6 schedule E1A
7 The Authority must not authorise the change of any information in the registry if clauses 2 to 5 are not complied with.

Compare: Electricity Governance Rules 2003 clause 7 schedule E1A

7A Despite clause 7, the Authority may authorise the change if the applicant distributor has not given written notice to the Authority within the time frame required under clause 4, if—
(a) the applicant distributor has complied with clauses 2, 3 and 5; and
(b) the Authority considers that it has not been materially disadvantaged by the applicant distributor's failure to comply with clause 4.


8 The notice must include any information requested by the Authority from time to time.

Compare: Electricity Governance Rules 2003 clause 8 schedule E1A

9 The registry manager must remove from the registry any information the registry manager has received under clause 7 of Schedule 11.1 if the information—
(a) relates to an ICP for which an applicant distributor has given written notice of a transfer under this Schedule; and
(b) was to come into effect after the date on which the Authority authorises the change of information in the registry under this Schedule.

Compare: Electricity Governance Rules 2003 clause 9 schedule E1A

10 A transfer may take effect on a date that is before the date on which the notice is given only with the consent of the Authority.

Compare: Electricity Governance Rules 2003 clause 10 schedule E1A

11 Each reconciliation participant must take a validated meter reading or permanent estimate on the date a transfer becomes effective for use in the creation of the reconciliation participant's submission file, unless the Authority authorises the reconciliation manager to provide additional seasonal adjustment shapes under clause 12.

Compare: Electricity Governance Rules 2003 clause 11 schedule E1A
12 The Authority may authorise the reconciliation manager to provide additional seasonal adjustment shapes for use in the creation of each reconciliation participant's submission file.

Compare: Electricity Governance Rules 2003 clause 12 schedule E1A
Schedule 11.3

Switching

Overview


1A Application of Schedule

(1) This Schedule prescribes 3 processes for switching ICPs as follows:

(a) a standard switch process that applies in the circumstances described in clause 1(1):

(b) a switch move process that applies in the circumstances described in clause 8(1):

(c) a gaining trader switch process that applies in the circumstances described in clause 13(1).

(2) If a trader proposes switching an ICP, the trader must use one of the switch processes set out in this Schedule.


Clause 1A: inserted on 9 October 2015, by clause 5(2) of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.

Clause 1A(2): inserted, on 1 November 2018, by clause 52(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

Standard switch process


1 Standard switch process for ICPs

(1) A standard switch process applies only when a trader (the "gaining trader") has an arrangement with a customer or embedded generator to commence trading electricity with the customer or embedded generator at, or to otherwise assume responsibility under clause 11.18(1) for, an ICP at which another trader (the "losing trader") trades electricity, and the gaining trader switch process under clauses 13 to 16 does not apply.

(1A) This clause and clauses 2 to 7 apply to a standard switch process.

(2) If subpart 2 of Part 4A of the Fair Trading Act 1986 applies to an arrangement described in subclause (1),—

(a) the gaining trader must identify the period within which the customer or embedded generator may cancel the arrangement in accordance with section 36M of the Fair Trading Act 1986; and

(b) for the purpose of this Schedule, the arrangement is deemed to come into effect on the day after the expiry of the period.

Compare: Electricity Governance Rules 2003 clauses 1.1A and 1.1B schedule E2

Clause 1 Heading: amended, on 29 August 2013, by clause 11(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

Clause 1 Heading: amended on 9 October 2015, by clause 7(1) of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.

Clause 1(1) and 1(1A): substituted on 9 October 2015, by clause 7(2) of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.
Clause 1(1)(a): substituted, on 29 August 2013, by clause 11(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

2 Gaining trader advises registry manager of standard switch request

(1) For each ICP to which a switch relates, the gaining trader must advise the registry manager of the switch no later than 2 business days after the arrangement to trade electricity with the customer or the embedded generator comes into effect.

(2) The gaining trader must include in its advice to the registry manager—

(a) [Revoked]

(b) that the switch type is TR; and

(c) 1 or more profile codes of a profile at the ICP.

Compare: Electricity Governance Rules 2003 clause 1.1 schedule E2
Clause 2 Heading: substituted on 9 October 2015, by clause 8(1) of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.
Clause 2(1) and (2): amended, on 5 October 2017, by clause 255(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

3 Losing trader response to standard switch request

No later than 3 business days after receiving notice of a switch request from the registry manager under clause 22(a), 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.

Compare: Electricity Governance Rules 2003 clause 1.2 schedule E2
Clause 3(a): substituted on 9 October 2015, by clause 5(1) of the Electricity Industry Participation Code Amendment (ICP Switching) 2015.
Clause 3(b): revoked on 9 October 2015, by clause 5(2) of the Electricity Industry Participation Code Amendment (ICP Switching) 2015.

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 losing trader receives notice from the registry manager in accordance with clause 22(a); 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 losing trader receives notice from the registry manager in accordance with clause 22(a).

(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 the losing trader received notice from the registry manager under clause 22(a), the losing trader had been responsible for less than 2 months.

Compare: Electricity Governance Rules 2003 clause 1.2A schedule E2

5 Losing trader must provide final information

If the losing trader has provided information under clause 3(a)(i) rather than under clause 3(a)(ii), no later than 5 business days after the event date, the losing trader must complete the switch by providing final information to the registry manager, including—

(a) the event date; and

(b) a switch event meter reading as at the event date for each meter or data storage device that is recorded in the registry with an accumulator type of C and a settlement indicator of Y; and

(c) if the switch event meter reading is not a validated meter reading, the date of the last meter reading of the meter or data storage device described in paragraph (b).

Compare: Electricity Governance Rules 2003 clause 1.3 schedule E2
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 receiving final information from the registry manager under clause 22(d),—
   (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.

Compare: Electricity Governance Rules 2003 clause 1.4 schedule E2
Clause 6(b): substituted on 9 October 2015, by clause 12(3) of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.
Clause 6(2) and (3): inserted on 9 October 2015, by clause 8 of the Electricity Industry Participation Code Amendment (ICP Switching) 2015.

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 registry manager gives the gaining trader written notice under clause 22(d) 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.

Clause 6A: amended on 9 October 2015, by clause 9(b) and (c) of the Electricity Industry Participation Code Amendment (ICP Switching) 2015.

7 Disputes

(1) A losing trader or a gaining trader may give written notice to the other trader that it disputes a switch event meter reading provided under clauses 1 to 6.

(2) The dispute must be resolved in accordance with the disputes procedure in clause 15.29 (with all necessary amendments).

Compare: Electricity Governance Rules 2003 clause 1.5 schedule E2

Switch move process

8 Switch move process for ICPs

(1) A standard switch process applies only when a trader (the “gaining trader”) has an arrangement with a customer or embedded generator to commence trading electricity with the customer or embedded generator at, or to otherwise assume responsibility under clause 11.18(1) for, an ICP for which no trader has an agreement to trade electricity and the gaining trader switch process under clauses 13 to 16 does not apply.

(1A) This clause and clauses 9 to 12 apply to a switch move process.

(2) If subpart 2 of Part 4A of the Fair Trading Act 1986 applies to an arrangement described in subclause (1)—

(a) the gaining trader must identify the period within which the customer or embedded generator may cancel the arrangement in accordance with section 36M of the Fair Trading Act 1986; and

(b) for the purpose of this Schedule, the arrangement is deemed to come into effect on the day after the expiry of the period.

Compare: Electricity Governance Rules 2003 clauses 2.1A and 2.1B schedule E2
Clause 8 Heading: amended, on 29 August 2013, by clause 12(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.
Clause 8(1) and 8(1A): substituted on 9 October 2015, by clause 15 of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.
Clause 8(1)(a): substituted, on 29 August 2013, by clause 12(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.
Clause 8(1): amended, on 1 November 2018, by clause 58(1) and (2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

9 Gaining trader informs registry manager of switch request
(1) For each ICP to which a switch relates, the gaining trader must advise the registry manager of the switch request no later than 2 business days after the arrangement to trade electricity with the customer or the embedded generator comes into effect.
(2) The gaining trader must include in its advice to the registry manager—
(a) a proposed event date; and
(b) that the switch type is MI; and
(c) 1 or more profile codes of a profile at the ICP.

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 trader that is recorded in the registry as being responsible for the ICP (the “losing trader”) must, no later than 5 business days after receiving the notice,—
(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]
(ii) confirmation of the event date; and
(iii) a valid switch response code approved by the Authority; and
(iv) 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 the date the losing trader receives the notice; 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 receiving the notice referred to in subclause (1), 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.

Compare: Electricity Governance Rules 2003 clause 2.2 schedule E2
Clause 10(1): amended, on 5 October 2017, by clause 263(1), (2) and (3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 10(1)(a)(ia) and (ib): inserted, on 9 October 2015, by clause 10(2)(b) of the Electricity Industry Participation Code Amendment (ICP Switching) 2015.

11 Losing trader must provide final information
The losing trader must provide final information to the registry manager for the purposes of clause 10(1)(a)(ii), including—
(a) the event date; and
(b) a switch event meter reading as at the event date for each meter or data storage device that is recorded in the registry with an accumulator type of C and a settlement indicator of Y; and
(c) if the switch event meter reading is not a validated meter reading, the date of the last meter reading of the meter or data storage device described in paragraph (b).

Compare: Electricity Governance Rules 2003 clause 2.3 schedule E2

12 Gaining trader may change switch event meter reading
(1) The gaining trader may use the switch event meter reading supplied by the losing trader or may, at its own cost, obtain its own switch event meter reading.
(2) If the gaining trader elects to use the new switch event meter reading, the gaining trader must advise the losing trader of the new switch event meter reading and the event date to which it refers as follows:
(a) if the switch event meter reading established by the gaining trader differs by less than 200 kWh from that provided by the losing trader, both traders must use the switch event meter reading provided by the gaining trader; 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.
(2A) Despite subclauses (1) and (2), subclause (2B) 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 with the customer or 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.

(2B) No later than 5 business days after receiving final information from the registry manager under clause 22(d),—
(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

(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 the registry manager gives the gaining trader written notice under clause 22(d) of having received information about the switch completion, provide to the losing trader a 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.

Compare: Electricity Governance Rules 2003 clause 2.4 schedule E2
Clause 12 Heading: amended, on 9 October 2015, by clause 18(1) of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.
Clause 12(1) and (3): amended, on 9 October 2015, by clause 18(2) of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.
Clause 12(2A) and (2B): inserted, on 9 October 2015, by clause 12 of the Electricity Industry Participation Code Amendment (ICP Switching) 2015.
Gaining trader switch process


13 Gaining trader switch processes

(1) A gaining trader switch process applies only when a trader (the “gaining trader”) has an arrangement with a customer or embedded generator to—

(a) trade electricity with the customer or embedded generator at an ICP at which another trader (the “losing trader”) trades electricity with the customer or embedded generator, and one of subparagraphs (i) to (iii) applies—

(i) at the ICP, the gaining trader will trade electricity through a half-hour metering installation that is a category 3 or higher metering installation; or

(ii) at the ICP—

(A) the gaining trader will trade electricity through a half-hour metering installation, and in the registry the ICP will have a submission type of half hour and an AMI flag of “N”; and

(B) the losing trader trades electricity through a non half-hour metering installation, and in the registry the ICP has a submission type of non half hour and an AMI flag of “N”; or

(iii) at the ICP—

(A) the gaining trader will trade electricity through a non half-hour metering installation, and the ICP will have a submission type of non half hour in the registry; and

(B) the losing trader trades electricity through a half-hour metering installation, and in the registry the ICP has a submission type of half hour and an AMI flag of “N”; or

(b) assume responsibility under clause 11.18(1) for an ICP described in subparagraph (a)(i), (a)(ii), or (a)(iii).

(1A) This clause and clauses 14 to 16 apply to a gaining trader switch process.

(2) If subpart 2 of Part 4A of the Fair Trading Act 1986 applies to an arrangement described in subclause (1)—

(a) the gaining trader must identify the period within which the customer or embedded generator may cancel the arrangement in accordance with section 36M of the Fair Trading Act 1986; and

(b) for the purpose of this Schedule, the arrangement is deemed to come into effect on the day after the expiry of the period.

Compare: Electricity Governance Rules 2003 clauses 3.1 and 3.1A schedule E2


Clause 13(1): amended, on 1 November 2018, by clause 62(1)(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.


Clause 13(1)(a)(i): amended, on 9 October 2015, by clause 13(a) and (b) of the Electricity Industry Participation Code Amendment (ICP Switching) 2015.

14 Gaining trader informs registry manager of switch request
(1) For each ICP to which a switch relates, the gaining trader must advise the registry manager of the switch request no later than 3 business days after the arrangement to trade electricity with the customer or the embedded generator comes into effect.
(2) The gaining trader must include in its advice to the registry manager—
   (a) a proposed event date; and
   (b) that the switch type is HH.
(3) Unless subclause (4) applies, the proposed event date must be a date that is after the date on which the gaining trader advises the registry manager.
(4) The proposed event date may be a date that is before the date on which the gaining trader advises the registry manager, if—
   (a) the proposed event date is in the same month as the date on which the gaining trader advises the registry manager; or
   (b) the proposed event date is no more than 90 days before the date on which the gaining trader advises the registry manager, and the losing trader and gaining trader agree on the proposed event date.

Compare: Electricity Governance Rules 2003 clause 3.2 schedule E2
Clause 14(2), (3), and (4): inserted, on 9 October 2015, by clause 21(2) of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.

15 Losing trader provides information
No later than 3 business days after the losing trader receives notice from the registry manager in accordance with clause 22(a), 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.

Compare: Electricity Governance Rules 2003 clause 3.3 schedule E2
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 receiving a valid switch response code from the registry manager under clause 22(c).

(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.

Compare: Electricity Governance Rules 2003 clause 3A schedule E2

Clause 16 Heading: amended, on 9 October 2015, by clause 23(1) of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.

Clause 16(1): amended, on 9 October 2015, by clause 23(2) of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.


Clause 16(2): inserted, on 9 October 2015, by clause 23(3) of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.

17 Withdrawal of switch requests

A losing trader or gaining trader may request that a switch request be withdrawn at any time until the expiry of 2 months after the event date.

Compare: Electricity Governance Rules 2003 clause 3A schedule E2


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:
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):

no later than 5 business days after receiving notice from the registry manager in accordance with clause 22(b), the trader receiving the withdrawal 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:

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:

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 receiving notice from the registry manager in accordance with clause 22(b), the losing trader must comply with clauses 3, 5, 10 and 11 (whichever is appropriate) and the gaining trader must comply with clause 16.

Participants to use file formats

Participants who exchange information in accordance with this Schedule must use the file formats determined and published by the Authority.

Method of exchanging files

The Authority may, from time to time, after consultation with participants, do all or any of the following:
(a) determine the method by which participants exchange information:
(b) determine the file formats that participants must use to exchange information:
(c) alter the file formats or the method by which participants exchange information.

The Authority must publish the file formats.
21 **Metering information**
For each *interrogation* or *switch event meter reading* carried out in accordance with this Schedule,—

(a) the *trader* who carries out the *interrogation* or *switch event meter reading* must ensure that the *interrogation* is as accurate as possible, or that the *switch event meter reading* is fair and reasonable (as the case may be); and

(b) the cost of each *interrogation* or *switch event meter reading* must be met as follows:
   (i) for each *interrogation* or *switch event meter reading* carried out in accordance with clauses 5(b) or 11(b) or (c), the cost must be met by the losing *trader*; and
   (ii) in every other case, the cost must be met by the gaining *trader*.

Compare: Electricity Governance Rules 2003 clause 5.3 schedule E2
Clause 21(a): amended, on 9 October 2015, by clause 26(2) of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.
Clause 21(b), and (c): substituted, on 9 October 2015, by clause 26(3) of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.

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 written notice 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 manager* must give written notice 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 give written notice 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 give written notice to the gaining *trader*, the losing *trader*, the *metering equipment provider*, and the relevant *distributor* of the information received.

Compare: Electricity Governance Rules 2003 clause 5.4 schedule E2
Schedule 11.4

cls 11.8A and 11.15A

Metering equipment provider switching and registry metering records


1 Metering equipment provider receives notice for ICP identifier

(1) Within 10 business days of being advised by the registry manager under clause 11.18A, a gaining metering equipment provider,—
   (a) must, if it intends to accept responsibility for each metering installation for the ICP—
      (i) enter into an arrangement with the trader; and
      (ii) advise the registry manager in the prescribed form that it accepts responsibility for each metering installation for the ICP and of the proposed date on which the metering equipment provider will assume responsibility for each metering installation for the ICP; or
   (b) may, if it intends to decline responsibility for each metering installation for the ICP, advise the registry manager in the prescribed form that it declines to accept responsibility for each metering installation for the ICP.

(2) The registry manager must, within 1 business day of a metering equipment provider advising under subclause (1)(b) that it declines to accept responsibility for each metering installation for the ICP, advise the trader of the declinature.

(3) The registry manager must, within 1 business day of a gaining metering equipment provider advising of acceptance under subclause (1)(a), advise the following participants for the ICP of the acceptance and proposed date on which the gaining metering equipment provider will assume responsibility for each metering installation for the ICP:
   (a) the trader; and
   (b) the distributor; and
   (c) if relevant, the losing metering equipment provider.


2 Gaining metering equipment provider to advise registry manager of registry metering records

If the metering equipment provider who is responsible for a metering installation for an ICP changes, the metering equipment provider must, within 15 business days of becoming the metering equipment provider for the metering installation, advise the registry manager of the registry metering records for the metering installation.

3 Metering equipment provider to advise registry manager of changes to registry metering records

If a metering equipment provider has an arrangement with a trader at an ICP that is not also an NSP, the metering equipment provider must advise the registry manager of the registry metering records, or any change to the registry metering records, for each metering installation for which it is responsible at the ICP, no later than 10 business days following:

(a) the electrical connection of the metering installation at the ICP;

(b) any subsequent change to the metering installation's metering records.


Clause 3 amended, on 1 November 2018, by clause 65(a), (b) and (c) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.


4 Registry manager requirement to advise

The registry manager must, within 1 business day of being advised—

(a) under clauses 2 or 3, advise the trader and distributor of the registry metering records:

(b) under clauses 3 or 6, advise—

(i) the trader and distributor of the details of the change to the registry metering records; and

(ii) the losing metering equipment provider of the date of change of the metering equipment provider for the ICP identifier.


5 Changes to registry metering records for ICP identifier

The registry manager must, within 1 business day of being advised of 1 or more of the following changes relating to an ICP identifier record, advise the metering equipment provider of the change:

(a) the trader participant identifier:

(b) the distributor participant identifier:

(c) the settlement type:

(d) the status of the ICP.


6 Correction of errors in registry
(1) A metering equipment provider must, by 0900 hours on the 13th business day of each reconciliation period, obtain the following information from the registry:
(a) a list of the ICP identifiers for the ICPs for the metering installations for which the metering equipment provider is recorded in the registry as being responsible; and
(b) the registry metering records for each ICP identifier obtained under paragraph (a).
(2) A metering equipment provider must, as soon as reasonably practicable but not later than 5 business days after it obtains the information under subclause (1), compare the information obtained with its own records.
(3) If the metering equipment provider finds a discrepancy between the information obtained under subclause (1) and its own records, the metering equipment provider must, within 5 business days of becoming aware of the discrepancy,—
(a) correct its records that are in error; and
(b) advise the registry manager of any necessary changes to the registry metering records.

7 Metering equipment provider to provide registry metering records to registry manager
(1) A metering equipment provider must, if required under this Part, provide to the registry manager the information indicated in Table 1 as being "Required", in the prescribed form, for each metering installation for which it is responsible.
(2) Despite anything to the contrary in this Code (except clause 11.2) the metering equipment provider must—
(a) provide the information set out in Table 1 indicated as being required for interim certified metering installations to the registry manager for all category 1 metering installations for which it is responsible; and
(b) ensure that the registry metering records provided in accordance with this clause are, for not less than 50% of the category 1 metering installations for which it is responsible, complete, accurate, not misleading or deceptive, and not likely to mislead or deceive, by no later than 1 October 2014; and
(c) ensure that the registry metering records provided in accordance with this clause are, for each category 1 metering installation for which it is responsible, complete, accurate, not misleading or deceptive, and not likely to mislead or deceive, by no later than 1 April 2015.
(3) The metering equipment provider must derive the information provided under subclause (2)(a) from—
(a) the metering equipment provider’s metering records; or
(b) the metering records contained within the current trader’s system.

### Table 1: Registry metering records

The following table sets out the registry metering records:

<table>
<thead>
<tr>
<th>No</th>
<th>Registry term</th>
<th>Description</th>
<th>Fully certified metering installation</th>
<th>Interim certified metering installation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>For each ICP identifier</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>participant identifier</td>
<td></td>
<td>Required</td>
<td>Required</td>
</tr>
<tr>
<td></td>
<td>For each metering installation for an ICP</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>metering installation number</td>
<td>a sequential number that is unique to the ICP's identifier, to identify the metering installation</td>
<td>Required</td>
<td>Required</td>
</tr>
<tr>
<td>3</td>
<td>highest metering category</td>
<td>the category recorded in the metering installation certification report</td>
<td>Required</td>
<td>Required</td>
</tr>
<tr>
<td>4</td>
<td>metering installation location code</td>
<td>a code from the list of codes in the registry, that identifies the location of the metering installation on a premises</td>
<td>Required</td>
<td>Required</td>
</tr>
<tr>
<td>5</td>
<td>the ATH participant identifier</td>
<td>the participant identifier of the ATH who certified the metering installation</td>
<td>Required</td>
<td>Optional</td>
</tr>
<tr>
<td>No</td>
<td>Registry term</td>
<td>Description</td>
<td>Fully certified metering installation</td>
<td>Interim certified metering installation</td>
</tr>
<tr>
<td>----</td>
<td>---------------</td>
<td>-------------</td>
<td>----------------------------------------</td>
<td>----------------------------------------</td>
</tr>
<tr>
<td>6</td>
<td>metering installation certification type</td>
<td>the certification type of the metering installation which may be either half hour or non half hour identified in the metering installation certification report</td>
<td>Required</td>
<td>Required</td>
</tr>
<tr>
<td>7</td>
<td>metering installation certification date</td>
<td>the effective certification date identified in the metering installation certification report</td>
<td>Required</td>
<td>Optional</td>
</tr>
<tr>
<td>8</td>
<td>the metering installation certification expiry date</td>
<td>the metering installation certification expiry date, identified in the metering installation certification report, or the date that the metering installation certification is cancelled</td>
<td>Required</td>
<td>Required</td>
</tr>
<tr>
<td>9</td>
<td>control device certification</td>
<td>confirmation that the control device used in the metering installation is included in the metering installation certification report</td>
<td>Required</td>
<td>Optional</td>
</tr>
<tr>
<td>No</td>
<td>Registry term</td>
<td>Description</td>
<td>Fully certified metering installation</td>
<td>Interim certified metering installation</td>
</tr>
<tr>
<td>----</td>
<td>---------------</td>
<td>-------------</td>
<td>----------------------------------------</td>
<td>-----------------------------------------</td>
</tr>
</tbody>
</table>
| 10 | certification variations | (a) Does an exemption under the Act for the metering installation apply?  
(b) Has the alternate measuring transformer certification process been used? | Required | Optional |
<p>| 11 | certification variations expiry date | the earlier of the expiry date of any certification variation under item 10 | Required | Optional |
| 12 | certification number | the certification number assigned to a metering installation’s certification | Required | Optional |
| 13 | maximum interrogation cycle | the maximum interrogation cycle for the metering installation included in its certification report | Required | Required |</p>
<table>
<thead>
<tr>
<th>No</th>
<th>Registry term</th>
<th>Description</th>
<th>Fully certified metering installation</th>
<th>Interim certified metering installation</th>
</tr>
</thead>
<tbody>
<tr>
<td>14</td>
<td>price code</td>
<td>if the metering equipment provider considers it relevant, an identifier that may be used to indicate the price that would apply to a lease for the use of the metering installation</td>
<td>Optional</td>
<td>Optional</td>
</tr>
</tbody>
</table>

The following details for each metering component in the metering installation for each ICP

<p>| 15 | metering component type | an identifier used to identify the type of metering component in the metering installation selected from the list of codes in the registry | Required | Required |
| 16 | metering component identifier | an identifier visible on the installed metering component that is either the manufacturer's serial number or the owner's component asset number | Required | Required for meter or data storage device. Optional for all other metering components |</p>
<table>
<thead>
<tr>
<th>No</th>
<th>Registry term</th>
<th>Description</th>
<th>Fully certified metering installation</th>
<th>Interim certified metering installation</th>
</tr>
</thead>
<tbody>
<tr>
<td>17</td>
<td>meter or data storage device type</td>
<td>an identifier used to identify the type of meter or data storage device in the metering installation, which may be half hour, non half hour, or prepay selected from the list of codes in the registry</td>
<td>Required for meter or data storage device.</td>
<td>Required for meter or data storage device.</td>
</tr>
<tr>
<td>18</td>
<td>AMI type</td>
<td>an identifier to identify if the metering component is an advanced metering infrastructure device</td>
<td>Required for meter or data storage device.</td>
<td>Required for meter or data storage device.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Optional for all other metering components.</td>
<td>Optional for all other metering components.</td>
</tr>
<tr>
<td>19</td>
<td>compensation factor</td>
<td>the compensation factor, which in the case of a complex compensation factor, must be obtained from the metering equipment provider</td>
<td>Required for meter or data storage device.</td>
<td>Required for meter or data storage device.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Optional for all other metering components.</td>
<td>Optional for all other metering components.</td>
</tr>
<tr>
<td>20</td>
<td>owner of a metering component</td>
<td>a free text field to identify the owner of a metering component, which may be a participant identifier if the owner is a participant</td>
<td>Optional</td>
<td>Optional</td>
</tr>
<tr>
<td>21</td>
<td>removal date of a meter or data storage device</td>
<td>a date that a meter or data storage device is removed</td>
<td>Optional for meter or data storage device</td>
<td>Optional for meter or data storage device</td>
</tr>
<tr>
<td>No</td>
<td>Registry term</td>
<td>Description</td>
<td>Fully certified metering installation</td>
<td>Interim certified metering installation</td>
</tr>
<tr>
<td>----</td>
<td>----------------</td>
<td>-------------</td>
<td>----------------------------------------</td>
<td>---------------------------------------</td>
</tr>
</tbody>
</table>
| 22 | **metering component** type | the **metering component** type identifier selected from the list of codes in the **registry** | Required for **meter** or **data storage device** that returns any 1 or more of the following values as a result of an **interrogation**:  
(a) **active energy**:  
(b) **reactive energy**:  
(c) apparent energy:  
(d) apparent power. |
| 23 | **register number** | a sequential number that identifies each data channel that is present in the **metering component** | Required for **meter** or **data storage device** that returns any 1 or more of the following values as a result of an **interrogation**:  
(a) **active energy**:  
(b) **reactive energy**:  
(c) apparent energy:  
(d) apparent power. | Required for **meter** or **data storage device** that returns any 1 or more of the following values as a result of an **interrogation**:  
(a) **active energy**:  
(b) **reactive energy**:  
(c) apparent energy:  
(d) apparent power. |

The following details for each **metering component** identified in rows 15 to 21 above.
<table>
<thead>
<tr>
<th>No</th>
<th>Registry term</th>
<th>Description</th>
<th>Fully certified metering installation</th>
<th>Interim certified metering installation</th>
</tr>
</thead>
<tbody>
<tr>
<td>24</td>
<td>number of dials</td>
<td>the number of dials or digits that relate to the data channel</td>
<td>Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power.</td>
<td>Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power.</td>
</tr>
<tr>
<td>25</td>
<td>register content code</td>
<td>an identifier for the contents of a channel or a data channel, selected from a list in the registry</td>
<td>Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power.</td>
<td>Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power.</td>
</tr>
<tr>
<td>No</td>
<td>Registry term</td>
<td>Description</td>
<td>Fully certified metering installation</td>
<td>Interim certified metering installation</td>
</tr>
<tr>
<td>----</td>
<td>---------------</td>
<td>-------------</td>
<td>---------------------------------------</td>
<td>----------------------------------------</td>
</tr>
<tr>
<td>26</td>
<td>period of availability</td>
<td>an identifier for the period of availability for which a control device is configured, selected from a list in the registry</td>
<td>Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power.</td>
<td>Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power.</td>
</tr>
<tr>
<td>27</td>
<td>unit of measurement</td>
<td>an identifier for the units recorded in a data channel, selected from a list in the registry</td>
<td>Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power.</td>
<td>Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power.</td>
</tr>
</tbody>
</table>

Optional for all other metering components.
<table>
<thead>
<tr>
<th>No</th>
<th>Registry term</th>
<th>Description</th>
<th>Fully certified metering installation</th>
<th>Interim certified metering installation</th>
</tr>
</thead>
<tbody>
<tr>
<td>28</td>
<td>energy flow direction</td>
<td>an identifier for the import or export recording in the data channel, selected from a list in the registry</td>
<td>Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power.</td>
<td>Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power.</td>
</tr>
<tr>
<td>29</td>
<td>accumulator type</td>
<td>an identifier for either absolute or cumulative recording in the data channel, selected from a list in the registry</td>
<td>Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power.</td>
<td>Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power.</td>
</tr>
</tbody>
</table>

Optional for all other metering components.
<table>
<thead>
<tr>
<th>No</th>
<th>Registry term</th>
<th>Description</th>
<th>Fully certified metering installation</th>
<th>Interim certified metering installation</th>
</tr>
</thead>
<tbody>
<tr>
<td>30</td>
<td>settlement indicator</td>
<td>an identifier determined as follows:</td>
<td>Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation:</td>
<td>Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(a) if the relevant meter or data storage device has an AMI flag of &quot;Y&quot;, the cumulative data channel identifier must be &quot;Y&quot; and the other data channel identifiers must be &quot;N&quot;; and</td>
<td>(a) active energy:</td>
<td>(a) active energy:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(b) for any other meter or data storage device, or for a control device, the data channel identifier must be the appropriate identifier selected from the list in the registry</td>
<td>(b) reactive energy:</td>
<td>(b) reactive energy:</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>(c) apparent energy:</td>
<td>(c) apparent energy:</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>(d) apparent power.</td>
<td>(d) apparent power.</td>
</tr>
<tr>
<td>31</td>
<td>event reading</td>
<td>the event meter read of a meter or data storage device</td>
<td>Optional</td>
<td>Optional</td>
</tr>
</tbody>
</table>

Table 1: row 6, column 2 amended, on 5 October 2017, by clause 279(a) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.  
Table 1: row 16 amended, on 29 August 2013, by clause 52(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).  
Table 1: row 19 amended, on 29 August 2013, by clause 52(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).
Table 1: row 21 amended, on 29 August 2013, by clause 52(3) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).
Table 1: row 21 replaced, on 5 October 2017, by clause 279(b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Table 1: row 23 amended, on 15 May 2014, by clause 31 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.
Table 1: row 30 amended, on 29 August 2013, by clause 5(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 3).
Table 1: rows 22 to 30 substituted, on 1 February 2016, by clause 45 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.
Schedule 11.5

Process for trader event of default

1 Purpose

The purpose of this Schedule is to set out the process that the Authority and each participant must comply with when the Authority is satisfied that a trader has committed an event of default under paragraph (a) or (b) or (f) or (h) of clause 14.41.

Clause 2, heading: amended, on 28 February 2015, by clause 10(1) of the Electricity Industry Participation Code Amendment (Trader Default) 2014.
Clause 2(1): amended, on 28 February 2015, by clause 10(2) of the Electricity Industry Participation Code Amendment (Trader Default) 2014.

2 Notice to trader who has committed event of default

(1) If the Authority is satisfied that a trader ("defaulting trader") has committed an event of default under paragraph (a) or (b) or (f) or (h) of clause 14.41 the Authority must give written notice to the defaulting trader that—

(a) the defaulting trader must—

(i) remedy the event of default; or

(ii) assign its rights and obligations under every contract under which a customer of the defaulting trader purchases electricity from the defaulting trader to another trader, and assign to another trader all ICPs for which the defaulting trader is recorded in the registry as being responsible; and

(b) if the defaulting trader does not comply with the requirements set out in paragraph (a) within 7 days of the notice, clause 4 will apply.

(2) The Authority may give written notice to the defaulting trader requiring the defaulting trader to provide to the Authority, within a time specified by the Authority, information about the defaulting trader's customers.

(3) The defaulting trader must provide the information requested by the Authority under subclause (2) within the time specified by the Authority.

Clause 2, heading: amended, on 28 February 2015, by clause 10(1) of the Electricity Industry Participation Code Amendment (Trader Default) 2014.
Clause 2(1): amended, on 28 February 2015, by clause 10(2) of the Electricity Industry Participation Code Amendment (Trader Default) 2014.
Electricity Industry Participation Code 2010  
Schedule 11.5

3 Authority may require distributor and registry manager to provide information  
(1) The Authority may, by notice in writing to a distributor on whose network a defaulting trader trades electricity, require the distributor to provide to the Authority the information about the defaulting trader's customers specified in the notice (if the distributor holds the information), within the period specified in the notice.  
(2) If the distributor holds the information, the distributor must provide the information requested by the Authority under subclause (1) within the time specified by the Authority.  
(3) The Authority may, by notice in writing to the registry manager, require the registry manager to provide to the Authority information about ICPs for which the defaulting trader is recorded in the registry as being responsible, within the period specified in the notice.  
(4) The registry manager must provide the information requested by the Authority under subclause (3) within the time specified by the Authority.

Clause 3(3) and (4): amended, on 5 October 2017, by clause 281(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

4 Failure by defaulting trader to remedy event of default  
(1) This clause applies if—  
(a) 7 days have elapsed since the Authority gave notice to the defaulting trader under clause 2(1); and  
(b) the Authority considers that—  
(i) the defaulting trader has not remedied the event of default or, in the case of an event of default under clause 14.41(b) in respect of which there is an unresolved invoice dispute under clause 14.25, has not reached an agreement with the Authority to resolve the event of default; and  
(ii) the defaulting trader still has 1 or more contracts under which a customer of the defaulting trader purchases electricity from the defaulting trader or is still recorded in the registry as being responsible for 1 or more ICPs.  

(2) The Authority must—  
(a) give written notice to the defaulting trader that the Authority considers that this clause applies; and  
(b) attempt to advise customers of the defaulting trader that—  
(i) the defaulting trader has committed an event of default; and  
(ii) the customer should enter into a contract for the purchase of electricity with another trader by the date that is 14 days after the day on which the Authority gave written notice to the defaulting trader under clause 2(1); and
(iii) if the customer fails to enter into a contract with another trader by that date, the Authority may assign the defaulting trader's rights and obligations under the customer’s contract with the defaulting trader to another trader under clause 5.

(3) [Revoked]

(4) [Revoked]

Clause 4, heading: amended, on 28 February 2015, by clause 12(1) of the Electricity Industry Participation Code Amendment (Trader Default) 2014.
Clause 4(2)(b)(ii) and (iii): amended, on 1 November 2018, by clause 69(c) and (d) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.
Clause 4(3) and 4(4): revoked, on 28 August 2015, by clause 12(4) of the Electricity Industry Participation Code Amendment (Trader Default) 2014.

4A Trader to provide information about NSPs and ICPs at which it cannot trade

(1) If the Authority gives written notice to a trader under clause 4, the Authority must give written notice to each trader (except the defaulting trader) that it must provide the information specified in subclause (2) to the registry manager by no later than 1600 on the business day following the day on which the notice under this subclause was given.

(2) The information that a trader must provide to the registry manager is—

(a) the NSPs at which the trader cannot trade because it does not have an arrangement with the relevant distributor on whose network the NSPs are located to trade at the NSP; and

(b) the ICPs at which the trader cannot trade for any of the following reasons:

(i) the type of each meter at the ICPs (for example, half hour, non half hour, or prepay):

(ii) the price category code assigned to the ICPs:

(iii) the metering installation category of the metering installation at the ICPs:

(iv) the installation type code assigned to the ICPs; and

(c) the reasons, being 1 or more reasons specified in paragraph (a) and (b), for the trader being unable to trade at the NSPs or ICPs.

(3) A trader must comply with a notice given to it under subclause (1).

Clause 4A: inserted, on 28 August 2015, by clause 13 of the Electricity Industry Participation Code Amendment (Trader Default) 2014.
4B Authority may direct registry manager to take certain actions

(1) If the Authority gives written notice to a trader under clause 4, the Authority may, by written notice to the registry manager, direct the registry manager not to—
   (a) complete the switch of any ICP to the defaulting trader; or
   (b) accept a request from the defaulting trader to withdraw a switch under clauses 17 and 18 of Schedule 11.3.

(2) If the Authority gives written notice under subclause (1), the registry manager must not—
   (a) complete the switch of any ICP to the defaulting trader; or
   (b) accept a request from the defaulting trader to withdraw a switch under clauses 17 and 18 of Schedule 11.3.

Clause 4B: inserted, on 28 August 2015, by clause 13 of the Electricity Industry Participation Code Amendment (Trader Default) 2014.

5 Authority may assign contracts and ICPs

(1) This clause applies if, by the end of the 17th day after the defaulting trader was given notice under clause 2(1),—
   (a) the defaulting trader has not remedied the event of default or, in the case of an event of default under clause 14.41(b) in respect of which there is an unresolved invoice dispute under clause 14.25, has not reached an agreement with the Authority to resolve the event of default; and
   (b) the defaulting trader continues to have 1 or more contracts under which a customer of the defaulting trader purchases electricity from the defaulting trader or the defaulting trader is still recorded in the registry as being responsible for 1 or more ICPs.

(2) The Authority may—
   (a) exercise its right under a contract under which a customer purchases electricity from the defaulting trader to assign the rights and obligations of the defaulting trader under the contract to a recipient trader in accordance with the contract; and
   (b) assign an ICP to a recipient trader and direct the registry manager to amend the record in the registry so that the recipient trader is recorded as being responsible for the ICP; and
   (c) specify the recipient trader to whom the rights and obligations under the contract or the ICP will be assigned.

(3) The Authority must, by notice in writing to each recipient trader, direct the recipient trader to accept an assignment under subclause (2).

(4) Before the Authority gives notice to a recipient trader under subclause (3), the Authority may decide not to assign rights and obligations of the defaulting trader under a contract or an ICP to a recipient trader if the recipient trader satisfies the Authority that the assignment would pose a serious threat to the financial viability of the recipient trader.
(5) A recipient trader must comply with a direction given to it under subclause (3).

(6) The registry manager must comply with a direction given to it under subclause (2).

(7) Before the Authority exercises its right to assign rights and obligations or an ICP under subclause (2), the Authority must, if the Authority considers it is practicable, consult with the defaulting trader as to the need for the notice.

(8) Nothing in this clause prevents the Authority from deciding to give a notice under subclause (3) to 1 or more recipient traders by undertaking a tender or other competitive process.

Clause 5, heading: amended, on 28 February 2015, by clause 14(1) of the Electricity Industry Participation Code Amendment (Trader Default) 2014.


5A Effect of assignment

If the Authority assigns an ICP to a recipient trader under clause 5, and at the time of the assignment the recipient trader does not comply with clause 10.24(a) in relation to the ICP, the recipient trader is excused from complying with that clause for the first 3 months after the assignment.

Clause 5A: inserted, on 28 August 2015, by clause 15 of the Electricity Industry Participation Code Amendment (Trader Default) 2014.

6 Authority must provide information to recipient trader

If the Authority exercises its right to assign rights and obligations or an ICP under clause 5(2), the Authority must provide the following information to each recipient trader:

(a) the number of customer contracts (to the extent that the Authority has the information) and ICPs assigned to the trader; and

(b) any information that the Authority holds about the customers and ICPs assigned to the trader.

Clause 6, heading: amended, on 28 February 2015, by clause 16(1) of the Electricity Industry Participation Code Amendment (Trader Default) 2014.

Clause 6: amended, on 28 February 2015, by clause 16(2) of the Electricity Industry Participation Code Amendment (Trader Default) 2014.

Clause 6(a) and (b): amended, on 1 November 2018, by clause 71(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

7 Registry manager may complete switch without required information

If the Authority gives written notice under clause 2, the registry manager may complete the switch of any ICP for which the defaulting trader is recorded in the
registry as being responsible even if the defaulting trader has not complied with its obligations under Schedule 11.3.

8 Terms of assigned contract
(1) If the Authority exercises its right to assign rights and obligations under clause 5(2), the Authority must attempt to advise the customer that the terms of the contract may be amended on assignment.

(2) The recipient trader must use reasonable endeavours to advise the customer of those terms.
Clause 8(1) and (2): amended, on 1 November 2018, by clause 72 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.
Electricity Industry Participation Code 2010

Part 12
Transport

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12.103 Contents of this subpart [Revoked]
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Subpart 6—Interconnection asset services

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12.106 Interconnection asset capacity and grid configuration
12.107 Transpower to identify interconnection branches, and propose service measures and levels
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12.114 Investments to meet the grid reliability standards
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12.116AB [Expired]
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12.117 Permanent removal of interconnection assets from service or permanent grid reconfiguration
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12.127 Transpower to report on availability and reliability
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Subpart 7—Preparation of Outage Protocol

12.129 Purpose of this subpart
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Review of Outage Protocol

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Principles and required content of Outage Protocol

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12.138 Reconsideration of planned outages
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12.140 Net benefit principle, requirements and methodologies
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12.142 Planned outages required in order to give effect to an investment or required by the Act
12.143 Required content of Outage Protocol in relation to unplanned outages
12.144 Reporting on compliance with Outage Protocol

Decisions on Outage Protocol

12.145 Authority may initially approve the proposed Outage Protocol or refer back to Transpower
12.146 Reconsideration of revised Outage Protocol by the Authority
12.147 Authority must consult on the proposed Outage Protocol
12.148 Authority may undertake additional consultation
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Complying with Outage Protocol

12.151 Compliance with Outage Protocol

Schedule 12.1
Categories of designated transmission customers

Schedule 12.2
Grid reliability standards

Schedule 12.3
Core grid determination

Schedule 12.4
Transmission Pricing Methodology

Connection charges

Interconnection charge
Subpart 1—General

12.1 Contents of this Part
This Part relates to the following aspects of transmission:
(a) transmission agreements (subpart 2):
(b) grid reliability and industry information (subpart 3):
(c) the transmission pricing methodology (subpart 4):
(d) [Revoked]
(e) interconnection asset services (subpart 6):
(f) the Outage Protocol (subpart 7).

12.2 Discretion to waive Code requirements
(1) The Authority may agree to waive Code requirements under this Part if, before the commencement of an amendment to this Part,—
   (a) Transpower or any other participant required to complete actions under this Code has in substance done what it would have been required to do under this Code; and
   (b) the Authority is satisfied that the actions have been completed.
(2) If the Authority agrees to waive Code requirements under subclause (1), the Authority must publish its decision and reasons for agreeing to waive Code requirements.

12.3 Interaction between Parts 7 and 8 and this Part
(1) The principal performance obligations in relation to the real time delivery of common quality and dispatch under Part 7 relate to the functions and obligations of the system operator.
(2) When it is exercising its functions and powers under this Part, the Authority must have regard to the desirability of Parts 7 and 8 and this Part operating in an integrated and consistent manner.
(3) The performance or non-performance of a function or obligation of the system operator under Parts 7 or 8, and a claim against the system operator under Parts 7 or 8, is
without prejudice to the functions and obligations of Transpower under this Part.

(4) The performance or non-performance of a function or obligation of Transpower under this Part, and any claim against Transpower under this Part or a transmission agreement, is without prejudice to the functions and obligations of the system operator under Parts 7 or 8.

Compare: Electricity Governance Rules 2003 rule 3 section I part F

Subpart 2—Transmission agreements

12.4 Contents of this subpart
This subpart deals with transmission agreements, and provides for the following:

(a) a process for the Authority to determine the structure of transmission agreements;
(b) the categories of participants that must enter into transmission agreements;
(c) an obligation on Transpower and designated transmission customers to enter into transmission agreements;
(d) matters to be included in transmission agreements;
(e) a process for the Authority to determine benchmark agreements that—
   (i) provide the basis for the negotiation of transmission agreements; or
   (ii) act as a default transmission agreement if Transpower and a designated transmission customer fail to execute a transmission agreement;
(f) a process for the Authority to determine a Connection Code;
(g) a process for variations in transmission agreements from benchmark agreements;
(h) a process for resolving disputes arising from the negotiation of transmission agreements, and the application of the benchmark agreement as a default transmission agreement;
(i) existing agreements.

Compare: Electricity Governance Rules 2003 rule 1 section II part F

12.5 Structure for transmission agreements
(1) The structure for transmission agreements that applies at the commencement of this Code is the structure for transmission agreements published by the Electricity Commission under rule 2 of section II of part F of the rules on 21 May 2007.
(2) Until the Authority reviews the structure for transmission agreements, it must continue to publish the structure referred to in subclause (1).

Compare: Electricity Governance Rules 2003 rule 2.1.2 section II part F

12.6 Review of structure for transmission agreements
(1) This clause applies if the Authority wishes to review the structure for transmission agreement referred to in clause 12.5, or a structure for transmission agreements determined by the Authority under this clause.
(2) The Authority must publish a proposed structure for transmission agreements.
(3) When the Authority publishes its proposed structure, the Authority must advise
registered participants of the date by which submissions on the proposed structure are to be received by the Authority. The date must be no earlier than 15 business days from the date of publication of the proposed structure.

(4) Each submission on the proposed structure must be made in writing to the Authority and received on or before the submission expiry date. In addition to receiving written submissions, the Authority may elect to hear 1 or more oral submissions.

(5) Within 20 business days after the submission expiry date (or such longer period as the Authority may allow), the Authority must complete its consideration of all submissions it receives and determine an appropriate transmission agreement structure.

(6) The transmission agreement structure determined by the Authority under this clause must be the structure of the benchmark agreements to be developed and approved by the Authority under clauses 12.27 to 12.34.

12.7 Categories of participants required to enter into transmission agreements

(1) The categories of designated transmission customers required to enter into transmission agreements with Transpower under clause 12.8 are as specified in Schedule 12.1.

(2) The Authority must record in the register whether a registered participant is a designated transmission customer.

(3) Registration has no effect on a participant’s status as a designated transmission customer.

Compare: Electricity Governance Rules 2003 rule 2.2 section II part F

Transpower and designated transmission customers must enter transmission agreements

12.8 Obligation to enter transmission agreements

Transpower and designated transmission customers must enter into transmission agreements.

Compare: Electricity Governance Rules 2003 rule 3.1.1 section II part F

12.9 When designated transmission customer must enter into transmission agreement

A participant who becomes a designated transmission customer must enter into a transmission agreement with Transpower within 2 months after the participant becomes a designated transmission customer.

Compare: Electricity Governance Rules 2003 rule 3.1.2.3 section II part F

12.10 Benchmark agreements to be default transmission agreements

(1) Subject to clauses 12.49 and 12.50, if, at the expiry of 2 months after a participant becomes a designated transmission customer, the designated transmission customer and Transpower have not entered into a transmission agreement in accordance with clause 12.9, the benchmark agreement applies as a binding contract between the
designated transmission customer and Transpower, and the designated transmission customer and Transpower must comply with the process specified in this clause.

(2) If this clause applies:

(a) within 10 business days of the date that is 2 months after the participant became a designated transmission customer, the designated transmission customer must provide Transpower, at the address for service for Transpower registered at the New Zealand Companies Office, with—

(i) the designated transmission customer’s full name; and

(ii) the designated transmission customer’s physical address, postal address and electronic address to which notices under the default transmission agreement are to be sent; and

(iii) the name of the contact person of the designated transmission customer to whom such notices should be addressed:

(b) by the date 20 business days after the receipt of the designated transmission customer’s details under paragraph (a), Transpower must provide the designated transmission customer with a draft default transmission agreement completed in accordance with the benchmark agreement, which must include the following:

(i) the designated transmission customer’s details as provided under paragraph (a):

(ii) Transpower’s physical address, postal address and electronic address to which notices under the default transmission agreement are to be sent:

(iii) the contact person to whom notices under the default transmission agreement should be addressed:

(iv) Transpower’s designated bank account for the purposes of receiving payments under the default transmission agreement:

(v) a draft Schedule 1, which sets out the connection locations, points of service and points of connection of the assets owned or operated by the designated transmission customer to the grid:

(vi) a draft Schedule 4 setting out, in the same form as the diagram in Schedule 4 of the benchmark agreement, the configuration of the connection assets in relation to each connection location listed in Schedule 1:

(vii) a draft Schedule 5 setting out proposed service levels for each connection location listed in Schedule 1 determined in accordance with subclause (3):

(viii) if applicable, a draft Schedule 6, including identifying the facilities, facilities area, and land that are to be subject to the access and occupation terms set out in the schedule and the licence charges under the schedule:

(c) the designated transmission customer and Transpower may discuss the schedules proposed under paragraph (b)(v) to (viii), as a result of which Transpower may amend any of the schedules:

(d) the designated transmission customer must advise Transpower in writing no later than 20 business days after receiving the draft default transmission agreement under paragraph (b) whether—
(i) it accepts the schedules as proposed by Transpower under paragraph (b)(v) to (viii); or
(ii) if Transpower has amended any of those schedules under paragraph (c), it accepts the schedules as amended.

(3) The service levels set out in Schedule 5 of a default transmission agreement must be determined on the following basis:

(a) the capacity service levels for each branch must be consistent with—
   (i) the capacities of the branch or component assets in the most recent asset capability statement provided by Transpower under clause 2(5) of Technical Code A of Schedule 8.3; or
   (ii) if the relevant information is not contained in the asset capability statement, the manufacturer’s specification for the component assets:

(b) the service levels for the voltage range specified in the capacity service measures for each branch must be consistent with,—
   (i) for assets of voltages of 50kV or above,—
      (A) the voltage ranges for the component assets specified in the AOPOs, if any; or
      (B) the voltage range specified in any equivalence arrangement approved or any dispensation granted under clauses 8.29 to 8.31 in respect of any asset that does not comply with the voltage range specified in the AOPOs; or
   (ii) for assets of voltages less than 50kV, the normal operating voltage of the component assets:

(c) Transpower must ensure that each connection asset is included in a branch:

(d) the availability and reliability service levels must—
   (i) be set at a level equivalent to the average annual availability and reliability at each point of service subject to the default transmission agreement over the 5 year period (being years ending 30 June) immediately before the date that is 2 months after the participant became a designated transmission customer; or
   (ii) if a point of service subject to the default transmission agreement has not been in existence for 5 years (being years ending 30 June) before the date referred to in subparagraph (i), reflect a reasonable estimate of the expected availability and reliability at the point of service having regard to the performance data available for the point of service and average annual availability and reliability of assets similar to the connection assets at the connection location at which the point of service is located:

(e) the reporting and response service levels must be consistent with Transpower’s practices existing on the date that is 2 months after the participant became a designated transmission customer, including Transpower’s documented policies and procedures, and must not result in changes to the management or operation of the grid that could materially affect Transpower or any other participant or end use customer, or require Transpower to materially alter the level of its normal on-going grid expenditure.
(4) If the designated transmission customer accepts the schedules as proposed by Transpower under subclause (2)(b)(v) to (viii), or as amended by Transpower under subclause (2)(c), the default transmission agreement applies as a binding contract between Transpower and the designated transmission customer from the date that is 2 months after the participant became a designated transmission customer.

(5) If Transpower and a designated transmission customer are unable to agree on the terms of any of the schedules to a default transmission agreement proposed by Transpower under subclause (2)(b)(v) to (viii), or as amended by Transpower under subclause (2)(c), either party may refer the matter to the Rulings Panel for determination under clauses 12.45 to 12.48.

(6) If a dispute is referred to the Rulings Panel, under subclause (5)—
   (a) the default transmission agreement as determined by the Rulings Panel in accordance with clauses 12.45 to 12.48 applies as a binding agreement between Transpower and the designated transmission customer from the date that is 2 months after the participant became a designated transmission customer or the date on which the Rulings Panel makes its determination or its determination is expressed to come into effect, whichever is later; and
   (b) if the Rulings Panel has not made a determination by the date that is 2 months after the participant became a designated transmission customer, the draft default transmission agreement provided under subclause (2)(b) applies as a binding agreement between Transpower and the designated transmission customer until the date on which the Rulings Panel makes its determination or the determination comes into effect.

Compare: Electricity Governance Rules 2003 rule 3.1.3 section II part F

12.11 Subsequent transmission agreements

If a benchmark agreement applies as a default transmission agreement, the benchmark agreement may be superseded by a subsequent transmission agreement entered into by Transpower and the designated transmission customer.

Compare: Electricity Governance Rules 2003 rule 3.1.4 section II part F

12.12 Changes to connection assets under default transmission agreements

(1) If Transpower reconfigures, replaces, enhances, or permanently removes a connection asset from service in accordance with the provisions of a default transmission agreement that applies under clauses 12.10 or 12.13,—
   (a) within 20 business days, to the extent necessary, Transpower must provide the designated transmission customer who is a party to that agreement with a revised Schedule 1, a revised Schedule 4, and a revised Schedule 5 for that agreement, reflecting any changes to the description of the connection locations, points of service, or points of connection in Schedule 1, the diagram in Schedule 4, or to the service levels specified in Schedule 5 resulting from the replacement or enhancement of the connection asset; and
(b) the designated transmission customer and Transpower may discuss the revised schedules, as a result of which Transpower may amend any of the revised schedules; and

(c) the designated transmission customer must advise Transpower within 20 business days of receiving the revised schedules under paragraph (a) whether—

(i) it accepts the revised schedules as proposed by Transpower under paragraph (a); or

(ii) if Transpower has amended any of those revised schedules under paragraph (b), it accepts the revised schedules as amended; and

(d) the revised schedules apply under the default transmission agreement from the date that acceptance is received by Transpower under paragraph (c).

(2) If the designated transmission customer does not accept the revised schedules under subclause (1)(c), either party may refer the matter to the Rulings Panel for determination under clauses 12.45 to 12.48.

(3) If a dispute is referred to the Rulings Panel in accordance with subclause (2)—

(a) the revised schedules proposed by Transpower under subclause (1)(a) apply from the date on which Transpower provides the designated transmission customer with the revised schedules under subclause (1)(a) until the date on which the Rulings Panel makes its determination or the determination comes into effect; and

(b) the revised schedules as determined by the Rulings Panel under clauses 12.45 to 12.48 apply under the default transmission agreement from the date determined by the Rulings Panel.

Compare: Electricity Governance Rules 2003 rule 3.1.5 section II part F

12.13 Expiry or termination of transmission agreements

If a transmission agreement, or an existing written agreement to which clause 12.49 applies, expires or terminates on or after the date that is 2 months after the participant became a designated transmission customer and Transpower and the designated transmission customer do not enter into a new transmission agreement within 2 months of that date, the following procedure applies:

(a) within 10 business days, the designated transmission customer must provide Transpower, at the address for service for Transpower registered at the New Zealand Companies Office, with—

(i) the designated transmission customer’s full name; and

(ii) the designated transmission customer’s physical address, postal address and electronic address to which notices under the default transmission agreement are to be sent; and

(iii) the name of the contact person of the designated transmission customer to whom such notices should be addressed:

(b) within 20 business days of receipt of the designated transmission customer’s details under paragraph (a), Transpower must provide the designated transmission customer with a draft default transmission agreement completed in accordance with the benchmark agreement, which must include—
(i) the designated transmission customer’s details as provided under paragraph (a); and
(ii) Transpower’s physical address, postal address and electronic address to which notices under the default transmission agreement are to be sent; and
(iii) the contact person to whom notices under the default transmission agreement should be addressed; and
(iv) Transpower’s designated bank account for the purposes of receiving payments under the default transmission agreement; and
(v) a draft Schedule 1, which sets out the connection locations, points of service and points of connection of the assets owned or operated by the designated transmission customer to the grid; and
(vi) a draft Schedule 4 setting out, in the same form as the diagram in Schedule 4 of the benchmark agreement, the configuration of the connection assets in relation to each connection location listed in Schedule 1; and
(vii) a draft Schedule 5 setting out proposed service levels for each connection location listed in Schedule 1 determined in accordance with clause 12.10(3); and
(viii) if applicable, a draft Schedule 6, including identifying the facilities, facilities area, and land that are to be subject to the access and occupation terms set out in that schedule.

(c) the designated transmission customer and Transpower may discuss the schedules proposed under paragraph (b)(v) to (viii), as a result of which Transpower may amend any of the schedules:

(d) the designated transmission customer must advise Transpower in writing within 20 business days of receiving the draft default transmission agreement under paragraph (b) above whether—
(i) it accepts the schedules as proposed by Transpower under paragraph (b)(v) to (viii); or
(ii) if Transpower has amended any of those schedules under paragraph (c), it accepts the schedules as amended:

(e) if the designated transmission customer accepts the schedules as proposed by Transpower under paragraph (b)(v) to (viii), or as amended by Transpower under paragraph (c), the default transmission agreement applies as a binding contract between Transpower and the designated transmission customer, effective from the date on which the previous transmission agreement or existing written agreement to which clause 12.49 applies expired:

(f) if Transpower and a designated transmission customer are unable to agree on the terms of any of the schedules to a default transmission agreement proposed by Transpower under paragraph (b)(v) to (viii), or as amended by Transpower under paragraph (c), either party may refer the matter to the Rulings Panel for determination under clauses 12.45 to 12.48:

(g) if a dispute has been referred to the Rulings Panel in accordance with paragraph (f)—
(i) the draft default transmission agreement provided under paragraph (b)
applies as a binding agreement between Transpower and the designated transmission customer, effective from the date on which the previous transmission agreement or existing written agreement to which clause 12.49 applies expired, until the date on which the Rulings Panel makes its determination or the determination comes into effect; and

(ii) the default transmission agreement as determined by the Rulings Panel in accordance with clauses 12.45 to 12.48 applies as a binding agreement between Transpower and the designated transmission customer from the date determined by the Rulings Panel.

Compare: Electricity Governance Rules 2003 rule 3.1.6 section II part F

Content of transmission agreements

12.14 Transmission agreements to be consistent with benchmark agreements and grid reliability standards
Subject to clauses 12.35 to 12.38, a transmission agreement entered into between Transpower and a designated transmission customer under clause 12.8 must be consistent in all material respects with—
(a) the benchmark agreement; and
(b) the grid reliability standards,—
as at the date the transmission agreement is entered into.

Compare: Electricity Governance Rules 2003 rule 3.2.1 section II part F

12.15 Transpower to publish information about transmission agreements and provide them on request

(1) Transpower must publish and update annually a list of all transmission agreements it has with designated transmission customers that includes, in respect of each transmission agreement contained in the list, the following information:

(a) the full name of the designated transmission customer that is a party to the transmission agreement; and
(b) the date on which the transmission agreement was executed; and
(c) whether the transmission agreement includes any material variations from the benchmark agreement; and
(d) if the transmission agreement includes any material variations from the benchmark agreement, a description of the variations; and
(e) if any schedule to the transmission agreement has been revised in accordance with clause 12.12, the date from which the revised schedule began to apply.

(2) A person may request from Transpower a copy of a transmission agreement that Transpower has with a designated transmission customer, and Transpower must provide a copy to the person as soon as practicable after receiving the request.
15 November 2018

12.16 Connection Code

(1) The Connection Code set out in schedule F2 of section II of part F of the rules immediately before this Code came into force, continues in force and is deemed to be the Connection Code that applies at the commencement of this Code, with the following amendments:

(a) every reference to the rules must be read as a reference to the Code:
(b) every reference to a provision of the rules must be read as a reference to the corresponding provision of the Code.

(2) The Authority must, as soon as practicable after this Code comes into force, publish a version of the Connection Code in which the provisions of this Code that correspond to the provisions of the rules referred to in the Connection Code are shown.

(3) Clause 12.26 applies to the Connection Code.

12.17 Purpose of Connection Code

The purpose of the Connection Code is to set out the technical requirements and standards that designated transmission customers must meet in order to be connected to the grid and that Transpower must comply with. Transpower and designated transmission customers must comply with the Connection Code under default transmission agreements that apply under clauses 12.10 and 12.13.

12.18 Review of Connection Code

(1) The Authority may review the Connection Code at any time.

(2) Clauses 12.19 to 12.25 apply to any such review.

12.19 Transpower to submit Connection Code

(1) Transpower must submit a proposed Connection Code to the Authority within 90 days (or such longer period as the Authority may allow) of receipt of a written request from the Authority. The Authority may issue such a request at any time. The proposed Connection Code must provide for the matters set out in clause 12.20 and give effect to the principles set out in clause 12.21.

(2) With its proposed Connection Code, Transpower must submit to the Authority an explanation of the proposed Connection Code and a statement of proposal for the
12.20 Required content of Connection Code

The Connection Code must provide for the following matters:

(a) connection requirements for **designated transmission customers**;
(b) technical requirements for **assets**, including assets owned by **Transpower**, and for other equipment and plant that is connected to a **local network** or an **embedded network** or that forms part of an **embedded network** or **embedded generating station** if the operation of that equipment and plant could affect the **grid assets**;
(c) operating standards for equipment that is owned by a **designated transmission customer**, used in relation to the conveyance of **electricity**, and that is situated on land owned by **Transpower**;
(d) information requirements to be met by **designated transmission customers** before equipment is connected to the **grid** and before changes are made to the equipment;
(e) an obligation on **Transpower** to provide a 10 year forecast of the expected maximum fault level of each point of service to **designated transmission customers** set out in the **transmission agreement** between **Transpower** and each **designated transmission customer**.

Compare: Electricity Governance Rules 2003 rule 3.3.2 section II part F

Clause 12.20(b) and (d): amended, on 5 October 2017, by clause 290(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

12.21 Principles for developing Connection Code

The Connection Code must give effect to the following principles:

(a) the principles of the **benchmark agreement** in clause 12.30;
(b) the desirability of the **Connection Code** and Part 8 operating in an integrated and consistent manner, if possible;
(c) the need to ensure that the **grid owner** can meet all obligations placed on it by the **system operator** for the purpose of meeting common security and power quality requirements under Part 8;
(d) the need to ensure that the safety of all personnel is maintained;
(e) the need to ensure that the safety and integrity of equipment is maintained.

Compare: Electricity Governance Rules 2003 rule 3.3.4 section II part F

12.22 Authority may initially approve proposed Connection Code or refer back to Transpower

(1) After consideration of **Transpower**’s proposed **Connection Code**, and accompanying
explanation and **statement of proposal**, the **Authority** may—

(a) provisionally approve the proposed **Connection Code** having regard to the matters set out in clause 12.20 and the principles in clause 12.21; or

(b) refer the proposed **Connection Code** and accompanying explanation and **statement of proposal** back to **Transpower** if, in the **Authority**’s view,—

(i) the proposed **Connection Code** does not contain the matters set out in clause 12.20; or

(ii) the proposed **Connection Code** does not adequately provide for the principles in clause 12.21; or

(iii) the explanation or **statement of proposal** provided with the proposed **Connection Code** in accordance with clause 12.19(2) is inadequate.

(2) **Transpower** may, no later than 20 **business days** (or such longer period as the **Authority** may allow) after the **Authority** advises **Transpower** of its decision under subclause (1), consider the **Authority**’s concerns and resubmit its proposed **Connection Code** and accompanying explanation and **statement of proposal** for consideration by the **Authority**.

Compare: Electricity Governance Rules 2003 rule 3.3.5 section II part F

### 12.23 Amendment of proposed Connection Code by Authority

If the **Authority** considers that the **Connection Code** resubmitted by **Transpower** under clause 12.22(b) does not adequately provide for the matters set out in clause 12.20 or adequately give effect to the principles in clause 12.21, the **Authority** may make any amendments to the proposed **Connection Code** it considers necessary.

Compare: Electricity Governance Rules 2003 rule 3.3.6 section II part F

### 12.24 Authority must consult on proposed Connection Code

(1) The **Authority** must publish the proposed **Connection Code**, either as provisionally approved by the **Authority** or as amended by the **Authority**, as soon as practicable, for consultation with any person that the **Authority** thinks is likely to be materially affected by the proposed **Connection Code**.

(2) As well as the consultation required under subclause (1), the **Authority** may undertake any other consultation it considers necessary.

Compare: Electricity Governance Rules 2003 rules 3.3.7 and 3.3.8 section II part F

### 12.25 Decision on Connection Code

(1) When the **Authority** has completed its consultation on the proposed **Connection Code** it must consider whether to incorporate the **Connection Code** by reference in this Code.

(2) If the **Authority** decides to incorporate the **Connection Code** by reference in this Code, the Authority must determine a date on which the incorporation by reference takes effect and comply with Schedule 1 of the **Act** in relation to it.

Compare: Electricity Governance Rules 2003 rule 3.3.9 section II part F
12.26 Incorporation of Connection Code by reference

(1) The Connection Code is incorporated by reference in this Code in accordance with section 32 of the Act.

(2) Subclause (1) is subject to Schedule 1 of the Act, which includes a requirement that the Authority must give notice in the Gazette before an amended or substituted Connection Code becomes incorporated by reference in this Code.


12.27 Benchmark agreement

(1) The benchmark agreement set out in schedule F2 of section II of part F of the rules immediately before this Code came into force, continues in force and is deemed to be the benchmark agreement that applies at the commencement of this Code, with the following amendments:

(a) every reference to the Board must be read as a reference to the Authority:

(b) every reference to the rules must be read as a reference to the Code:

(c) every reference to the Electricity Governance Regulations must be read as a reference to the Code:

(d) every reference to a provision of the rules or the Electricity Governance Regulations must be read as a reference to the corresponding provision of the Code:

(e) the references in clause 40.2 to the value of unserved energy in schedule F4 of section III of part F of the rules must be read as references to the value of expected unserved energy in clause 4 of Schedule 12.2:

(f) the reference in clause 40.2(f)(2) to Transpower asking the Board of the Electricity Commission to request Transpower to submit a grid upgrade plan must be read as a reference to Transpower asking the Commerce Commission under clause 12.44 to request Transpower to submit an investment proposal.

(2) The Authority must, as soon as practicable after this Code comes into force, publish a version of the benchmark agreement in which the provisions of this Code that correspond to the provisions of the rules referred to in the benchmark agreement are shown.

(3) Clause 12.34 applies to the benchmark agreement.


12.28 Authority may initiate review

(1) Having regard to the statutory objective of the Authority in section 15 of the Act and to the principles for benchmark agreements set out in clause 12.30, the Authority may initiate a review of a benchmark agreement at any time. Reviews of the Connection Code must be carried out in accordance with clause 12.18.

(2) A review of a benchmark agreement must follow the purpose, process and principles in clauses 12.29 to 12.33.
12.29 Purpose of benchmark agreements
The purpose of benchmark agreements is to—
(a) facilitate commercial arrangements between Transpower and designated transmission customers by providing a basis for negotiating transmission agreements required under clause 12.8 that meet the particular requirements of Transpower and designated transmission customers; and
(b) act as a default transmission agreement if Transpower and a designated transmission customer fail to enter into a transmission agreement by the date that is 2 months after the participant became a designated transmission customer.

12.30 Principles for benchmark agreements
A benchmark agreement should—
(a) reflect a fair and reasonable balance between the requirements of designated transmission customers and the legitimate interests of Transpower as asset owner; and
(b) reflect the interests of end use customers; and
(c) reflect the reasonable requirements of designated transmission customers at the grid injection points and grid exit points, and the ability of Transpower to meet those requirements; and
(d) reflect the differing needs of different classes of designated transmission customers; and
(e) be appropriate to the technical requirements of services provided at the point of connection to the grid, but not duplicate requirements that are more appropriately included in the grid reliability standards; and
(f) establish common standards for a common configuration based on factors such as size of connection and voltage level; and
(g) encourage efficient and effective processes for enforcement of obligations and dispute resolution.

12.31 Contents of benchmark agreements
(1) A benchmark agreement must include—
(a) an obligation on the parties to design, construct, maintain and operate all relevant plant and equipment in accordance with—
   (i) relevant laws; and
   (ii) the requirements of this Code (including obligations on designated transmission customers to provide information to facilitate system planning, as set out in clause 12.54); and
(iii) good electricity industry practice and applicable New Zealand technical and safety standards; and

(b) an obligation on designated transmission customers to comply with Transpower’s reasonable technical connection and safety requirements; and

(c) an obligation on designated transmission customers to pay prices calculated in accordance with the transmission pricing methodology approved by the Authority under subpart 4; and

(d) arbitration or mediation processes for resolving disputes; and

(e) service definitions, service levels, and service measures to the extent practicable for transmission services, other than the services to which the clauses in subpart 6 apply.

(2) A benchmark agreement must be consistent in all material respects with the grid reliability standards.

Compare: Electricity Governance Rules 2003 rule 4.3 section II part F

12.32 Authority must consult on draft benchmark agreement

(1) The Authority must publish draft benchmark agreements.

(2) When the Authority publishes a draft benchmark agreement, the Authority must advise registered participants of the date (which must not be earlier than 15 business days after the date of publication of the draft benchmark agreement) by which submissions on the draft benchmark agreement must be received by the Authority.

(3) Each submission on a draft benchmark agreement must be made in writing to the Authority and received on or before the submission expiry date. In addition to receiving written submissions, the Authority may elect to hear 1 or more oral submissions.

Compare: Electricity Governance Rules 2003 rules 4.4 and 4.5 section II part F

12.33 Decision on benchmark agreement

(1) Within 20 business days after the submission expiry date (or such longer period as the Authority may allow), the Authority must complete its consideration of all submissions it receives on the draft benchmark agreement and consider whether to incorporate the draft benchmark agreement by reference as the benchmark agreement.

(2) If the Authority decides to incorporate the benchmark agreement by reference in this Code, the Authority must determine a date on which the incorporation by reference takes effect and comply with Schedule 1 of the Act in relation to it.

Compare: Electricity Governance Rules 2003 rule 4.6 section II part F

12.34 Incorporation of benchmark agreement by reference

(1) The benchmark agreement is incorporated by reference in this Code in accordance with section 32 of the Act.
(2) Subclause (1) is subject to Schedule 1 of the Act, which includes a requirement that the Authority must give notice in the Gazette before an amended or substituted benchmark agreement becomes incorporated by reference in this Code.


Variations from benchmark agreements and grid reliability standards and enhancement and removal of connection assets

12.35 Increased service levels and reliability

(1) This clause applies if—

(a) a proposed transmission agreement is not consistent in all material respects with the benchmark agreement because it increases the service levels above those that would apply if the benchmark agreement applied in accordance with clauses 12.10 or 12.13; or

(b) subject to clause 12.39, a proposed transmission agreement or other agreement between Transpower and a designated transmission customer increases the level of reliability above the grid reliability standards for a particular grid injection point or grid exit point.

(2) If this clause applies, the parties to the proposed transmission agreement must confirm in writing to the Authority that—

(a) they have consulted with affected end use customers in relation to—

(i) the proposed service levels or the proposed increase in reliability; and

(ii) any resulting price implications; and

(b) there are no material unresolved issues affecting the interests of those end use customers.

Compare: Electricity Governance Rules 2003 rule 5.1 section II part F


12.36 Decreased service levels and reliability

(1) This clause applies if—

(a) a proposed transmission agreement is not consistent in all material respects with the benchmark agreement because it decreases the service levels below those that would apply if the benchmark agreement applied in accordance with clauses 12.10 or 12.13; or

(b) subject to clause 12.39, a proposed transmission agreement or other agreement between Transpower and a designated transmission customer decreases the level of reliability below the grid reliability standards for a particular grid injection point or grid exit point.

(2) If this clause applies, the parties must obtain the Authority's approval of the proposed service levels or the lower level of reliability.

(3) The parties must satisfy the Authority that the Authority should grant an approval under subclause (2), having regard to any potential material adverse impacts of the
proposed service levels or the lower level of reliability on—
(a) current and future service levels or reliability for any affected designated transmission customer or end use customer; and
(b) the price paid for transmission or distribution services, or electricity, by any affected designated transmission customer or end use customer.

Compare: Electricity Governance Rules 2003 rule 5.2 section II part F

12.37 Variations that may increase or decrease reliability
If it is uncertain whether, subject to clause 12.39, a proposed transmission agreement or other agreement increases or decreases the service levels from those that would apply if the benchmark agreement applied, or whether a proposed transmission agreement or other agreement increases or decreases the level of reliability above or below the grid reliability standards, for a particular grid injection point or grid exit point, the parties must obtain the Authority’s approval described in clause 12.36(2).

Compare: Electricity Governance Rules 2003 rule 5.3 section II part F

12.38 Other variations from terms of benchmark agreements
(1) This clause applies if a proposed transmission agreement to be entered into by Transpower and a designated transmission customer under clause 12.8 is not consistent in all material aspects with the benchmark agreement, other than a situation to which clauses 12.35 to 12.37 apply.
(2) If this clause applies, the parties must obtain the Authority’s approval to the proposed variation from the benchmark agreement. The parties to the proposed transmission agreement must satisfy the Authority that they have consulted with any affected end use customers and designated transmission customers in relation to the proposed variation, and there are no material unresolved issues affecting the interests of those persons.

Compare: Electricity Governance Rules 2003 rule 5.4 section II part F

12.39 Customer specific value of expected unserved energy
(1) [Revoked]
(2) Transpower or a designated transmission customer may apply to the Authority—
(a) if permitted under a transmission agreement, for provisional approval to use a different value of expected unserved energy than the value specified in clause 4 of Schedule 12.2 for the purposes of determining whether to replace or enhance connection assets as provided for under that transmission agreement; or
(b) for approval to use a different value of expected unserved energy than the value specified in clause 4 of Schedule 12.2 for the purposes of applying the grid reliability standards under clauses 12.35 to 12.37 for a grid injection point or grid exit point, regardless of whether Transpower or the designated transmission customer has applied for the Authority’s provisional approval under subclause (4).
(3) An application under subclause (2) must be made in writing to the Authority—
(a) in the case of an application under subclause (2)(a), within 20 business days of the designated transmission customer proposing that different value to Transpower under the transmission agreement; and
(b) in the case of an application under subclause (2)(b), within 20 business days of the designated transmission customer reaching an agreement with Transpower to which clauses 12.35 to 12.37 apply.

(4) If Transpower or a designated transmission customer applies for approval of a different value of expected unserved energy under subclause (2)(a), the Authority may provisionally approve that value if the Authority considers that the value is a reasonable estimate of the value of expected unserved energy in respect of the grid injection point or grid exit point for the designated transmission customer concerned.

(5) If Transpower or a designated transmission customer applies for approval of a different value of expected unserved energy under subclause (2)(b) the Authority—
(a) may approve that value if the Authority considers that the value is a reasonable estimate of the value of expected unserved energy in respect of the grid injection point or grid exit point for the designated transmission customer concerned; and
(b) may decline to approve that value despite having provisionally approved that value under subclause (4).

(6) If the Authority approves the value of expected unserved energy proposed by Transpower or the designated transmission customer under subclause (2)(b), that value of expected unserved energy applies for the purposes of applying the grid reliability standards under clauses 12.35 to 12.37 for the grid injection point or grid exit point instead of the value of expected unserved energy specified under clause 4 of Schedule 12.2.

(7) If the Authority does not approve the value of expected unserved energy proposed by Transpower or the designated transmission customer under subclause (2)(b), the value of expected unserved energy under clause 4 of Schedule 12.2 applies for the purposes of applying the grid reliability standards under clauses 12.35 to 12.37 for the grid injection point or grid exit point.

Compare: Electricity Governance Rules 2003 rule 5.5 section II part F
12.40 Replacement and enhancement of shared connection assets

(1) If 2 or more designated transmission customers are connected to a point of connection and Transpower has advised those designated transmission customers, in accordance with the provisions of a transmission agreement between Transpower and each of the designated transmission customers, that a grid reliability report published by Transpower in accordance with clause 12.76 sets out that the power system is not reasonably expected to meet the N-1 criterion at all times over the next 5 years because of a connection asset related to that point of connection, Transpower must—

(a) as soon as practicable after advising the designated transmission customers, investigate whether the connection asset meets the grid reliability standards; and

(b) if it finds that the connection asset does not meet the grid reliability standards, develop proposals for investment in the grid to ensure that the connection asset meets the grid reliability standards and propose them to the designated transmission customers as soon as reasonably possible after publication of the grid reliability report.

(2) Transpower and the designated transmission customers advised under subclause (1) must attempt in good faith, within 6 months of the date on which Transpower makes its proposals to the designated transmission customers under subclause (1)(b), or such longer period as the Authority may allow, to reach an agreement for an investment or other solution that will have the effect of—

(a) maintaining the level of reliability for the connection asset at the level of reliability in the grid reliability standards; or

(b) increasing or decreasing the level of reliability for the connection asset above or below the grid reliability standards, so long as Transpower and the designated transmission customers have complied with clauses 12.35 to 12.37 and 12.39.

(3) Transpower may undertake an investment proposed under subclause (2) only—

(a) if the designated transmission customers unanimously agree with the proposal in accordance with subclause (2); or

(b) if the designated transmission customers do not unanimously agree or none of the designated transmission customers agree with the proposed investment, if—

(i) the proposal has been approved under a grid upgrade plan requested by the Electricity Commission in accordance with rule 5.10 of section II of part F of the rules before this Code came into force; or

(ii) the proposal is approved by the Commerce Commission under an investment proposal requested by the Commerce Commission in accordance with clause 12.44(1); or

(iii) the proposal is permitted under an input methodology determined by the Commerce Commission under section 54S of the Commerce Act 1986.

Compare: Electricity Governance Rules 2003 rule 5.6 section II part F
12.41 Removal of shared connection assets from service
(1) If 2 or more designated transmission customers are connected to a point of connection, and Transpower is required by a transmission agreement between Transpower and each of those designated transmission customers to provide the connection assets at the point of connection, Transpower may decommission a connection asset at that point of connection from service only—
   (a) if the designated transmission customers unanimously agree with the decommissioning and clauses 12.35 to 12.37 (if applicable) are complied with; or
   (b) if the designated transmission customers do not unanimously agree, or none of the designated transmission customers agree, with the decommissioning, if the decommissioning results in a net benefit, as calculated under the test set out in clause 12.43.
(2) To avoid doubt, this clause applies only if Transpower proposes to remove a connection asset from service and not replace the asset with another connection asset.

Compare: Electricity Governance Rules 2003 rule 5.7 section II part F

12.42 Reconfiguration of shared connection assets
If 2 or more designated transmission customers are connected to a point of connection, and Transpower is required by a transmission agreement between Transpower and each of those designated transmission customers to provide the connection assets in the configuration specified in each of those transmission agreements, Transpower may only change that configuration—
   (a) if the designated transmission customers unanimously agree with the reconfiguration and clauses 12.35 to 12.37 (if applicable) are complied with; or
   (b) if the designated transmission customers do not unanimously agree, or none of the designated transmission customers agree with the reconfiguration, if the reconfiguration results in a net benefit, as calculated under the test set out in clause 12.43.

Compare: Electricity Governance Rules 2003 rule 5.8 section II part F

12.43 Net benefits test
(1) When Transpower is required to apply a net benefit test, Transpower must—
   (a) estimate the following costs:
      (i) any additional fuel costs incurred by a generator in respect of any generating units that will be dispatched or are likely to be dispatched during or after the removal of the connection asset or the reconfiguration of the connection assets, arising as a result of the removal or reconfiguration:
(ii) any direct labour and material costs that will be incurred by Transpower and the designated transmission customers undertaking the removal of the connection asset or the reconfiguration of the connection assets:

(iii) any increase in the estimate of expected unserved energy in MWh multiplied by the value per MWh of that expected unserved energy, arising as a result of the removal of the connection asset or the reconfiguration of the connection assets:

(iv) any of the following costs, if the cost is to a person that produces, transmits, retails, or consumes electricity in New Zealand:
   (A) changes in fuel costs of existing assets, committed projects and modelled projects:
   (B) changes in the value of involuntary demand curtailment:
   (C) changes in the costs of demand-side management:
   (D) changes in costs resulting from deferral of capital expenditure on modelled projects:
   (E) changes in costs resulting from differences in the amount of capital expenditure on modelled projects:
   (F) changes in costs resulting from differences in operations and maintenance expenditure on existing assets, committed projects, and modelled projects:
   (G) changes in costs for ancillary services:
   (H) changes in losses, including local losses:
   (I) subsidies or other benefits provided under or arising pursuant to all applicable laws, regulations and administrative determinations:
   (J) the value of the expected change in economic surplus due to a change in competition among participants arising as a result of the removal of the connection asset or the reconfiguration of the connection assets, excluding any expected change in economic surplus due to a change in another cost in this net benefit test:

(v) any other relevant cost to a person that produces, transmits, retails or consumes electricity in New Zealand; and

(b) estimate the following benefits:

(i) any reduction in maintenance costs arising as a result of the removal of the connection asset or the reconfiguration of the connection assets (including Transpower's and any designated transmission customer's costs):

(ii) any reduction in fuel costs incurred by a generator in respect of any generating units, arising or likely to arise during or after the removal of the connection asset or the reconfiguration of the connection assets, as a result of the removal or reconfiguration:

(iii) any decrease in the estimate of expected unserved energy in MWh multiplied by the value per MWh of that expected unserved energy, arising as a result of the removal of the connection asset or the reconfiguration of the connection assets:

(iv) any of the following benefits, if the benefit is to a person that produces,
transmits, retails or consumes electricity in New Zealand:

(A) changes in fuel costs of existing assets, committed projects and modelled projects:

(B) changes in the value of involuntary demand curtailment:

(C) changes in the costs of demand-side management:

(D) changes in costs resulting from the deferral of capital expenditure on modelled projects:

(E) changes in costs resulting from differences in the amount of capital expenditure on modelled projects:

(F) changes in costs resulting from differences in operations and maintenance expenditure on existing assets, committed projects, and modelled projects:

(G) changes in costs for ancillary services:

(H) changes in losses, including local losses:

(I) subsidies or other benefits provided under or arising pursuant to all applicable laws, regulations and administrative determinations:

(J) the value of the expected change in economic surplus due to a change in competition among participants arising as a result of the removal of the connection asset or the reconfiguration of the connection assets, excluding any expected change in economic surplus due to a change in another benefit in this net benefit test:

(v) any other relevant benefit to a person that produces, transmits, retails or consumes electricity in New Zealand; and

deduct the costs estimated under paragraph (a) from the benefits estimated under paragraph (b) to determine the net benefit of the proposed removal of the connection asset or the reconfiguration of the connection assets.

(2) Transpower may apply the test under this clause at differing levels of rigour in different circumstances, which may include taking into account the number of assets to be removed or reconfigured, the value of the assets involved, and the size of the load served by the assets.

(3) Transpower is only required to—

(a) make a reasonable estimate of the costs and benefits identified in subclause (1), based on information reasonably available to it at the time it undertakes the test, and taking into account the proposed number of assets to be removed or reconfigured, the value of the assets involved, and the size of the load served by the assets; and

(b) take account of events that can be reasonably foreseen.

(4) Transpower’s estimate of fuel costs under subclause (1) must—

(a) in relation to thermal generating stations, be a reasonable estimate of the fuel costs, based on the economic value of the fuel required for the relevant thermal generating station, and justified by Transpower with reference to opinions on the economic value of the fuel, provided by 1 or more independent and suitably qualified persons; and

(b) in relation to hydroelectric generating stations—
(i) be a reasonable estimate of the fuel costs, based on the economic value of
the water stored at a hydroelectric generating station, provided by a
suitably qualified person other than—
   (A) Transpower; or
   (B) an employee of Transpower; and
(ii) be published, as provided for in the Outage Protocol.

(5) The direct labour costs of Transpower and designated transmission customers under
subclause (1)(a) may include any amounts paid to contractors, but must not include any
apportionment of the overheads or office costs of Transpower or designated
transmission customers.

(6) The material costs of Transpower and designated transmission customers under
subclause (1)(a) are the costs of the materials used in carrying out the work during the
removal of the connection asset or the reconfiguration of the connection assets.

(7) In assessing costs and benefits under subclause (1), Transpower must consider any
reasonably expected operating conditions, forecasts in the system security forecast,
likely fuel costs, and any other reasonable assumptions.

(8) The estimate of expected unserved energy in MWh multiplied by the value per MWh
of that expected unserved energy under subclause (1) must be based on—
   (a) the estimated amount and value of the expected unserved energy as agreed
       between Transpower and each affected designated transmission customer; or
   (b) if Transpower and a designated transmission customer cannot agree on the
       amount and value of the expected unserved energy under paragraph (a), the
       value of expected unserved energy in clause 4 of Schedule 12.2 and
       Transpower's estimate of the expected unserved energy in respect of each
       affected designated transmission customer and end use customer.

Compare: Electricity Governance Rules 2003 rule 5.9 section II part F
Clause 12.43 substituted, on 16 December 2013, by clause 5 of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.

12.44 Request to the Commerce Commission to request an investment proposal be
submitted

(1) Transpower may request in writing that the Commerce Commission request that
Transpower submit an investment proposal to the Commerce Commission—
   (a) for the purposes of clause 12.40(3); or
   (b) if permitted by a transmission agreement.

(2) Unless requested to do so by the Commerce Commission, Transpower must not submit
an investment proposal to the Commerce Commission for approval in respect of an
investment that has been proposed by Transpower in accordance with a transmission
agreement or clause 12.40(3).

Compare: Electricity Governance Rules 2003 rules 5.10 section II, and 12.2.2 section III part F
12.45 Certain disputes relating to transmission agreements may be referred to Rulings Panel

If a dispute between Transpower and a designated transmission customer concerning—
(a) the customer specific terms of a transmission agreement being negotiated between those parties; or
(b) a requested variation of any of the terms of a default transmission agreement (other than a variation under clause 12.12) that applies between Transpower and the designated transmission customer in accordance with clauses 12.10 to 12.13 (including a requested variation from the services described in the default transmission agreement); or
(c) the schedules proposed by Transpower under clauses 12.10(2)(b)(v) to (viii) for a default transmission agreement; or
(d) any revision to Schedule 4 or Schedule 5 of a default transmission agreement proposed by Transpower under clause 12.12; or
(e) the schedules proposed by Transpower under clauses 12.13(1)(b)(v) to (viii) on the expiry or termination of a transmission agreement—is not resolved within a reasonable time, either party may refer the matter to the Rulings Panel for determination.

Compare: Electricity Governance Rules 2003 rule 6.1 section II part F

12.46 Rulings Panel has discretion to determine dispute

(1) The Rulings Panel may, in its discretion, decide whether or not to undertake the determination of a dispute under clause 12.45(a) or (b).

(2) If the Rulings Panel decides not to undertake the determination of the dispute, the Rulings Panel must inform Transpower or the designated transmission customer—
(a) that the Rulings Panel intends to do no more in relation to the matter; and
(b) of the reasons for that intention.

Compare: Electricity Governance Rules 2003 rule 6.2 section II part F

12.47 Determinations by Rulings Panel

(1) In determining a dispute under this clause, the Rulings Panel must take into account—
(a) the principles for benchmark agreements in clause 12.30; and
(b) the desirability of consistent treatment of designated transmission customers except if special circumstances justify a departure; and
(c) the potential impact of a decision on the contents of other transmission agreements or existing agreements as described in clauses 12.49 and 12.50.

(2) The Rulings Panel must not determine disputes relating to the interpretation or enforcement of a transmission agreement including a benchmark agreement.

(3) The Rulings Panel must give notice to the parties of its determination, as soon as reasonably practicable.
12.48 Status of default transmission agreement while Rulings Panel determining dispute
Nothing in clauses 12.45 to 12.47 overrides the application of a benchmark agreement as a default transmission agreement under clause 12.10, pending a determination of the Rulings Panel.

Compare: Electricity Governance Rules 2003 rule 6.5 section II part F

Existing agreements not affected

12.49 Existing agreements
(1) Except as provided for by clause 12.95, this Part does not apply to or affect the rights, powers or obligations of a participant or Transpower under a written agreement entered into between that participant and Transpower for connection to and/or use of the grid that is—
   (a) entered into before 29 October 2003; or
   (b) based on Transpower’s standard connection contract and entered into before 28 June 2007.

(2) The exception from this Part in subclause (1) does not apply to a right, power or obligation of a participant that arises because of the variation of an agreement described in subclause (1).

(3) To avoid doubt, the posted terms and conditions of Transpower do not constitute a written agreement.

Compare: Electricity Governance Rules 2003 rule 8.1 section II part F


12.50 Copies of other agreements to be provided to Authority
(1) If requested to do so by the Authority, Transpower or a participant must provide a copy of any written agreement for connection to and/or use of the grid that Transpower or the participant is a party to and that was entered into before 28 June 2007.

(2) The copy that is provided must be—
   (a) a copy of the complete agreement; and
   (b) certified by a director or the chief executive of Transpower or the participant, to the best of the director’s or chief executive’s knowledge and belief, to be a true and complete copy of the agreement.

(3) An agreement must be published by the Authority, unless the parties establish to the satisfaction of the Authority that there is good reason for not publishing the agreement.

Compare: Electricity Governance Rules 2003 rule 8.2 section II part F

Subpart 3— Grid reliability and industry information

12.52 Contents of this subpart
This subpart relates to—
(a) grid reliability standards; and
(b) investment contracts; and
(c) [Revoked]
(d) grid reliability reporting.

12.53 Purpose of the reliability and industry information clauses
The purposes of this subpart are to—
(a) facilitate Transpower’s ability to develop and implement long term plans
   (including timely securing of land access and resource consents) for investment in
   the grid; and
(b) assist participants to identify and evaluate investments in transmission
   alternatives; and
(c) facilitate efficient investment in generation; and
(d) facilitate any processes pursuant to Part 4 of the Commerce Act 1986.

12.54 Obligations to provide information
(1) Each participant must provide information reasonably required by the Authority for
    the purposes of this subpart and respond to requests from the Authority under this
    subpart promptly and accurately.
(2) Each participant must use reasonable endeavours to provide accurate information.
(3) The Authority is not liable for the accuracy of information provided by a participant.
(4) Subject to the Official Information Act 1982, the Authority may at its discretion, or on
    the application of an affected party, withhold publication of confidential aspects of the
    information provided by a participant to the Authority if the Authority reasonably
    considers that there is good reason for withholding it.

12.55 Authority determines grid reliability standards
(1) The Authority must determine the most appropriate grid reliability standards.
(2) The Authority must consider and determine grid reliability standards, having regard
    to the purposes set out in clause 12.56 and the principles set out in clause 12.57.
(3) The grid reliability standards that apply at the commencement of this Code are the grid reliability standards in Schedule 12.2.

Compare: Electricity Governance Rules 2003 rule 4.1 section III part F

12.56 Purpose of grid reliability standards
The purpose of the grid reliability standards is to provide a basis for Transpower and other parties to appraise opportunities for transmission investments and transmission alternatives.

Compare: Electricity Governance Rules 2003 rule 4.2 section III part F

12.57 Principles of grid reliability standards
The grid reliability standards should—
(a) take into account that transmission investments are long-lived assets and require a long-term planning perspective; and
(b) reflect the public interest in reasonable stability in planning, having regard to the long term nature of investment in transmission assets; and
(c) be consistent with good electricity industry practice; and
(d) provide flexibility to allow the form of the standards to evolve over time, reflecting any changes in good electricity industry practice.

Compare: Electricity Governance Rules 2003 rule 4.3 section III part F

12.58 Content of grid reliability standards
(1) The grid reliability standards must contain 1 or more standards for reliability of the grid, which may include without limitation a primary reliability standard and other reliability standards.

(2) The reliability standards set out in the grid reliability standards may differ to reflect differing circumstances in different regions supplied by the grid.

(3) The grid reliability standards may include 1 or more standards for reliability of the core grid.

(4) The grid reliability standards may contain supporting information, such as information summarising economic assessments balancing different levels of reliability and the expected value of energy at risk.

Compare: Electricity Governance Rules 2003 rule 4.4 section III part F

Review of grid reliability standards

12.59 Interested parties may request review of grid reliability standards
(1) 1 or more interested parties may request a review by the Authority of the grid reliability standards. The request must be in the form of a written submission to the Authority describing—
(a) the nature of the interest of each party seeking the review; and
(b) how the review might enable the grid reliability standards to better reflect the purpose and principles set out in clauses 12.56 and 12.57

(2) In addition to receiving written submissions, the Authority may elect to hear 1 or more oral submissions.
(3) The Authority must either undertake a review of the grid reliability standards, or decline to review the grid reliability standards and publish reasons for declining.

Compare: Electricity Governance Rules 2003 rule 5.1 section III part F

12.60 Authority review of grid reliability standards

The Authority may initiate a review of the grid reliability standards for any reason consistent with the statutory objective of the Authority in section 15 of the Act and the purpose and principles set out in clauses 12.56 and 12.57.

Compare: Electricity Governance Rules 2003 rule 5.2 section III part F

12.61 Authority must publish draft grid reliability standards

(1) This clause applies if the Authority undertakes a review of the grid reliability standards under clauses 12.59 or 12.60.

(2) The Authority must publish draft grid reliability standards.

(3) At the time the Authority publishes the draft grid reliability standards the Authority must publish the date by which submissions on the draft grid reliability standards are to be received by the Authority. The date must be no earlier than 15 business days from the date of publication of the draft grid reliability standards.

(4) Each submission on the draft grid reliability standards must be made in writing to the Authority and be received on or before the submission expiry date. In addition to receiving written submissions, the Authority may elect to hear 1 or more oral submissions.

Compare: Electricity Governance Rules 2003 rules 4.5 and 4.6 section III part F


12.62 Decision on grid reliability standards

Within 20 business days of the submission expiry date (or such longer period as the Authority may allow), the Authority must complete its consideration of all submissions it receives on the draft grid reliability standards and consider whether to include the grid reliability standards as a schedule to this Part, in accordance with the Act.

Compare: Electricity Governance Rules 2003 rule 4.7 section III part F

Core grid determination

12.63 Authority determines core grid determination

(1) The Authority must determine the most appropriate core grid determination.

(2) The core grid specified in the core grid determination must include—
   (a) at a minimum, those assets that comprise the main elements of the grid; and
   (b) at most, all assets that form part of the grid and operate at nominal voltages of 66kV and above.

(3) In determining the most appropriate core grid determination, and in a subsequent review of the core grid determination, the Authority must have regard to—
   (a) the purposes set out in clause 12.64; and
   (b) the principles set out in clause 12.57 for the grid reliability standards; and
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(c) the objectives set out in clause 12.65.

(4) In determining the most appropriate core grid determination, the Authority may engage Transpower or any other person to assist in the preparation of all or part of the core grid determination.

(5) The core grid determination that applies at the commencement of this Code is the core grid determination in Schedule 12.3.

Compare: Electricity Governance Rules 2003 rule 5A.1 section III part F

12.64 Purpose of core grid determination

The purpose of the core grid determination is to provide a basis for—

(a) the Authority to determine the grid reliability standards; and

(b) Transpower and other parties to appraise opportunities for transmission investment and transmission alternatives.

Compare: Electricity Governance Rules 2003 rule 5A.2 section III part F

12.65 Objectives of core grid determination

The Authority must have regard to the following objectives in determining, and in any subsequent review of, the core grid determination:

(a) avoiding the failure or removal from service of any asset forming part of the core grid, if the failure or removal from service of that asset may result in cascade failure;

(b) providing flexibility to allow the core grid to evolve over time, reflecting any changes in the grid;

(c) reflecting the public interest in reasonable stability in planning for transmission.

Compare: Electricity Governance Rules 2003 rule 5A.3 section III part F

Review of core grid determination

12.66 Interested parties may request review of core grid determination

(1) 1 or more interested parties may request a review by the Authority of the core grid determination. The request must be in the form of a written submission to the Authority describing—

(a) the nature of the interest of each party seeking the review; and

(b) how the review might enable the core grid determination to better reflect the purpose and objectives set out in clauses 12.64 and 12.65 respectively.

(2) In addition to receiving written submissions, the Authority may elect to hear 1 or more oral submissions.

(3) The Authority must either undertake a review of the core grid determination, or decline to review the core grid determination and publish reasons for declining.

Compare: Electricity Governance Rules 2003 rule 5B.1 section III part F

12.67 Authority review of grid determination

The Authority may initiate a review of the core grid determination for any reason consistent with the statutory objective of the Authority in section 15 of the Act and the purpose and objectives set out in clauses 12.64 and 12.65 respectively.
12.68 Authority must publish draft core grid determination

(1) This clause applies if the Authority undertakes a review of the core grid determination in accordance with clauses 12.66 or 12.67.

(2) The Authority must publish a draft core grid determination.

(3) When the Authority publishes the draft core grid determination the Authority must publish the date by which submissions on the draft core grid determination are to be received by the Authority. The date must be no earlier than 15 business days from the date of publication of the draft core grid determination.

(4) Each submission on the draft core grid determination must be made in writing to the Authority and be received on or before the submission expiry date. In addition to receiving written submissions, the Authority may elect to hear 1 or more oral submissions.

12.69 Decision on core grid determination

Within 20 business days of the submission expiry date (or such longer period as the Authority may allow), the Authority must complete its consideration of all submissions it receives on or before the submission expiry date. In addition to receiving written submissions, the Authority may elect to hear 1 or more oral submissions.

12.70 Purpose

Clause 12.71 provides for investment contracts to be agreed between designated transmission customers and Transpower, and establishes a process to manage any potential implications for grid reliability standards.

12.71 Investment contracts

Transpower may enter into an investment contract with implications for grid reliability standards only if—

(a) the investment contract is consistent with the grid reliability standards or the proposed investment has been approved by the Authority under clause 12.36(2), and clause 12.36(2) will apply as if the investment contract was a transmission agreement; and

(b) Transpower advises the Authority of the proposed investment contract.

[Revoked]

Cross Heading: revoked, on 1 February 2016, by clause 51(1) of the Electricity Industry Participation Code
12.72 [Revoked]  
Compare: Electricity Governance Rules 2003 rule 11.1 section III part F  

12.73 [Revoked]  
Compare: Electricity Governance Rules 2003 rule 11.2 section III part F  
Clause 12.73: revoked, on 1 February 2016, by clause 51(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

12.74 [Revoked]  
Compare: Electricity Governance Rules 2003 rule 11.3 section III part F  

12.75 [Revoked]  
Compare: Electricity Governance Rules 2003 rule 11.4 section III part F  
Clause 12.75: revoked, on 1 February 2016, by clause 51(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

Grid reliability reporting

12.76 Transpower to publish grid reliability report  
(1) **Transpower** must publish a grid reliability report setting out—  
(a) a forecast of demand at each grid exit point over the next 10 years; and  
(b) a forecast of supply at each grid injection point over the next 10 years; and  
(c) whether the power system is reasonably expected to meet the N-1 criterion, including in particular whether the power system would be in a secure state at each grid exit point, at all times over the next 10 years; and  
(d) proposals for addressing any matters identified in accordance with paragraph (c).  
(2) **Transpower** must publish a grid reliability report no later than 2 years after the date on which it published the previous grid reliability report, or such other date as determined by the Authority (having consulted with Transpower).  
(3) If there is a material change in the forecast demand at a grid exit point or in the forecast supply at a grid injection point in the period to which the most recent grid reliability report relates, **Transpower** must publish a revised grid reliability report as soon as reasonably practicable after the material change.  
Compare: Electricity Governance Rules 2003 rule 12A section III part F  
Subpart 4—Transmission pricing methodology

12.77 Recovery of investment costs by Transpower
The costs incurred by Transpower (irrespective of when they are incurred) in relation to an approved investment are recoverable by Transpower from designated transmission customers on the basis of the transmission pricing methodology and must be paid by designated transmission customers accordingly.

Compare: Electricity Governance Rules 2003 rule 17.1 section III part F

12.78 Purpose for establishing transmission pricing methodology
The purpose of the transmission pricing methodology is to ensure that, subject to Part 4 of the Commerce Act 1986, the full economic costs of Transpower’s services are allocated in accordance with the Authority’s objective in section 15 of the Act.

Compare: Electricity Governance Rules 2003 rule 1 section IV part F

12.79 Statutory objective
Transpower, in developing the transmission pricing methodology, and the Authority, in approving the transmission pricing methodology, must assess the transmission pricing methodology against the Authority’s objective in section 15 of the Act.

Compare: Electricity Governance Rules 2003 rule 2 section IV part F

12.80 Application and interpretation of pricing principles
[Revoked]

Compare: Electricity Governance Rules 2003 rule 3 section IV part F

12.81 Authority must prepare an issues paper
(1) The Authority must prepare an issues paper on—
(a) the process for development and approval of the transmission pricing methodology; and
(b) the guidelines to be followed by Transpower in preparing a methodology for allocating Transpower’s revenues to designated transmission customers.

(2) The process and guidelines must be developed in accordance with the Authority’s objective in section 15 of the Act.

Compare: Electricity Governance Rules 2003 rule 4 section IV part F

12.82 Authority must consult on issues paper
(1) When the Authority publishes the issues paper, the Authority must publish of the date by which submissions are to be received by the Authority. The date must be no earlier than 15 business days from the date of publication of the issues paper.
(2) Each submission on the issues paper must be made in writing to the Authority and received on or before the submission expiry date. In addition to receiving written submissions, the Authority may elect to hear one or more oral submissions.

(3) Within 20 business days of the submission expiry date (or such longer period as the Authority may allow), the Authority must complete its consideration of all submissions it receives on the issues paper.

12.83 Authority must publish process and guidelines for development of transmission pricing methodology
After consideration of submissions in clause 12.82(3), the Authority must, as soon as reasonably practicable, publish—
(a) the process for the development of the transmission pricing methodology; and
(b) any guidelines that Transpower must follow in developing the transmission pricing methodology.

Development of transmission pricing methodology by Transpower

12.84 A Transmission pricing methodology
The transmission pricing methodology that applies at the commencement of this Code is the transmission pricing methodology in Schedule 12.4.

Review of an approved transmission pricing methodology

12.85 Review by Transpower
At any time, Transpower may submit to the Authority a proposed variation of its transmission pricing methodology, provided that the submission is made at least 12 months after the last Authority approval of the transmission pricing methodology.

12.86 Review by the Authority
The Authority may review an approved transmission pricing methodology if it considers that there has been a material change in circumstances.

12.87 Process for review
A review of the transmission pricing methodology must take into account the requirements of clauses 12.79 and 12.89(1). The Authority must follow the processes.
Electricity Industry Participation Code 2010
Part 12

outlined in clauses 12.91 to 12.94 when reviewing a transmission pricing methodology.
Compare: Electricity Governance Rules 2003 rule 11.3 section IV part F

12.88 Transpower to submit methodology
(1) Transpower must submit a proposed transmission pricing methodology to the Authority within 90 days (or such longer period as the Authority may allow) of receipt of a written request from the Authority.
(2) The Authority may, after publishing the process described in clause 12.83(a) and the guidelines described in clause 12.83(b), issue such a request.
Compare: Electricity Governance Rules 2003 rule 7.1 section IV part F

12.89 Form of proposed transmission pricing methodology
(1) Transpower must develop its proposed transmission pricing methodology consistent with—
(a) any determination made under Part 4 of the Commerce Act 1986; and
(b) the Authority’s objective in section 15 of the Act; and
(c) any guidelines published under clause 12.83(b).
(2) Transpower’s proposed transmission pricing methodology must include indicative prices to allow the Authority and interested parties to understand the impact of the methodology on designated transmission customers.
Compare: Electricity Governance Rules 2003 rule 7.2 section IV part F

12.90 Authority may decline to consider proposed transmission pricing methodology
(1) The Authority may decline to consider the proposed Transpower transmission pricing methodology if, in the Authority’s view, Transpower has not provided sufficient information for the Authority to make an informed assessment of the matters referred to in clauses 12.91 to 12.94.
(2) If the Authority so declines, the Authority must advise Transpower of the extra information required, and Transpower must provide a revised transmission pricing methodology by a date specified by the Authority.
Compare: Electricity Governance Rules 2003 rule 7.3 section IV part F

Process for determination of transmission pricing methodology

12.91 Authority may approve proposed transmission pricing methodology or refer back to Transpower
(1) After consideration of Transpower’s proposed transmission pricing methodology, the Authority may either—
(a) approve the proposed transmission pricing methodology having regard to the requirements of clause 12.89(1); or
(b) refer the proposed transmission pricing methodology back to Transpower if in the Authority’s view the proposed transmission pricing methodology does not adequately conform to the requirements of clause 12.89(1) and Transpower will
have 20 business days to consider the Authority’s concerns and to resubmit its proposed transmission pricing methodology for consideration by the Authority.

(2) If the Authority considers that the transmission pricing methodology resubmitted by Transpower under subclause (1)(b) does not conform to the requirements of clause 12.89(1), the Authority may make any amendments it considers necessary to ensure that the proposed transmission pricing methodology adequately conforms to the requirements of clause 12.89(1).

Compare: Electricity Governance Rules 2003 rule 8.1 section IV part F

12.92 Authority must publish proposed transmission pricing methodology

(1) The Authority must publish the proposed transmission pricing methodology as soon as practicable.

(2) At the time the Authority publishes the proposed transmission pricing methodology the Authority must publish the date by which submissions are to be received by the Authority. The date must be no earlier than 15 business days from the date of publication of the proposed transmission pricing methodology.

(3) Each submission on the proposed transmission pricing methodology must be made in writing to the Authority and received on or before the submission expiry date. In addition to receiving written submissions, the Authority may elect to hear 1 or more oral submissions.

Compare: Electricity Governance Rules 2003 rules 8.2 and 8.3 section IV part F

12.93 Decision on transmission pricing methodology

Within 40 business days of the submission expiry date (or such longer period as the Authority may allow), the Authority must complete its consideration of all submissions it receives on a proposed transmission pricing methodology and consider whether to include the transmission pricing methodology in a schedule to this Part and, if so, the date that the transmission pricing methodology will take effect.

Compare: Electricity Governance Rules 2003 rule 8.4 section IV part F

12.94 Authority to determine commencement date

In determining a date on which the transmission pricing methodology must take effect, the Authority must consult with Transpower.

Compare: Electricity Governance Rules 2003 rule 8.5 section IV part F

Application of approved transmission pricing methodology

12.95 Charges to comply with approved transmission methodology

(1) Except for the input connection contracts, new investment agreement contracts, and notional embedding contracts, Transpower must charge for those transmission services affected only in accordance with the approved transmission pricing methodology.

(2) [Revoked]

Compare: Electricity Governance Rules 2003 rule 9.1 section IV part F


12.96 Development of transmission prices

After approval of the transmission pricing methodology, Transpower must—
(a) develop and publish transmission prices consistent with the transmission pricing methodology based on its total revenue requirement for connection to or use of the grid; and
(b) demonstrate to the Authority that the prices are consistent with the transmission pricing methodology.

Compare: Electricity Governance Rules 2003 rule 9.2 section IV part F

Audit of transmission prices

12.97 Audit of transmission prices

(1) The Authority may appoint an auditor to confirm whether Transpower’s transmission prices have been calculated in accordance with the transmission pricing methodology.

(2) Transpower must ensure that the auditor's report includes the auditor's view on whether the application of the transmission pricing methodology by Transpower contains errors or inconsistencies that may have a material impact on the prices of any individual designated transmission customers, or designated transmission customers in general.

(3) Transpower must provide the auditor with all relevant information required by the auditor to complete its review.

Compare: Electricity Governance Rules 2003 rule 9.3 section IV part F

12.98 Transpower may respond to auditor’s report

Transpower must ensure that the auditor's report includes any comments that Transpower provided to the auditor within 15 business days of Transpower receiving a draft of the report.

Compare: Electricity Governance Rules 2003 rule 9.4 section IV part F

12.99 Final auditor report to the Authority

(1) Transpower must ensure that, within 10 business days after the auditor receives Transpower’s response under clause 12.98, the auditor provides a report to the Authority certifying that either—
(a) Transpower had applied correctly the approved transmission pricing methodology; or
(b) material errors remained in Transpower’s application of the transmission pricing methodology.

(2) Within 5 business days of receiving the report, the Authority must publish the auditor’s report.

Compare: Electricity Governance Rules 2003 rules 9.5 and 9.6 section IV part F

12.100 Transpower to redetermine transmission prices

If the auditor concludes that there are material errors in Transpower’s application of the transmission pricing methodology, Transpower must recalculate and publish revised transmission prices to correct identified errors.

Compare: Electricity Governance Rules 2003 rule 9.7 section IV part F

12.101 Auditor’s costs

Transpower must meet the actual and reasonable expenses of the auditor.

Compare: Electricity Governance Rules 2003 rule 9.8 section IV part F

12.102 Enforcement of transmission charges

(1) The approved transmission pricing methodology must be incorporated in transmission agreements between Transpower and designated transmission customers.

(2) The amount payable by a designated transmission customer under a transmission agreement under subclause (1)—

(a) is recoverable in any court of competent jurisdiction as a debt due to Transpower; and

(b) may be challenged in any proceedings to recover the debt on the ground that Transpower has incorrectly applied the transmission pricing methodology in a manner that is adverse to the designated transmission customer but the transmission pricing methodology itself may not be challenged.

Compare: Electricity Governance Rules 2003 rule 10 section IV part F

Subpart 5—Financial transmission rights [Revoked]


12.103 Contents of this subpart
[Revoked]

Compare: Electricity Governance Rules 2003 rule 1 section V part F

12.104 Design
[Revoked]

Compare: Electricity Governance Rules 2003 rule 2 section V part F
12.105 Purpose of this subpart
The purpose of this subpart is to—
(a) create incentives on Transpower, through enforceable service measures, to provide interconnection assets at the capacity ratings required by designated transmission customers and other grid users; and
(b) ensure that Transpower provides information on the capacity of interconnection assets, and their reliability and availability, to enable grid users to monitor the capacity and performance of interconnection assets; and
(c) establish processes for the identification of investments in the grid, and alternatives to such investments, to ensure efficient decision-making on the use of and upgrades to the grid; and
(d) specify the circumstances in which Transpower may permanently or temporarily remove interconnection assets from service or reconfigure the grid.

Compare: Electricity Governance Rules 2003 rule 1 section VI part F

12.106 Interconnection asset capacity and grid configuration
(1) The interconnection asset capacity and grid configuration set out in schedule F6 of section VI of part F of the rules immediately before this Code came into force, continues in force and is deemed to be the interconnection asset capacity and grid configuration that applies at the commencement of this Code.

(2) Clause 12.110 applies to the interconnection asset capacity and grid configuration.

12.107 Transpower to identify interconnection branches, and propose service measures and levels
(1) Transpower must provide the Authority with the information set out in subclause (4) and a diagram showing the configuration of the grid, other than connection assets.

(2) Transpower must provide the information and diagram referred to in subclause (1) to the Authority in the form specified by the Authority.

(3) The interconnection asset capacity and grid configuration referred to in subclause (1) must be provided within 3 months of the date on which the Authority, in accordance with subclause (2), sets the form in which the interconnection asset capacity and grid configuration must be provided.

(4) The information required under subclause (1) is—
(a) for each interconnection circuit branch, the following service measures and service levels:
   (i) the overall continuous capacity rating of the interconnection circuit branch, for both summer and winter periods in MVA and amperes;
   (ii) the level of impedance of the interconnection circuit branch both resistive
and reactive and for assets arranged in both shunt and series in PU, using a base of 100 MVA, provided the impedance of the interconnection circuit branch is equal to or more than 0.0001 PU, using 100 MVA as the base:

(iii) the nominal high voltage rating of each interconnection circuit branch in kV:

(iv) the high voltage range that each interconnection circuit branch can be operated over in kV, specified as a maximum and a minimum; and

(b) for each interconnection transformer branch, the following information:

(i) the overall 24 hour post contingency capacity rating of the interconnection transformer branch, for both the summer and winter period, in amperes and MVA as follows:
   (A) for 2 Winding interconnection transformer branches, the overall 24 hour post contingency capacity rating:
   (B) for 3 Winding interconnection transformer branches, the overall 24 hour post contingency capacity rating, at HV, MV, and LV:

(ii) the continuous capacity rating of the interconnection transformer branch in amperes and MVA as follows:
   (A) for 2 Winding interconnection transformer branches, the continuous capacity rating:
   (B) for 3 Winding interconnection transformer branches, the continuous capacity rating, at HV, MV, and LV:

(iii) the level of impedance of the interconnection transformer branch, both resistive and reactive and for assets arranged in both shunt and in series in PU, using a base of 100 MVA, as follows:
   (A) for 2 Winding interconnection transformer branches, the level of impedance of the interconnection transformer branch:
   (B) for 3 Winding interconnection transformer branches, the level of impedance of the interconnection transformer branch, at HV, MV, and LV:

(iv) the nominal high voltage rating of the interconnection transformer branch in kV:

(v) the high voltage range that the interconnection transformer branch can be operated over in kV, specified as a maximum, and a minimum:

(vi) in respect of the tapping steps and ranges of the interconnection transformer branch:
   (A) the tap voltage range in volts, specified as a maximum and a minimum:
   (B) the number of tapping steps:
   (C) the size of each tapping step as a percentage of the operational voltage range:
   (D) whether the tapping step is on-load or off-load:
   (E) whether on-load tapping capacity is automatic or manual;
   (F) if on-load tapping capacity is automatic, whether it is auto-selected:
   (G) if on-load tapping capacity is manual, the tap step it is normally set to,
which for the purposes of this clause is the actual or expected position at winter peak demand; and

(c) the transfer capacity in the North and South transfer for each configuration of the HVDC link expressed as follows:
   (i) DC sent in MW;
   (ii) AC received in MW; and

(d) for each shunt asset, the following service measures and service levels:
   (i) the overall capacity rating, in MVAr, in terms of both absorption or provision:
   (ii) the nominal voltage rating of the shunt asset in kV:
   (iii) the maximum and minimum voltage range in kV that the shunt asset can operate over; and

(e) in addition to the information required under paragraph (d) in relation to shunt assets:
   (i) whether each shunt asset is dynamic or static:
   (ii) if the shunt asset is dynamic, whether it is an SVC or synchronous compensator:
   (iii) any shunt assets that may directly affect the capacity of the HVDC link as set out in paragraph (c) and the likely magnitude of such effect; and

(f) the dates for the summer and winter periods or other such defined periods as may apply for the purposes of paragraphs (a) and (b).

(5) The information provided under subclause (4) must,—

(a) in the case of information provided under subclause (4)(a), (c) and (d), be consistent with the information disclosed by Transpower in the most recent asset capability statement provided by Transpower under clause 2(5) of Technical Code A of Schedule 8.3; and

(b) in the case of information provided under subclause (4)(b), be consistent with the manufacturer’s specification for the component assets and the information disclosed by Transpower in the most recent asset capability statement provided under clause 2(5) of Technical Code A of Schedule 8.3, if this differs from the manufacturer’s specifications;

(c) in the case of information provided under subclause (4)(a), be consistent with the thermal design rating of each interconnection branch; and

(d) cover every interconnection asset, either as part of an interconnection circuit branch, interconnection transformer branch, the HVDC link or as a shunt asset.

(6) After reviewing the interconnection asset capacity and grid configuration provided under subclause (1), the Authority may request Transpower to reconsider whether any of the interconnection asset capacity and grid configuration, is accurate, and require Transpower to resubmit the interconnection asset capacity and grid configuration to the Authority for reconsideration.

Compare: Electricity Governance Rules 2003 rules 2.1 to 2.6 section VI part F

12.108 Consultation on proposed interconnection asset capacity and grid configuration

(1) If the Authority is provisionally satisfied that the interconnection asset capacity and grid configuration provided under clause 12.107(1) or resubmitted under clause 12.107(6) are correct, the Authority must publish the proposed interconnection asset capacity and grid configuration as soon as practicable for consultation with any person that the Authority thinks is likely to be materially affected by the incorporation of the proposed interconnection asset capacity and grid configuration by reference in this Code.

(2) As well as the consultation required under subclause (1), the Authority may undertake any other consultation it considers necessary.

Compare: Electricity Governance Rules 2003 rules 2.7 and 2.8 section VI part F

12.109 Decision on interconnection asset capacity and grid configuration

(1) When the Authority has completed its consultation on the proposed interconnection asset capacity and grid configuration, it must consider whether to incorporate the proposed interconnection asset capacity and grid configuration by reference in this Code.

(2) If the Authority decides to incorporate the interconnection asset capacity and grid configuration by reference in this Code, the Authority must determine a date on which the incorporation by reference takes effect and comply with Schedule 1 of the Act in relation to it.

Compare: Electricity Governance Rules 2003 rule 2.9 section VI part F

12.110 Incorporation of interconnection asset capacity and grid configuration by reference

(1) The interconnection asset capacity and grid configuration is incorporated by reference in this Code in accordance with section 32 of the Act.

(2) Subclause (1) is subject to Schedule 1 of the Act, which includes a requirement that the Authority must give notice in the Gazette before an amended or substituted interconnection asset capacity and grid configuration becomes incorporated by reference in this Code.


12.111 Transpower to make interconnection branches and other assets available and keep grid configuration

(1) Transpower must make each interconnection circuit branch, interconnection transformer branch, the HVDC link, and each shunt asset identified in the interconnection asset capacity and grid configuration available for use by the system operator for the conveyance of electricity—

(a) at least at the service levels specified in the interconnection asset capacity and grid configuration in accordance with clause 12.107(4); and

(b) in accordance with good electricity industry practice and relevant health and
safety standards.

(2) **Transpower** must keep the grid in the configuration set out in the interconnection asset capacity and grid configuration.

(3) **Transpower** is not required to comply with subclauses (1)(a) or (2) if clause 12.112(1) applies.

Compare: Electricity Governance Rules 2003 rule 3 section VI part F

12.112 Exceptions to clause 12.111

(1) **Transpower** is not required to comply with clause 12.111(1)(a) or (2) if—

(a) permitted under the Outage Protocol made under subpart 7; or

(b) an interconnection asset that forms part of an interconnection branch or the HVDC link, or a shunt asset—

(i) is permanently removed from service, the grid is permanently reconfigured, or the transmission capacity of such an asset is reduced, and the decision to remove the asset from service or reconfigure the grid or reduce the transmission capacity of the asset takes into account the effect of the removal of the asset, reconfiguration of the grid, or the reduction in transmission capacity of the asset, on other materially affected parties, and is undertaken—

(A) in order to maintain the health and safety of any person; or

(B) in order to maintain the safety and integrity of equipment; or

(C) in accordance with demonstrably prudent economic criteria; or

(iaa) has been temporarily removed from service, or the grid has been temporarily reconfigured, in accordance with clause 12.116AA; or

(ia) [Expired]

(ii) has been permanently removed from service, or the grid has been permanently reconfigured, in accordance with clause 12.117; or

(c) a modification to an interconnection branch, the HVDC link, a shunt asset or to the configuration of the grid, has been made as a result of an investment in the grid; or

(d) a modification to an interconnection branch, the HVDC link, a shunt asset or to the configuration of the grid has been made as a result of an investment made under an investment contract entered into in accordance with clauses 12.70 and 12.71; or

(e) the voltage range specified in the AOPOs for an interconnection asset that forms part of an interconnection branch is modified, or any equivalence arrangement is approved or dispensation is granted under clauses 8.29 to 8.31 in respect of the asset; or

(ea) in relation to the HVDC link—

(i) the HVDC owner is operating the HVDC link in accordance with—

(A) a commissioning plan agreed with the system operator under clause 2(6) to (9) of Technical Code A of Schedule 8.3; or

(B) a test plan provided to the system operator under clause 2(6) to (9) of Technical Code A of Schedule 8.3; and
(ii) the configuration of the HVDC link is—
(A) Pole 3 and Pole 2 bipole round power; or
(B) Pole 3 and Pole 2 bipole not round power; or

(f) Transpower and a designated transmission customer have agreed otherwise in accordance with clause 12.128.

(2) If subclause (1)(c) to (e) applies, or the grid is reconfigured under subclause (1)(b)(i) or (ii), Transpower must—
(a) make the interconnection branch, the HVDC link or the shunt asset available to the system operator at least at its modified capacity rating, and at its modified service levels; and
(b) keep the grid in its modified configuration.

(2AA) Subclause (2AB) applies—
(a) if subclause (1)(b)(iaa) applies; and
(b) while—
   (i) an interconnection asset that forms part of an interconnection branch or the HVDC link, or a shunt asset, has been temporarily removed; or
   (ii) the grid has been temporarily reconfigured.

(2AB) Transpower must make the interconnection branch, the HVDC link or the shunt asset available to the system operator at least at its modified capacity rating, and at its modified service levels.

(2A) [Expired]
(2B) [Expired]

(3) If a decision to remove an asset, or reconfigure the grid, or reduce the transmission capacity of an asset has been made under subclause (1)(b)(i) or (ii), Transpower must as soon as reasonably possible publish the analysis it undertook in accordance with subclause (1)(b)(i) or (ii), or a summary of that analysis.

Compare: Electricity Governance Rules 2003 rule 4 section VI part F
Clause 12.112(2AA) and (2AB): inserted, from 15 March 2013 to 15 December 2013, by clause 5(3) of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2013.
Clause 12.112(2AA) and (2AB): inserted, on 16 December 2013, by clause 7(5) of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.

12.113 Transpower to maintain interconnection assets
Transpower must design, construct, maintain and operate all interconnection assets in accordance with good electricity industry practice.

Compare: Electricity Governance Rules 2003 rule 5 section VI part F

Transpower to propose investments

12.114 Investments to meet the grid reliability standards
(1) If a grid reliability report identifies, in accordance with clause 12.76(1)(c), that the power system is not reasonably expected to meet the N-1 criterion at a grid exit point at all times over the 5 years following the date on which the report is published and that this is due to an interconnection asset, Transpower must—
(a) as soon as practicable, investigate whether the interconnection asset meets the grid reliability standards; and
(b) if the interconnection asset does not meet the grid reliability standards, consider reasonably practicable options for ensuring that the grid reliability standards can be met in respect of that asset; and
(c) if Transpower considers that 1 or more investments are required in respect of that interconnection asset in order to meet the grid reliability standards, submit an investment proposal to the Commerce Commission—
(i) in sufficient time to avoid a breach of the grid reliability standards; or
(ii) if the grid reliability standards have already been breached, within 6 months, or such longer period as the Authority may allow, after the publication of the grid reliability report that sets out the investment or investments that Transpower proposes to make; and
(d) if it considers that an investment is not necessary, publish the reasons for this and any alternative measures that Transpower proposes to undertake.

(2) If an investment proposal submitted under this clause is approved by the Commerce Commission under section 54R of the Commerce Act 1986 or permitted under an input methodology determined under section 54S of that Act, Transpower must undertake the investment—
(a) before the grid falls below the grid reliability standards for the reason referred to in subclause (1); or
(b) if the grid had already fallen below the grid reliability standards, or if it is not reasonably practicable to undertake the investment as provided in paragraph (a), as
soon as reasonably practicable.

(3) Transpower does not need to submit an investment proposal under subclause (1)(c) if the investment to which the proposal relates has previously been included in an investment proposal submitted to, and considered—
(a) before this Code came into force, by the Electricity Commission under section III of part F of the rules; or
(b) after this Code came into force, by the Commerce Commission under section 54R or section 54S of the Commerce Act 1986.

Compare: Electricity Governance Rules 2003 rule 6.1 section VI part F

12.115 Other investments

(1) Transpower must publish a grid economic investment report on whether there are investments that it considers, other than the investments identified under clause 12.114, could be made in respect of the interconnection assets.

(2) Transpower must publish a grid economic investment report no later than 2 years after the date on which it published the previous grid economic investment report, or such other date as determined by the Authority.

(3) If a grid economic investment report identifies that there are investments that could be made, Transpower must publish within 6 months a report setting out a proposed timetable for Transpower to consider whether to submit 1 or more investment proposals to the Commerce Commission in respect of those possible investments.

(4) The grid economic investment report does not need to report on possible investments that have been previously included in an investment proposal submitted to, and considered,—
(a) before this Code came into force, by the Electricity Commission under section III of part F of the rules; or
(b) after this Code came into force, by the Commerce Commission under section 54R or section 54S of Part 4 of the Commerce Act 1986.

Compare: Electricity Governance Rules 2003 rule 6.2 section VI part F

12.116 Information on capacities of individual interconnection assets

(1) Transpower must publish the following information in respect of each interconnection asset:
(a) for each transformer that is an interconnection asset, the overall 24 hour post contingency capacity rating of the asset in amperes and MVA, for both the summer and winter periods;
(b) for all other interconnection assets, the overall capacity rating of the asset in amperes and MVA and, if the interconnection assets are circuits, for both the summer and winter periods.

(2) The information required under subclause (1)—
(a) must be consistent with the manufacturer's specification for the asset or with the most recent asset capability statement provided by Transpower under clause 2(5) of Technical Code A of Schedule 8.3, if this differs from the manufacturer's specification; and
(b) must be in a form that allows the branch to which each asset belongs to be easily
identified; and

(c) must be published in the form determined by the Authority as soon as reasonably practicable after the Authority has determined the form.

Compare: Electricity Governance Rules 2003 rule 7 section VI part F

12.116AA Temporary removal of interconnection assets from service or temporary grid reconfiguration

(1) Transpower must temporarily remove 1 or more interconnection assets from service, or temporarily reconfigure the grid as permitted under clause
12.112(1)(b)(iaa), if—
(a) the removal or reconfiguration is requested by the system operator in accordance with clause 9.13B; and
(b) the removal or reconfiguration will result in a net benefit, as calculated under the test set out in clause 12.117.

(2) If Transpower temporarily removes interconnection assets from service or temporarily reconfigures the grid in response to a notice given under clause
9.13B, Transpower must, as soon as is reasonably practicable after the circumstances specified in that notice cease to exist—
(a) restore the interconnection assets to service; or
(b) restore the grid to its original configuration.


12.116AB [Expired]


12.116AC Information to be published

If Transpower receives a notice given in accordance with clause 9.13B, Transpower must publish,—
(a) as soon as practical, a copy of the notice; and
(b) by no later than 5 business days after receiving the notice, a summary of Transpower’s application of the net benefit test that relates to the exceptional circumstances stated in the notice.

12.116A [Expired]

12.116B [Expired]

12.116C [Expired]

12.117 Permanent removal of interconnection assets from service or permanent grid reconfiguration

(1) Transpower may permanently remove interconnection assets from service or permanently reconfigure the grid as permitted under clause 12.112(1)(b) only if removal of the asset or reconfiguration of the grid results in a net benefit, as calculated under the test set out in subclause (2).

(2) When Transpower is required to apply a net benefit test, Transpower must—

(a) estimate the following costs:

(i) any additional fuel costs incurred by a generator in respect of any generating units that will be dispatched or are likely to be dispatched during or after the removal of the interconnection asset or the reconfiguration of the grid, arising as a result of the removal or reconfiguration:

(ii) any direct labour and material costs that will be incurred by Transpower and the designated transmission customers undertaking the removal of the interconnection asset or the reconfiguration of the grid:

(iii) any increase in the estimate of expected unserved energy in MWh multiplied by the value per MWh of that expected unserved energy, arising as a result of the removal of the interconnection asset or the reconfiguration of the grid:

(iv) any relevant cost specified in clause 12.43(1)(a)(iv):

(v) any other relevant cost to a person that produces, transmits, retails or consumes electricity in New Zealand; and

(b) estimate the following benefits:

(i) any reduction in maintenance costs arising as a result of the removal of the interconnection asset or the reconfiguration of the grid (including Transpower's and any designated transmission customer's costs):

(ii) any reduction in fuel costs incurred by a generator in respect of any generating units, arising or likely to arise during or after the removal
of the interconnection asset or the reconfiguration of the grid, as a result of the removal or reconfiguration:

(iii) any decrease in the estimate of expected unserved energy in MWh multiplied by the value per MWh of that expected unserved energy, arising as a result of the removal of the interconnection asset or the reconfiguration of the grid:

(iv) any relevant benefit specified in clause 12.43(1)(b)(iv):

(v) any other relevant benefit to a person that produces, transmits, retails or consumes electricity in New Zealand; and

(c) deduct the costs estimated under paragraph (a) from the benefits estimated under paragraph (b) to determine the net benefit of the proposed removal of the interconnection asset or the reconfiguration of the grid.

(3) Transpower may apply the test under this clause at differing levels of rigour in different circumstances, which may include taking into account the number of assets to be removed or reconfigured, the value of the assets involved, and the size of the load served by the assets.

(4) Transpower is only required to—

(a) make a reasonable estimate of the costs and benefits identified in subclause (2), based on information reasonably available to it at the time it undertakes the test, and taking into account the proposed number of assets to be removed or reconfigured, the value of the assets involved, and the size of the load served by the assets; and

(b) take account of events that can be reasonably foreseen.

(5) Transpower's estimate of fuel costs under subclause (2) must—

(a) in relation to thermal generating stations, be a reasonable estimate of the fuel costs, based on the economic value of the fuel required for the relevant thermal generating station, and justified by Transpower with reference to opinions on the economic value of the fuel, provided by 1 or more independent and suitably qualified persons; and

(b) in relation to hydroelectric generating stations—

(i) be a reasonable estimate of the fuel costs, based on the economic value of the water stored at a hydroelectric generating station, provided by a suitably qualified person other than—

(A) Transpower; or

(B) an employee of Transpower; and

(ii) be published, as provided for in the Outage Protocol.

(6) The direct labour costs of Transpower and designated transmission customers under subclause (2)(a) may include any amounts paid to contractors, but must not include any apportionment of the overheads or office costs of Transpower or designated transmission customers.

(7) The material costs of Transpower and designated transmission customers under subclause (2)(a) are the costs of the materials used in carrying out the work during the removal of the interconnection asset or the reconfiguration of the grid.
In assessing the costs and benefits under subclause (2), Transpower must consider any reasonably expected operating conditions, forecasts in the system security forecast, likely fuel costs, and any other reasonable assumptions.

The estimate of expected unserved energy in MWh multiplied by the value per MWh of that expected unserved energy under subclause (2) must be based on the value of expected unserved energy in clause 4 of Schedule 12.2 and Transpower's estimate of the expected unserved energy in respect of each affected designated transmission customer and end use customer.

To avoid doubt, this clause applies to the removal of interconnection assets from service if Transpower does not propose to replace those assets with another asset.

12.118 Transpower to provide and publish annual report on interconnection asset capacity and grid configuration

(1) Transpower must provide the Authority with and publish an annual report including—

(a) any matter required to be reported on for the purposes of this clause by the Outage Protocol; and

(b) the extent to which, in the preceding year ending 30 June, it has complied with the requirements of clause 12.111(1)(a) and (2); and

(c) any specific instances in which Transpower has not complied with clause 12.111(1)(a) and (2); and

(d) to the extent practicable, the circumstances that have given rise to any failure to comply with clause 12.111(1)(a) and (2); and

(e) to the extent practicable, any steps that it intends to take or other options to reduce the likelihood of failing to comply with clause 12.111(1)(a) and (2) in the future; and

(f) any modifications made to interconnection circuit branches, the HVDC link, and each shunt asset under clause 12.112(c) to (e) in the preceding year ending 30 June and the extent to which it has complied with clause 12.112(2) in respect of those modifications, including any specific instances in which Transpower has not complied; and

(g) any interconnection assets that have been removed from service, or any reconfigurations to the grid made, in accordance with clause 12.116AA or clause
12.117; and
(h) copies of any agreements made under clause 12.128 or, in respect of interconnection assets only, clause 12.151 in the preceding year ending 30 June; and
(i) an update of the interconnection asset capacity and grid configuration required under clause 12.107(1), as at the end of the preceding year ending 30 June.

(2) Transpower must provide to the Authority and publish, the report referred to in subclause (1) by 30 November each year.

(3) The Authority may incorporate by reference in this Code the updated interconnection asset capacity and grid configuration referred to in subclause (1)(i) in accordance with clause 12.110. The Authority may consult with any person the Authority considers is likely to be materially affected by the proposed amendments to the interconnection asset capacity and grid configuration, as it sees fit. Transpower must comply with the interconnection asset capacity and grid configuration incorporated by reference in this Code in accordance with clause 12.110.

Compare: Electricity Governance Rules 2003 rule 9 section VI part F

Reporting on availability and reliability

12.119 Index measures for availability and reliability
The index measures for availability and reliability for each interconnection branch, shunt asset and the HVDC link are the index measures for reliability for each interconnection branch, shunt asset and the HVDC link in Schedule 12.5.

12.120 Updating of availability and reliability index measures
(1) This clause applies if interconnection assets—
(a) are modified or replaced as permitted under clause 12.112(1); or
(b) have been damaged or degraded but, after conducting the investigation required under clause 12.114(1), Transpower considers that they still meet the grid reliability standards.

(2) If this clause applies, if, after the availability and the reliability or availability index measures for an interconnection branch, shunt asset and the HVDC link or aggregated interconnection branches or shunt assets no longer meet the requirements of clause 12.122, the availability and reliability index measures in Schedule 12.5 must be updated following the procedure specified in clauses 12.121 to 12.127.

(3) Transpower must propose the revised index measures under clause 12.121 within 20 business days of the modification or replacement, or such longer period as the Authority may allow.
12.121 Transpower to submit draft index measures for availability and reliability

(1) Transpower must provide the Authority with proposed index measures for availability and reliability for each interconnection branch, shunt asset and the HVDC link, in accordance with this clause.

(2) For the purposes of subclause (1), Transpower must categorise interconnection branches and shunt assets into groups of interconnection branches and shunt assets comprising similar assets.

(3) The index measures to be provided under subclause (1) are—

(a) annual unavailability of each interconnection branch, shunt asset and the HVDC link due to planned outages of 1 minute or longer in hours per year ending 30 June, expressed as a percentage; and

(b) annual unavailability of each interconnection branch, shunt asset and the HVDC link due to unplanned outages of 1 minute or longer in hours per year ending 30 June, expressed as a percentage; and

(c) annual number of planned interruptions of 1 minute or longer caused by planned outages of 1 minute or longer of each interconnection branch, shunt asset and the HVDC link; and

(d) annual number of unplanned interruptions of 1 minute or longer caused by unplanned outages of 1 minute or longer of each interconnection branch, shunt asset and the HVDC link;

(e) total unserved energy per year ending 30 June in MWh resulting from planned interruptions of 1 minute or longer caused by planned outages of 1 minute or longer of each interconnection branch, shunt asset and the HVDC link; and

(f) total unserved energy per year ending 30 June in MWh resulting from unplanned interruptions of 1 minute or longer caused by unplanned outages of 1 minute or longer of each interconnection branch, shunt asset and the HVDC link.

(4) At the same time, Transpower must propose availability and reliability index measures for aggregated interconnection branches and shunt assets, such as by asset class or for all of the grid.

12.122 Requirements for index measures

(1) The proposed availability and reliability index measures under clause 12.121(3) must be based on the average annual availability and reliability of each category of interconnection branch, or shunt asset and of the HVDC link over the 5 year period (ending 30 June) immediately before this clause came into force.

(2) The proposed index measures under clause 12.121(3) must be accompanied by an explanation showing how the requirements of subclause (1) were applied.

(3) The index measure for unserved energy under clause 12.121(3)(e) and (f) must be determined in accordance with the methodology for determining expected unserved energy.
energy relating to outages of interconnection assets specified in the Outage Protocol.

(4) In proposing the availability and reliability index measures under clause 12.121(4), Transpower must specify its reasons for proposing those measures.

Compare: Electricity Governance Rules 2003 rule 10.2 section VI part F

12.123 Authority may initially approve proposed index measures or refer back to Transpower

After considering Transpower's proposed availability and reliability index measures and accompanying reasons the Authority may either—

(a) provisionally approve the proposed availability and reliability index measures; or

(b) refer the proposed availability and reliability index measures and accompanying explanation back to Transpower if in the Authority’s view—

(i) the proposed availability and reliability index measures under clause 12.121 are not consistent with the requirements of clause 12.122(1) or the methodology referred to in clause 12.122(3); or

(ii) the proposed availability and reliability index measures under clause 12.121 do not provide sufficient information to meet the reasonable needs of grid users; or

(iii) the reasons provided with the availability and reliability targets in accordance with clause 12.122 are inadequate—

and Transpower must within 20 business days (or such longer period as the Authority may allow) consider the Authority’s concerns and resubmit the proposed availability and reliability index measures and accompanying explanations for consideration by the Authority.

Compare: Electricity Governance Rules 2003 rule 10.3 section VI part F

12.124 Amendment of proposed index measures by the Authority

If the Authority considers that the availability and reliability index measures resubmitted by Transpower under clause 12.123(b) are not consistent with the requirements of clause 12.122(1) or the methodology referred to in clause 12.122(3), or do not provide relevant information to grid users, the Authority may make any amendments to the index measures it considers necessary.

Compare: Electricity Governance Rules 2003 rule 10.4 section VI part F

12.125 Authority must consult on proposed index measures

(1) The Authority must publish the proposed availability and reliability index measures, either as provisionally approved by the Authority or as amended by the Authority, as soon as is practicable, for consultation with any person that the Authority thinks is likely to be materially affected by the proposed index measures.

(2) As well as the consultation required under subclause (1), the Authority may undertake any other consultation it considers necessary.

Compare: Electricity Governance Rules 2003 rules 10.5 and 10.6 section VI part F
12.126 Decision on index measures
When the Authority has completed its consultation on the proposed availability and reliability measures it must consider whether to include the index measures as a schedule to this Part.
Compare: Electricity Governance Rules 2003 rule 10.7 section VI part F

12.127 Transpower to report on availability and reliability
(1) By 30 November in each year, Transpower must publish and provide to the Authority information on availability and reliability of interconnection assets including—
(a) annual unavailability of each interconnection branch, shunt asset and the HVDC link due to planned outages of 1 minute or longer in the preceding year ending 30 June in hours per year expressed as a percentage; and
(b) annual unavailability of each interconnection branch, shunt asset and the HVDC link due to unplanned outages of 1 minute or longer in the preceding year ending 30 June in hours per year, expressed as a percentage; and
(c) annual number of planned interruptions of 1 minute or longer caused by planned outages of one minute or longer of each interconnection branch, shunt asset and the HVDC link in the preceding year ending 30 June; and
(d) annual number of unplanned interruptions of 1 minute or longer caused by unplanned outages of one minute or longer of each interconnection branch, shunt asset and the HVDC link in the preceding year ending 30 June; and
(e) total unserved energy in the preceding year ending 30 June resulting from planned interruptions of 1 minute or longer caused by planned outages of 1 minute or longer of interconnection branches, shunt assets and the HVDC link; and
(f) total unserved energy in the preceding year ending 30 June resulting from unplanned interruptions of 1 minute or longer caused by unplanned outages of 1 minute or longer of interconnection branches, shunt assets and the HVDC link; and
(g) annual number of outages of each interconnection branch, shunt asset and the HVDC link that are shorter than 1 minute in the preceding year ending 30 June; and
(h) the annual number of interruptions shorter than 1 minute caused by outages that are shorter than 1 minute of each interconnection branch, shunt asset and the HVDC link, in the preceding year ending 30 June; and
(i) a comparison of the information required by paragraphs (a) to (f) against the availability and reliability index measures for interconnection branches, shunt assets and the HVDC link included in a schedule to this Part under clause 12.126; and
(j) to the extent practicable, an explanation of the reasons for not meeting the reliability and availability index measures for interconnection branches, shunt assets and the HVDC link included in a schedule to this Part under clause 12.126 and any steps or other options it intends to take in future to meet the index measures; and
12.127 Transpower and designated transmission customers may agree on other requirements

(1) Transpower and each designated transmission customer must comply with this Part, unless agreed otherwise by Transpower and the designated transmission customer in respect of specified interconnection circuit branches, the HVDC link, shunt assets or interconnection assets, or the designated transmission customer in accordance with subclause (2).

(2) An agreement between Transpower and a designated transmission customer under this clause must not exclude the application of subclause (3)(b) and must be conditional in all respects on—
   (a) obtaining agreement from all other potentially affected designated transmission customers that this Part does not apply to the specified interconnection circuit branches, the HVDC link, shunt assets or interconnection assets, or the designated transmission customer; and
   (b) Transpower and the designated transmission customer confirming in writing to the Authority that they have consulted with all potentially affected end use customers on this Part not applying to the specified interconnection branches, circuit branches, the HVDC link, shunt assets or interconnection assets or the designated transmission customer, and that there are no material unresolved issues affecting the interests of those end use customers.

(3) Transpower must—
   (a) give written notice to the Authority as soon as practicable if Transpower enters into an agreement with a designated transmission customer under this clause; and
   (b) publish the agreement no later than 20 business days after entering into the agreement.

Compare: Electricity Governance Rules 2003 rule 11 section VI part F
Subpart 7—Preparation of Outage Protocol

12.129 Purpose of this subpart
The purpose of this subpart is to provide for the making of an Outage Protocol, with input from Transpower and in consultation with other interested parties, that—
(a) specifies the circumstances in which Transpower may temporarily remove any assets forming part of the grid from service or reduce the capacity of assets to efficiently manage the operation of the grid; and
(b) specifies procedures and policies for Transpower to plan for outages and for carrying out such outages to—
(i) ensure Transpower involves designated transmission customers in making decisions on planned outages as much as possible; and
(ii) ensure coordination between Transpower and designated transmission customers; and
(iii) enable Transpower to efficiently manage the operation of the grid; and
(c) specifies procedures and policies for dealing with unplanned outages of the grid.

Compare: Electricity Governance Rules 2003 rule 1 section VII part F

12.130 Definition of outage
(1) An outage exists when interconnection assets or connection assets are temporarily not provided in accordance with—
(a) the requirements of a transmission agreement; or
(b) the requirements of subpart 6.
(2) Without limiting subclause (1), an outage includes any situation in which—
(a) Transpower removes assets from service temporarily; or
(b) assets are not able to be provided due to grid emergencies, in order to deal with health and safety issues, or due to circumstances beyond Transpower’s reasonable control; or
(c) Transpower reduces the capacity of branches below the capacity required by a transmission agreement or clause 12.111; or
(d) Transpower changes the configuration of the grid; or
(e) Transpower is required by law to carry out an outage.

Compare: Electricity Governance Rules 2003 rule 2 section VII part F

12.131 Outage Protocol
(1) The Outage Protocol set out in schedule F7 of section VII of part F of the rules immediately before this Code came into force, continues in force and is deemed to be the Outage Protocol that applies at the commencement of this Code, with the following amendments:
(a) every reference to the Board must be read as a reference to the Authority:
(b) every reference to the rules must be read as a reference to the Code:
(c) every reference to a provision of the rules must be read as a reference to the corresponding provision of the Code:
(d) the reference in clause 3.1.2(d), clause 3.3.5(c), and clause 3.3.8(a) to a reliability investment or an economic investment approved by the Board must be read as a reference to an approved investment:

(e) the reference in clause 10.2.1(a) and (b) to the benchmark agreement in schedule F2 must be read as a reference to the benchmark agreement incorporated by reference into this Code under clause 12.34:

(f) the reference in clauses A1.1(a)(ii), A7.2(a)(ii), and A7.2(b)(i) to the value of unserved energy in clause 8.3.4 of schedule F4 of section III must be read as a reference to the value of expected unserved energy in clause 4 of Schedule 12.2:

(g) the reference in clauses A6.1(f) and A6.2(e) to the matters specified in clauses 27.1 to 27.9 of schedule F4 of section III must be read as the matters specified in clause 12.43(1)(a)(iv) and (b)(iv):

(h) the reference in clause A8.1(a)(i) to fuel costs specified in the statement of opportunities must be read as a reference to fuel costs calculated in accordance with clause 12.141(3)(a)(i).

(2) The Authority must as soon as practicable after this Code comes into force, publish a version of the Outage Protocol in which the provisions of this Code that correspond to the provisions of the rules referred to in the Outage Protocol are shown.

(3) Clause 12.150 applies to the Outage Protocol.

Review of Outage Protocol

12.132 Review of Outage Protocol

The Authority may review the Outage Protocol at any time, in accordance with the requirements of clauses 12.133 and 12.145 to 12.149.

Compare: Electricity Governance Rules 2003 rule 14 section VII part F

12.133 Transpower to submit proposed Outage Protocol

(1) Transpower must submit a proposed Outage Protocol to the Authority within 3 months (or such longer period as the Authority may allow) of receipt of a written request from the Authority. The Authority may issue such a request at any time.

(2) The proposed Outage Protocol must give effect to or promote the principles set out in clause 12.134 and provide for the matters set out in clauses 12.135 to 12.144.

(3) With its proposed Outage Protocol, Transpower must submit to the Authority an explanation of the proposed Outage Protocol and a statement of proposal for the proposed Outage Protocol.

Compare: Electricity Governance Rules 2003 rule 8 section VII part F

Principles and required content of Outage Protocol

12.134 Principles for developing Outage Protocol

The Outage Protocol must give effect to the following principles:

(a) the matters in clause 12.129;

(b) the need for a fair and reasonable balance of interests between the grid owner and designated transmission customers:
(c) the need to ensure that the grid owner can meet all obligations placed on it by the system operator for the purpose of meeting common security and power quality requirements under Part 8 of this Code;
(d) the need to ensure that the safety of all personnel is maintained;
(e) the need to ensure that the safety and integrity of equipment is maintained:
(f) the desirability of the Outage Protocol and Part 8 operating in an integrated and consistent manner, if possible.

Compare: Electricity Governance Rules 2003 rule 3 section VII part F

12.135 Required content of Outage Protocol

(1) The Outage Protocol must—
   (a) require Transpower to plan for outages, other than outages that are not reasonably foreseeable, in accordance with clause 12.136; and
   (b) require Transpower and designated transmission customers to act reasonably and in good faith in planning for outages, in accordance with clause 12.137; and
   (c) set out the situations and times at which Transpower must reconsider the timing of proposed planned outages, as specified in clause 12.138; and
   (d) permit Transpower to vary a proposed planned outage, as specified in clause 12.139;
   (e) set out the requirements for Transpower to consider when planning for outages, in order to give effect to the net benefit principle, as specified in clause 12.140; and
   (f) permit Transpower to undertake outages in order to give effect to an approved investment, and to undertake outages that are required by the Electricity Act 1992, as specified in clause 12.142; and
   (g) permit Transpower to undertake outages, or take such other steps, as the system operator may reasonably require.

(2) The Outage Protocol must require Transpower to set out the procedures and policies for dealing with unplanned outages, as specified in clause 12.143.

(3) The Outage Protocol must require Transpower to report on compliance with the Outage Protocol, in accordance with clause 12.144.

(4) The Outage Protocol must set out—
   (a) processes for Transpower to consult with designated transmission customers and to determine an outage plan setting out planned outages for each year ending 30 June, and processes for the outage plan to be updated; and
   (b) requirements on Transpower to keep designated transmission customers informed about planned outages, including minimum notice periods for Transpower to advise affected designated transmission customers of planned outages not set out in the outage plan; and
   (c) procedures for outage co-ordination by Transpower and between Transpower and designated transmission customers; and
   (d) requirements on Transpower to provide information to designated transmission customers about unplanned outages.
(5) The Outage Protocol is not limited to the matters referred to in this clause, and may provide for any other matters related to outages. 

Compare: Electricity Governance Rules 2003 rule 4 section VII part F 

12.136 Planning for outages

The Outage Protocol must require Transpower to plan for outages, other than outages that are not reasonably foreseeable—

(a) in respect of interconnection assets, in accordance with the requirements of the Outage Protocol specified under clause 12.140(1); and

(b) in respect of connection assets, by agreeing with each affected designated transmission customer on the timing and duration of the outage or, failing agreement, in accordance with the requirements of the Outage Protocol specified under clause 12.140(1); and

(c) in respect of outages of both interconnection assets and connection assets that are required in order to give effect to an approved investment or are required by the Electricity Act 1992, in accordance with the requirements of the Outage Protocol specified under clause 12.142.

Compare: Electricity Governance Rules 2003 rule 5.1 section VII part F

12.137 Transpower and designated transmission customers to act reasonably and in good faith

(1) The Outage Protocol must require Transpower, in planning for outages in accordance with clauses 12.136, 12.140, and 12.142, reconsidering the timing of proposed planned outages in accordance with clause 12.138 or varying proposed planned outages in accordance with clause 12.139, to act reasonably and in good faith, taking into account the information reasonably known at the time or that can be reasonably forecast.

(2) The Outage Protocol must require designated transmission customers, in exercising rights or undertaking obligations under the Outage Protocol, to act reasonably and in good faith.

Compare: Electricity Governance Rules 2003 rule 5.2 section VII part F

12.138 Reconsideration of planned outages

The Outage Protocol must set out the situations and the times at which Transpower must reconsider the timing of proposed planned outages, and the extent to which the proposed timing of planned outages needs to be reconsidered, which may include—

(a) whenever material new information has been provided to Transpower about the likely effect of a proposed planned outage; and

(b) whenever circumstances relating to a proposed planned outage have changed sufficiently to justify reconsideration of the requirements specified under clauses 12.140 or 12.142, and Transpower is aware or has been made aware of the change in circumstances.

Compare: Electricity Governance Rules 2003 rule 5.3 section VII part F
12.139 Variations to planned outages

(1) The Outage Protocol may permit Transpower to vary a proposed planned outage only if—

(a) in respect of a proposed planned outage of interconnection assets, the variation of the proposed planned outage is permitted in accordance with the requirements of the Outage Protocol specified under clauses 12.140 or 12.142; or

(b) in respect of a proposed planned outage of connection assets, Transpower and each affected designated transmission customer agree on the variation as provided for in the Outage Protocol or, failing agreement, the variation of the proposed planned outage is permitted in accordance with the requirements of the Outage Protocol specified under clauses 12.140 or 12.142; or

(c) the variation is necessary as a result of a grid emergency, in order to deal with health and safety issues, in order to comply with the Act or due to other circumstances beyond Transpower’s reasonable control; or

(d) the variation is required to meet a request of the system operator that Transpower vary a proposed planned outage.

(2) The Outage Protocol must require Transpower, if possible, to give notice of a variation before the proposed planned outage, and if prior notice is not possible, to advise of the variation to the proposed planned outage as soon as possible after the variation occurs.

Compare: Electricity Governance Rules 2003 rule 5.4 section VII part F

12.140 Net benefit principle, requirements and methodologies

(1) The requirements of the Outage Protocol relating to planning for outages under clause 12.136(a) or (b), or for varying proposed planned outages under clause 12.139(1)(a) or (b)—

(a) must give effect to the net benefit principle specified in subclause (2), in determining the timing and duration of a planned outage, and whether to undertake a planned outage, either by including the particular requirements set out in clause 12.141(2), or by some other means; and

(b) may include methodologies and processes for Transpower to apply when planning for outages; and

(c) may include other requirements that may apply in different situations.

(2) The net benefit principle is that, in planning and varying a planned outage, Transpower must ensure that the planned outage is likely to result in net benefits to persons who produce, transmit, distribute, retail or consume electricity—

(a) in respect of interconnection assets, to the extent those persons are affected by an outage; and

(b) in respect of connection assets, if Transpower has not agreed the timing and duration of the outage with the relevant designated transmission customer in accordance with the Outage Protocol, to the extent those persons are affected by an outage.

Compare: Electricity Governance Rules 2003 rule 5.5 section VII part F
12.141 Consideration of the likely effects of planned outages

(1) The Outage Protocol may require Transpower to determine the likely effect of a proposed planned outage on the power system, generators and consumers, and—
   (a) if a proposed outage is not reasonably expected to—
      (i) result in the power system failing to meet the grid reliability standards; and/or
      (ii) give rise to binding constraints; and/or
      (iii) result in loss of supply to consumers,
       may permit Transpower to undertake the outage; and
   (b) if a proposed outage is likely to result in, or give rise to, the matters referred to in paragraph (a), the Outage Protocol may require Transpower to comply with the particular requirements specified in subclause (2).

(2) The requirements in subclause (1) that the Outage Protocol may provide are—
   (a) if a proposed planned outage is likely to result in the power system failing to meet the grid reliability standards, but is not expected to give rise to binding constraints or result in loss of supply to consumers, Transpower must—
      (i) estimate the following costs:
         (A) any direct labour and material costs that Transpower will incur in undertaking the outage;
         (B) any direct labour and material costs that designated transmission customers will incur as a result of Transpower undertaking the outage;
         (C) if the outage will result in an increased risk of loss of supply, any increase in the estimate of expected unserved energy in MWh multiplied by the value per MWh of that expected unserved energy;
         (D) any relevant cost specified in clause 12.43(1)(a)(iv):
         (E) any relevant benefit specified in clause 12.43(1)(b)(iv):
      (ii) estimate the following benefits:
         (A) if the outage will result in a decreased risk of loss of supply, any decrease in the estimate of expected unserved energy in MWh multiplied by the value per MWh of that expected unserved energy:
         (B) any reduction in maintenance costs arising as a result of the outage including Transpower’s and any designated transmission customer’s costs:
         (C) any relevant benefit specified in clause 12.43(1)(b)(iv):
         (D) any other relevant benefit to a person that produces, transmits, retails or consumes electricity in New Zealand; and
   (b) if a proposed planned outage is likely to give rise to binding constraints, whether or not the outage is also likely to result in a loss of supply to consumers, Transpower must—
(i) estimate the following costs:
   (A) any direct labour and material costs that Transpower will incur in undertaking the outage;
   (B) any direct labour and material costs that designated transmission customers will incur as a result of Transpower undertaking the outage;
   (C) if the outage will result in an increased risk of loss of supply, any increase in the estimate of expected unserved energy in MWh multiplied by the value per MWh of that expected unserved energy;
   (D) any additional fuel costs incurred by a generator in respect of any generating units that will be dispatched or are likely to be dispatched during or after the outage and as a result of the outage;
   (E) any relevant cost specified in clause 12.43(1)(a)(iv);
   (F) any other relevant costs to a person that produces, transmits, retails or consumes electricity in New Zealand; and

(ii) estimate the following benefits:
   (A) any reduction in maintenance costs resulting from the outage (including Transpower’s and any designated transmission customer’s costs);
   (B) any reduction in fuel costs incurred by a generator in respect of any generating units, arising or likely to arise during or after the outage and as a result of the outage;
   (BA) if the outage will result in a decreased risk of loss of supply, any decrease in the estimate of expected unserved energy in MWh multiplied by the value per MWh of that expected unserved energy;
   (C) any relevant benefit specified in clause 12.43(1)(b)(iv);
   (D) any other relevant benefit to a person that produces, transmits, retails or consumes electricity in New Zealand; and

(iii) carry out the outage only if the costs estimated under subparagraph (i) are less than the benefits estimated under subparagraph (ii); and

(c) if a proposed planned outage is likely to lead to loss of supply to consumers, whether or not the outage is also likely to give rise to binding constraints, Transpower must—

(i) estimate the following costs:
   (A) any direct labour and material costs that Transpower will incur in undertaking the outage;
   (B) any direct labour and material costs that designated transmission customers will incur as a result of Transpower undertaking the outage;
   (C) any increase in the estimate of expected unserved energy in MWh multiplied by the value per MWh of that expected unserved energy, arising from the loss of supply during the outage:
(CA) any additional fuel costs incurred by a generator in respect of any generating units that will be dispatched or are likely to be dispatched during or after the outage and as a result of the outage:
(D) any relevant cost specified in clause 12.43(1)(a)(iv):
(E) any other relevant cost to a person that produces, transmits, retails or consumes electricity in New Zealand; and

(ii) estimate the following benefits:
(A) any reduction in maintenance costs resulting from the outage (including Transpower’s and any designated transmission customer’s costs):
(B) if the outage will result in a decreased risk of loss of supply, any decrease in the estimate of expected unserved energy in MWh multiplied by the value per MWh of that expected unserved energy:
(C) any reduction in fuel costs incurred by a generator in respect of any generating units, arising or likely to arise during or after the outage and as a result of the outage:
(D) any relevant benefit specified in clause 12.43(1)(b)(iv):
(E) any other relevant benefit to a person that produces, transmits, retails or consumes electricity in New Zealand; and

(iii) carry out the outage only if the costs estimated under subparagraph (i) are less than the benefits estimated under subparagraph (ii).

(3) In providing for the matters referred to in subclause (2), the Outage Protocol must include the following requirements:
(a) Transpower’s estimate of the fuel costs under subclause (2)(b) and (c) must—
(i) in relation to thermal generating stations, be a reasonable estimate of the fuel costs, based on the economic value of the fuel required for the relevant thermal generating station, and justified by Transpower with reference to opinions on the economic value of the fuel, provided by 1 or more independent and suitably qualified persons; and
(ii) in relation to hydroelectric generating stations—
(A) be a reasonable estimate of the fuel costs, based on the economic value of the water stored at a hydroelectric generating station, provided by a suitably qualified person other than—
(1) Transpower; or
(2) an employee of Transpower; and
(B) be published, as provided for in the Outage Protocol:
(b) the direct labour costs of Transpower and designated transmission customers under subclause (2) may include any amounts paid to contractors, but must not include any apportionment of the overheads or office costs of Transpower or designated transmission customers:
(c) the material costs of Transpower and designated transmission customers under subclause (2) are the costs of the materials used in carrying out the work during the outage:
(d) The estimate of expected unserved energy in MWh multiplied by the value per MWh of that expected unserved energy under subclause (2) must—

(i) in the case of connection assets, be based on—

(A) the estimated amount and value of the expected unserved energy as agreed between Transpower and each affected designated transmission customer; or

(B) if Transpower and a designated transmission customer cannot agree on the amount and value of the expected unserved energy under subsubparagraph (A), the value of expected unserved energy in clause 4 of Schedule 12.2 and Transpower's estimate of the expected unserved energy in respect of each affected designated transmission customer and end use customer; and

(ii) in the case of interconnection assets, be based on—

(A) the value of expected unserved energy in clause 4 of Schedule 12.2; and

(B) Transpower's estimate of the expected unserved energy in respect of each affected designated transmission customer and end use customer.

(4) In addition to the requirements in subclause (3), the Outage Protocol must require Transpower, in planning for outages, to consider any reasonably expected operating conditions, forecasts in the system security forecast, likely fuel costs, and any other reasonable assumptions.

(5) The Outage Protocol must include a methodology for determining expected unserved energy for the purposes of subclause (2)(a) to (c) that complies with subclauses (3)(d) and (4).

(6) The Outage Protocol may permit Transpower to—

(a) make only a reasonable estimate of the matters specified in subclauses (2) to (4) based on information reasonably available to it at the time Transpower considers whether to carry out a planned outage, and taking into account the number of assets to which the proposed outage applies, the value of the assets involved, the size of the load served by the assets, the proposed duration of the outage; and

(b) apply differing levels of rigour in different circumstances, which may include taking into account the number of assets to which a proposed outage applies, the value of the assets involved, the size of the load served by the assets, the proposed duration of the outage, and any other relevant matters.
12.142 Planned outages required in order to give effect to an investment or required by the Act
(1) The Outage Protocol must set out requirements for Transpower to consider when determining the timing of planned outages that are required in order to give effect to an approved investment or that are required by the Electricity Act 1992.
(2) The requirements specified under subclause (1) must require Transpower to give effect to the net benefit principle in clause 12.140(2) in determining the timing and duration of outages subject to this clause, and may require Transpower to consider some or all of the costs and benefits specified in clause 12.141.

Compare: Electricity Governance Rules 2003 rule 5.7 section VII part F

12.143 Required content of Outage Protocol in relation to unplanned outages
(1) The Outage Protocol must—
   (a) set out procedures and policies for dealing with unplanned outages, so as to minimise the costs and, if relevant, maximise the benefits arising from an unplanned outage; and
   (b) set out the reasonable steps and measures that Transpower must take in order to be prepared for unplanned outages, so as to ensure that it is readily able to deal with unplanned outages in a way that minimises the costs and, if relevant, maximises the benefits arising from an unplanned outage; and
   (c) require Transpower to deal with unplanned outages as quickly as reasonably possible, in accordance with the procedures specified in the Outage Protocol.
(2) The costs and benefits under subclause (1) are the costs and benefits of the outage to persons who produce, transmit, distribute, retail, or consume electricity.

Compare: Electricity Governance Rules 2003 rule 6 section VII part F

12.144 Reporting on compliance with Outage Protocol
The Outage Protocol must require Transpower to publish and report to designated transmission customers and the Authority, whether in the report provided under clause 12.118 or otherwise, on its compliance with the requirements of the Outage Protocol, including the requirements specified in clause 12.140(1) for giving effect to the net benefit principle specified in clause 12.140(2) and the requirements of the Outage Protocol relating to unplanned outages specified in clause 12.143.

Compare: Electricity Governance Rules 2003 rule 7 section VII part F

Decisions on Outage Protocol

12.145 Authority may initially approve the proposed Outage Protocol or refer back to Transpower
After consideration of Transpower’s proposed Outage Protocol and accompanying explanation and statement of proposal, the Authority may—
(a) provisionally approve the proposed Outage Protocol having regard to the principles in clause 12.134 and the matters set out in clauses 12.135 to 12.144; or
(b) refer the proposed Outage Protocol and accompanying explanation and regulatory statement back to Transpower, if in the Authority’s view—

(i) the proposed Outage Protocol does not adequately give effect to or promote the principles in clause 12.134; or

(ii) the proposed Outage Protocol does not adequately provide for the matters set out in clauses 12.135 to 12.144; or

(iii) the explanation or statement of proposal provided with the Outage Protocol in accordance with clause 12.133(3) is not adequate—

and Transpower must, within 20 business days (or such longer period as the Authority may allow), consider the Authority’s concerns and resubmit its proposed Outage Protocol and accompanying explanation and statement of proposal for reconsideration by the Authority.

Compare: Electricity Governance Rules 2003 rule 9 section VII part F

12.146 Reconsideration of revised Outage Protocol by the Authority

After reconsideration of Transpower’s proposed Outage Protocol, and accompanying explanation and statement of proposal, as revised under clause 12.145(b), the Authority may either—

(a) provisionally approve the proposed Outage Protocol, as revised, having regard to the principles in clause 12.134 and the matters set out in clauses 12.135 to 12.144; or

(b) if the Authority considers that the Outage Protocol resubmitted by Transpower under clause 12.145(b) does not adequately give effect to or promote the principles in clause 12.134, or adequately provide for the matters set out in clauses 12.135 to 12.144, the Authority may make any amendments to the proposed Outage Protocol, as revised, that it considers necessary.

Compare: Electricity Governance Rules 2003 rule 10 section VII part F

12.147 Authority must consult on the proposed Outage Protocol

The Authority must publish the proposed Outage Protocol, either as provisionally approved by the Authority or as amended by the Authority, as soon as is practicable, for consultation with any person that the Authority thinks is likely to be materially affected by the proposed Outage Protocol.

Compare: Electricity Governance Rules 2003 rule 11 section VII part F

12.148 Authority may undertake additional consultation

As well as the consultation required under clause 12.147, the Authority may undertake any other consultation it considers necessary.

Compare: Electricity Governance Rules 2003 rule 12 section VII part F

12.149 Decision on Outage Protocol

(1) When the Authority has completed its consultation on the proposed Outage Protocol, it must consider whether to incorporate the proposed Outage Protocol by reference as the Outage Protocol.
(2) If the Authority decides to incorporate the Outage Protocol by reference in this Code, the Authority must determine a date on which the incorporation by reference takes effect and comply with Schedule 1 of the Act in relation to it.

Compare: Electricity Governance Rules 2003 rule 13 section VII part F

12.150 Incorporation of Outage Protocol by reference

(1) The Outage Protocol is incorporated by reference in this Code in accordance with section 32 of the Act.

(2) Subclause (1) is subject to Schedule 1 of the Act, which includes a requirement that the Authority must give notice in the Gazette before an amendment or substituted Outage Protocol becomes incorporated by reference in this Code.


Complying with Outage Protocol

12.151 Compliance with Outage Protocol

(1) Transpower and each designated transmission customer must comply with the Outage Protocol, unless agreed otherwise by Transpower and a designated transmission customer in respect of specified assets or the designated transmission customer in accordance with subclause (2).

(2) An agreement between Transpower and a designated transmission customer to which the Outage Protocol does not apply in respect of specified assets must not exclude the application of subclause (3)(b) and must be conditional in all respects on—

(a) obtaining agreement from all other potentially affected designated transmission customers that the Outage Protocol does not apply in respect of the specified assets or the designated transmission customer; and

(b) Transpower and the designated transmission customer satisfying the Authority that they have consulted with all potentially affected end use customers on the Outage Protocol not applying in respect of the specified assets or the designated transmission customer and that there are no material unresolved issues affecting the interests of those end use customers.

(3) Transpower must—

(a) give written notice to the Authority as soon as practicable if Transpower enters into an agreement with a designated transmission customer under this clause; and

(b) publish the agreement no later than 20 business days after entering into the agreement.

Compare: Electricity Governance Rules 2003 rule 15 section VII part F


Schedule 12.1
Categories of designated transmission customers

1 Categories of designated transmission customers required to enter into transmission agreements with Transpower

(1) The categories of designated transmission customers required to enter into transmission agreements with Transpower are—

(a) connected asset owners; and

(b) [Revoked]

(c) generators that are directly connected to the grid.

(2) [Revoked]

(3) [Revoked]

(4) [Revoked]

(5) [Revoked]

Compare: Electricity Governance Rules 2003 schedule F1 part F
Schedule 12.1, clause 1(2) to (5): revoked, on 16 December 2013, by clause 9(2) of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.
Schedule 12.2
Grid reliability standards

1 Preamble
Clause 12.55 of this Code, requires the Authority to determine the most appropriate grid reliability standards and in so doing must have regard to the purposes in clause 12.56 and the principles set out in clause 12.57, as required by clause 12.55.

Compare: Electricity Governance Rules 2003 clause 2 schedule F3 part F

2 The grid reliability standards
(1) The purpose of the grid reliability standards is to provide a basis for Transpower and other parties to appraise opportunities for transmission investments and transmission alternatives.

(2) For the purpose of subclause (1), the grid satisfies the grid reliability standards if—
   (a) the power system is reasonably expected to achieve a level of reliability at or above the level that would be achieved if all economic reliability investments were to be implemented; and
   (b) with all assets that are reasonably expected to be in service, the power system would remain in a satisfactory state during and following a single credible contingency event occurring on the core grid.

(3) For the purpose of subclause (2)(a), the expected level of reliability of the power system must be assessed at each and every grid exit point and grid injection point (wherever located on the grid).

(4) For the purpose of subclause (2)(a) and (b), the expected level of reliability, and state, of the power system must be assessed using the range of relevant operating conditions that could reasonably be expected to occur.

Compare: Electricity Governance Rules 2003 clauses 3 to 6 schedule F3 part F

3 Interpretation and definitions
(1) For the purposes of these grid reliability standards, unless the context calls for another interpretation—
   (a) the terms defined in Part 1 of this Code take that defined meaning; and
   (b) the term defined in subclause (2) takes that defined meaning; and
   (c) a reference—
      (i) to the singular includes the plural and conversely; and
      (ii) to a person includes an individual, company, other body corporate, association, partnership, firm, joint venture, trust, or Government Agency; and
   (d) the word including or includes means including, but not limited to, or includes, without limitation; and
   (e) the other grammatical forms of the term defined in subclause (2) have a corresponding meaning.

(2) Economic reliability investments means investments in the grid and transmission.
alternatives that would satisfy the economic test for an investment proposal applied by the Commerce Commission under Part 4 of the Commerce Act 1986—
(a) assuming that the economic test was applied to both investments in the grid and transmission alternatives; and
(b) having regard to Parts 7 and 8 (including the policy statement).

Compare: Electricity Governance Rules 2003 clauses 7 and 8 schedule F3 part F

4 Value of expected unserved energy
(1) The value of any expected unserved energy is—
(a) $20,000 per MWh; or
(b) such other value as the Authority may determine.
(2) The Authority may determine different values of expected unserved energy under this clause for different purposes and for different times.
(3) If the Authority determines a value of expected unserved energy under this clause, the Authority must publish its determination.

Schedule 12.3

Core grid determination

1 Background
Clause 12.63 of this Code, requires the Authority to determine the most appropriate core grid determination and in so doing to have regard to the purposes set out in clause 12.64, the principles set out in clause 12.57 for the grid reliability standards and the objectives set out in clause 12.65.

Compare: Electricity Governance Rules 2003 clause 2 schedule F3A part F

2 The core grid determination
(1) The purpose of this core grid determination is to define the core grid for the purposes of the grid reliability standards and so provide a basis for—
   (a) the Authority to determine the grid reliability standards; and
   (b) Transpower and other parties to appraise opportunities for transmission investment and transmission alternatives.
(2) The core grid consists of those assets that comprise the transmission links listed in Table 1 below:

Table 1

<table>
<thead>
<tr>
<th>North Island core grid links</th>
<th>South Island core grid links</th>
</tr>
</thead>
<tbody>
<tr>
<td>220kV Huapai-Marsden</td>
<td>220kV Islington-Kikiwa</td>
</tr>
<tr>
<td>220kV Huapai-Bream Bay</td>
<td>220kV Kikiwa-Stoke</td>
</tr>
<tr>
<td>220kV Bream Bay-Marsden</td>
<td>220kV Twizel-Tekapo B</td>
</tr>
<tr>
<td>110kV Marsden-Maungatapere</td>
<td>220kV Tekapo B-Islington</td>
</tr>
<tr>
<td>220 kV Henderson-Huapai</td>
<td>220kV Twizel-Opihi-Timaru-Ashburton</td>
</tr>
<tr>
<td>220 kV Albany-Huapai</td>
<td>220kV Ashburton-Bromley</td>
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<tr>
<td>220 kV Albany-Henderson</td>
<td>220kV Bromley-Islington</td>
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<tr>
<td>110kV Albany-Henderson</td>
<td>220kV Twizel-Opihi-Timaru-Islington</td>
</tr>
<tr>
<td>110kV Henderson-Hepburn Rd</td>
<td>220kV Livingstone-Islington</td>
</tr>
<tr>
<td>220kV Otahuhu-Henderson</td>
<td>220kV Benmore-Ohau B</td>
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<tr>
<td>220kV Otahuhu-Southdown</td>
<td>220kV Ohau B-Twizel</td>
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<td>220kV Southdown-Henderson</td>
<td>220kV Benmore-Twizel</td>
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<tr>
<td>220kV Otahuhu-Penrose</td>
<td>220kV Benmore-Ohau C</td>
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<tr>
<td>110kV Mangere-Roskill</td>
<td>220kV Ohau C-Twizel</td>
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<td>110kV Otahuhu-Roskill</td>
<td>220kV Benmore-Aviemore</td>
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<td>110kV Otahuhu-Pakuranga</td>
<td>220kV Clyde-Cromwell</td>
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<td>110kV Otahuhu-Wiri</td>
<td>220kV Cromwell-Twizel</td>
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<tr>
<td>220kV Otahuhu-Takanini</td>
<td>220kV Roxburgh-Clyde</td>
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<tr>
<td>220kV Huntly-Takanini</td>
<td>220kV Naseby-Livingstone</td>
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<tr>
<td>110kV Wiri-Bombay</td>
<td>220kV Roxburgh-Naseby</td>
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<tr>
<td>220kV Huntly-Glenbrook</td>
<td>220kV Roxburgh-Three Mile Hill</td>
</tr>
</tbody>
</table>
## North Island core grid links

<table>
<thead>
<tr>
<th>Link Description</th>
<th>South Island core grid links</th>
</tr>
</thead>
<tbody>
<tr>
<td>220kV Glenbrook-Takanini</td>
<td>220kV Three Mile Hill-Half Way Bush</td>
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<tr>
<td>220kV Otahuhu-Whakamaru</td>
<td>220kV Three Mile Hill-Sth Dunedin</td>
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<tr>
<td>220kV Otahuhu-Huntly</td>
<td>220kV Sth Dunedin-Half Way Bush</td>
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<td>220kV Huntly-Hamilton</td>
<td>220kV Manapouri-Invercargill</td>
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<td>220kV Manapouri-Nth Makarewa</td>
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<td>220kV Nth Makarewa-Invercargill</td>
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<td>220kV Tarukenga-Edgecumbe</td>
<td>220kV Invercargill-Roxburgh</td>
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<td>220kV Edgecumbe-Kawerau</td>
<td>220kV Invercargill-Tiwi Pt</td>
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<td>220kV Kawerau-Ohakuri</td>
<td>220kV Nth Makarewa-Tiwi Pt</td>
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<tr>
<td>220kV Wairakei-Ohakuri</td>
<td>220/66kV interconnection Islington</td>
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<td>220kV Ohakuri-Atiamuri</td>
<td>66kV Islington-Addington</td>
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<td>220/66kV interconnection Bromley</td>
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<td>220kV Atiamuri-Whakamaru</td>
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<td>220kV Wairakei-Redclyffe</td>
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<td>220kV Wairakei-Whirinaki</td>
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<td>220kV Whirinaki-Redclyffe</td>
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<td>220kV Rangipo-Tangiwhai</td>
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<td>220kV Rangipo-Wairakei</td>
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<td>220kV Wairakei-Poihipi</td>
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<td>220kV Poihipi-Whakamaru</td>
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<tr>
<td>220kV Stratford-New Plymouth</td>
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<tr>
<td>110kV New Plymouth-Carrington St</td>
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<td>220kV Bunnythorpe-Haywards</td>
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<td>220kV Haywards-Wilton</td>
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<td>220kV Haywards-Linton</td>
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<td>220kV Wilton-Linton</td>
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<tr>
<td>220kV Bunnythorpe-Linton</td>
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<td>110kV Wilton-Central Park</td>
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<td>110kV Takapu Rd-Wilton</td>
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<td>220kV Bunnythorpe-Brunswick</td>
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<td>220kV Brunswick-Stratford</td>
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<td>110kV Otahuhu-Mangere</td>
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<td>110kV Haywards-Takapu Rd</td>
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<td>220/110kV interconnection Marsden</td>
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<td>220/110kV interconnection Hamilton</td>
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</table>
### North Island core grid links
- 220/110kV interconnection Tarukenga
- 220/110kV interconnection New Plymouth
- 220/110kV interconnection Stratford
- 220/110kV interconnection Redclyffe
- 220/110kV interconnection Bunnythorpe
- 220/110kV interconnection Haywards
- 220/110kV interconnection Wilton

### South Island core grid links

3 **Interpretation**

For the purposes of this *core grid determination*, unless the context calls for another interpretation, a term has the meaning given to that term in the *grid reliability standards*.

Compare: Electricity Governance Rules 2003 clause 5 schedule F3A part F
1 **Introduction**

The transmission pricing methodology is used to recover the full economic costs of Transpower’s services, with the exception of investment contracts entered into under clauses 12.70 and 12.71 of this Code, existing new investment contracts and other contracts of the kind referred to in clause 12.95 of this Code. The full economic costs of Transpower’s services include costs relating to investments which are not subject to approval by the Commerce Commission under section 54R of the Commerce Act 1986 or to which the input methodology under section 54S of that Act applies.

Compare: Electricity Governance Rules 2003 clause 1 schedule F5 part F

2 **Overview of the Pricing Methodology**—

(1) Transpower's principal objective as a State Owned Enterprise is to operate as a successful business. To this end Transpower's pricing must, subject to Part 4 of the Commerce Act 1986, recover the costs of providing its transmission services, which include capital, maintenance, operating and overhead costs. Before the start of each pricing year, Transpower's Board approves forecasts of—

   (a) the revenue required to recover the costs of providing AC transmission services during the pricing year. This forecast is referred to as the AC revenue for that pricing year; and

   (b) the revenue required to recover the costs of providing the HVDC assets during the pricing year. This forecast is referred to as the HVDC revenue for that pricing year.

(2) The transmission pricing methodology comprises—

   (a) connection charges, which recover part of Transpower's AC revenue by reference to the cost of providing connection assets. Clauses 8 to 26 describe how connection charges are calculated;

   (b) interconnection charges, which recover the remainder of Transpower's AC revenue. Clauses 27 to 30 describe how interconnection charges are calculated; and

   (c) HVDC charges, which recover Transpower's HVDC revenue. Clauses 31 to 33D describe how HVDC charges are calculated.

(3) An overview of how Transpower's AC revenue and HVDC revenue are recovered through these charges is shown in diagrammatic form in Appendix A.

(4) The transmission pricing methodology also describes—

   (a) how the costs of transmission alternative services are charged and recovered, if and when transmission alternatives services are provided and/or funded by Transpower (clause 35); and

   (b) practical ways to facilitate greater transparency in relation to Transpower’s prudent discount policy, which helps to ensure that the transmission pricing
methodology does not provide incentives for inefficient by-pass of the existing grid (clauses 36 to 42).


3 Definitions and interpretation
Unless the context otherwise requires—

AC asset means a grid asset other than an HVDC asset

AC revenue has the meaning set out in clause 2(1)

AC switch means a switch that is an AC asset

alternative project means an investment proposed by a customer, which if implemented, would bypass existing grid assets, but does not include proposed new generation

annual charges means any or all of the annual connection charge, annual interconnection charge and annual HVDC charge for a customer at a connection location for a pricing year

annual connection charge has the meaning set out in clause 8(2)

annual HVDC charge has the meaning set out in clause 31

annual interconnection charge has the meaning set out in clause 27

anytime maximum demand or AMD for a customer at a connection location means the average of the 12 highest offtake quantities for that customer at that connection location during the capacity measurement period for the relevant pricing year. This definition is subject to clause 34 of this transmission pricing methodology and any prudent discount agreement

anytime maximum injection or AMI for a customer at a connection location means the average of the 12 highest injection quantities for that customer at that connection location during the capacity measurement period for the relevant pricing year. This definition is subject to clause 34 of this transmission pricing methodology and any prudent discount agreement

capacity measurement period means, for a pricing year—

(a) for every purpose other than determining regional peak demand periods for the Lower South Island, Lower North Island and Upper North Island, the 12 month period commencing 1 September and ending with the close of 31 August, immediately before the commencement of the pricing year:

(b) for the purpose of determining regional peak demand periods for the Lower South Island, Lower North Island, and Upper North Island, the period specified in
paragraph (a), excluding within that period the period commencing 1 November and ending with the close of 30 April

Schedule 12.4, clause 3, capacity measurement period: replaced, on 1 April 2017, by clause 5(1)(a) of the Electricity Industry Participation Code Amendment (Transmission Pricing) 2015.

connection asset has the meaning set out in clause 6(1)

connection link has the meaning set out in clause 5(c)

connection location means the substation or other location at which a customer's assets are directly connected to the grid


connection node has the meaning set out in clause 5(b)

customer means a person who has or controls assets directly connected to the grid and, in relation to a connection location, means a person who has or controls assets directly connected to the grid at that connection location. A customer may be both an offtake customer and an injection customer at the same connection location


customer allocation has the meaning set out in clause 25(1)

financial year means the financial year adopted by Transpower from time to time, being a 12 month period or such other period as Transpower determines.

Transpower's current financial year is a 12 month period from 1 July to 30 June

grid assets means assets and other works (including land and buildings) owned or operated by Transpower, which form part of the grid or are required to support the grid

GXP tie means a situation in which GXPs are simultaneously connected to the grid at more than 1 point of connection

Schedule 12.4, clause 3, GXP tie: inserted, on 1 April 2017, by clause 5(2) of the Electricity Industry Participation Code Amendment (Transmission Pricing) 2015.

historical anytime maximum injection or HAMI is the value calculated under clauses 33D and 34

Schedule 12.4, clause 3, historical anytime maximum injection or HAMI: replaced, on 1 April 2017, by clause 5(1)(b) of the Electricity Industry Participation Code Amendment (Transmission Pricing) 2015.

HVDC assets means the HVDC link and all land and buildings associated with the HVDC link

HVDC customer means a customer who is, from time to time, the owner or operator of—

(a) South Island generation which is directly connected to the grid assets; or

(b) a local network to which South Island generation is connected, either directly or indirectly;


HVDC revenue has the meaning set out in clause 2(1)
independent expert means an independent person who is a recognised technical expert in the matter that has been referred to him or her. In appointing an independent expert the party referring the matter to the independent expert must nominate 3 persons and the other party may agree that any one of them be appointed. Failing agreement between the parties, the independent expert will be appointed by the Authority

injection means the net quantity of electricity flow into the grid at a connection location from a customer’s assets during a half hour determined from metering information. This definition is subject to clause 34 of this transmission pricing methodology and any prudent discount agreement

injection customer means, subject to clause 34, in relation to a connection location, a customer who has or controls assets from which electricity flowed into the grid at that connection location in any half hour during the capacity measurement period for the relevant pricing year or, if the connection location is a South Island generation connection location, an HVDC customer who has or controls assets from which electricity flowed into the grid at the South Island generation connection location in any half hour during the capacity measurement period for the relevant pricing year or a capacity measurement period for any of the 4 immediately preceding capacity measurement periods

interconnection asset has the meaning set out in clause 6(2)

interconnection link has the meaning set out in clause 5(d)

interconnection node has the meaning set out in clause 5(a)

land and buildings means any and all land or interest in land (including easements) acquired by Transpower for the purposes of establishing a connection location or substation, or for supporting grid assets, together with all buildings, oil containment facilities and the capitalised cost of establishing a connection location or substation or other grid asset (as the case may be)

link has the meaning set out in clause 4(3)

monthly charges means any or all of the monthly connection charge, monthly interconnection charge and monthly HVDC charge for a customer at a connection location

monthly connection charge has the meaning set out in clause 8(2)

monthly HVDC charge has the meaning set out in clause 31

monthly interconnection charge has the meaning set out in clause 27

new investment contract means a contract entered into at any time between Transpower and a customer of Transpower, under which Transpower agrees to provide any new or upgraded grid assets and the customer agrees to pay charges based on Transpower’s cost of providing the new or upgraded grid assets. It includes, but is not limited to a new investment agreement contract as defined in Part 1 of this Code

node has the meaning set out in clause 4(1)
**offtake** means the net quantity of **electricity** flow out of the **grid** at a **connection location** into **customer assets** during a **half hour** determined from **metering information**. This definition is subject to clause 34 of this transmission pricing methodology and any prudent discount agreement.

**offtake customer** means, subject to clause 34, in relation to a **connection location**, a **customer** who has or controls assets into which electricity flowed from the **grid** at that **connection location** in any **half hour** during the **capacity measurement period** for the relevant **pricing year**.

**optimised replacement cost** means, for any assets or group of assets, the optimised replacement cost of that asset or group of assets recorded in a Transpower asset register as at the **transition date**.

**point of injection** means a **connection location** at which an **injection customer** has assets **connected** to the **grid**.

Schedule 12.4, clause 3, **point of injection**: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

**pricing year** means the period from April 1 to March 31, in respect of which Transpower calculates its prices.

**region** means a group of **connection locations**, being one of the groups described in Appendix B as—

(a) Upper North Island; and

(b) Lower North Island; and

(c) Upper South Island; and

(d) Lower South Island.

Schedule 12.4, clause 3, **region**: amended, on 1 April 2017, by clause 5(3) of the Electricity Industry Participation Code Amendment (Transmission Pricing) 2015.

**regional coincident peak demand** or **RCPD** for a **customer** at a **connection location** means the **customer's offtake** at that **connection location** during a **regional peak demand period**. This definition is subject to clause 34 of this transmission pricing methodology and any prudent discount agreement.

Schedule 12.4, clause 3 **regional coincident peak demand**: inserted, on 15 May 2014, by clause 34(b) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

**regional demand** means, in any **half hour**, the sum over all **customers** at all **connection locations** in a **region** of all **offtake** quantities at those **connection locations**.

**regional peak demand period** means, for each **region**, a **half hour** in which any of the 100 highest **regional demands** occur in the **region** during a **capacity measurement period** for the relevant **pricing year**. This definition is subject to clause 34 of this transmission pricing methodology and any prudent discount agreement.

Schedule 12.4, clause 3 **regional peak demand period**: replaced, on 1 April 2017, by clause 5(1)(c) of the Electricity Industry Participation Code Amendment (Transmission Pricing) 2015.

**regional coincident peak** [Revoked]

replacement cost means—

(a) for a connection asset commissioned before the transition date, the cost of replacing that asset (either separately or as part of a group of assets) with a modern equivalent asset with the same service potential, multiplied by the replacement cost adjustment factor; and

(b) for any other grid asset, the cost of replacing that asset (either separately or as part of a group of assets) with a modern equivalent asset with the same service potential,

as determined by Transpower and (unless stated otherwise) recorded in a Transpower asset register;

replacement cost adjustment factor means for any asset (or group of assets) the percentage which is the optimised replacement cost divided by the cost, as at (or about) the transition date, of replacing that asset (or group of assets) with the then modern equivalent asset with the same service potential

reverse flow means electricity exiting the grid at a GXP and entering the grid at another GXP as a result of a GXP tie

South Island generation means, subject to clause 34, any generating unit or generating station located in the South Island, which:

(a) is directly connected to the grid or is connected to a local network which is connected (directly or indirectly) to the grid; and

(b) has (directly or indirectly) injected electricity into the grid at any time during any capacity measurement period for all or any of the previous 5 pricing years

South Island generation connection location means any connection location at which South Island generation is connected to the grid either directly, or indirectly via connection of a local network, to which South Island generation is in turn either directly or indirectly connected substation means a substation, including all land and buildings, switches, transformers, revenue meters and all other assets comprising or located at that substation

South Island mean injection or SIMI is the value calculated under clauses 33B and 34

transition date means the date of the last ODV report published by Transpower before the date on which this transmission pricing methodology takes effect
weighted average cost of capital means, for any pricing year, the pre-tax nominal weighted average cost of capital used by Transpower to determine AC revenue or HVDC revenue (as the case may be) for that pricing year.

Compare: Electricity Governance Rules 2003 clauses 3.1 to 3.53 schedule F5 part F

4 Definition of Nodes and Links

(1) A node is any of the following:
   (a) a connection location:
   (b) a location where a circuit, which is connected to 2 or more other nodes, diverges or terminates (such as a “tee” point or a deviation):
   (c) any substation or switching station.

(2) Any node which connects with 1 or more multiple circuits on the same towers or poles where at least 1 of those circuits deviates or terminates at that node is treated as a single node encompassing all of those circuits at that location.

Figure 1: Illustration of definition of a node

(3) A link is either a single circuit or multiple parallel circuits (of the same voltage) connecting 2 nodes (and includes any grid assets, such as circuit breakers, that are required to connect the link at either node).

(4) Figures 1 and 2 illustrate how nodes and links are identified. In Figure 1, A, B, C, D, E, F and G are all nodes. C is a single node, because 1 of the circuits of the link AC terminates at C. AC, CD (and DE, EF, FG and GD) and BC are separate links, although AB may be recorded as a single line in a Transpower asset register. Figure 2 shows the same configuration as Figure 1 but describes the circuits by way of links.
5 Identification of Nodes and Links as Connection or Interconnection

Nodes and links are identified as **connection nodes** or **connection links** or **interconnection nodes** or **interconnection links** according to the following:

(a) an **interconnection node** is any **node connected** to 2 or more **nodes** in a “loop”, other than a “small regional loop”. A loop is a continuous path of **nodes** and **links** with the same start and end **node**. A “small regional loop” is where a loop path exists between any group of **nodes** (excluding the **nodes** at Benmore and Haywards) with only a single **link** from the loop back to the next **node** that is outside the loop (see Figure 3 below):

(b) a **connection node** is any **node** that is not an **interconnection node**:

Figure 3 – Example of a small regional loop
6 Definition of Connection Assets and Interconnection Assets

(1) A connection asset is—

(a) any grid asset at a connection node other than voltage support equipment that is for grid voltage support purposes and has not been installed at a customer's request; and

(b) at an interconnection node that is a connection location,—

(i) any grid asset that is specifically required to connect a customer, including a supply transformer, feeder bay or supply transformer high voltage or low voltage breaker. Low voltage breakers, low voltage bus section breakers, voltage transformers, revenue meters and other equipment where they are on the same bus as the feeders are also connection assets; and

(ii) any grid asset that is used both to connect a customer (whether injection or offtake) and for grid operation generally; and

(iii) a proportion of the land and buildings at that connection location. The proportion of land and buildings defined as a connection asset is that proportion which the replacement cost of the connection assets identified in subparagraph (i) but excluding land and buildings, bears to the replacement cost of all grid assets (excluding land and buildings) at the connection location; and

(c) any grid asset that is a connection link. A single line, recorded as such in a Transpower asset register, may form part of more than 1 link, so that a portion of a line may be identified as a connection asset with the remaining portion identified as an interconnection asset. For example, in Figure 1, if a line AB were recorded in a Transpower asset register, it would form part of a connection link BC and an interconnection link AC. If part of a line is, or forms part of, a connection link, the value and costs ascribed to the connection link for the purposes of calculating connection charges is the same proportion that the ratio of the length of the connection link bears to the total length of the line.

(2) An interconnection asset is any grid asset that is not a connection asset, or an HVDC asset.

(3) A connection asset which connects a customer's assets at a connection location to the interconnection assets is referred to as a connection asset "for" or "which connects" (or other grammatical form of that phrase) that connection location or customer's assets (as the case may be).

Compare: Electricity Governance Rules 2003 clauses 3.59 to 3.61 schedule F5 part F
7 Interpretation

Unless the context otherwise requires—

(a) all defined terms are shown in bold text; and

(b) terms defined in Part 1 of this Code have that defined meaning:

(c) terms defined below and elsewhere in the text of this transmission pricing methodology take that defined meaning, and any other grammatical form of that term has a corresponding meaning; and

(d) if there is any inconsistency between the text description of a calculation for which there is formula and the particular formula, the formula takes precedence; and

(e) diagrams are for information only and do not form a binding part of this transmission pricing methodology; and

(f) a reference—

(i) to the singular includes the plural and conversely; and

(ii) to a person includes an individual, company, other body corporate, association, partnership, firm, joint venture, trust or Government agency; and

(g) the word "including" is to be read as "including, but not limited to", and the word "includes" is to be read as "includes, without limitation"; and

(h) if any matter is to be determined by Transpower or Transpower's Board, it is to be determined in Transpower's or Transpower's Board (as the case may be) sole discretion while acting at all times reasonably; and

(i) a reference to a preceding financial year is a reference to the first complete financial year that precedes the start of the pricing year in respect of which the relevant calculation is undertaken; and

(j) a reference to a prudent discount agreement includes any agreement entered into under the prudent discount policy in clauses 36 to 42 and any agreement which has the same or similar purpose as the prudent discount policy (including a notional embedding contract) entered into between Transpower and a customer whether before or after commencement of this transmission pricing methodology.

Compare: Electricity Governance Rules 2003 clauses 3.62 to 3.71 schedule F5 part F

Connection Charges

8 Calculation of the Connection Charges

(1) A connection charge for each connection asset for a connection location is calculated for each pricing year for each customer at that connection location by multiplying the sum of the asset, maintenance, operating and (for injection customers) overhead cost components for a connection asset by the relevant customer allocation, as follows:
connection charge = (A_{conn} + M_{conn} + O_{conn} + IO_{conn}) \times CA_{conn}

where

A_{conn} is the asset component for the connection asset calculated in accordance with clauses 10 to 12

M_{conn} is the maintenance component for the connection asset calculated in accordance with clauses 13 to 17 and is M_{conn subs} or M_{conn line type} depending on the nature of the connection asset

O_{conn} is the operating component for the connection asset calculated in accordance with clauses 18 to 20

IO_{conn} is the injection overhead component for the connection asset calculated in accordance with clauses 21 to 24

CA_{conn} is the customer allocation for the connection asset for the connection location in respect of which the connection charge is being calculated, calculated in accordance with clause 25(1) and (2)(a) to (c).

(2) The sum of all connection charges calculated for a customer for all connection assets for a connection location in accordance with subclause (1) is the annual connection charge for that customer at that connection location in that pricing year. The customer's monthly connection charge at that connection location for that pricing year is (subject to clause 34 of this transmission pricing methodology) calculated as 1/12 of the annual connection charge. The example connection charge report at clause 25(3) illustrates how a customer's annual connection charge for a connection location is calculated. (3) If a customer is both an offtake customer and an injection customer at a connection location, connection charges for that connection location are calculated separately for that customer as an offtake customer and an injection customer.

Compare: Electricity Governance Rules 2003 clauses 4.1 to 4.3 schedule F5 part F
Schedule 12.4, clause 8: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

9 Calculation of Connection Charge Components

(1) Each of the asset, maintenance, operating and overhead cost components of the connection charge is calculated by reference to a rate set for that component which is then applied to the particular connection asset. Different rates may be set for different types of connection assets; for example, different rates are used to calculate the maintenance component depending on whether the connection asset is located at a substation or is a line. Different types of lines have different rates. Clauses 10 to 26 describe how the rates are set and applied to determine each component of the connection charge.
10 Asset Component
The asset component of the connection charge allocates a portion of the cost of funding all connection assets plus their depreciation to the connection asset for which the connection charge is being calculated.

11 Asset Return Rate
The asset return rate used to calculate the asset component is referred to as $ARR_{\text{conn}}$ and is expressed as a proportion. $ARR_{\text{conn}}$ is calculated by dividing the product of the weighted average cost of capital and the regulatory asset value of all connection assets plus the annual depreciation of those assets by the replacement cost of all connection assets as follows:

$$ARR_{\text{conn}} = \frac{\text{WACC} \times \text{RAV}_{\text{conn}} + D_{\text{conn}}}{\sum_{\text{conn}} \text{RC}_{\text{conn}}}$$

where

- WACC is the weighted average cost of capital (expressed as a percentage)
- $\text{RAV}_{\text{conn}}$ is the regulatory asset value of all connection assets, as determined by Transpower and recorded in a Transpower asset register (expressed in dollars)
- $D_{\text{conn}}$ is total annual depreciation of all connection assets in the preceding financial year as determined by Transpower and recorded in a Transpower asset register (expressed in dollars)
- $\sum_{\text{conn}} \text{RC}_{\text{conn}}$ is the total replacement cost of all connection assets.

12 Calculation of Asset Component
The asset component of a connection charge is calculated by multiplying $ARR_{\text{conn}}$ by the replacement cost of the connection asset for which the connection charge is being calculated as follows:
Electricity Industry Participation Code 2010
Schedule 12.4

\[ A_{\text{conn}} = ARR_{\text{conn}} \times RC_{\text{conn}} \]

where

\[ RC_{\text{conn}} \]

is the replacement cost of the connection asset for which the connection charge is being calculated (expressed in dollars).

Compare: Electricity Governance Rules 2003 clause 4.8 schedule F5 part F

13 Maintenance component

(1) The maintenance component of the connection charge allocates a portion of Transpower's total maintenance costs for all connection assets to the connection asset for which the connection charge is being calculated.

(2) Maintenance recovery rates are set separately for connection assets located at substations and for the different types of lines. The different line types (all AC) used are—
   (a) 220kV or higher voltage towerlines;
   (b) other towerlines; and
   (c) pole lines.

Compare: Electricity Governance Rules 2003 clauses 4.9 and 4.10 schedule F5 part F

14 Substation Maintenance Recovery Rate

The maintenance recovery rate used to calculate the maintenance component of the connection charge for connection assets located at substations is referred to as \( MRR_{\text{conn subs}} \) and is expressed as a proportion. \( MRR_{\text{conn subs}} \) is calculated as the average of the annual maintenance costs incurred by Transpower for all connection assets located at all substations in each of the 4 immediately preceding financial years divided by the sum of the replacement costs of all connection assets located at all substations as follows:

\[ MRR_{\text{conn subs}} = \frac{\sum \sum M_{\text{conn subs}}}{\sum \sum RC_{\text{conn subs}}} \]

where

\[ M_{\text{conn subs}} \]

is the average of the annual maintenance costs incurred by Transpower for all connection assets located at all substations in each of the 4 immediately preceding financial years, as determined by Transpower and recorded in Transpower's Maintenance Management System accounts for each of those financial years (expressed in dollars)
Schedule 12.4

15 Calculation of Maintenance Component for a Connection Asset Located at a Substation

The maintenance component of the connection charge for a connection asset located at a substation is calculated by multiplying $\text{MRR}_{\text{conn subs}}$ by the replacement cost of the connection asset for which the connection charge is being calculated as follows:

$$M_{\text{conn subs}} = M_{\text{RR conn subs}} \times RC_{\text{conn subs}}$$

where

$RC_{\text{conn subs}}$ is the replacement cost of the connection asset for which the connection charge is being calculated (expressed in dollars).

16 Line Maintenance Recovery Rate

The maintenance recovery rate used to calculate the maintenance component of the connection charge for connection assets which are lines is referred to as $\text{MRR}_{\text{conn line type}}$ and is expressed as a dollar cost per length (expressed in km) of line for each line type. $\text{MRR}_{\text{conn line type}}$ is calculated for each of the 3 types of line referred to in clause 13(2) and is the average of annual maintenance costs incurred by Transpower for all lines of the type for which $\text{MRR}_{\text{conn line type}}$ is being calculated in each of the preceding 4 financial years divided by the total line length of line of that type as follows:

$$\text{MRR}_{\text{conn line type}} = \frac{MC_{\text{conn line type}}}{TL_{\text{conn line type}}}$$

where

$MC_{\text{conn line type}}$ is the average of the annual maintenance costs incurred by Transpower for all lines of the type for which the maintenance recovery rate is being calculated in each of the 4 immediately preceding financial years, as determined by Transpower and recorded in Transpower's Maintenance Management System accounts for each of those financial years (expressed in dollars)

$TL_{\text{conn line type}}$ is the total length of line of the type for which the maintenance recovery rate is being calculated forming part of the grid assets (other than HVDC assets), as determined by Transpower and
17 Calculation of the Maintenance Component for Line Connection Assets

The maintenance component of the connection charge for a connection asset which is a line is calculated by multiplying \( M_{\text{conn line type}} \) by the length of the line which is the connection asset for which the connection charge is being calculated as follows:

\[
M_{\text{conn line type}} = M_{\text{Rconn line type}} \times L_{\text{conn line}}
\]

where

\( L_{\text{conn line}} \) is the length of the line which is the connection asset for which the connection charge is being calculated, as determined by Transpower and recorded in a Transpower asset register (expressed in km).

18 Operating Component

The operating component of the connection charge allocates a portion of Transpower's total operating cost for all AC assets to the connection asset for which the connection charge is being calculated.

19 Operating Recovery Rate

The operating recovery rate used to calculate the operating component of the connection charge is referred to as ORR and is expressed as a dollar cost per switch. ORR is calculated by dividing the cost of operating all AC switches incurred by Transpower in the preceding financial year by the total number of AC switches less the product of 0.1 multiplied by the total number of AC switches operated by customers as follows:

\[
\text{ORR} = \frac{OC}{TS}
\]

where

\( OC \) is the cost associated with operating all AC switches incurred by Transpower in the immediately preceding financial year, as determined by Transpower and recorded in its Maintenance...
Management System accounts for that financial year (expressed in dollars)

TS is the total number of AC switches, based on the number of switching devices in a substation or switching station, (as determined by Transpower and recorded in a Transpower asset register as at the end of the immediately preceding financial year) less the product of 0.1 multiplied by the total number of AC switches operated by customers.

Compare: Electricity Governance Rules 2003 clause 4.16 schedule F5 part F

20 Calculation of the Operating Component of the Connection Charge for a Connection Asset

The operating component of the connection charge for a connection asset is calculated by multiplying ORR by the number of AC switches that form part of the connection asset for which the connection charge is being calculated less the product of 0.1 multiplied by the number of AC switches within the connection asset that are operated by customers as follows:

\[ O_{\text{conn}} = \text{ORR} \times S_{\text{conn}} \]

where

\[ S_{\text{conn}} \]

is the number of switches that form part of the connection asset for which the connection charge is being calculated, (as determined by Transpower and recorded in a Transpower asset register) less the product of 0.1 multiplied by the number of AC switches within the connection asset that are operated by customers.

Compare: Electricity Governance Rules 2003 clause 4.17 schedule F5 part F

21 Injection Overhead Component

Offtake customers pay a portion of AC revenue overhead costs through the interconnection charge. Injection customers are not charged an interconnection charge, so a share of AC revenue overhead cost is allocated through their connection charges. The injection overhead component of the connection charge is calculated only for connection assets that connect a customer's assets at a point of injection to the interconnection assets and therefore applies only to injection customers.

Compare: Electricity Governance Rules 2003 clause 4.18 schedule F5 part F

22 Injection Overhead Revenue

The portion of AC overhead cost to be recovered from injection customers is referred to as \( \text{OHC}_{\text{inj}} \). \( \text{OHC}_{\text{inj}} \) is calculated by reference to the proportion that the sum of the
maintenance components for all connection assets for all points of injection bears to total maintenance costs of AC assets as follows:

\[ OHC_{eq} = OHC_{AC} \times \frac{MC_{inj}}{MC_{AC}} \]

where

- \( OHC_{AC} \) is the overhead cost component of Transpower's AC revenue for the relevant pricing year, as determined by Transpower when setting the AC revenue
- \( MC_{inj} \) is the sum of the maintenance cost of the connection assets for all points of injection in the preceding financial year, as determined by Transpower and recorded in Transpower’s Maintenance Management System accounts for that financial year
- \( MC_{AC} \) is the sum of the maintenance cost of the AC assets in the preceding financial year, as determined by Transpower and recorded in Transpower’s Maintenance Management System accounts for that financial year.

Compare: Electricity Governance Rules 2003 clause 4.19 schedule F5 part F

23 Injection Overhead Rate
The injection overhead rate used to calculate the injection overhead component of the connection charge is referred to as IOR. IOR is calculated by dividing \( OHC_{inj} \) by the sum of the proportion of the replacement cost of each connection asset connecting injection customer assets at all points of injection to the interconnection assets as follows:

\[ IOR = \frac{\sum \text{conn inj} \cdot OHC_{inj} \cdot \text{CA}_{	ext{conn inj}}}{\sum \text{conn inj} \cdot \text{RC}_{	ext{conn inj}} \cdot \text{CA}_{	ext{conn inj}}} \]

where

- \( \text{RC}_{	ext{conn inj}} \) is the replacement cost of a connection asset connecting injection customer assets at a point of injection to the interconnection assets
- \( \text{CA}_{	ext{conn inj}} \) is the customer allocation of the relevant connection asset for the relevant injection customer at the relevant connection location
- \( \sum \text{conn inj} \cdot \text{RC}_{	ext{conn inj}} \cdot \text{CA}_{	ext{conn inj}} \) is the sum of all amounts calculated as \( \text{RC}_{	ext{conn inj}} \times \text{CA}_{	ext{conn inj}} \) for all injection customers’ connection assets for all points of injection.

Compare: Electricity Governance Rules 2003 clause 4.20 schedule F5 part F
24 Injection Overhead Component

The injection overhead component of the connection charge is calculated for a connection asset for a point of injection by multiplying the IOR by the replacement cost of that connection asset for which the connection charge is being calculated as follows:

\[ IO_{\text{conn}} = \text{IOR} \times RC_{\text{conn inj}} \]

Compare: Electricity Governance Rules 2003 clause 4.21 schedule F5 part F


25 Customer Allocation

(1) Each customer at a connection location is allocated a proportion (expressed as a percentage) of each connection asset for that connection location. This percentage is referred to as the customer allocation for that connection asset at that connection location. The customer allocation is calculated in accordance with subclause (2). If a customer is both an offtake customer and an injection customer at a connection location, a customer allocation for each connection asset for that connection location will be calculated for that customer as both an offtake customer and as an injection customer.

(2) The customer allocation is calculated as follows:

(a) for a connection asset which connects only 1 connection location to interconnection assets, except for a connection asset of the kind referred to in clause (6)(1)(b)(ii), the customer allocation is the proportion that the customer's anytime maximum demand or anytime maximum injection (as the case may be) at that connection location bears to the sum of all customers' anytime maximum demands and anytime maximum injections at that connection location:

(b) for a connection asset which connects more than 1 connection location to interconnection assets, except for a connection asset of the kind referred to in clause (6)(1)(b)(ii), the customer allocation is the proportion that the customer's anytime maximum demand or anytime maximum injection (as the case may be) at that connection location bears to the sum of all customers’ anytime maximum demands and anytime maximum injections at all connection locations for that connection asset:

(c) for a connection asset of the kind referred in clause (6)(1)(b)(ii), the customer allocation is the proportion that the customer’s anytime maximum demand or anytime maximum injection (as the case may be) at the connection location bears to the total capacity of that connection asset, as specified in a Transpower asset register.

(3) The following table illustrates the calculation of an offtake customer’s annual connection charge at a particular connection location. It lists all connection assets for that connection location and the proportion of the connection charge for each of those connection assets (including the amount of each of the asset, maintenance, and
operating components of the connection charge together with the customer allocation for the relevant connection asset). The column headed "Recovery" is provided for information only and indicates whether the asset, maintenance and operating components (respectively) are recovered under this transmission pricing methodology (TPM) or under a new investment contract (NIC).

### Connection charge report

**2007 - Connection Charge Components**

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**Example figures only**

Compare: Electricity Governance Rules 2003 clauses 4.22 to 4.24 schedule F5 part F


### 26 Exceptions to the Application of the Connection Charge

1. If a connection asset is provided by Transpower under a new investment contract, in which the capital costs of that connection asset are recovered, calculation of the connection charge for that connection asset for the customer who is a party to that new investment contract (irrespective of when that agreement was entered into) is as follows:

   a. for the purposes of calculating the connection charge for that connection asset under clause 8(1), the asset component \( A_{\text{conn}} \) is $0. Recovery of the amount that would otherwise be recovered as the asset component for that connection asset is determined by, and recovered under, the new investment contract, in accordance with the provisions of the new investment contract:

   b. the maintenance component and operating component of the connection charge are calculated as per clauses 15, 17, and 20; and

   c. if the connection asset connects more than 1 connection location or it connects a connection location at which there is more than 1 customer, the customer allocation is determined in accordance with the relevant new investment contract, rather than in accordance with clause 25(2) of this transmission pricing methodology.

2. If Transpower has entered into a prudent discount agreement in which it is agreed that notional connection assets that form part of the alternative project specified in the prudent discount agreement substitute for connection assets at a connection location, then for the purposes of clause 8(1) the customer’s customer allocation for the connection assets so substituted is deemed to be 0.
(3) If a customer is connected at a connection location subject to an input connection contract, the following apply:

(a) those assets that the customer uses to connect at that connection location will not be included in the calculation of the total connection charge for that connection location;

(b) the customer will be charged in accordance with the terms of the applicable input connection contract.

Compare: Electricity Governance Rules 2003 clauses 4.25 to 4.27 schedule F5 part F

Interconnection Charge

27 Interconnection Charge
The purpose of the interconnection charge is to recover the remainder of Transpower's AC revenue that is not recovered via connection charges. Monthly interconnection charges are paid by offtake customers in respect of each connection location at which they have assets connected to the grid. An annual interconnection charge is calculated for each customer at a connection location in accordance with clauses 28 to 30. A customer's monthly interconnection charge at that connection location is \(\frac{1}{12}\) of the annual interconnection charge, subject to clause 34 of this transmission pricing methodology.

Compare: Electricity Governance Rules 2003 clause 5.1 schedule F5 part F

28 Interconnection Revenue
The portion of AC revenue to be recovered by interconnection charges is calculated as the difference between Transpower's AC revenue and the amounts recovered by the connection charges for that pricing year as follows:

\[
R_{IC} = \text{AC revenue} - \sum \text{connection charges}
\]

where

\(\text{AC revenue}\) is Transpower's AC revenue for the relevant pricing year

\(\sum \text{connection charges}\) is the sum of all connection charges calculated for the relevant pricing year.

Compare: Electricity Governance Rules 2003 clause 5.2 schedule F5 part F

29 Interconnection Rate
The interconnection rate used to determine the annual interconnection charge is referred to as IR and is the same for all offtake customers at all connection locations in all regions. The IR is calculated by dividing the interconnection revenue by the sum
of the average of the RCPDs for each customer at a connection location for all customers at all connection locations for all regions as follows:

\[ IR = \frac{R_{IC}}{\sum_{\text{regions}} \sum_{\text{cust}} \sum_{\text{loc}} \frac{1}{N_{\text{reg}}} \sum_{i=1}^{N_{\text{regions}}} RCPD_i} \]

where

\( R_{IC} \) is the interconnection revenue calculated in accordance with clause 28

\[ \sum_{\text{regions}} \sum_{\text{cust}} \sum_{\text{loc}} \frac{1}{N_{\text{reg}}} \sum_{i=1}^{N_{\text{regions}}} RCPD_i \] is the sum of the average RCPDs for each customer at a connection location for all customers at all connection locations for all regions.

Compare: Electricity Governance Rules 2003 clause 5.3 schedule F5 part F

30 Calculating the Interconnection Charge
An annual interconnection charge is calculated for each offtake customer at a connection location by multiplying the interconnection rate by the sum of the customer’s RCPD at a connection location as follows:

\[ \text{interconnection charge} = IR \times \frac{1}{N_{\text{reg}}} \sum_{i=1}^{N_{\text{regions}}} RCPD_i \]

where

\( IR \) is IR

\[ \frac{1}{N_{\text{reg}}} \sum_{i=1}^{N_{\text{regions}}} RCPD_i \] the average RCPD for the offtake customer in respect of whom the interconnection charge is being calculated at the relevant connection locations.

Compare: Electricity Governance Rules 2003 clause 5.4 schedule F5 part F

HVDC charge

31 HVDC Charge
The purpose of the HVDC charge is to recover Transpower's HVDC revenue. HVDC charges are paid by all HVDC customers. An annual HVDC charge is calculated for each HVDC customer at each South Island generation connection location. The monthly HVDC charge is 1/12 of the annual HVDC charge subject to clause 34 of this transmission pricing methodology.

Compare: Electricity Governance Rules 2003 clause 6.1 schedule F5 part F

32 HVDC Rate
[Revoked]

Compare: Electricity Governance Rules 2003 clause 6.2 schedule F5 part F

Schedule 12.4, clause 32: revoked, on 1 April 2017, by clause 7 of the Electricity Industry Participation Code
33 Calculating the HVDC charge

The annual HVDC charge is calculated for each HVDC customer at each South Island generation connection location as follows:

\[
\text{HVDC charge} = (\text{DCR}_\text{SIMI} \times \text{SIMI}) + (\text{DCR}_\text{HAMI} \times \text{HAMI})
\]

where

- **DCR\text{SIMI}** is the SIMI-based rate calculated in accordance with clause 33A, in $/\text{MWh}$
- **SIMI** is the South Island mean injection for the HVDC customer at the South Island generation connection location calculated in accordance with clause 33B, in \text{MWh}
- **DCR\text{HAMI}** is the HAMI-based rate calculated in accordance with clause 33C, in $/\text{kW}$
- **HAMI** is the historical anytime maximum injection for the HVDC customer at the South Island generation connection location as calculated in accordance with clause 33D, in kW.


33A SIMI-based rate

The SIMI-based rate is calculated for each pricing year by dividing HVDC revenue by the sum of the SIMI of all HVDC customers at all South Island generation connection locations, as follows:

\[
\text{DCR}_\text{SIMI} = \left( i \right) \frac{\text{R}_{\text{HVDC}}}{\sum \text{SIMI}}
\]

Where

- **DCR\text{SIMI}** is the SIMI-based rate for the relevant pricing year, in $/\text{MWh}$
- **R\text{HVDC}** is HVDC revenue for the relevant pricing year, in dollars
- **\sum \text{SIMI}** is the sum of the SIMI of all HVDC customers at all South Island generation connection locations for the relevant pricing year, in \text{MWh}.
Schedule 12.4, clause 33A: inserted, on 1 April 2017, by clause 8 of the Electricity Industry Participation Code Amendment (Transmission Pricing) 2015.

33B Calculation of South Island mean injection

South Island mean injection or SIMI is calculated for each HVDC customer at each South Island generation connection location for a pricing year, and is the average of the total injection from the HVDC customer’s assets at the South Island generation connection location in the capacity measurement period for the pricing year and the capacity measurement periods for previous pricing years, as follows:

\[
SIMI = \frac{\sum \text{injection}}{1 + p}
\]

Where

- SIMI is the HVDC customer’s South Island mean injection for the relevant pricing year, in MWh
- \(\sum \text{injection}\) is the total injection from the HVDC customer’s assets at the South Island generation connection location in the capacity measurement period for the pricing year for which SIMI is being calculated and the capacity measurement periods for the \(p\) immediately preceding pricing years, in MWh

\(P\)

- for the pricing year 2017/18 \(p=0\)
- for the pricing year 2018/19 \(p=1\)
- for the pricing year 2019/20 \(p=2\)
- for the pricing year 2020/21 \(p=3\)
- for each subsequent pricing year \(p=4\).

Schedule 12.4, clause 33B: inserted, on 1 April 2017, by clause 8 of the Electricity Industry Participation Code Amendment (Transmission Pricing) 2015.

33C HAMI-based rate

The HAMI-based rate is calculated for each pricing year by dividing HVDC revenue by the sum of the HAMI for all HVDC customers at all South Island generation connection locations for the relevant pricing year, as follows:

\[
DCR_{\text{HAMI}} = \left(\frac{4-i}{4}\right)^{\frac{R_{\text{HVDC}}}{\sum HAMI}}
\]

Where

- DCR_{\text{HAMI}} is the HAMI-based rate for the relevant pricing year, in $/kW
- \(I\)
  - for the pricing year 2017/18 \(i=1\)
  - for the pricing year 2018/19 \(i=2\)
  - for the pricing year 2019/20 \(i=3\)
for each subsequent pricing year \( i = 4 \)

\[ R_{HVDC} \]

is HVDC revenue for the relevant pricing year, in dollars

\[ \sum HAMI \]

is the sum of the HAMI of all HVDC customers at all South Island generation connection locations for the relevant pricing year, in kW.

Schedule 12.4, clause 33C: inserted, on 1 April 2017, by clause 8 of the Electricity Industry Participation Code Amendment (Transmission Pricing) 2015.

33D Calculation of historical anytime maximum injection

Historical anytime maximum injection or HAMI is calculated for each HVDC customer at each South Island generation connection location for a pricing year, and is—

(a) for the pricing year 2017/18, the greater of the following:
   (i) the average of the customer's 12 highest injections at the connection location during the pricing year 2013/14;
   (ii) the average of the customer's 12 highest injections at the connection location during the pricing year 2014/15;
   (iii) the average of the customer's 12 highest injections at the connection location during the period commencing on 1 April 2015 and ending with the close of 31 August 2015;
   (iv) the average of the customer's 12 highest injections at the connection location during the capacity measurement period for the pricing year 2016/17; and

(b) for the pricing year 2018/19, the greater of the following:
   (i) the average of the customer's 12 highest injections at the connection location during the pricing year 2014/15;
   (ii) the average of the customer's 12 highest injections at the connection location during the period commencing on 1 April 2015 and ending with the close of 31 August 2015;
   (iii) the average of the customer's 12 highest injections at the connection location during the capacity measurement period for the pricing year 2016/17; and

(c) for the pricing year 2019/20, the greater of the following:
   (i) the average of the customer's 12 highest injections at the connection location during the period commencing on 1 April 2015 and ending with the close of 31 August 2015;
   (ii) the average of the customer's 12 highest injections at the connection location during the capacity measurement period for the pricing year 2016/17.

Schedule 12.4, clause 33D: inserted, on 1 April 2017, by clause 8 of the Electricity Industry Participation Code Amendment (Transmission Pricing) 2015.
34 Adjustments to AMD, AMI, HAMI, SIMI and RCPD and calculation of customer charges

(1) Before the start of a pricing year, and otherwise during a pricing year as provided in this clause, Transpower will calculate—
   (a) AMD AMI, HAMI, SIMI and RCPD quantities (for each regional peak demand period); and
   (b) annual charges; and
   (c) monthly charges—
   in each case for every customer at every connection location for that pricing year.
   When a monthly charge is recalculated for part of a pricing year, all inputs used in the calculation will be the same as those used to calculate that monthly charge before the start of the pricing year except for the adjustments specifically provided in this clause.

(2) If, when calculating AMD, AMI, HAMI, SIMI and RCPD quantities before the start of a pricing year, Transpower, in its sole discretion, considers that exceptional operating circumstances during the relevant capacity measurement period(s) have resulted in—
   (a) abnormal regional demand resulting in an exceptional regional peak demand period for that pricing year; and/or
   (b) distortions to a customer's AMD, AMI, HAMI, SIMI and/or any RCPD quantity at a connection location for that pricing year—
   Transpower may, but is under no obligation to—
   (c) determine that the exceptional regional peak demand period is to be ignored when assessing the regional peak demand periods for that pricing year; and/or
   (d) adjust the customer's AMD, AMI, HAMI, SIMI and/or any RCPD for the quantity at the relevant connection location to minimise the impact of such distortion, as assessed by Transpower acting reasonably but otherwise in its sole discretion, as applicable. Such adjusted AMD, AMI, HAMI, SIMI and RCPD qualities, as the case may be, shall be used to calculate monthly charges for that customer for that connection location for that pricing year.

(3) If Transpower—
   (a) is advised that South Island generation at a connection location has been permanently de-rated (including decommissioning) to a specified aggregate rate capacity (“maximum de-rated capacity”); and
   (b) is satisfied that such South Island generation has been so permanently de-rated,—
   then, for the purposes of calculating a customer’s HAMI and SIMI at the relevant connection location for any pricing year that commences not less than 6 months after the date on which Transpower is satisfied under paragraph (b), any injection at that connection location in any half-hour period up to the date on which Transpower is satisfied under paragraph (b) which:
   (c) is used to determine the customer’s HAMI and SIMI; and
   (d) exceeds the maximum de-rated capacity,—
   will be deemed to be equal to the maximum de-rated capacity.
Electricity Industry Participation Code 2010
Schedule 12.4

(4) If not less than 6 months before the start of a pricing year, Transpower—
(a) is advised that the offtake and/or injection capacity of a customer’s assets at a connection location has been permanently de-rated (including decommissioning); and
(b) is satisfied that the offtake and/or injection capacity of such assets has been so permanently de-rated—
then, for the purpose of calculating the customer’s AMD, AMI and/or RCPD quantities at that connection location for any pricing year that commences not less than 6 months after the date on which Transpower is satisfied under paragraph (b),—
(c) Transpower will estimate (acting reasonably but otherwise in its sole discretion) the customer’s likely future offtake or injection (as the case may be) at that connection location, having regard to the change in the customer’s offtake and/or injection; and
(d) injection or offtake quantities for any half-hour period up to the date on which Transpower is satisfied under paragraph (b) which—
(i) are used to determine the customer’s AMD, AMI or RCPD quantities; and
(ii) exceed Transpower’s estimate under paragraph (c),—
will be deemed to be no more than the amounts estimated by Transpower under paragraph (c).

(5) If—
(a) Transpower decommissions a connection location; or
(b) a customer causes all of its assets connected to the grid at a connection location to be, and Transpower is satisfied that the customer’s assets have been, permanently disconnected from the grid at that connection location,—
then—
(c) the customer’s monthly charges for the month in which the connection location is decommissioned, will be pro-rated for the number of days that the connection location was decommissioned or assets were disconnected and the monthly charges will be reduced accordingly; and
(d) from the month following the month in which such decommissioning or disconnection occurred, the customer’s AMD, AMI, HAMI, SIMI and all RCPD quantities at that connection location and the customer’s monthly charges at that connection location will be deemed to be 0.

(6) If a customer connects assets to the grid at a connection location where that customer does not already have assets connected to the grid (including a new connection location), the following applies:
(a) Transpower will agree with the customer whether the customer is to be an offtake customer or an injection customer at the relevant connection location and the customer will, until such time as the assets have been connected for a full capacity measurement period, be deemed to be an offtake customer and/or an injection customer accordingly;
(b) if the asset is a generating unit or generation station located in the South Island, the generating unit or generation station will be deemed to be South Island generation:
(c) **Transpower** will assign the **new connection location** to a **region** (unless it is an existing **connection location**):

(d) from the time of **connection** of the **assets** until such time as the **assets** have been **connected** to the **grid** for the whole of the **capacity measurement period** for a **pricing year**, or, in the case of assets which are deemed to be **South Island generation** under paragraph (b), have been **connected** to the grid for 5 consecutive **capacity measurement periods**, the **customer’s AMD**, **AMI**, **HAMI**, **SIMI** and **RCPD** quantities at the **connection location** will be determined using **Transpower’s** estimates of the customer’s likely offtake and/or injection at the **connection location** for that period:

(e) the **customer** will pay **monthly charges** at the **connection location** from the date the **customer’s assets** are **connected** to the **grid**. If the **customer’s assets** are **connected** part way through a month, the **monthly charges** for that month will be reduced by an amount, being a pro-rata proportion of the **monthly charges** for the number of days in the month that the **customer’s assets** were not **connected**.

(7) If—

(a) a **customer’s connection** of new **assets** at a **connection location** to which subclause (5) applies, (the “first **connection location**”) is a direct consequence of that **customer’s de-rating of assets** at another **connection location**, (the “second **connection location**”) without the **customer** terminating the second **connection location** as a **point of connection** under any relevant **transmission agreement**; and

(b) the **connection assets** for the second **connection location** are shared with any other **customer**,—

then—

(c) **Transpower** will estimate (acting reasonably but otherwise in its sole discretion) the **customer’s likely offtake or injection** at the second **connection location** from the date on which the new **assets** are **connected** at the first **connection location** (“load transfer date”) until those assets have been **connected** to the **grid** for the whole of a **capacity measurement period** for a **pricing year**; and

(d) the **customer’s monthly connection charges** at the second **connection location** will be recalculated from the load transfer date. When recalculating the **customer’s monthly connection charges** from the load transfer date, any **injection** and/or **offtake** prior to the load transfer date used to calculate the **customer’s AMD and/or AMI** at the second **connection location** will be capped at **Transpower’s estimates** in accordance with subclause (6)(a); and

(e) if the load transfer date occurs part way through a month, the **customer’s monthly connection charges** at the second **connection location** for that month will be the sum of:

(i) a pro-rata proportion of the **customer’s monthly connection charges** at the second **connection location** immediately before the load transfer date, based on the number of days in the month prior to the load transfer date; and

(ii) a pro-rata proportion of the **customer’s monthly connection charges** at the second **connection location** recalculated in accordance with
subclause (6)(e), based on the number of days in the month including and subsequent to the load transfer date.

(8) If Transpower enhances or upgrades connection assets for a connection location under a new investment contract with a customer (a “NIC customer”), excluding NIC customers to whom subclause (5) applies,—

(a) if the enhancement or upgrade is commissioned part way through a pricing year, monthly connection charges at that connection location for the NIC customer will be recalculated from the date the enhanced or upgraded connection assets are commissioned to take into account those enhanced or upgraded connection assets; and

(b) if the connection asset enhancement or upgrade is commissioned part way through a month, the NIC customer’s monthly connection charge for that month will be the recalculated monthly connection charge reduced by an amount, being a pro-rata proportion of the recalculated monthly connection charge for the number of days in the month before commissioning of the enhancement or upgrade.

(9) If under this clause, Transpower estimates a customer’s likely offtake or injection over any period, Transpower may, but is not obliged to, review its estimate from time to time, but not more frequently than at 3 monthly intervals. If Transpower revises its estimate, the customer’s—

(a) AMD, AMI, HAMI, SIMI and RCPD quantities; and

(b) monthly charges—

will be recalculated accordingly and such recalculated monthly charges will be payable upon Transpower giving such notice as required in the relevant transmission agreement with the customer.

(10) If subclauses (6), (7) or (8) apply, or Transpower revises any estimate and monthly grid charges under subclause (9), there will be a wash-up and reconciliation at the end of the relevant pricing year of—

(a) monthly connection charges paid by—

(i) all customers at the connection location; and

(ii) all other customers at connection locations which share the same connection assets; and

(b) monthly HVDC charges paid by all HVDC customers,—

in each case, in that pricing year as follows:

(c) in the case of monthly connection charges, the wash-up and reconciliation is to be undertaken in respect of all charges calculated in accordance with clause 8(1) for each shared connection asset—

(i) using AMD or AMI for each customer as at the last day of the pricing year (including any Transpower estimate); and

(ii) so that the sum of the percentage proportions allocated to customers in accordance with clause 25(1) does not exceed 100% for any connection asset and so that Transpower, in turn, does not recover, in aggregate, more than 100% of the sum of the asset, maintenance, operating and overhead
cost components calculated in accordance with clauses 8 to 26 for any connection asset:
(d) in the case of monthly HVDC charges, the wash-up and reconciliation is to be undertaken—
   (i) using HAMI and SIMI for each HVDC customer as at the last day of the pricing year; and
   (ii) so that the sum of all monthly HVDC charges paid by the HVDC customer for that pricing year does not exceed the HVDC revenue for that pricing year:
(e) Transpower will issue a credit note for any overpayment by a customer consequent upon the wash-up.

(11) If a prudent discount agreement commences part way through a pricing year, Transpower will recalculate the customer’s monthly charges at the relevant connection location(s) consistently with the prudent discount agreement from the date the prudent discount agreement takes effect until it terminates or otherwise ceases to apply. If the prudent discount agreement commences part way through a month, the customer’s monthly charges for that month will be the sum of—
   (a) a pro-rata proportion of the monthly charges calculated in accordance with this transmission pricing methodology being the proportionate number of days in the month before the commencement of the prudent discount agreement; and
   (b) a pro-rata proportion of the monthly charges calculated in accordance with the prudent discount agreement being the proportionate number of days in the month on and from commencement of the prudent discount agreement.

(12) Transpower must adjust a customer's AMD, AMI, HAMI, SIMI, or RCPD at a connection location to minimise the impact of reverse flow at the connection location if—
   (a) the customer has an agreement with the system operator under clause 6 of Technical Code A of Schedule 8.3; and
   (b) within 20 business days after the reverse flow commences at the connection location, the customer has advised Transpower that there is reverse flow at the connection location; and
   (c) Transpower agrees that there is reverse flow at the connection location.

(13) If Transpower makes an adjustment under subclause (12), Transpower must, no later than 20 business days after making the adjustment, make available on its website the reasons for the adjustment, and how the adjustment was calculated.

(14) Transpower is not required to calculate HAMI quantities under this clause for any pricing year after the pricing year 2019/20.
Compare: Electricity Governance Rules 2003 clause 7 schedule F5 part F
Schedule 12.4, clause 34 Heading: amended, on 1 April 2017, by clause 9(1) of the Electricity Industry Participation Code Amendment (Transmission Pricing) 2015.
Schedule 12.4, clause 34(1) to (10): amended, on 1 April 2017, by clause 9(2) to (4) of the Electricity Industry Participation Code Amendment (Transmission Pricing) 2015.
Schedule 12.4, clause 34(3)(a), (4)(a) and (12)(b): amended, on 1 November 2018, by clause 81(a) to (c) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.
Transmission alternatives

35 Transmission Alternatives
(1) Charges for transmission alternative services will apply when transmission alternative services are provided and/or funded by Transpower. Transmission alternative services are services which substitute for the services provided by connection assets or interconnection assets or both.

(2) If a transmission alternative service substitutes for a service which would otherwise be provided by connection assets, a charge recovering Transpower's costs of funding that transmission alternative service is added to the connection charge(s) of the customer(s) for the relevant connection location(s). The costs of the transmission alternative service are allocated between all customers at the relevant connection locations(s) in the same proportion that each customer's total connection charges for the relevant connection location(s) bears to the sum of all customers' connection charges for those connection location(s).

(3) If a transmission alternative service substitutes for services which would otherwise be provided by interconnection assets a charge recovering the cost of the transmission alternative service is allocated between offtake customers in the same proportion that each offtake customer's interconnection charges bears to the sum of all offtake customers' interconnection charges.

(4) If a transmission alternative service substitutes for both connection assets and interconnection assets, the allocation of the costs of the transmission alternative service as between connection assets and interconnection assets must be calculated in accordance with clause 25(2) for shared connection assets at an interconnection node.

(5) The costs of funding transmission alternative services will be charged to, and payable by, customers in the month following the month in which Transpower is invoiced for those costs.

Compare: Electricity Governance Rules 2003 clause 8 schedule F5 part F

Prudent Discount Policy

36 Purpose of the Prudent Discount Policy
(1) The purpose of the prudent discount policy is to help ensure that the transmission pricing methodology does not provide incentives for the uneconomic bypass of existing grid assets. The prudent discount policy aims to deter investment in alternative projects which would allow a customer to reduce its own transmission charges while increasing the total economic costs to the nation as a whole.
(2) In order for a customer to obtain a prudent discount a customer’s alternative project must be—
   (a) technically, operationally and commercially viable and have a reasonable prospect of being able to be successfully implemented; and
   (b) uneconomic to implement given Transpower’s economic costs of providing existing grid assets and the economic costs that would be incurred by the customer if it proceeded with the alternative project,—
determined in accordance with this prudent discount policy.

Compare: Electricity Governance Rules 2003 clauses 9.1 and 9.2 schedule F5 part F

37 Information Required in a Prudent Discount Application
(1) In order for an alternative project to be accepted by Transpower as a prudent discount application it must be developed to a level of detail equivalent to the detail that a prudent company Board would reasonably expect when considering an investment proposal.
(2) If a customer wishes to apply for a prudent discount, that customer must (at its own expense) submit to Transpower a written proposal describing the alternative project and the likely impact of that alternative project on that customer's transmission charges.
(3) The proposal must, to the extent relevant, contain all of the information described in Appendix C, together with any other information which is likely to be relevant to Transpower's consideration of the alternative project.
(4) Without limiting subclause (3) Transpower may require the customer to provide any additional information which Transpower considers is reasonably necessary to enable it to conduct its assessment of the alternative project in accordance with clauses 38 and 39.

Compare: Electricity Governance Rules 2003 clauses 9.3 to 9.6 schedule F5 part F

38 Assessment of Technical, Operational and Commercial Viability of Alternative Project
(1) Transpower will, within a reasonable time of receiving the proposal, assess the alternative project to determine whether or not—
   (a) it is technically feasible; and
   (b) it is operationally feasible and compliant with the asset owner performance obligations and technical codes, and any other relevant requirements as set out in Part 8 of this Code; and
   (c) the alternative project could reasonably be expected to provide the customer with transmission charges that would result in a lower overall commercial cost having regard to the capital, operating, maintenance and all other costs likely to be incurred by the customer as a result of undertaking the alternative project to the customer than the current Transpower charges, for the same or a similar level of service.
(2) In undertaking its assessment of the alternative project, Transpower may adjust any of the information provided by the customer to reflect Transpower's reasonable
assessments of current market prices, good engineering practice and any consequential impacts of the alternative project on the grid assets and the customer's assets.

Compare: Electricity Governance Rules 2003 clauses 9.7 and 9.8 schedule F5 part F

39 Assessment that the Alternative Project is Uneconomic

(1) If Transpower considers that the alternative project does not satisfy one or more of the criteria specified in clause 38(1), no prudent discount will be provided.

(2) If Transpower considers that the alternative project satisfies all of the criteria specified in clause 38(1), Transpower will, within a reasonable time thereafter, assess the alternative project to determine whether or not it is uneconomic in accordance with subclauses (3) to (7).

(3) Transpower will calculate the present value of the estimated total costs of the alternative project including capital costs and operating and maintenance costs. Transpower may use the cost estimates provided by the customer or may reasonably adjust those costs to reflect current market prices, good engineering practice and consequential impacts of the alternative project on grid assets and the customer's assets.

(4) The discount rate used to undertake the calculations required by subclauses (3) to (7) must be a discount rate determined by the Authority, from time to time, or if the Authority has not determined a discount rate, a discount rate of, or equivalent to, a pre-tax real rate of 7%. The calculations required by subclauses (3) to (7) will be carried out using a period of 15 years or the remaining life of the grid assets which the alternative project would bypass, whichever is the lesser.

(5) Transpower will then calculate the present values of—

(a) Transpower's costs of continuing to provide transmission services to the customer if the alternative project does not proceed, including operating and maintenance costs and planned future capital expenditure needed to maintain required service levels; and

(b) Transpower's costs of continuing to provide transmission services to the customer if the alternative project does proceed, including operating and maintenance costs and planned future capital expenditure needed to maintain required service levels.

(6) If the amount calculated under subclause (5)(a) minus the amount calculated under subclause (5)(b) is greater than the amount calculated under subclause (3), the alternative project will be determined to be economic and no discount will be provided.

(7) If the amount calculated under subclause (5)(a) minus the amount calculated under subclause (5)(b) is less than the amount calculated under subclause (3), the alternative project will be determined to be uneconomic.

Compare: Electricity Governance Rules 2003 clauses 9.9 to 9.15 schedule F5 part F

40 Independent Review

(1) The customer may, within 60 days of being advised of Transpower's decision to offer a prudent discount agreement or that no discount will be provided, request a review by
an independent expert of any or all of the assessments undertaken by Transpower for the purposes of that decision.

(2) Within a reasonable time of being appointed, the independent expert is to report his or her findings to Transpower and the customer. The findings of the independent expert will be binding on Transpower and the customer. If the independent expert finds that the customer’s alternative project is uneconomic and satisfies all the requirements of clause 38(1), the provisions of clause 41(1) will apply.

(3) The costs of the independent expert are to be met by the party requesting the review if the information or assessments reviewed are confirmed as reasonable; otherwise the costs will be met by the other party.

Compare: Electricity Governance Rules 2003 clauses 9.16 to 9.18 schedule F5 part F

41 Prudent Discount Agreement

(1) If the customer’s alternative project is considered by Transpower to be uneconomic and to satisfy all the requirements of clause 38(1), Transpower will offer a prudent discount agreement to all customers that are directly affected by the proposal. The prudent discount agreement will provide for—

(a) the customer to pay to Transpower an annuity (the amount of which is to be specified in the prudent discount agreement) determined by reference to the customer's cost of funding, maintaining and operating the alternative project over the duration of the prudent discount agreement, applying a commercial discount rate; and

(b) Transpower to calculate the customer’s transmission charges in accordance with this transmission pricing methodology as if the alternative project had been implemented.

(2) The commencement date of a prudent discount agreement will take full account of the time that would reasonably be required for the customer to implement the alternative project.

(3) The duration of a prudent discount agreement will be the lesser of the remaining economic life of the grid assets that are affected by the agreement, or 15 years.

Compare: Electricity Governance Rules 2003 clauses 9.19 to 9.21 schedule F5 part F

42 Prudent Discount Details to be Published

(1) As soon as reasonably practicable after concluding a prudent discount agreement with a customer, Transpower must publish the decision made, the analysis supporting that decision and the following information:

(a) the cost estimate used by Transpower in assessing the alternative project and the calculations undertaken by Transpower using those cost estimates:

(b) any report prepared by an independent expert:

(c) the annual amount payable by the customer under clause 41(1)(a):

(d) details of how the customer’s transmission charges will be calculated under clause 41(1)(b).

Compare: Electricity Governance Rules 2003 clause 9.22 schedule F5 part F
Appendix A – Allocation of Transpower’s AC Revenue and HVDC Revenue to its Customers

AC Revenue Determined by Transpower Board in accordance with Part 4 of the Commerce Act

HVDC Revenue determined by Transpower Board in accordance with Part 4 of Commerce Act

Revenue set in accordance with Part 4 of the Commerce Act

Transmission Pricing Methodology

Connection Allocation
1) Asset return (derived from regulated asset value)
2) Maintenance cost of connection substations (average of last 4 years)
3) Maintenance cost – lines (average of last 4 years)
4) Operating costs of switches
5) Injection overhead (set by Transpower Board)

Interconnection Allocation
(AC Revenue – ∑ Connection Charges)

Allocated to customers by:
Regional Coincident peak demands of offtake customers using N+T2

Allocated to connection locations by:
1) Replacement cost (RC) of connection assets (adjusted to preserve last optimised values)
2) RC of connection substation assets
3) Length of connection lines
4) Number of switches
5) RC of injection connection assets

Further allocated to customers that share Connection Assets
BY:
1) Anytime Maximum Demand (AMD)
2) Anytime Maximum Injection (AMI)

Allocated to individual customer

Allocated to South Island Injection customers by:
HAMI and SIMI

Allocated to connection locations

Compare: Electricity Governance Rules 2003 appendix A schedule F5 part F
Schedule 12.4, Appendix A: amended, on 1 April 2017, by clause 10(1) and (2) of the Electricity Industry Participation Code Amendment (Transmission Pricing) 2015.
Appendix B
Regions

North Island
(a) Upper North Island (UNI): all connection locations on, or north and west of, a line—
   (i) commencing at 38°02'S and 174°42'E; then
   (ii) proceeding in a generally north-easterly direction directly to 37°36'S and 175°27'E; then
   (iii) proceeding north along the 175°27'E line of longitude.
(b) Lower North Island (LNI): all connection locations south and east of the line described in paragraph (a).

South Island
(a) Upper South Island (USI): all connection locations on, or north of, a line passing through 43°30'S and 169°30'E, and 44°40'S and 171°12'E.
(b) Lower South Island (LSI): all connection locations south of the line described in paragraph (a).

Compare: Electricity Governance Rules 2003 appendix B schedule F5 part F
Appendix C
Information Required to Support a Prudent Discount Application

General information
1. Location of the *alternative project*.
2. A brief description of the *alternative project*.
3. A sketch or schematic of the *alternative project*.

Part A: Information required to enable a technical evaluation of the proposal
(1) A report on the technical viability of the *alternative project*, provided by either the *customer*, or an external consultant on behalf of the *customer*. The report must include details of voltage quality, especially if there are switched capacitors and/or switched loads, such as motor starting, and information on the size of load, the size of any capacitors, the frequency of switching and the size of voltage steps.
(2) A circuit diagram.
(3) For a *customer* who operates a distribution network, a diagram of the *customer’s* distribution network that is sufficiently detailed to run load-flow models. The network diagram should contain load distribution data, circuit parameters and the parameters of any embedded generation.
(4) A description of how the requirement for any additional physical space will be met.
(When attaching to existing equipment, or to an existing facility, there may be a need for physical space for new equipment, e.g. a new circuit breaker bay or a connection point to a generator bus.)
(5) The following information, except if it is not applicable to the *alternative project*:
   • Voltage (kV)
   • Demand (peak MW/low MW)
   • Conductor rating and type
   • Circuit length (km) and type (single or double)
   • Voltage support type and rating (VARs)
   • Estimated losses (MW/km)
   • Transformers: size (VA) and impedance (Ω)

Part B: Cost of the alternative project
The following information is required to enable independent validation of the *customer’s* cost estimates. This information must be provided, except if it does not apply to the *alternative project*.

Capital cost (line)
(1) Conductor type, capital cost per metre, distance in metres and total estimated cost.
(2) Type of structures (poles or lattice towers), number of structures, capital cost per structure and total estimated cost.
(3) Type and number of insulators, capital cost per insulator and total estimated cost.
(4) The capital cost of line fittings.
(5) Any other capital costs of lines.

**Capital cost (substation)**

1. The type and number of transformers, the capital cost per unit and the total estimated cost.
2. The type and number of circuit breakers, the capital cost per unit and the total estimated cost.
3. The type and number of disconnectors, the capital cost per unit and the total estimated cost.
4. The type of protection and metering, the capital cost per unit and the total estimated cost.
5. The type and capital cost of buswork.
6. The type and capital cost of other infrastructure.
7. Any other miscellaneous substation costs.

**Labour cost**

1. Estimated labour costs.
2. Estimated design and project management costs.

**Cost of system losses**
The estimated cost of the electrical line losses that would result if the alternative were implemented, specifically:

- Estimated additional losses in MW/km.
- Estimated additional losses per annum in MWh.
- The estimated average price of energy in $/MWh.
- Total estimated value of additional electrical losses per annum in dollars.

**The cost of easements and consents**

1. A topographical map of the line route in sufficient detail to verify estimates of the costs of easements and consents, or to verify that easements and consents are not required.
2. An estimate of consent costs.
3. An estimate of easements costs.
4. Estimate of property right costs.

**Part C: Commercial evaluation**

An analysis by the customer that provides a prima facie demonstration that the proposed alternative project would provide the customer with Transpower charges that would result in a lower overall commercial cost to the customer than the current Transpower charges, for the same or a similar level of service.

**Part D: Legal matters**
The implementation of some alternative project proposals will require the customer to enter into contractual agreements with third parties and to satisfy statutory requirements. In this
case, the **customer** must provide reasonable evidence that the **alternative project** would be able to be successfully implemented, including but not limited to—

1. a report from appropriately qualified planning, legal and property consultants that demonstrates that all consents required to implement the **alternative project** are either held, or are reasonably likely to be obtained; and

2. evidence of access, easement and other property rights required to implement the **alternative project**.

Compare: Electricity Governance Rules 2003 appendix C schedule F5 part F
### Schedule 12.5

**Availability and reliability index measures**

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<th>Asset category</th>
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<th>Planned unserved energy MWh</th>
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Compare: Electricity Governance Rules 2003 schedule F6A part F
Electricity Industry Participation Code 2010

Part 12A
Distributor use-of-system agreements and distributor tariffs

Contents

12A.1 Contents of this Part

Use-of-system agreements
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12A.3 Mediation
12A.4 Prudential requirements
12A.4A Election of prudential requirements
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12A.7 Distributors must consult concerning changes to tariff structures

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12A.8 Changes to tariff rates [Revoked]
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Schedule 12A.1
Distributor indemnity in use-of-system agreements [Revoked]

12A.1 Contents of this Part
This Part—
(a) specifies requirements that must be complied with in negotiating use-of-system agreements; and
(b) specifies requirements that must be complied with if prudential requirements are included in use-of-system agreements; and
(c) [Revoked]
(d) requires that distributors who do not send accounts to consumers directly consult with traders about changes to the distributor's tariff structure; and
(e) [Revoked]
Electricity Industry Participation Code 2010
Part 12A

(f) [Revoked]
(g) provides that the Authority may prescribe EIEPs that distributors and traders must comply with when exchanging information.
Clause 12A.1(g): inserted, on 16 December 2013, by clause 5(b) of the Electricity Industry Participation (Electricity Information Exchange Protocols) Code Amendment 2013.

Use-of-system agreements

12A.2 Negotiating use-of-system agreements
(1) A distributor and a trader must negotiate the terms of a use-of-system agreement (including any amendment to a use-of-system agreement) in good faith.

(2) [Revoked]

12A.3 Mediation
(1) If a distributor or a trader considers that it is unlikely that it will agree the terms of a use-of-system agreement with the other party, the distributor or the trader may give written notice to the other party of that fact.
(2) The notice given under subclause (1) must—
(a) state that it is a notice given under subclause (1); and
(b) include a copy of subclause (1); and
(c) state that at the close of the 20th business day after the date of the notice, the distributor or trader (as the case may be) may require the other party to enter into mediation.
(3) No earlier than the close of the 20th business day after the date on which the notice referred to in subclause (2) is given, the distributor or the trader may, by written notice to the other party, require the other party to undertake mediation with the party who gave notice under this subclause.
(4) The notice given under subclause (3) must—
(a) state that it is a notice given under subclause (3); and
(b) include a copy of subclause (3).
(5) On receipt of a notice given under subclause (3), the distributor and the trader must attempt in good faith to agree on the following matters:
(a) the mediator:
(b) the date or dates for the mediation:
(c) the location of the mediation:
(d) the scope of the mediation:
(e) the allocation of the costs of the mediation.
(6) If, at the close of the 15th business day after receipt of the notice given under subclause (3), the distributor and the trader are in dispute regarding 1 or more of the matters specified in subclause (5), either party may refer the dispute to the Rulings Panel for determination.

(7) The Rulings Panel may make such determination as it thinks fit.

(8) The distributor and the trader must carry out the mediation in accordance with any agreement reached under subclause (5) and any determination made under subclause (7).

(9) [Revoked]


12A.4 Prudential requirements

Clauses 12A.4A to 12A.5A apply in relation to a use-of-system agreement if—

(a) the distributor party to the use-of-system agreement has 1 or more consumers connected to its network to whom the distributor does not send accounts for line function services directly; and

(b) the distributor's charges for line function services are collected from consumers or paid by the trader party to the use-of-system agreement in accordance with the use-of-system agreement; and

(c) the distributor requires that the use-of-system agreement provides that the trader—

(i) must comply with prudential requirements; or

(ii) must comply with prudential requirements if required to do so by the distributor.


12A.4A Election of prudential requirements

(1) Subject to clause 12A.5A, if a use-of-system agreement provides that the trader party to the use-of-system agreement must comply with prudential requirements, including if required to do so by the distributor, the use-of-system agreement must provide that the trader may elect to comply with the prudential requirements in either of the following ways:

(a) the trader must maintain an acceptable credit rating in accordance with subclause (3); or

(b) the trader must provide and maintain acceptable security by, at the trader's election,—

(i) providing the distributor with a cash deposit; or

(ii) arranging for a third party with an acceptable credit rating to provide that security in a form acceptable to the distributor; or

(iii) providing a combination of the securities described in subparagraphs (i) and (ii).

(2) The use-of-system agreement must provide that the trader may change its election at any time.

(3) For the purposes of this clause, a trader or third party has an acceptable credit rating if it—
(a) carries a long term credit rating of at least—
   (i) BBB- (Standard & Poors Rating Group); or
   (ii) a rating that is equivalent to the rating specified in subparagraph (i) from a
        rating agency that is an approved rating agency for the purposes of Part 5D
        of the Reserve Bank of New Zealand Act 1989; and
(b) is not subject to negative credit watch or any similar arrangement by the agency
    that gave it the credit rating.

(4) Subject to clause 12A.5, the value of the acceptable security described in subclause
    (1)(b) must be the distributor's reasonable estimate of the line function services
    charges that the trader will be required to pay to the distributor in respect of any
    period of not more than 2 weeks.

(5) A use–of–system agreement must specify that, if the trader elects to provide
    acceptable security as described in subclause (1)(b), the distributor must—
(a) hold any security provided by the trader in the form of a cash deposit in a trust
    account in the name of the trader at an interest rate that is the best on-call rate
    reasonably available at the time the trader provides the cash deposit; and
(b) pay interest earned in respect of the cash deposit to the trader on a quarterly
    basis, net of account fees and any amounts that are required to be withheld by law.

Clause 12A.4A: inserted, on 1 February 2016, by clause 68 of the Electricity Industry Participation Code Amendment
(Code Review Programme) 2015.

12A.5 Requirements if distributors require additional security
(1) A distributor may require that its use-of-system agreement provides 1 or both of the
    following:
   (a) that if the trader elects to provide acceptable security as specified in
       clause 12A.4A(1)(b), the trader must provide acceptable security that is additional
       to the amount provided for in clause 12A.4A(4):
   (b) that the distributor may, during the term of the use-of-system agreement,
       require the trader to provide such additional security.

(2) If a use-of-system agreement has a provision provided for in subclause (1), the
    distributor must ensure that the total value of additional security specified in the use-of-system agreement
    must be such that the total value of all security required to be provided by the trader must not be more than the distributor's reasonable estimate of the line function services charges that the trader will be required to pay to the distributor in respect of any 2 month period.

(3) If a use-of-system agreement has a provision provided for in subclause (1), the
    distributor must ensure that the use-of-system agreement provides the following:
   (a) if any additional security provided by the trader is in the form of a cash deposit,
       the distributor must pay a charge to the trader for each day that the distributor
       holds the additional security at a per annum rate equal to the sum of the bank bill
       yield rate for that day plus 15% on the amount of additional security held on that
       day:
   (b) if any additional security provided by the trader is in the form of security from a
       third party, the distributor must pay a charge to the trader for each day that the
       distributor holds the additional security at a per annum rate of 3% on the amount
       of additional security held on that day:
(c) any money required to be paid by the **distributor** to the **trader** as specified in paragraph (a) or (b) must be paid by the **distributor** to the **trader** on a quarterly basis.

(4) For the purposes of this clause, the bank bill yield rate is—
(a) the daily bank bill yield rate (rounded upwards to 2 decimal places) published on the wholesale interest rates page of the website of the Reserve Bank of New Zealand (or its successor or equivalent page) on that day as being the daily bank bill yield for bank bills having a tenor of 90 days; or
(b) for any day for which such a rate is not available, the bank bill yield rate is deemed to be the bank bill yield rate determined in accordance with paragraph (a) on the last day that such a rate was available.

Clause 12A.5(1)(a): amended, on 1 February 2016, by clause 69(1)(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.


12A.5A Agreement to less onerous terms

Despite clause 12A.4A, a **distributor** and a **trader** may agree prudential requirements that are less onerous on the **trader** than the requirements described in clauses 12A.4 to 12A.5.


12A.6 Distributor indemnity [Revoked]


*Changes to tariff structures*

12A.7 Distributors must consult concerning changes to tariff structures

(1) This clause applies to each **distributor** who has 1 or more **consumers** connected to its **network** to whom the **distributor** does not send accounts for **line function services** directly.

(2) The **distributor** must consult with each **trader** trading on the **distributor's network** in respect of the **distributor's** tariff structure for the **consumers** referred to in subclause (1) before making a change to the tariff structure that materially affects 1 or more **traders** or **consumers**.

(3) For the purpose of subclause (2), changes to a **distributor's** tariff structure that may materially affect 1 or more **traders** or **consumers** include, but are not limited to, any of the following:

(a) a change by the **distributor** to the eligibility criteria for 1 or more of the **distributor's** tariff rates:

(b) a change by the **distributor** to the **distributor's** tariff structure by the introduction of a new tariff rate:
(c) a change by the distributor to the distributor's tariff structure that means that 1 or more of the distributor's tariff rates are no longer available.

(4) However, the fact that a change is listed in subclause (3) does not mean that a distributor is required to consult on the change if the change will not materially affect traders or consumers.

(5) [Revoked]


[Revoked]

Changes to tariff rates cross heading: revoked, on 16 December 2013, by clause 6(1) of the Electricity Industry Participation (Electricity Information Exchange Protocols) Code Amendment 2013.

12A.8 Changes to tariff rates [Revoked]

Clause 12A.8: revoked, on 16 December 2013, by clause 6(2) of the Electricity Industry Participation (Electricity Information Exchange Protocols) Code Amendment 2013.

12A.9 Requirement to comply with EIEP12 [Revoked]


12A.10 Requirement to use standard tariff codes [Revoked]


Exchange of information


12A.12 Distributor or trader may require provision of information

(1) The **distributor** may, by notice in writing, require the **trader** to provide information to the **distributor**—
   (a) to invoice and reconcile charges for line function services; or
   (b) to provide information to the **extended reserve manager**.

(2) The **trader** may, by notice in writing, require the **distributor** to provide information to the **trader**, to enable the **trader** to invoice and reconcile charges for line function services.

(3) A **trader** or **distributor** that receives a notice under subclause (1) or subclause (2) must provide the information within 15 **business days** (or such other date as agreed between the parties) after receiving the notice.

(4) The **distributor** may use volume information to—
   (a) enable invoicing and reconciling charges for line function services:
   (b) enable the **distributor** to provide information to the **extended reserve manager**.

(5) Nothing in this clause prevents the **distributor** and **trader** agreeing to provide volume information to each other for any other purpose.


12A.13 Authority may prescribe EIEPs that must be used

(1) The **Authority** may **prescribe** 1 or more **EIEPs** that set out standard formats that **distributors** and **traders** must use when exchanging information.

(1A) The **Authority** must **publish** an **EIEP** it prescribes under subclause (1).

(2) When prescribing an **EIEP** under subclause (1), the **Authority** must specify the date on which the **EIEP** will come into effect.

(3) The information to which an **EIEP** prescribed under subclause (1) may relate includes, but is not limited to, the following information:
   (a) ICP level billing information:
   (b) summary level billing information:
   (c) **half hourly** billing information:
   (d) **distributor** tariff rate change information.

(4) Before the **Authority** prescribes an **EIEP** under subclause (1), or amends an **EIEP** it has prescribed under subclause (1), it must consult with the **participants** that the **Authority** considers are likely to be affected by the **EIEP**.

(5) The **Authority** need not comply with subclause (4) if it proposes to amend an **EIEP** prescribed under subclause (1) if the **Authority** is satisfied that—
   (a) the nature of the amendment is technical and non-controversial; or
   (b) there has been adequate prior consultation so that the **Authority** has considered all relevant views.

(6) **Revoked**
12A.14 Distributors and traders must comply with EIEPs

(1) If the Authority prescribes an EIEP under clause 12A.13, the distributor and the trader must, when exchanging information to which the EIEP relates, comply with the EIEP from the date on which the EIEP comes into effect.

(2) [Revoked]

(3) However, a distributor and a trader may, after the Authority prescribes an EIEP, agree to exchange information other than in accordance with the EIEP, by recording the agreement in each use-of-system agreement between the distributor and trader.

(4) An agreement to exchange information other than in accordance with an EIEP is not effective in relieving a distributor and a trader of the obligation to comply with subclause (1), unless the agreement comes into effect on or after the date on which the relevant EIEP comes into effect.

(5) An agreement under subclause (3) is not affected by the Authority prescribing an amendment to the EIEP.

(6) Subclause (1) does not apply to an EIEP prescribed under clause 12A.15.

12A.15 Authority may prescribe voluntary EIEPs

(1) The Authority may prescribe 1 or more EIEPs that set out standard formats that distributors and traders may, but are not required to, use when exchanging information.

(2) The Authority must publish an EIEP it prescribes under subclause (1)
12A.16 Transitional provision relating to EIEPs

(1) This clause applies to any EIEP that a distributor or trader was required to comply with immediately before this clause came into force.

(2) An EIEP to which this clause applies—
   (a) is deemed to be an EIEP prescribed under clause 12A.13(1); and
   (b) despite clause 12A.13(2), comes into effect on the date on which this clause comes into force.

(3) The Authority need not comply with clause 12A.13(4) in respect of an EIEP to which this clause applies, unless the Authority proposes to amend the EIEP.

(4) [Revoked]

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13.1 Contents of this Part

This Part provides for processes by which—

(a) purchasers and generators submit and revise bids and offers for electricity, grid owners submit and revise information, ancillary service agents submit and revise reserve offers, the system operator forecasts demand at conforming GXP, and the system operator collects information to enable schedules to be prepared; and

(b) the system operator prepares and publishes information from the price-responsive schedules, non-response schedules, dispatch schedules, and real time price schedules, and formulates and issues dispatch instructions; and

(c) the clearing manager holds must-run dispatch auctions; and

(d) the pricing manager collects data and produces provisional prices, interim prices, and final prices; and

(da) the Authority determines whether each GXP is either a conforming GXP or a non-conforming GXP; and

(db) the clearing manager calculates constrained off amounts and constrained on amounts; and

(e) generators may apply to the Authority to have 1 or more generating units approved as—

(i) a type A industrial co-generating station; or

(ii) a type B industrial co-generating station; and

(f) information about risk management contracts is disclosed; and

(fa) disclosing participants prepare and submit spot price risk disclosure statements; and

(g) the FTR manager prepares and publishes the FTR allocation plan, creates and allocates FTRs, and operates the FTR register; and

(h) the clearing manager collects and allocates FTR auction revenue; and

(i) information about FTRs is provided; and

(j) a device or a group of devices may be approved to be a dispatch-capable load station.

Compare: Electricity Governance Rules 2003 rule 1 section I part G
Clause 13.1(a) and (b): substituted, on 28 June 2012, by clause 5(a) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
13.2 Misleading, deceptive, or incorrect information

(1) A participant must not disclose to any person any information under this Part that, at the time the information was disclosed, was misleading or deceptive or likely to mislead or deceive when taken in the context of activities under this Part.

(1A) In assessing whether information, at the time of disclosure, is misleading or deceptive or is likely to mislead or deceive, a participant must act reasonably and prudently.

(2) If a participant discovers that information previously disclosed by it to a person under this Part was misleading, deceptive or incorrect, the participant must, as soon as reasonably practicable,—

(a) disclose further information so that the person is not misled or deceived by the information; or

(b) disclose corrected information to the person.


13.2A Participant must make disclosure information readily available

(1) Each participant must make all disclosure information in relation to the participant readily available to the public, free of charge, as soon as reasonably practicable after the participant becomes aware of the information.

(2) Despite subclause (1), a participant is not required to make disclosure information readily available to the public if—

(a) the disclosure information is excluded Code information; or

(b) [Revoked]

(ba) a reasonable person would not expect the disclosure information to be made readily available; or

(c) the participant is bound by a legal obligation to keep the disclosure information confidential; or

(d) doing so will be a breach of law; or

(e) the disclosure information is already readily available to the public; or

(f) the disclosure information concerns an incomplete proposal or negotiation; or

(g) the disclosure information comprises matters of supposition or is insufficiently definite to warrant being made readily available to the public; or

(h) the participant claims legal professional privilege or privilege against self-incrimination in respect of the disclosure information; or

(i) the disclosure information is a trade secret.

(3) A participant that relies on subclause (2) must, as soon as reasonably practicable, make the disclosure information readily available to the public, free of charge, if subclause (2) ceases to apply to the disclosure information.

(4) If information ceases to be disclosure information, a participant is no longer required to make the information readily available to the public.

(5) A participant that does not make information readily available to the public under this clause must, if required to do so by the Authority,—
(a) satisfy the Authority that subclause (2) applies to the disclosure information, if the participant relies on subclause (2); or
(b) satisfy the Authority that the information is not disclosure information.

(6) A participant must not enter into a confidentiality agreement with another person for the purpose of avoiding making disclosure information readily available to the public under this clause.


13.3 Approval process for industrial co-generating stations
A generator may apply to the Authority to have 1 or more generating units approved as—
(a) a type A industrial co-generating station under clause 8(1)(a)(i) of Schedule 13.4; or
(b) a type B industrial co-generating station under clause 8(1)(a)(ii) of Schedule 13.4.

Compare: Electricity Governance Rules 2003 rule 3 section I part G

13.3A Approval process for dispatch-capable load stations
(1) A purchaser at a GXP may apply to the system operator for approval for a device or a group of devices at the GXP to be a dispatch-capable load station under Schedule 13.8.
(2) The system operator must consider the application in accordance with Schedule 13.8.
(3) If the system operator approves a device or a group of devices as a dispatch-capable load station,—
(a) the approval is valid until the date the approval is revoked under clause 10 of Schedule 13.8; but
(b) a device or group of devices in respect of which the approval is granted is not a dispatch-capable load station while its approval is suspended under clause 10 of Schedule 13.8.


13.3B Purchasers to advise system operator of changes to dispatch-capable load station
(1) A purchaser to which a dispatch-capable load station approval is granted must advise the system operator of any change to the factors the system operator considered in granting approval, including an intended change of the dispatchable load purchaser.
(2) A purchaser must advise the system operator of the change no later than 10 business days before the change takes effect.
(3) The system operator must consider the change advised and decide whether—
(a) to amend the approval under clause 10 of Schedule 13.8; or
(b) to revoke the approval under clause 10 of Schedule 13.8; or
(c) to suspend the approval under clause 10 of Schedule 13.8.


13.3C System operator to publish dispatch-capable load station approval process guidelines

(1) The system operator must publish guidelines for the purpose of assisting purchasers to obtain approval under clause 13.3A.

(2) Before publishing the guidelines under subclause (1), the system operator must consult with participants on the guidelines.

(3) To avoid doubt, consultation undertaken before the commencement of this clause is to be treated as the consultation required for the purpose of subclause (2).

Clause 13.3C: inserted, on 15 May 2014, by clause 7 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Subpart 1—Bids and offers

13.4 Contents of this subpart

This subpart provides for processes to facilitate trading by which—

(a) bids and offers for electricity are submitted and revised by generators and purchasers; and

(b) information from the grid owners is submitted and revised; and

(c) reserve offers are submitted and revised by ancillary service agents; and

(d) the system operator collects the information referred to in this subpart; and

(e) information about bids and offers is to be made available.

Compare: Electricity Governance Rules 2003 rule 1 section II part G

13.5 Bids and offers must be lawful

A purchaser, generator or ancillary service agent must not make or maintain a bid, offer or reserve offer if the purchaser or generator or ancillary service agent knows or ought reasonably to know that acting in accordance with the bid, offer or reserve offer would contravene any law.

Compare: Electricity Governance Rules 2003 rule 2 section II part G


13.5A Conduct in relation to generators' offers and ancillary service agents' reserve offers

(1) Each generator and ancillary service agent must ensure that its conduct in relation to offers and reserve offers is consistent with a high standard of trading conduct.

(2) Subclause (1) applies when—

(a) a generator submits or revises an offer; or

(b) an ancillary service agent submits or revises a reserve offer.


13.5B Safe harbours for clause 13.5A

(1) A generator complies with clause 13.5A if—

(a) the generator makes offers in respect of all of its generating capacity that is able to operate in a trading period; and

(b) when the generator decides to submit or revise an offer, it does so as soon as it can; and

(c) in the case of a generator that is pivotal,—

(i) prices and quantities in the generator's offers do not result in a material increase in the final price at which electricity is supplied in a trading period at any node at which the generator is pivotal, compared with the final price at the node in an immediately preceding trading period or other comparable trading period in which the generator is not pivotal at that node; or

(ii) the generator's offers are generally consistent with offers it has made when it has not been pivotal; or

(iii) the generator does not benefit financially from an increase in the final price at which electricity is supplied in a trading period at a node at which the generator is pivotal.

(2) A generator does not breach clause 13.5A only because the generator does not comply with subclause (1).

(3) An ancillary service agent complies with clause 13.5A if—

(a) the ancillary service agent makes reserve offers in respect of all of its capacity to provide instantaneous reserve that is able to operate in a trading period; and

(b) when the ancillary service agent decides to submit or revise a reserve offer, it does so as soon as it can; and

(c) in the case of an ancillary service agent that is pivotal,—

(i) prices and quantities in the ancillary service agent's reserve offers do not result in a material increase in the final reserve price in a trading period in an island in which the ancillary service agent is pivotal, compared with the final reserve price in the island in an immediately preceding trading period or other comparable trading period in which the ancillary service agent is not pivotal; or

(ii) the ancillary service agent's reserve offers are generally consistent with reserve offers it has made when it has not been pivotal; or

(iii) the ancillary service agent does not benefit financially from an increase in the final reserve price in a trading period in an island in which the ancillary service agent is pivotal.

(4) An ancillary service agent does not breach clause 13.5A only because the ancillary service agent does not comply with subclause (3).

Clause 13.5B: inserted, on 17 July 2014, by clause 5 of the Electricity Industry Participation Code Amendment (Pivotal Supply) 2014.

Clause 13.5B(1)(b) and (3)(b): amended, on 29 June 2017, by clause 6 of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.
Bids and offer preparation

13.6 Requirements for generators when submitting offers

(1) Each generator with a point of connection to the grid, and each embedded generator required by the system operator to submit an offer under clause 8.25(5), must—
   (a) submit to the system operator an offer for each trading period in the schedule period, under which the generator is prepared to sell electricity to the clearing manager; and
   (b) ensure that the system operator receives an offer at least 71 trading periods before the beginning of the trading period to which the offer relates.

(2) Despite subclause (1), a generator must give at least 5 business days' notice in writing to the system operator and the pricing manager before the generator makes an offer for the 1st time in respect of the generating plant that is the subject of the offer.

(3) The notice must state—
   (a) the point of connection to the grid at which electricity generated by the generator is sold to the clearing manager under clause 14.3 or 14.4; and
   (b) whether the generating plant is an intermittent generating station.

(4) A generator must comply with any request from the system operator for information concerning generating plant that is the subject of a notice under subclause (2) if the system operator requires the information for the purposes of scheduling and dispatch in accordance with this Code.

(5) Despite subclause (1), if a generator intends to permanently cease to submit offers to the system operator in respect of any generating plant, the generator must give at least 5 business days' notice in writing to the system operator, the pricing manager, and the clearing manager.

13.7 Purchaser to submit bids for dispatch-capable load station

(1) This clause applies to each dispatchable load purchaser.

(2) Unless the dispatchable load purchaser relies on clause 13.8A, the dispatchable load purchaser must submit to the system operator for each of its dispatch-capable load stations for each trading period in the schedule period—
   (a) a nominated non-dispatch bid; or
   (b) a nominated dispatch bid.

(3) A nominated bid submitted under subclause (2) must represent a reasonable estimate of the total quantity of electricity the dispatchable load purchaser will purchase—
   (a) for the dispatch-capable load station; and
   (b) for the trading period; and
   (c) at the prices specified in the nominated bid.

Compare: Electricity Governance Rules 2003 rules 3.3 and 3.4 section II part G
Clause 13.6(1)-(3): substituted, on 28 June 2012, by clause 7 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.8A Rules for dispatchable load purchasers

(1) The dispatchable load purchaser may submit only one nominated dispatch bid and one nominated non-dispatch bid for each dispatch-capable load station that the dispatchable load purchaser operates.

(2) The nominated dispatch bid and nominated non-dispatch bid must each be nominated for the same trading period.

(3) A nominated dispatch bid submitted under subclause (1) must specify at least the quantity of electricity the dispatchable load purchaser will purchase for each trading period in the schedule period.

(4) The nominated dispatch bid that is submitted first takes priority over the nominated non-dispatch bid.

13.9A Excluding offers that are outside the nominated range

(1) The system operator may exclude from the market, and refuse to include in the market, an offer that is outside the nominated range.

(2) The nominated range is the range specified in the nominated bid.

Compare: Electricity Governance Rules 2003 rules 3.5 and 3.6 section II part G
Clause 13.8A Heading: substituted, on 28 June 2012, by clause 8(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clause 13.7(1A) and (1B): inserted, on 28 June 2012, by clause 8(2) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.


13.7AA Purchaser to submit bids for non-dispatch-capable load

(1) This clause applies to each purchaser that—
   (a) purchases non-dispatch-capable load; and
   (b) in relation to a nominated bid, does not rely on clause 13.8A.

(2) The purchaser—
   (a) must, if it purchases non-dispatch-capable load at a non-conforming GXP, submit to the system operator for each trading period in the schedule period a nominated non-dispatch bid that represents a reasonable estimate of the total non-dispatch-capable load that the purchaser will purchase—
      (i) at the GXP; and
      (ii) for the trading period; and
      (iii) at the prices specified in the nominated non-dispatch bid; and
   (b) may, if it purchases non-dispatch-capable load at a conforming GXP, submit to the system operator for a trading period a difference bid that represents a reasonable estimate of an increase or decrease in the purchaser's usual non-dispatch-capable load purchased—
      (i) at the GXP; and
      (ii) for the trading period; and
      (iii) at the prices specified in the difference bid.

13.7AB Timeframe for submitting bids to system operator

(1) Each purchaser that submits a nominated bid to the system operator must submit the nominated bid at least 71 trading periods before the beginning of the trading period to which the nominated bid applies.

(2) Each purchaser that submits a difference bid to the system operator must submit the difference bid at least 4 trading periods before the beginning of the trading period to which the difference bid applies.

13.7AC Submitting bid for first time

(1) Despite anything in this Code, a purchaser must give at least 5 business days' notice in writing to the system operator and the clearing manager before the purchaser submits a bid for the first time.

(2) The system operator may request from a purchaser information—
   (a) about the purchaser; and
   (b) that the system operator requires for the purposes of scheduling and dispatch in accordance with this Code.

(3) A purchaser must comply with a request made under subclause (2).
13.7AD Submitting bid for last time
Despite anything in this Code, if a purchaser intends to permanently cease to provide bids to the system operator, the purchaser must give at least 5 business days' notice in writing to the system operator, the pricing manager, and the clearing manager.
Clause 13.7AD: inserted, on 29 June 2017, by clause 8 of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.

13.7A System operator to prepare forecast of non-dispatch-capable load at conforming GXPs
(1) The system operator must prepare a forecast of non-dispatch-capable load for each conforming GXP for each trading period in a schedule period.
(2) The system operator must—
   (a) disclose to the Authority a description of the processes and methodology it uses to prepare the forecast under subclause (1); and
   (b) publish and keep published, either—
      (i) the description it disclosed to the Authority under paragraph (a); or
      (ii) a summary of the processes and methodology it uses to prepare the forecast under subclause (1).
(3) Despite subclause (2), the system operator is required to disclose or publish information under subclause (2) only if the information—
   (a) is available to the system operator; and
   (b) is not confidential or commercially sensitive.

13.7B Authority may request system operator to report on accuracy of forecasts of non-dispatch-capable load at conforming GXPs
(1) The Authority may, from time to time, request the system operator to report to the Authority on the accuracy of the forecast that it prepares under clause 13.7A(1).
(2) A request—
   (a) must specify the period that must be covered by the report; and
   (b) must specify a reasonable date by which the system operator must provide the report; and
   (c) must be made no more frequently than once per calendar month, unless the system operator agrees otherwise.
(3) The system operator must comply with a request made under this clause.
13.8 Deemed offers

(1) This clause applies if, on any trading day ("the current trading day"), a generator has not submitted an offer for a trading period in the trading day following the next trading day.

(2) A generator is deemed to have submitted, for that trading period, an offer that is the same as the offer the generator made for the corresponding trading period on the current trading day, and clause 13.9A applies accordingly.

(3) A deemed offer under subclause (2) applies until the generator revises the offer in accordance with clauses 13.17 to 13.19.

Compare: Electricity Governance Rules 2003 rule 3.5 section II part G
Clause 13.8: substituted, on 28 June 2012, by clause 10 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clause 13.8(3): amended, on 29 June 2017, by clause 9(2) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017

13.8A Deemed nominated bids

(1) This clause applies if, on any trading day ("the current trading day"), a purchaser has not submitted a nominated bid for a trading period in the trading day following the next trading day.

(2) A purchaser is deemed to have submitted, for that trading period, a nominated bid that is the same as the nominated bid the purchaser made for the corresponding trading period on the current trading day.

(3) A deemed nominated bid under subclause (2) applies until the purchaser revises the nominated bid in accordance with clause 13.19A.

(4) A purchaser must ensure that each of its deemed nominated bids under this clause,—
(a) if it is a nominated bid for a dispatch-capable load station, represents a reasonable estimate of the total quantity of electricity that the purchaser will purchase for the dispatch-capable load station at the specified prices for the trading period; or
(b) if it is a nominated bid for non-dispatch-capable load, represents a reasonable estimate of the non-dispatch-capable load that the purchaser will purchase at the GXP at the specified prices for the trading period.

Clause 13.8A(2) & (3): amended, on 15 May 2014, by clause 12(a) & (b) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.8B Deemed reserve offers

(1) This clause applies if, on a trading day ("the current trading day"), an ancillary service agent who provides instantaneous reserves has not submitted a reserve offer for a trading period in the trading day following the next trading day.
(2) An ancillary service agent is deemed to have submitted, for that trading period, a reserve offer that is the same as the reserve offer the ancillary service agent made for the corresponding trading period on the current trading day, and clause 13.38(2)(c) applies accordingly.

(3) A deemed reserve offer under subclause (2) applies until the ancillary service agent revises the reserve offer in accordance with clauses 13.46 to 13.49.


13.9 Information that offers must contain

Each offer submitted by a generator must—

(a) other than for intermittent generators, type A co-generators, and type B co-generators, contain all information required by Form 1 in Schedule 13.1; and

(b) [Revoked]

(c) if the offer is submitted by an intermittent generator for an intermittent generating station,—

(i) contain the information required by Form 2 in Schedule 13.1; and

(ii) have a maximum of 1 price band for each trading period; and

(iii) specify a price of either $0.00 (subject to clause 13.116) or $0.01 for the price band; and

(d) if the offer is submitted by a type A co-generator for a type A industrial co-generating station or by a type B co-generator for a type B industrial co-generating station,—

(i) contain the information required by Form 3 in Schedule 13.1; and

(ii) have a maximum of 2 price bands for each trading period; and

(iii) specify a price of either $0.00 (in accordance with clause 13.116) or $0.01 for the price band.

Compare: Electricity Governance Rules 2003 rule 3.6 section II part G

13.9A Offer not to exceed capability

The total MW specified in each offer submitted by a generator must, in relation to the generating plant that is the subject of the offer, not exceed the total MW that the generator expects to be capable of generating at the relevant point of connection to the grid for the relevant trading period.

13.10 Generators must specify units in offers
Each offer submitted by a generator must—
(a) be specific to individual generating units for generating plant in respect of which electricity is offered by that generator that cannot synchronise and come up to minimum load within the duration of a trading period; or
(b) be specific to individual generating stations for other generating plant in respect of which electricity is offered by that generator.
Compare: Electricity Governance Rules 2003 rule 3.7 section II part G

13.11 Offers may be made by unit or plant
(1) Despite clause 13.10, a generator, other than an intermittent generator, may offer electricity in respect of any generating plant on a unit basis. A generator may exercise this option by giving the system operator at least 5 business days’ notice in writing of the exercise of the option. The system operator must, during the 5 business day period, make any necessary changes to the scheduling software.
(2) If a generator has offered electricity in respect of any generating plant on a unit basis in accordance with subclause (1), it may change to submitting offers in accordance with clause 13.10. Such a change may be effected by giving the system operator at least 5 business days’ notice in writing of the change. The system operator must, during the 5 business day period, make any necessary changes to the scheduling software.
Compare: Electricity Governance Rules 2003 rule 3.8 section II part G

13.12 Offers may contain up to 5 price bands
Subject to clause 13.9(c) and (d), an offer submitted by a generator may have a maximum of 5 price bands for each trading period. The price offered in each band must increase progressively from band to band as the aggregate quantity increases.
Compare: Electricity Governance Rules 2003 rule 3.9 section II part G

13.13 Information to be contained in bids
(1) A purchaser must ensure that each of its nominated bids—
(a) contains all information required by Form 4 in Schedule 13.1; and
(aa) if it is a nominated bid for a dispatch-capable load station, specifies whether it is—
(i) a nominated dispatch bid; or
(ii) a nominated non-dispatch bid.
(b) [Revoked]
(c) if it is a nominated dispatch bid, specifies a price for each band that is one of the following:
(i) $15,000/MWh or less; or
(ii) if the Authority has published a price for the purposes of this paragraph, the published price; or
(iii) if the Authority has not published a price for the purposes of this paragraph, $600,000/MWh.
(1A) The Authority may publish a price for the purposes of subclause (1)(c) if,—
(a) the **system operator** has given to the **Authority** an updated list of values of model parameters in accordance with clause 13.189(2)(a), and the **Authority** has considered any advice it has received from the **system operator** under clause 13.189(2)(b) and (2A); or

(b) the **Authority** considers that it is necessary to publish a new price.

(2) A **purchaser** must ensure that each of its **difference bids** contains all information required by Form 4A in Schedule 13.1.

Compare: Electricity Governance Rules 2003 rule 3.10 section II part G

**13.14 Nominated bids may contain up to 10 price bands**

(1) A **nominated bid** submitted by a **purchaser** may have a maximum of 10 price bands for each **trading period**.

(2) The price in each band must decrease progressively from band to band as the aggregate quantity increases.

(3) The highest price band in each **nominated bid** is deemed to start at a quantity of 0.

Compare: Electricity Governance Rules 2003 rule 3.11 section II part G

**13.14A Difference bids may contain up to 10 price bands**

A **difference bid** submitted by a **purchaser** may have a maximum of—

(a) 5 price bands for each **trading period** representing the **purchaser’s** progressive increase in its usual quantity of **electricity** demanded for the **trading period**. The price in bands 2 to 5 must, in each case, be lower than the price in the preceding band; and

(b) 5 price bands for each **trading period** representing the **purchaser’s** progressive decrease in its usual quantity of **electricity** demanded for the **trading period**. The price in bands 2 to 5 must, in each case, be higher than the price in the preceding band.


**13.15 How price is to be specified in bids or offers**

Prices in **bids** or **offers** must be expressed in dollars and whole cents per **MWh** excluding any **GST.** There is no upper limit on the prices that may be specified and the lower limit is $0.00/MWh, subject to clauses 13.9(c) and (d), 13.24, 13.26, and 13.116.

Compare: Electricity Governance Rules 2003 rule 3.12 section II part G
13.16 How quantity is to be specified in bids or offers
For each price band, a bid or offer must specify a quantity expressed in MW to not more than 3 decimal places. The minimum quantity that may be bid or offered in a price band for a trading period is 0.000 MW.

Compare: Electricity Governance Rules 2003 rule 3.13 section II part G

13.17 Offers may be revised
(1) Subject to subclauses (2) to (4), a generator may revise an offer at any time before the beginning of the trading period to which the offer relates by submitting a new offer to the system operator.

(2) A generator must not revise any of its offer prices during a gate closure period.

(3) A generator must not revise the MW specified in any price band in an offer during a gate closure period, unless clause 13.18(1), 13.18(1A), 13.18A, or 13.19 applies.

(4) A generator must not revise any of the following offer parameters during a gate closure period, unless clause 13.19 applies:
(a) ramp rates:
(b) maximum output (including overload).

Compare: Electricity Governance Rules 2003 rule 3.14 section II part G

13.18 When revised offer to be submitted
(1) A generator must immediately submit a revised offer to the system operator if the total MW specified in an offer exceeds, by more than 5 MW, the total MW that the generator expects to be capable of generating at the relevant point of connection to the grid for the relevant trading period.

(1A) A generator may submit a revised offer to the system operator if the total MW specified in an offer exceeds, by 5 MW or less, the total MW that the generator expects to be capable of generating at the relevant point of connection to the grid for the relevant trading period.

(1B) The submission of a revised offer under subclause (1) or subclause (1A) does not relieve the generator of liability for breach of any other provision of this Code.

(2) [Revoked]

(3) Subclause (1) does not apply—
(a) in every case, after the beginning of the trading period to which an offer relates; and
(b) in relation to an intermittent generator, during the 2 hours immediately preceding the trading period to which an offer relates.

Compare: Electricity Governance Rules 2003 rules 3.15 and 3.16 section II part G

13.18A Intermittent generators to submit revised offers

(1) During the 2 hours immediately preceding the trading period to which an offer relates, each intermittent generator must submit revised offers in respect of MW offered to the system operator at a frequency of at least 1 revised offer per trading period.

(2) A revised offer submitted under subclause (1) must be based on a persistence model, unless otherwise agreed with the Authority.

(3) For the purposes of this clause, a persistence model means a method for producing a forecast of the intermittent generator's generation, in MW, that takes into account only the following factors:

(a) if the relevant intermittent generating station is generating at the time the revised offer is submitted, the actual output from the intermittent generating station at that time; and

(b) any expected changes in availability and capability of generating plant forming all or part of the relevant intermittent generating station.


13.19 When revised offers may be submitted during gate closure period

(1) A generator may submit a revised offer to the system operator during a gate closure period if—

(a) the revision is necessary due to a bona fide physical reason; or

(b) the system operator issues a formal notice under clause 5 of Technical Code B of Schedule 8.3; or

(c) a bona fide physical reason that made a revision necessary under paragraph (a) ceases to exist sooner than was expected at the time it arose, and—

(i) the 1st trading period after the original bona fide physical reason ceases to exist is within 24 hours after the circumstances that constituted the original bona fide physical reason arose; and

(ii) the total change in MW specified in the offer that is revised as a result of the bona fide physical reason ceasing to exist is the same or less than the
total change in MW specified in the offer that was made as a result of the original bona fide physical reason.

(2) A generator that submits a revised offer under subclause (1)(c) must do so as soon as possible after the relevant bona fide physical reason ceases to exist.

13.19AA Limitations on revised offers

A generator that submits a revised offer under clauses 13.18(1), 13.18(1A), or 13.19(1) during a gate closure period must ensure that—

(a) the revised offer only differs from the original offer to the extent necessary to ensure that the MW specified in the revised offer is the MW that the generator expects to be capable of generating at the relevant point of connection to the grid for the relevant trading period; and

(b) the revised offer complies with the following:

(i) the reduction in MW specified in the revised offer must be first deducted from the MW offered in the highest price band;

(ii) if the reduction in MW exceeds the MW in the highest price band, the remainder must be deducted from the price bands below the highest, in descending order as the MW in each price band is reduced to zero, until all of the reduction is reflected in the revised offer.

13.19A Bids may be revised

(1) Each purchaser may, at any time before the beginning of a trading period in respect of which a bid is made,—

(a) revise any of its bid prices or the MW specified in any price band in a bid for any trading period by submitting a new bid to the system operator; or

(aa) revise a nominated bid—

(i) from being a nominated dispatch bid to being a nominated non-dispatch bid; or

(ii) from being a nominated non-dispatch bid to being a nominated dispatch bid.

(b) [Revoked]

(1A) Despite subclause (1), a dispatchable load purchaser must not do any of the following during a gate closure period:

(a) revise the price of a nominated dispatch bid:

(b) revise the MW specified in any price band in a nominated dispatch bid, unless subclause (1B) or clause 13.19B applies.

(1B) A dispatchable load purchaser may revise the MW specified in any price band in a nominated dispatch bid during a gate closure period if—
(a) the revision is necessary due to a **bona fide physical reason**; or
(b) the **system operator** issues a **formal notice** under clause 5 of **Technical Code B** of Schedule 8.3; or
(c) a **bona fide physical reason** that made a revision necessary under paragraph (a) ceases to exist sooner than was expected at the time it arose, and—
   (i) the 1st **trading period** after the original **bona fide physical reason** ceases to exist is within 24 hours after the circumstances that constituted the original **bona fide physical reason** arose; and
   (ii) the total change in **MW** specified in the **nominated dispatch bid** that is revised as a result of the **bona fide physical reason** ceasing to exist is the same or less than the total change in **MW** specified in the **nominated dispatch bid** that was made as a result of the original **bona fide physical reason**.

(2) [Revoked]

(3) [Revoked]

(3A) If a **purchaser** revises a **nominated bid** for a **dispatch-capable load station** in the **trading period** that is immediately before the **trading period** to which the **nominated bid** applies, the revised **nominated bid** is a **nominated non-dispatch bid**.

(3B) Despite subclause (1), a **dispatchable load purchaser** must not, during the 2 **trading periods** immediately preceding the **trading period** to which a **nominated non-dispatch bid** relates, revise the **nominated non-dispatch bid** to being a **nominated dispatch bid**.

(4) [Revoked]

(5) [Revoked]

(6) If the **system operator** declares a **grid emergency**, a **dispatchable load purchaser** must comply with clause 13.99A.

Clause 13.19A(1A) and (1B): inserted, on 29 June 2017, by clause 18(6) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.
Clause 13.19A(3A): inserted, on 1 December 2015, by clause 4 of the Electricity Industry Participation Code Amendment (Dispatchable Demand: Late Bid Revisions) 2015.

13.19B Bids must be revised
(1) Before the beginning of the trading period to which a nominated bid relates, the purchaser that submitted the nominated bid must immediately submit a revised nominated bid in respect of MW to the system operator if the purchaser expects, or ought reasonably to expect, that the MW it is likely to purchase at the prices indicated in the nominated bid will,—
(a) if the nominated bid is a nominated non-dispatch bid, differ from the MW specified in the nominated bid by more than the lesser of—
(i) 20 MW; and
(ii) 20% of the nominated bid MW; or
(b) if the nominated bid is a nominated dispatch bid, differ from the MW specified in the nominated bid by more than the lesser of—
(i) 10 MW; and
(ii) 10% of the nominated bid MW.
(2) Despite subclause (1), a purchaser is not required to submit a revised nominated bid in respect of MW if the expected change in MW is less than 5 MW.

13.20 System operator advised of revised nominated bids or offers in certain circumstances
(1) This clause applies to each purchaser or generator that submits a revised nominated bid or offer during the 15 minutes immediately preceding the trading period to which the revised nominated bid or offer relates.
(2) A purchaser or generator that submits a revised nominated bid or offer in the time frame described in subclause (1) must immediately advise the system operator of the revision.
(3) Subclause (2) does not apply to an intermittent generator submitting a revised offer under clause 13.18A.
Compare: Electricity Governance Rules 2003 rule 3.18 section II part G

13.21 Authority informed of revised nominated dispatch bid or offer during gate closure period
(1) A dispatchable load purchaser or generator that submits a revised nominated dispatch bid or a revised offer to the system operator during a gate closure period...
must report each revision to the Authority in writing together with an explanation of the reasons for the revision.

(1A) The dispatchable load purchaser or generator must report the revision to the Authority no later than 1700 hours on the 1st business day following the trading day on which the revision was made.

(1B) Subclauses (1) and (1A) do not apply to an intermittent generator submitting a revised offer under clause 13.18A.

(2) [Revoked]

Compare: Electricity Governance Rules 2003 rules 3.19 and 3.20 section II part G
Clause 13.21 Heading: replaced, on 29 June 2017, by clause 21(1) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.
Clause 13.21(1A) and (1B): inserted, on 29 June 2017, by clause 21(2) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.

13.22 Transmission of information

(1) Except where specified otherwise in clauses 13.6 to 13.27, all information that a purchaser or generator must submit under clauses 13.6 to 13.27 must be submitted to the system operator using WITS.

(2) The system operator must immediately confirm receipt of any information that the system operator receives from a purchaser or generator under clauses 13.6 to 13.27. Each confirmation must contain a copy of the information received by the system operator together with the time of receipt.

(3) If a purchaser or generator has not received the confirmation within 10 minutes of submitting the information under clauses 13.6 to 13.27 to the system operator, the purchaser or generator must—

(a) check whether the system operator has received the information; and

(b) if the system operator has not received the information, resend the information; and

(c) repeat the process set out in this clause until the system operator has confirmed receipt of the information from the purchaser or generator.

Compare: Electricity Governance Rules 2003 rules 3.21 to 3.23 section II part G
13.23 Backup procedures if WITS is unavailable

(1) If WITS is unavailable to receive bids or offers or to confirm the receipt of bids or offers, each purchaser and generator or the system operator, as the case may be, must follow the backup procedures specified by the WITS manager.

(2) The backup procedures referred to in subclause (1) must be specified by the WITS manager following consultation with the Authority and each purchaser, generator and the system operator.

Compare: Electricity Governance Rules 2003 rules 3.24 and 3.25 section II part G

13.24 Plant with special circumstances

Despite clauses 13.9(b) and 13.18(1), a generator is not required to submit a revised offer in respect of an automatic control plant if—

(a) the offer submitted in respect of the automatic control plant is based on a profile of the pre-programmed levels of the automatic control plant; and

(b) the offer is made at a 0 price and clause 13.116(2) applies to the generator; and

(c) the offer is otherwise made in accordance with clauses 13.6 to 13.27; and

(d) the system operator has confirmed in writing to the generator that it is satisfied that the offer meets the requirements of the dispatch objective; and

(e) the generator expects that the ability of the automatic control plant to generate the quantity scheduled for a trading period at a grid injection point will not change by more than 10 MW of the scheduled quantity.

Compare: Electricity Governance Rules 2003 rule 3.26 section II part G

13.25 Exception for small generation

(1) Despite clause 13.6(1), a generator is not required to submit an offer for a generating station that is 10 MW or smaller and any electricity sold to the clearing manager from the generating station is regarded as unoffered generation for the purpose of this Code.

(2) The system operator may require the relevant generator to provide information in a form reasonably determined by the system operator on the expected generation output for any unoffered generation from a generating station with a point of connection to the grid.

Compare: Electricity Governance Rules 2003 rule 3.27 section II part G

13.26 Exception for embedded generation

An embedded generator required to submit an offer in accordance with clause 8.25(5) may make an offer at a 0 price and clause 13.116(2) applies to the embedded generator.

Compare: Electricity Governance Rules 2003 rule 3.28 section II part G
13.27 System operator to retain bids and offers

The system operator must retain, in a form that it considers appropriate, all bids and offers for electricity submitted by participants under this subpart, including all revised bids and offers.

Compare: Electricity Governance Rules 2003 rule 3.29 section II part G

Process for determining conforming and non-conforming grid exit points


13.27A Authority determines conforming and non-conforming GXPs on own initiative

The Authority may, on its own initiative,—

(a) determine whether a GXP, which is deemed to be a conforming GXP under clause 13.27F, is a conforming GXP or a non-conforming GXP;

(b) reconsider a previous determination, and as a result may decide to replace the previous determination with a new determination.


13.27B Authority to determine conforming and non-conforming GXPs if requested

(1) Subclause (4) applies if—

(a) a purchaser or the system operator makes a request under clause 13.27H; and

(b) the Authority decides there are valid grounds to consider the request.

(2) The Authority must decide whether to proceed with the request within a reasonable time after receiving the request.

(3) If the Authority decides there are no valid grounds to consider the request, the Authority must give written notice to the requester of—

(a) the Authority’s decision; and

(b) the grounds for the Authority’s decision.

(4) If subclause (1) applies, the Authority must—

(a) determine whether a GXP, which is deemed to be a conforming GXP under clause 13.27F, is a conforming GXP or a non-conforming GXP;

(b) reconsider a previous determination, and as a result may decide to replace the previous determination with a new determination.


13.27C Process for making determination

(1) In making a determination, the Authority must—

(a) apply the methodology set out in Schedule 13.7; and

(b) request and take into account advice from the system operator; and

(c) take into account any information submitted by a purchaser who purchases electricity at the GXP.
The Authority must make a determination in accordance with the methodology in Schedule 13.7, unless—

(a) the Authority has applied the methodology; and

(b) according to the methodology, the GXP is a conforming GXP; and

(c) the Authority considers that the GXP should be treated as a non-conforming GXP; and

(d) the Authority has published criteria under clause 13.27E; and

(e) making a determination that the GXP is a non-conforming GXP is in accordance with the criteria.

If paragraphs (a) to (e) in subclause (2) apply, the Authority may make a determination in accordance with the criteria published under clause 13.27E.

As soon as practicable after making a determination, the Authority must—

(a) advise the WITS manager, all purchasers, and the system operator—

(i) of its determination; and

(ii) whether, in making the determination, the Authority has followed—

(A) the methodology set out in Schedule 13.7; or

(B) the criteria published under clause 13.27E; and

(b) advise all purchasers and the system operator of the right to request, under clause 13.27H, a reconsideration of the determination; and

(c) if the determination was requested under clause 13.27H, provide reasons for its decision to the requester.

The system operator must provide the advice requested under clause 13.27C(1)(b) within a reasonable time specified by the Authority.

The Authority may publish criteria for determining GXP to be non-conforming

(a) publishing the criteria under subclause (1):

(b) amending the criteria published under subclause (1).
13.27F GXP deemed to be conforming GXP before determination is made
If the Authority has not made a determination for a GXP, the GXP is deemed to be a conforming GXP until the Authority determines otherwise.


13.27G Authority must publish and maintain list of non-conforming and conforming GXPs
The Authority must publish and maintain a list of all non-conforming GXPs and all conforming GXPs, including—
(a) the mean demand (in MW) for each GXP calculated in accordance with clause 1(b) of Schedule 13.7; and
(b) if the mean demand for a GXP is 10 MW or more, the unpredictability measure for the GXP calculated in accordance with clause 1(c) of Schedule 13.7.


13.27H Right to request determination or reconsideration of determination
(1) A purchaser may request that the Authority—
(a) determine whether a GXP is a conforming GXP or a non-conforming GXP, in respect of a GXP—
   (i) at which the purchaser purchases electricity; and
   (ii) which is deemed to be a conforming GXP under clause 13.27F;
(b) reconsider a determination made under clause 13.27A or clause 13.27B(4) for a GXP at which the purchaser purchases electricity.

(2) The system operator may request that the Authority—
(a) determine whether a GXP, which is deemed to be a conforming GXP under clause 13.27F, is a conforming GXP or a non-conforming GXP;
(b) reconsider a determination made under clause 13.27A or clause 13.27B(4).

(3) The person making the request may provide the Authority with information that the person considers relevant to its request.


13.27I Effect of determination
(1) When making a determination, the Authority must specify a date and a trading period from which the determination takes effect.

(2) The Authority must not specify a date that is earlier than 5 business days after the date on which the Authority makes the determination.

13.27J New GXPs
At least 1 month before a grid owner connects a GXP to the grid for the first time, the grid owner must advise the Authority in writing of its intention to connect the GXP.

13.27K Authority to provide information at purchaser’s request
(1) After the Authority has made a determination under clause 13.27A or clause 13.27B(4) for a GXP, a purchaser who purchases electricity at the GXP may request from the Authority the following information in relation to the GXP:
(a) reconciled half hour demand data (in MW), as described in clause 2(1)(a) of Schedule 13.7;
(b) information about the way in which demand switching information (described in clause 2(1)(b) of Schedule 13.7) has been used to prepare the adjusted reconciled half hour demand data described in clause 1(a) of Schedule 13.7;
(c) information about the one-off events described in clause 2(1)(c) and clause 2(3) of Schedule 13.7 and the way in which those one-off events have been used to prepare the adjusted reconciled half hour demand data described in clause 1(a) of Schedule 13.7;
(d) the adjusted reconciled half hour demand data (in MW), as described in clause 1(a) of Schedule 13.7;
(e) the estimates of the adjusted reconciled half hour demand produced by the statistical predictive model under clause 3(1)(a) of Schedule 13.7, and the residuals calculated under clause 3(1)(b) of Schedule 13.7.
(2) If a purchaser requests information under subclause (1), the Authority must provide the information if the information—
(a) is available to the Authority; and
(b) is not confidential; and
(c) is not commercially sensitive.

Special treatment of some grid exit points
Heading: inserted, on 28 June 2012, by clause 22 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.28 Special treatment of some grid exit points
(1) For the purpose of this subpart and subparts 2 and 4, a purchaser, generator or market operation service provider may apply to the Authority to have 2 or more grid exit points treated as 1 grid exit point for the purposes of determining the status of a GXP under clause 13.27A or clause 13.27B(4), submitting bids, scheduling, switching,
dispatch, pricing, clearing and settlement where there are 2 or more local networks supplied from the grid at the same physical location.

(2) In determining an application under subclause (1), the Authority must consider the following factors:

(a) the efficiency or otherwise, of creating a separate price for grid exit points that are at the same, or at a geographically similar location;

(b) the geographical similarity of the grid exit points that are the subject of the application:

(c) the effect on a market operation service provider in terms of added processing time and complexity in treating as separate 2 or more grid exit points that are in the same or in a geographically similar location:

(d) any submissions received from participants under subclause (3):

(e) any other matter the Authority thinks fit.

(3) The Authority must give written notice to participants of an application under subclause (1) within 2 business days of the application being received by the Authority. Each participant has 5 business days to make submissions to the Authority on the application. The Authority must not consider an application until after the period for making submissions on the application has expired.

(4) If an application under subclause (1) has been approved, the Authority must consult with each market operation service provider about the time it may take to implement changes that are required to accommodate the decision. The Authority must then give written notice to each participant of the date from which its decision takes effect.

Compare: Electricity Governance Rules 2003 rule 4 section II part G

Information from grid owners

13.29 Standing data on grid capability to be provided to system operator

In addition to the asset owner obligations to provide information under clauses 2(5) and (6) and 3(1) of Technical Code A of Schedule 8.3, each grid owner must provide standing data on the capability of the transmission system to the system operator that is consistent with the configuration of the transmission system in the algorithms described in Schedule 13.3. The transmission data must include—

(a) AC system configuration, including the transmission lines; and

(b) AC system capacity including the limits of each transmission line of the transmission system; and

(c) AC system loss characteristics including transmission loss functions for each transmission line of the transmission system.

Compare: Electricity Governance Rules 2003 rule 5.1 section II part G
13.30 Standing data on HVDC capability to be provided to system operator

(1) In addition to the asset owner obligations to provide information under clauses 2(5) and (6), and 3(1) of Technical Code A of Schedule 8.3, the HVDC owner must provide standing data on the capability of the HVDC link to the system operator consistent with the configuration of the HVDC link.

(2) The data provided under subclause (1) must include—
   (a) the HVDC transmission lines and system capacity, including reserve capacity; and
   (b) HVDC link capacity, including limits of each HVDC transmission line of the HVDC transmission system; and
   (c) HVDC system loss characteristics including transmission loss functions for each transmission line of the HVDC transmission system; and
   (d) in relation to Pole 2, or Pole 3, or Pole 2 and Pole 3, of the HVDC link—
      (i) if the HVDC owner imposes a limit on transfer direction, the direction of that transfer limit (northward or southward); and
      (ii) if the HVDC owner imposes a minimum transfer limit, that minimum transfer limit (in MW); and
      (iii) if the HVDC owner imposes a maximum transfer limit, that maximum transfer limit (in MW).

(3) Subclause (2)(d) applies only if—
   (a) the HVDC owner is operating the HVDC link in accordance with—
      (i) a commissioning plan agreed with the system operator under clause 2(6) to (9) of Technical Code A of Schedule 8.3; or
      (ii) a test plan provided to the system operator under clause 2(6) to (9) of Technical Code A of Schedule 8.3; and
   (b) the configuration of the HVDC link is—
      (i) Pole 3 and Pole 2 bipole round power; or
      (ii) Pole 3 and Pole 2 bipole not round power.

Compare: Electricity Governance Rules 2003 rule 5.2 section II part G

13.31 Standing data on transformer capability to be provided to system operator

In addition to the asset owner obligations to provide information under clauses 2(5) and (6), and 3(1) of Technical Code A of Schedule 8.3 each grid owner must provide standing data on the capability of transformers to the system operator consistent with the configuration of those transformers. The data must include—
   (a) the transformer capacity of each transformer; and
   (b) the transformer loss characteristics, including transformer loss functions, for each transformer.

Compare: Electricity Governance Rules 2003 rule 5.3 section II part G
13.32 Transmission grid capability information to be updated
In addition to the asset owner obligations to provide information under clauses 2(5) and (6) of Technical Code A of Schedule 8.3, and subject to any timetable agreed with the system operator under clause 3(1) of Technical Code A of Schedule 8.3, each grid owner must submit to the system operator for each trading period of a schedule period, or for such longer period of time as agreed between the system operator and each grid owner, any updates to the information described in clauses 13.29 to 13.31 and 13.33(d).
Compare: Electricity Governance Rules 2003 rule 5.4 section II part G

13.33 Grid owners must submit revised information to system operator
Up to 1 hour before the beginning of the relevant trading period, but subject to any timetable agreed with the system operator under clause 3(1) of Technical Code A of Schedule 8.3, each grid owner must immediately submit revised information to the system operator if there has been or is likely to be—
(a) a change to the information described in clauses 13.29 or 13.30; or
(b) a change of 5% or more in the capacity limit of any transmission line of the transmission system, of the HVDC link, or of any transformer, represented in the algorithms described in Schedule 13.3; or
(c) a change to loss characteristics, including loss functions, for any transmission line of the transmission system or of the HVDC link, or for any transformer, represented in the algorithms described in Schedule 13.3 that causes any losses or marginal losses to change by 5% or more; or
(d) a change in the availability of assets forming part of the grid.
Compare: Electricity Governance Rules 2003 rule 5.5 section II part G

13.34 Changes may be made within 1 hour before trading period
(1) A grid owner may update the information submitted under clause 13.33 later than 1 hour before the relevant trading period only if—
(a) a bona fide physical reason necessitates the change; or
(b) the system operator issues a formal notice; or
(c) an unforeseeable change occurs in the availability of a grid owner’s assets, which were the subject of a planned or unplanned outage in relation to which the grid owner gave written notice to the system operator.
(2) If a grid owner has sent revised information to the system operator under subclause (1) later than 15 minutes before the relevant trading period, the grid owner must also immediately advise the system operator of the revised information by telephone or by such other mechanism as may be agreed from time to time in writing between grid owners and the system operator.
(3) [Revoked]
(4) [Revoked]
13.35 System operator to confirm receipt of grid owner information

(1) [Revoked]

(2) The system operator must immediately confirm to each grid owner receipt of all information received from that grid owner under clauses 13.29 to 13.35. The confirmation must also contain a record of the time of receipt.

(3) If a grid owner has not received a confirmation that its information has been received by the system operator within 10 minutes after that information has been sent, the grid owner must telephone the system operator to check whether the information has been received. If it has not, the grid owner must resend the information. The process set out in this clause must be repeated until the system operator confirms receipt of the information.

Compare: Electricity Governance Rules 2003 rules 5.10 to 5.12 section II part G

13.36 [Revoked]

Compare: Electricity Governance Rules 2003 rules 5.13 and 5.14 section II part G

Offering instantaneous reserve

13.37 System operator to approve ancillary service agents wishing to make reserve offers

Before an ancillary service agent makes a reserve offer under clauses 13.38 to 13.54, the ancillary service agent must have a valid and enforceable contract with the system operator to provide reserve offers in accordance with this Code.

Compare: Electricity Governance Rules 2003 rule 6.1 section II part G

13.38 Ancillary service agents to submit reserve offers to system operator

(1) Each ancillary service agent who has a contract described in clause 13.37 may submit reserve offers to the system operator.
(1A) An ancillary service agent who submits a reserve offer must ensure that the system operator receives the reserve offer at least 71 trading periods before the beginning of the trading period to which the reserve offer applies.

(2) Each reserve offer submitted by an ancillary service agent under subclause (1) may be for fast instantaneous reserve, sustained instantaneous reserve or both and must—
   (a) contain all the information required by Form 5 in Schedule 13.1 for partly loaded spinning reserve or tail water depressed reserve; and
   (b) contain all the information required by Form 6 in Schedule 13.1 for interruptible load; and
   (c) be a reasonable estimate of the quantity of instantaneous reserve available from the ancillary service agent at that grid injection point, grid exit point or interruptible load group GXP.

(3) Each reserve offer submitted under subclause (1), by an ancillary service agent that is a generator, must be made by reference to the same generating unit or generating station that is the subject of an offer under clauses 13.10 or 13.11.

13.39 Inter-relationship between reserve and energy offers
Reserve offers and offers made under clauses 13.38(1) and 13.6(1) to (3) respectively, if they are in respect of the same individual generating unit or individual generating station (as required under clauses 13.10 and 13.11), are inter-related in that the greater the energy dispatched the lower the instantaneous reserve may be and vice versa. Accordingly, an ancillary service agent that is a generator does not breach clauses 13.9(b) or 13.38(2)(c) if the offer quantity under clauses 13.6 to 13.27 and quantity of instantaneous reserve offered under clauses 13.37 to 13.54 are duplicated, and the ancillary service agent must not be scheduled by the system operator and a dispatch instruction from the system operator must not be given the effect of which is that the combined dispatch quantity and instantaneous reserve exceeds the capacity of the individual generating unit or individual generating station, as the case may be.

13.40 Inter-relationship between reserve offers of interruptible load and bids
Bids and reserve offers of interruptible load are inter-related in that demand electrically connected in response to an under-frequency event and in accordance with a dispatched reserve offer may lower the quantity purchased at that grid exit point. Accordingly, a purchaser does not breach the reasonable estimate requirement in clauses 13.7(3), 13.7AA(2), and 13.8A(4) if the purchaser is acting as an ancillary


**service agent** and **electrically disconnects** corresponding **demand** in response to an **under-frequency event** in accordance with a dispatched **reserve offer**.

Compare: Electricity Governance Rules 2003 rule 6.6 section II part G

### 13.41 Reserve offers may contain up to 3 price bands

Each **reserve offer** submitted by an **ancillary service agent** may, for each type of **instantaneous reserve**, have a maximum of 3 price bands for each **trading period**. The price offered in each band must increase progressively from band to band as the aggregate quantity increases.

Compare: Electricity Governance Rules 2003 rule 6.7 section II part G

### 13.42 How price to be specified in reserve offers

When submitting a **reserve offer** under clause 13.38, an **ancillary service agent**—

(a) must express the price in each band in dollars and whole cents per **MW** excluding GST; and

(b) must specify a price that is equal to or greater than $0.00/MW.

Compare: Electricity Governance Rules 2003 rule 6.8 section II part G

### 13.43 [Revoked]

Compare: Electricity Governance Rules 2003 rule 6.9 section II part G

### 13.44 How quantity is to be specified in reserve offers

For each price band, a **reserve offer** must specify the quantity of **instantaneous reserve** offered to respond as **fast instantaneous reserves** or **sustained instantaneous reserves** as a proportion of **electricity** output or consumption up to a specified maximum quantity or as a quantity available to be interrupted, and must be expressed in **MW** to not more than 3 decimal places. The minimum quantity that may be offered in a price band for a **trading period** is 0.000 **MW**.

Compare: Electricity Governance Rules 2003 rule 6.10 section II part G
13.45 Reserve offers revised if energy offers revised

An ancillary service agent that has made a reserve offer must revise the reserve offer if it has, in accordance with clauses 13.6 to 13.27, revised the offer made in respect of the equivalent item of generating plant.

Compare: Electricity Governance Rules 2003 rule 6.11 section II part G

13.46 Reserve offers may be revised

(1) Subject to subclauses (1A) and (1B), an ancillary service agent may revise a reserve offer at any time before the beginning of the trading period in respect of which the reserve offer is made by submitting a new reserve offer to the system operator.

(1A) An ancillary service agent must not revise its reserve offer prices during a gate closure period.

(1B) An ancillary service agent must not revise the MW specified in any price band in a reserve offer during a gate closure period unless subclause (3) or clause 13.47 applies.

(2) An ancillary service agent that revises a reserve offer for an embedded generating station must use reasonable endeavours to submit the reserve offer at least 1 hour before the beginning of the trading period in respect of which the reserve offer is made.

(3) Before the beginning of the trading period to which the reserve offer applies, and despite clauses 13.97 to 13.101, an ancillary service agent must immediately submit a revised reserve offer in respect of MW offered to the system operator if—

(a) the MW specified in any price band in the reserve offer no longer represents a reasonable estimate of the instantaneous reserve available from the ancillary service agent at the grid injection point, grid exit point or interruptible load group GXP; or

(b) the relevant MW specified in the non-response schedule most recently published by the system operator is not likely to be achieved by the ancillary service agent at the relevant grid injection point, grid exit point or interruptible load group GXP.

(4) [Revoked]

Compare: Electricity Governance Rules 2003 rules 6.12 and 6.13 section II part G
Clause 13.46(1A) and (1B): inserted, on 29 June 2017, by clause 28(2) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.
Clause 13.46(3): amended, on 29 June 2017, by clause 28(4)(a) and (b) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.
13.47 MW change during gate closure period

(1) An ancillary service agent may revise a reserve offer during a gate closure period if—
   (a) the revision is necessary due to a bona fide physical reason; or
   (b) the system operator issues a formal notice under clause 5 of Technical Code B of Schedule 8.3; or
   (c) a bona fide physical reason that made a revision necessary under paragraph (a) ceases to exist sooner than was expected at the time it arose, and—
      (i) the 1st trading period after the original bona fide physical reason ceases to exist is within 24 hours after the circumstances that constituted the original bona fide physical reason arose; and
      (ii) the total change in MW specified in the reserve offer that is revised as a result of the bona fide physical reason ceasing to exist is the same or less than the total change in MW specified in the reserve offer that was made as a result of the original bona fide physical reason.

(2) [Revoked]

Compare: Electricity Governance Rules 2003 rule 6.14 section II part G
Clause 13.47 Heading: replaced, on 29 June 2017, by clause 29(1) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.

13.48 System operator advised of revised reserve offers in certain circumstances

(1) This clause applies to each ancillary service agent that submits a revised reserve offer during the 15 minutes immediately preceding the trading period to which the revised reserve offer relates.

(2) The ancillary service agent must immediately advise the system operator of the revision.

Compare: Electricity Governance Rules 2003 rule 6.15 section II part G
Clause 13.48(2): amended, on 5 October 2017, by clause 351(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017

13.49 Authority advised of revised reserve offer during gate closure period

(1) An ancillary service agent that submits a revised reserve offer to the system operator during a gate closure period must report each revision to the Authority in writing together with an explanation of the reason for the revision.

(2) The ancillary service agent must report a revision to the Authority no later than 1700 hours on the 1st business day following the trading day on which it made the revision.

Compare: Electricity Governance Rules 2003 rule 6.16 section II part G
13.50 System operator to advise Authority of revision of reserve offers

(1) The system operator must advise the Authority of any revision of the availability of reserves that are provided under ancillary services contracts not covered by clauses 13.37 to 13.54.

(1A) The system operator must advise the Authority of a revision no later than 1700 hours on the 1st business day following the trading day on which the revision was made.

(2) [Revoked]

Compare: Electricity Governance Rules 2003 rules 6.17 and 6.18 section II part G
Clause 13.50(1): amended, on 29 June 2017, by clause 32(2)(a) and (b) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.
Clause 13.50(1A): inserted, on 29 June 2017, by clause 32(3) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.

13.51 Transmission of reserve offers

(1) All reserve offers or cancellations of reserve offers submitted by an ancillary service agent under clauses 13.37 to 13.54 must be transmitted to the system operator through WITS.

(2) The system operator must immediately confirm receipt to the ancillary service agent of all reserve offers or cancellations of reserve offers received from the ancillary service agent through WITS. Such confirmation must also contain a copy of the reserve offer or cancellation of reserve offer received by the system operator, together with the time of receipt.

(3) If an ancillary service agent has not received confirmation that the system operator has received its reserve offer or cancellation of a reserve offer within 10 minutes after the ancillary service agent submitted the reserve offer or cancellation of a reserve offer, the ancillary service agent must check whether the system operator has received the reserve offer or cancellation of a reserve offer. If the system operator has not received the reserve offer or cancellation of a reserve offer, the ancillary service agent must resend the reserve offer or cancellation of a reserve offer. The processes set out in this clause must then be repeated until the system operator confirms receipt of the reserve offer or cancellation of a reserve offer from the ancillary service agent.

Compare: Electricity Governance Rules 2003 rules 6.19 to 6.21 section II part G

13.52 Backup procedures if WITS is unavailable

(1) If WITS is unavailable to receive reserve offers or cancellations of reserve offers or to confirm the receipt of such reserve offers or cancellations, an ancillary service agent
or the system operator, as the case may be, must follow the backup procedures specified by the WITS manager.

(2) The backup procedures referred to in subclause (1) must be specified by the WITS manager following consultation with the Authority, ancillary service agents and the system operator.

Compare: Electricity Governance Rules 2003 rules 6.22 and 6.23 section II part G

13.53 Additional information to be provided by participants

Despite clauses 13.22, 13.23, 13.51, and 13.52, if an ancillary service agent submits a reserve offer for partly loaded spinning reserve or tail water depressed reserve in accordance with clauses 13.37 to 13.54, the ancillary service agent must also provide the following information in relation to the capability to provide partly loaded spinning reserve or tail water depressed reserve to the system operator in a manner and at such times as are approved by the system operator (such approval not to be unreasonably withheld):

(a) the maximum quantity of fast response partly loaded spinning reserve expressed in MW and the maximum quantity of sustained response partly loaded spinning reserve expressed in MW:

(b) the maximum quantity of fast response tail water depressed reserve expressed in MW and the maximum quantity of sustained response tail water depressed reserve expressed in MW.

Compare: Electricity Governance Rules 2003 rule 6.24 section II part G

13.54 System operator to retain reserve offers

The system operator must retain, in a form that it considers appropriate, all reserve offers submitted by all ancillary service agents in accordance with this subpart, including all revised reserve offers.

Compare: Electricity Governance Rules 2003 rule 6.25 section II part G

13.55 Availability of bids, offers, and reserve offers

(1) The WITS manager must, within 24 hours of the end of each day, make available on WITS and at no cost on a publicly accessible approved system, all final bids, final offers and final reserve offers received for the trading periods of the previous trading day.

(2) All information made available on WITS and on the publicly accessible approved system must remain available for inspection for a period of at least 4 weeks—

(a) on WITS; and

(b) at no cost on the publicly accessible approved system.
(3) If WITS is unavailable for the purposes of subclause (2)(a), the WITS manager must follow the backup procedures specified by the WITS manager from time to time.

(4) The backup procedures referred to in subclause (3) must be put in place by the WITS manager in consultation with the Authority, purchasers, generators and ancillary service agents.

(5) If the publicly accessible approved system is not available for the purposes of subclause (2)(b), the WITS manager is not obliged to follow any backup procedures, but the WITS manager must make the information available at no cost as soon as practicable once the publicly accessible approved system becomes available.

(6) [Revoked]

(7) [Revoked]

Compare: Electricity Governance Rules 2003 rule 7 section II part G
Clause 13.55(6) and (7): revoked, on 28 June 2012, by clause 28(2) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.55A System operator to make information available

(1) The system operator must retain, for at least 2 years,—

(a) information about all bids, cancelled bids, offers, cancelled offers, reserve offers, and cancelled reserve offers submitted by a purchaser, generator, or ancillary service agent for a trading period; and

(b) each forecast prepared under clause 13.7A(1).

(2) Any person may request that the system operator make available any of the information described in subclause (1) for any trading period that occurred at least 1 day before the date of the request.

(3) The system operator must make the requested information available in a manner, and for a fee, that is reasonable having regard to the size and nature of the request.


Subpart 2—Scheduling and dispatch

13.56 Contents of this subpart

This subpart specifies—

(a) the system operator’s dispatch objective; and

(b) the process for preparing a price-responsive schedule and non-response schedule, including the contents of and inputs for those schedules; and
(c) the process by which the system operator prepares a dispatch schedule; and
(d) the process by which the system operator prepares and issues dispatch instructions; and
(e) the requirement for generators, ancillary service agents, and dispatched purchasers to comply with dispatch instructions; and
(f) the process for preparation and publication by the system operator of the schedule of real time prices; and
(g) the implications of a grid emergency for bids, offers and reserve offers; and
(h) the system operator’s reporting obligations; and
(i) the requirement for the system operator to publish scheduling information.

Compare: Electricity Governance Rules 2003 rule 1 section III part G

13.57 The dispatch objective
The system operator’s dispatch objective is to maximise for each half hour the gross economic benefits to all purchasers of electricity at the grid exit points, less the cost of supplying the electricity at the grid injection points and the costs of ancillary services purchased by the system operator under subpart 3 of Part 8, in accordance with the methodology set out in Schedule 13.3, subject to—
(a) the capability of generation, dispatch-capable load stations for which a nominated dispatch bid was submitted, and ancillary services and the configuration and capacity of the grid and information made available by asset owners; and
(b) achieving the principal performance obligations and any arrangements of the type described in clause 8.6; and
(c) meeting the requirements of clause 8.5 in relation to restoration of the power system—
provided that in the case of any conflict between paragraphs (b) and (c), paragraph (c) takes priority.

Compare: Electricity Governance Rules 2003 rule 2 section III part G

13.58 Process for preparing price-responsive schedule and non-response schedule
(1) The system operator must prepare—
(a) a price-responsive schedule; and
(b) a non-response schedule.
(1A) The system operator must prepare the schedules listed in subclause (1) in accordance with the timing required under clause 13.62.
(2) [Revoked]
(3) [Revoked]
(3A) In preparing each price-responsive schedule, the system operator must—
(a) use the most recent information received under subpart 1; and
(b) use all other information described in clause 13.58A(1); and
(c) act in accordance with Schedule 13.3.

(3B) In preparing each non-response schedule, the system operator must—
(a) use the most recent information received under subpart 1; and
(b) use all other information described in clause 13.58A(2); and
(c) act in accordance with Schedule 13.3.

(4) As soon as practicable after the system operator has completed preparing a price-responsive schedule and a non-response schedule, the system operator must make the schedules available to the clearing manager using WITS.

Compare: Electricity Governance Rules 2003 rules 3.1 to 3.4 section III part G
Clause 13.58(2) and (3): revoked, on 28 June 2012, by clause 31 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clause 13.58(3A) and (3B): inserted, on 28 June 2012, by clause 31 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.58A Inputs for price-responsive schedule and non-response schedule

(1) The system operator must prepare a price-responsive schedule using the following inputs:
   (a) offers and reserve offers; and
   (b) nominated bids; and
   (c) the forecast prepared by the system operator under clause 13.7A(1); and
   (d) difference bids; and
   (e) information provided to the system operator by a grid owner under clauses 13.29 to 13.34 about—
      (i) the AC transmission system configuration, capacity, and losses; and
      (ii) the capability of the HVDC link including its configuration, capacity, losses, the direction of any transfer limit, and any minimum or maximum transfer limits; and
      (iii) transformer configuration, capacity, and losses; and
   (f) the adjustments specified in subclause (2)(e), subject to any exceptions specified in the policy statement; and
   (g) information about voltage support from contracts held by the system operator under the procurement plan; and
   (h) information from ancillary service agents about instantaneous reserves procured under the procurement plan.

(2) The system operator must prepare a non-response schedule using the following inputs:
   (a) offers, nominated dispatch bids, and reserve offers; and
   (b) nominated non-dispatch bid quantities; and
   (c) the forecast prepared by the system operator under clause 13.7A(1); and
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(d) information provided to the system operator by a grid owner under clauses 13.29 to 13.34 referring to—
(i) the AC transmission system configuration, capacity, and losses; and
(ii) the capability of the HVDC link including its configuration, capacity, losses, the direction of any transfer limit, and any minimum or maximum transfer limits; and
(iii) transformer configuration, capacity, and losses; and
(e) adjustments made by the system operator under clause 13(1) of Schedule 13.3, in order to meet the dispatch objective; and
(f) information about voltage support from contracts held by the system operator under the procurement plan; and
(g) information from ancillary service agents about instantaneous reserves procured under the procurement plan.


13.59 Contents of each price-responsive schedule and non-response schedule
For each trading period in the schedule length period,—
(a) each price-responsive schedule and each non-response schedule prepared by the system operator must specify—
(i) the expected average level of electricity output for each generating plant or generating unit; and
(ii) the expected average level of instantaneous reserve for each generating plant or generating unit; and
(iii) the expected average level of interruptible load for each ancillary service agent for each grid exit point or interruptible load group grid exit point; and
(iv) the indicative frequency keeping units for each island; and
(v) the expected average level of demand at each grid exit point; and
(vi) forecast prices; and
(vii) forecast reserve prices; and
(viii) forecast marginal location factors for each grid injection point and each grid exit point; and
(ix) the expected largest single reserve risk for each island; and
(x) the expected level of fast instantaneous reserve and sustained instantaneous reserve required in each island; and
(xi) a stack of reserve offers for each island (ranking in price order from lowest to highest), and for each island separate stacks must be provided for fast instantaneous reserve and sustained instantaneous reserve; and
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(xii) a stack of all reserve offers for each island (ranking in price order from lowest to highest) adjusted for the expected level of energy output for each generating plant or generating unit, and for each island separate stacks must be provided for fast instantaneous reserve and sustained instantaneous reserve; and

(xiii) the expected HVDC component flows; and

(xiv) the expected HVDC risk offsets; and

(xv) the expected near-constraint arc flows; and

(xvi) the expected near-group-constraint arc flows; and

(xvii) the group constraint formulas relating to the expected near-group-constraint arc flows; and

(xviii) the expected deficit quantities for energy, fast instantaneous reserve, and sustained instantaneous reserve (if any); and

(xix) whether the HVDC link is out of service; and

(b) each price-responsive schedule prepared by the system operator must specify the expected quantities for each bid; and

(c) each non-response schedule prepared by the system operator must specify the expected—

(i) non-dispatch-capable load at each conforming GXP; and

(ii) demand for each nominated bid.

Compare: Electricity Governance Rules 2003 rule 3.5 section III part G
Clause 13.59(a)(xviii) and (xix): inserted, on 1 June 2013, by clause 6 of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

13.60 Block dispatch may occur

(1) A generator and the system operator may agree to treat a group of generating stations as a block dispatch group.

(2) If an agreement for block dispatch has been reached, the following procedures apply:

(a) the generator must give written notice to the clearing manager of the agreement, at least 5 business days before the agreement takes effect, specifying—

(i) the trading day and the trading period in which the agreement will take effect; and

(ii) the generating stations that are the subject of the agreement; and

(iii) the terms of the agreement; and

(b) the system operator must identify in each non-response schedule the generating stations or generating units that are part of a block dispatch group.

(3) The generator must give written notice to the clearing manager of any change to an agreement for block dispatch made under this clause or clause 13.61 at least 5 business days before the change takes effect.

Compare: Electricity Governance Rules 2003 rules 3.6 to 3.6.2 section III part G
13.61 System operator to give notice of block security constraints

(1) The system operator must give notice on WITS to generators of the implication of any block security constraints that apply within the block dispatch group. The notice must include—
   (a) the trading periods for which the block security constraint applies; and
   (b) how the block security constraint divides the generating stations or generating units of a block dispatch group into sub-block dispatch groups.

(2) If a notice has been sent in accordance with subclause (1), the notice remains valid until the earliest of—
   (a) completion of the trading periods set out in the notice; or
   (b) receipt of another notice from the system operator in accordance with subclause (1) for the same block dispatch group for the same trading period or trading periods; or
   (c) receipt of a notice from the system operator that the block security constraint no longer exists; or
   (d) receipt of an instruction from the system operator in accordance with clause 13.75(1)(f) for the same block dispatch group for the applicable trading period, and such instruction remains valid for the trading periods specified in that instruction.

(3) [Revoked]

Compare: Electricity Governance Rules 2003 rules 3.6.3 to 3.6.5 section III part G
Clause 13.61(1)(a) and (b): amended, on 1 February 2016, by clause 79(1) and (2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

13.62 Frequency of price-responsive schedules and non-response schedules

(1) The system operator must use reasonable endeavours to commence preparing a price-responsive schedule and a non-response schedule—
   (a) once in every 4th trading period throughout the trading day, for a period covering—
(i) the trading period in which the system operator commences preparing the relevant schedule; and
(ii) the following 7 trading periods; and
(b) once in each trading period for a period covering—
(i) the trading period in which the system operator commences preparing the relevant schedule; and
(ii) the following 7 trading periods.

(2) The system operator must use reasonable endeavours to ensure that—
(a) each time it prepares a price-responsive schedule, it prepares a non-response schedule at the same time; and
(b) each time it prepares a non-response schedule, it prepares a price-responsive schedule at the same time.

(3) The system operator must complete a schedule—
(a) if it commenced preparing the schedule under subclause (1)(a), by the end of the trading period after the trading period in which the system operator commenced preparing the schedule; and
(b) if it commenced preparing the schedule under subclause (1)(b), by the end of the trading period in which the system operator commenced preparing the schedule.

Compare: Electricity Governance Rules 2003 rule 3.7 section III part G

13.63 Trading period information to be made available to pricing manager and clearing manager

The system operator must, by 0730 hours of each trading day, make the final information provided to the system operator under subpart 1 in relation to each trading period of the previous trading day available to the pricing manager and clearing manager on WITS or through an approved system.

Compare: Electricity Governance Rules 2003 rule 3.8 section III part G

13.64 Station dispatch may occur

(1) A generator may elect to have its generating plant dispatched as a station dispatch group by giving the system operator at least 15 business days’ notice in writing in the form set out in Form 8 of Schedule 13.1. The system operator must use best endeavours to implement the election within 15 business days after receiving the notice.

(2) The system operator must give written notice to the generator and the clearing manager of the effective date of the election at least 5 business days before the date. On and from the effective date, the procedures set out in clauses 13.65 and 13.66 must be followed by the system operator and the generator.

Compare: Electricity Governance Rules 2003 rule 3.9 section III part G
13.65 System operator to give notice of station security constraints

(1) The system operator must give notice on WITS to the generator of the implication of any station security constraints that apply within a station dispatch group. The notice must include—
   (a) the trading periods for which the station security constraint applies; and
   (b) how the station security constraint divides the generating units or generating stations of a station dispatch group into a sub-station dispatch group or limits the generation of a station dispatch group.

(2) If a notice has been sent in accordance with subclause (1), the notice remains valid until the earliest of—
   (a) completion of the trading periods set out in the notice; or
   (b) receipt of another notice from the system operator in accordance with subclause (1) for the same station dispatch group for the same trading period or trading periods; or
   (c) receipt of a notice from the system operator that the station security constraint no longer exists; or
   (d) receipt of an instruction from the system operator in accordance with clause 13.75(1)(g) for the same station dispatch group for the applicable trading period, and the instruction remains valid for the trading periods specified in the instruction.

Compare: Electricity Governance Rules 2003 rules 3.9.1 and 3.9.2 section III part G

13.66 Generator gives written notice of change from station to unit dispatch

If a generator changes the dispatch of its generating plant from a station dispatch group basis to a generating unit basis, it must give the system operator at least 15 business days’ notice in writing. The system operator must use best endeavours to implement the change within 15 business days of receiving a notice. The system operator must give written notice to the generator and the clearing manager of the effective date of the change at least 5 business days before the date.

Compare: Electricity Governance Rules 2003 rule 3.9.3 section III part G

13.67 Transmission of information

(1) [Revoked]
(2) If WITS or the publicly accessible approved system is unavailable for the purposes of making information available under clauses 13.58 to 13.66, the system operator must follow the backup procedures specified by the WITS manager.

(3) The WITS manager must specify the backup procedures referred to in subclause (2) following consultation with the Authority, the system operator, the clearing manager, and the pricing manager.

Compare: Electricity Governance Rules 2003 rules 3.10 to 3.12 section III part G
Clause 13.67(2) and (3): replaced, on 5 October 2017, by clause 363(2)(b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

The dispatch process

13.68 Receipt of new non-response schedule supersedes old schedule [Revoked]
Compare: Electricity Governance Rules 2003 rule 4.1 section III part G

13.69 System operator may adjust dispatch schedule [Revoked]
Compare: Electricity Governance Rules 2003 rule 4.2 section III part G

13.69A System operator to prepare dispatch schedule
The system operator must prepare a dispatch schedule in accordance with the methodology set out in Schedule 13.3.

13.70 System operator may depart from dispatch schedule
The system operator may exercise discretion in departing from the dispatch schedule only if it is necessary to meet—
(a) the dispatch objective; or
(b) the requirements of clause 8.5 in relation to restoration of the power system.
Compare: Electricity Governance Rules 2003 rule 4.3 section III part G

13.71 System operator to use certain things
(1) In determining dispatch instructions when implementing a dispatch schedule under clause 13.72(1)(a), the system operator must use—
(a) the price order in the current dispatch schedule; and
(b) any revised offer from a generator submitted in accordance with clause 13.19 (except for revised offers submitted by an intermittent generator under clause 13.19(1)(a)(iii)); and
(c) any ramp rates of **generators**. For **intermittent generators**, the ramp rates are those agreed between the **intermittent generator** and the **system operator**; and

(d) any revised **nominated bid** quantities from a **purchaser** submitted in accordance with clause 13.19A; and

(e) any additional information regarding the future output of an **intermittent generator** submitted by an **intermittent generator** in agreement with the **system operator**; and

(f) the actual profile of **demand** during the previous **trading period**; and

(g) the expected profile of **demand** within the current **trading period** and the subsequent **trading periods**; and

(h) the current output levels of each **generator**; and

(i) any revised **reserve offer** from an **ancillary service agent** advised in accordance with clause 13.48; and

(j) any revised information received from a **grid owner** under clause 13.34(1); and

(k) the order in which reserves may be called as specified by the **system operator** from time to time.

(2) In determining **dispatch instructions** under clause 13.72(1)(b), the **system operator** must use revised **nominated dispatch bids** submitted under clause 13.19A.

**Compare:** Electricity Governance Rules 2003 rule 4.4 section III part G


### 13.72 System operator to issue dispatch instructions

(1) The **system operator** must implement—

(a) a **dispatch schedule**, and any departure from the **dispatch schedule** under clause 13.70, by issuing **dispatch instructions** to,—

(i) **generators**; and

(ii) **ancillary service agents**;

(b) a **non-response schedule** by issuing **dispatch instructions** to **dispatchable load purchasers** that have submitted **nominated dispatch bids**.

(2) The **system operator** must issue each **dispatch instruction** in a reasonable and timely manner to enable the **participant** to which the **dispatch instruction** is issued to comply with the **dispatch instruction**.

(3) Despite subclause (1), the **system operator** is not required to issue a **dispatch instruction** to a **participant** if—

(a) the **dispatch instruction** is—

(i) to provide a quantity of **active power** under clause 13.73(1)(a); or

(ii) to provide a quantity of **instantaneous reserve** under clause 13.73(1)(b); and

(b) the **dispatch instruction** would differ from the most recent **dispatch instruction** issued to the **participant** by 1 MW or less.

**Compare:** Electricity Governance Rules 2003 rule 4.5 section III part G

13.73 Content of dispatch instructions to generators, ancillary service agents, and dispatchable load purchasers

(1) The system operator must ensure that each dispatch instruction it issues under clause 13.72(1)(a) instructs the generator or ancillary service agent to carry out 1 of the following in relation to a generating plant, a generating unit, a block dispatch group, a station dispatch group, a frequency keeping unit, or interruptible load:
   (a) provide a quantity of active power;
   (b) provide a quantity of instantaneous reserve;
   (c) provide a quantity and quality of reserve power or alternative to regulate frequency continuously;
   (d) provide a quantity of reactive power;
   (e) adjust transformer tap positions to maintain voltage levels;
   (f) provide a level of voltage;
   (g) synchronise or de-synchronise generating plant within the current trading period or the next trading period either directly or in accordance with any process that may be agreed with the generator;
   (h) switch on or switch off schemes for over frequency tripping where such capability exists in generating plant that a generator has offered to provide to the system operator;
   (i) manage the generating plant within a block dispatch group or station dispatch group so as to ensure the largest single reserve risk within that block dispatch group or station dispatch group does not exceed the relevant maximum reserve risk advised by the system operator for the North Island or the South Island for each trading period;
   (j) manage the total aggregate generation for each sub-block dispatch group or sub-station dispatch group for that generator so as not to exceed the total sum of the dispatched quantities for each generating plant or generating unit comprising that sub-block dispatch group or sub-station dispatch group for the duration of the notice received under clauses 13.60, 13.61, or 13.64 to 13.66;
   (k) manage the total aggregate generation for each block dispatch group or station dispatch group for that generator so as to meet the total sum of the dispatched quantities for each generating station or generating unit comprising that block dispatch group or station dispatch group.

(2) The system operator must ensure that each dispatch instruction issued under clause 13.72(1)(b) instructs the dispatchable load purchaser to use a specified quantity of electricity in relation to a dispatch-capable load station.

Compare: Electricity Governance Rules 2003 rule 4.6 section III part G
Clause 13.73 Heading: amended, on 3 October 2013, by clause 6(a) of the Electricity Industry Participation (Technology Neutral Language in Frequency Keeping) Code Amendment 2013.
Clause 13.73: amended, on 3 October 2013, by clause 6(b) and (c) of the Electricity Industry Participation (Technology Neutral Language in Frequency Keeping) Code Amendment 2013.
Clause 13.73(c); amended, on 3 October 2013, by clause 6(d) of the Electricity Industry Participation (Technology Neutral Language in Frequency Keeping) Code Amendment 2013.
13.74 Content of dispatch instructions to reserve, interruptible load, and frequency keeping suppliers [Revoked]

Compare: Electricity Governance Rules 2003 rule 4.7 section III part G

13.75 Form of dispatch instruction

(1) When issuing a dispatch instruction under clause 13.72(1)(a), the system operator must specify—
   (a) the generating plant, generating unit, block dispatch group, station dispatch group, interruptible load, or frequency keeping units to which the dispatch instruction applies; and
   (b) the desired outcome of the dispatch instruction; and
   (c) if the start time for the dispatch instruction differs from the issue time, the start time within the current trading period or the next trading period; and
   (d) if specific ramp rates are concerned, a specific target time to reach the desired outcome; and
   (e) the time at which the dispatch instruction was issued; and
   (f) any block security constraint that occurs within a block dispatch group and how the block security constraint divides the generating stations or generating units of a block dispatch group into sub-block dispatch groups as part of such a dispatch instruction; and
   (g) any station security constraint that occurs within a station dispatch group and how the station security constraint divides the generating stations or generating units of a station dispatch group into sub-station dispatch groups; and
   (h) if it is a dispatch instruction specified in clause 13.73(1)(i), the maximum reserve risk for the relevant island.

(2) When issuing a dispatch instruction under clause 13.72(1)(b), the system operator must specify—
   (a) the dispatch-capable load station to which the dispatch instruction applies; and
   (b) the trading period for which the dispatch instruction is issued; and
   (c) the desired outcome of the dispatch instruction.

Compare: Electricity Governance Rules 2003 rule 4.8 section III part G
Clause 13.75(1)(h): inserted, on 15 May 2014, by clause 28(c) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.
13.76 System operator to issue and log dispatch instructions

(1) The **system operator** must issue **dispatch instructions**,—
   (a) to each **generator**, using an **approved system**; and
   (b) to each **dispatchable load purchaser** that has submitted a **nominated dispatch bid**, on WITS; and
   (c) to each **ancillary service agent**, verbally or in writing.

(2) [Revoked].

(3) The **system operator** must log and record each **dispatch instruction**.

(4) Each **generator** and each **ancillary service agent** must log each **dispatch instruction** received from the **system operator**.

(5) The **system operator** must provide a copy of each **dispatch instruction**—
   (a) to the **clearing manager**, by 1600 hours on the **7th business day** of the **billing period** after the **billing period** in which the **system operator** issues and logs the **dispatch instruction**; and
   (b) to the **Authority**, by 1600 hours on the **first business day** after the day on which the **system operator** issues and logs the **dispatch instruction**.

(6) For the purpose of subclause (5), if the **system operator** has issued more than 1 **dispatch instruction** for a **dispatch-capable load station** for the same **trading period**, the **system operator** must provide a copy of the latest **dispatch instruction**.

Compare: Electricity Governance Rules 2003 rule 4.9 section III part G

13.77 Dispatch instructions to plant required by system operator [Revoked]

Compare: Electricity Governance Rules 2003 rule 4.9.1 section III part G

13.78 Active power dispatch instructions to clearing manager [Revoked]

Compare: Electricity Governance Rules 2003 rule 4.9.2 section III part G

13.79 Acknowledgement of dispatch instructions

If the **system operator** has issued a **dispatch instruction** to a **generator** or an **ancillary service agent**, that person must acknowledge to the **system operator** receipt of that **dispatch instruction** within 4 minutes of receiving that **dispatch instruction**, and must use its reasonable endeavours to acknowledge to the **system operator** receipt of the **dispatch instruction** within 3 minutes of receiving the **dispatch instruction**.

Compare: Electricity Governance Rules 2003 rule 4.9.3 section III part G

13.80 Dispatch instructions provided to grid owner

(1) If the system operator has issued a dispatch instruction to an embedded generator to generate from a generating plant required by the system operator to be scheduled, the system operator must inform the grid owner that is connected to the local network in which the embedded generator is located of the quantity of active power that was the subject of such dispatch instruction and the trading periods for which the dispatch instruction was issued.

(2) The system operator must provide the information to the relevant grid owner by 0400 hours on the day after the dispatch instruction was issued.

Compare: Electricity Governance Rules 2003 rule 4.9.4 section III part G

13.81 Backup procedures if communication not possible

(1) The system operator must follow the backup procedures specified by it from time to time if—
   
   a none of the mechanisms described in clause 13.76 are available to issue dispatch instructions under clause 13.72(1)(a); or
   
   b the system operator does not receive an acknowledgement from a generator or ancillary service agent of receipt of a dispatch instruction within 10 minutes after issuing the dispatch instruction.

(2) If the system operator is not able to issue a dispatch instruction on WITS under clause 13.17(1)(b) to a dispatchable load purchaser that has submitted a nominated dispatch bid, the dispatchable load purchaser must follow the backup procedures specified by the system operator.

Compare: Electricity Governance Rules 2003 rule 4.10 section III part G

13.82 Dispatch instructions to be complied with

(1) This clause applies to—
   
   a generator; and
   
   b an ancillary service agent; and
   
   c a dispatched purchaser.
Each participant to which this clause applies must comply with a dispatch instruction properly issued by the system operator under clause 13.72 unless,—

(a) in the participant's reasonable opinion,—
   (i) personnel or plant safety is at risk; or
   (ii) following the dispatch instruction will contravene a law; or

(b) the generating plant or dispatch-capable load station is already responding to an automated signal to activate—
   (i) capacity reserve; or
   (ii) instantaneous reserve; or
   (iii) automatic under-frequency load shedding; or
   (iv) over frequency reserve; or

(c) the participant is a generator or ancillary service agent acting in accordance with clause 13.86; or

(d) the participant is an intermittent generator that has complied with clause 13.17 and clause 13.18A, and the system operator has not advised that there is—
   (i) a grid emergency; or
   (ii) a system constraint that directly affects the intermittent generator; or

(e) the participant—
   (i) is a generator; and
   (ii) deviates from a dispatch instruction for active power to comply with clause 8.17; or

(f) the participant—
   (i) is a dispatched purchaser; and
   (ii) deviates from the dispatch instruction—
      (A) to comply with a request issued by the system operator under clause 5(4) of Technical Code B of Schedule 8.3; or
      (B) to comply with clause 8.18; or

(g) the participant—
   (i) is a dispatched purchaser; and
   (ii) cannot comply with the dispatch instruction because demand has been electrically disconnected under clause 7A of Technical Code B of Schedule 8.3; or

(ga) the participant—
   (i) is a dispatched purchaser; and
   (ii) the dispatch instruction is issued for a trading period for which the latest nominated bid for the relevant dispatch-capable load station is a nominated non-dispatch bid; or

(h) the participant—
   (i) is a generator or an ancillary service agent; and
   (ii) deviates from a dispatch instruction to comply with clause 9 of Technical Code B of Schedule 8.3; or

(i) the participant—
   (i) is a generator or an ancillary service agent; and
   (ii) is acting in accordance with a commissioning plan or test plan that—
      (A) is required under clause 2(6) of Technical Code A of Schedule 8.3; and
(B) expressly allows the generator or ancillary service agent to depart from the dispatch instruction for the purpose of the commissioning plan or test plan; and

(iii) has no reasonable means of complying with the dispatch instruction while acting in accordance with the commissioning plan or test plan; or

(j) the participant is a type B co-generator and the system operator has not advised that there is—

(i) a grid emergency; or

(ii) a system constraint that directly affects the type B co-generator.

(3) A participant to which the exception in subclause (2)(a) applies must immediately advise the system operator of the circumstance in which the exception arises.

(4) If a dispatched purchaser is issued with more than 1 dispatch instruction for the same dispatch-capable load station for the same trading period, the dispatched purchaser must comply with the latest dispatch instruction.

(5) To avoid doubt, a dispatch instruction listed in clause 13.73(1)(b) to 13.73(1)(f) or 13.73(1)(h) is properly issued only if—

(a) the generator or ancillary service agent to which the dispatch instruction is given has an enforceable contract with the system operator for the provision of services relating to the dispatch instruction; or

(b) the dispatch instruction is consistent with an enforceable contract between the system operator and the generator or ancillary service agent for the provision of services relating to the dispatch instruction; or

(c) the dispatch instruction is given for the purposes of clause 8.5 or 13.70; or

(d) the dispatch instruction is consistent with—

(i) the asset owner performance obligations under clauses 8.22 to 8.24; or

(ii) the technical codes concerning voltage; or

(iii) a dispensation.

(6) A dispatched purchaser issued with a dispatch instruction for a dispatch-capable load station must not make changes to its other load at the same GXP with the intention of offsetting the dispatch instruction for the dispatch-capable load station.

Compare: Electricity Governance Rules 2003 rule 4.11 section III part G
Clause 13.82(2)(ga): inserted, on 1 December 2015, by clause 5 of the Electricity Industry Participation Code Amendment (Dispatchable Demand: Late Bid Revisions) 2015.
13.83 Generators to make staff or facilities available to meet dispatch instructions

(1) Each generator must ensure, with respect to each of its generating plants that is the subject of an offer, that appropriate personnel or facilities are available to receive and comply with any dispatch instruction given by the system operator to the generator.

(2) Nothing in this clause limits the ability of a generator to have a control centre that operates 1 or more items of generating plant by remote control.

Compare: Electricity Governance Rules 2003 rule 4.12 section III part G

13.83A Dispatchable load purchasers to make staff or facilities available to meet dispatch instructions

(1) Each dispatchable load purchaser that has submitted a nominated dispatch bid must ensure that appropriate personnel or facilities are available to receive and comply with each dispatch instruction issued to the dispatchable load purchaser.

(2) Nothing in this clause limits the ability of a dispatchable load purchaser to have a control centre that operates 1 or more dispatch-capable load stations by remote control.


13.84 Ancillary service agents to make staff or facilities available to meet dispatch instructions

Each ancillary service agent must ensure, with respect to any instantaneous reserve that is the subject of a reserve offer for the trading period, that appropriate personnel or facilities are available to receive and comply with any dispatch instruction given by the system operator to that ancillary service agent.

Compare: Electricity Governance Rules 2003 rule 4.13 section III part G

13.85 Generators have flexibility within block dispatch group or station dispatch group

Each generator may synchronise, de-synchronise, or alter the output of any generating plant within a block dispatch group or station dispatch group if it first consults with the system operator with regard to such action.

Compare: Electricity Governance Rules 2003 rule 4.15 section III part G

13.86 Generators and ancillary service agents not obliged to comply with dispatch instructions below threshold

For any generating plant, generating unit, block dispatch group or station dispatch group, a generator or ancillary service agent is not required to comply with 1 or more dispatch instructions given by the system operator in accordance with clause 13.72(1)(a) if implementing the dispatch instruction or those dispatch instructions together would change by less than or equal to—

(a) for ancillary service agents, 1 MW from the last dispatch instruction that the ancillary service agent complied with; or

(b) for generators other than type A co-generators, 1 MW from the last dispatch instruction that the generator complied with; or
(c) for type A co-generators, 5 MW from the last dispatch instruction that the type A co-generator complied with.

Compare: Electricity Governance Rules 2003 rule 4.16 section III part G
Cross heading: revoked, on 28 June 2012, by clause 38(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.87 [Revoked]

Clause 13.87: revoked, on 28 June 2012, by clause 38(2) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Real time prices

13.88 Preparation of schedule of real time prices
(1) The purpose of this clause is to require the system operator to produce the schedule of real time prices.
(2) Each schedule of real time prices prepared by the system operator must cover 1 real time pricing period.
(3) In preparing each schedule of real time prices, the system operator must use the methodology in Schedule 13.3.
(4) The system operator must use its reasonable endeavours to complete a new schedule of real time prices for a real time pricing period as soon as practicable after the relevant real time pricing period, provided that the information required to calculate the schedule of real time prices (as set out in Schedule 13.3) is available to the system operator.

Compare: Electricity Governance Rules 2003 rule 6 section III part G

13.89 Publication of schedule of real time prices
The system operator must use reasonable endeavours to publish each schedule of real time prices in accordance with clauses 13.90 to 13.96.

Compare: Electricity Governance Rules 2003 rule 7.1 section III part G

13.90 Process for making real time prices available
(1) The system operator must use reasonable endeavours to make available on WITS, for each real time pricing period, as soon as practicable after the real time pricing period,—
(a) a schedule of real time prices; and
(b) the following additional information for each schedule of real time prices:

(i) the number of transmission lines or transformers that have a MW arc flow equal to the maximum flow limit (in MW) on that transmission line or transformer set by the grid owner in accordance with clauses 13.29 to 13.32:

(ii) the number of groups of transmission lines or transformers, or both, that have a total MW arc flow equal to the relevant maximum flow limit (in MW) as set by the system operator in accordance with Schedule 13.3:

(iii) the aggregate of the following occurrences:

(A) the number of occurrences at which energy (in MW) for a generator at a set of grid injection points is equal to the minimum and/or maximum generation (in MW) for that set of grid injection points set by the system operator in accordance with Schedule 13.3:

(B) the number of occurrences at which energy (in MW) and reserves (in MW) for a generator at a set of grid injection points is equal to the maximum generation (in MW) for that set of grid injection points set by the system operator in accordance with Schedule 13.3:

(C) the number of occurrences at which reserve (in MW) for a participant at a set of grid exit points is equal to the maximum reserve (in MW) for that set of grid exit points as determined under Schedule 13.3:

(iv) the number of occurrences at which the ramp up rate is equal to the maximum ramp up rate specified in the relevant offer:

(v) the number of occurrences at which the ramp down rate is equal to the maximum ramp down rate as specified in the relevant offer:

(vi) the number of grid exit points at which demand was estimated.

(2) For each grid injection point and each grid exit point, the system operator must use reasonable endeavours to make available on WITS a time-weighted average of the real time prices for each trading period.

Compare: Electricity Governance Rules 2003 rule 7.2 section III part G

13.91 System operator to use backup procedures if WITS unavailable

(1) [Revoked]

(2) If WITS is unavailable for the purposes of making information available under clauses
13.89 to 13.96, the system operator must follow the backup procedures specified by the WITS manager.

(3) The WITS manager must specify the backup procedures referred to in subclause (2) following consultation with the Authority, purchasers, generators, and the system operator.

Compare: Electricity Governance Rules 2003 rules 7.3 to 7.5 section III part G
Clause 13.91(2) and (3): replaced, on 5 October 2017, by clause 371(2)(b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

13.92 Transmission of information through publicly accessible approved system

(1) The WITS manager must make any information it receives from the system operator under clause 13.90 available at no cost on a publicly accessible approved system.

(2) If the publicly accessible approved system under subclause (1) is unavailable, the WITS manager is not required to—
(a) follow any backup procedures; or
(b) make the information available on the publicly accessible approved system at a later time.

Compare: Electricity Governance Rules 2003 rules 7.6 and 7.7 section III part G

13.93 Authority to appoint person to monitor and assess demand side participation and real time prices

(1) The Authority may monitor and assess, or appoint a person at any time to monitor and assess, the real time prices made available by the system operator under clauses 13.89 to 13.96 in the context of demand side participation.

(2) The system operator must use reasonable endeavours to make available to the Authority or the person appointed by the Authority under subclause (1), in a manner agreed between the system operator and that person,—
(a) if that person is not the Authority, the information the system operator makes available to the participants and the Authority under clause 13.90; and
(b) for each grid injection point and each grid exit point, a volume weighted average of the real time prices for each trading period.

Compare: Electricity Governance Rules 2003 rules 7.8 and 7.9 section III part G

13.94 System operator may suspend publication of real time prices

Despite anything in this Code, the system operator may delay the making available and transmitting of real time prices and any other information under clauses 13.89 to 13.96 if the system operator—
(a) issues a formal notice in accordance with clause 5 of Technical Code B of Schedule 8.3; or
(b) reasonably believes that its principal performance obligations are not being met for the period specified in the system operator’s instruction.

Compare: Electricity Governance Rules 2003 rule 7.10 section III part G

13.95 Real time prices not binding

The real time prices published and made available under clauses 13.89 to 13.96 are indicative only and are not provisional prices, interim prices, final prices or binding in relation to the settlement and clearing processes.

Compare: Electricity Governance Rules 2003 rule 7.11 section III part G

13.96 Purchaser to co-operate with system operator to manage response to real time prices

(1) This clause applies to a purchaser that wishes to increase or decrease its total demand, other than demand for a dispatch-capable load station for which a nominated dispatch bid is submitted, across 1 or more of its grid exit points in response to real time prices by—

(a) greater than 50 MW in any 15 minute period in the North Island; or
(b) greater than 30 MW in any 15 minute period in the South Island.

(2) If this clause applies, the purchaser must—

(a) advise the system operator by telephone of the increase or decrease at least 5 minutes before the change; and
(b) if instructed by the system operator by telephone, manage any such increase or decrease in accordance with the instructions.

Compare: Electricity Governance Rules 2003 rule 7.12 section III part G


Grid emergencies

13.97 Grid emergency situations

(1) The system operator may, at any time, declare a grid emergency in accordance with Technical Code B of Schedule 8.3.

(2) Despite clauses 13.6 to 13.27 and clauses 13.37 to 13.54, if the system operator has declared a grid emergency,—

(a) a generator, other than an intermittent generator, may not reduce the MW specified in any of the offers made by the generator for the trading periods and grid injection points affected by the grid emergency, unless the generator has a bona fide physical reason that makes the reduction necessary; and

(b) an ancillary service agent may not reduce the instantaneous reserve specified in any of the reserve offers made by the ancillary service agent for the trading periods and points of connection with the grid affected by the grid emergency, unless the ancillary service agent has a bona fide physical reason that makes the reduction necessary; and

(c) the system operator must accept any reduction made under paragraphs (a) or (b).

Compare: Electricity Governance Rules 2003 rules 8.1 and 8.2 section III part G

13.98 Generators and ancillary service agents may change other parameters

Despite clause 13.97(2), during a grid emergency,—

(a) a generator may reduce the MW specified in any price band offered in respect of certain generating plant, if equivalent increased MW is, in substitution, offered for other items of generating plant owned or operated by that generator at grid injection points in the electrical or geographical region affected as specified in the system operator's notice issued under clause 5(1) of Technical Code B of Schedule 8.3; and

(b) an ancillary service agent may reduce the instantaneous reserves offered, if equivalent increased instantaneous reserves are, in substitution, offered by that ancillary service agent at points of connection with the grid in the electrical or geographical region affected as specified in the system operator's notice issued under clause 5(1) of Technical Code B of Schedule 8.3; and

(c) despite clauses 13.6 to 13.27, a generator may—

(i) submit revised offers in respect of generating plant already subject to an offer before the grid emergency, so that the total MW offered by the generator from the generating plant for that trading period is increased; and

(ii) submit new offers in respect of a generating plant not subject to an offer before the grid emergency; and

(d) despite clause 13.17(2), a generator may submit a new price band or bands for new offers or revised offers in respect of the increased MW made under paragraph (e), but may not revise the price band or bands in respect of the MW offered before the notice of the grid emergency; and

(e) despite clauses 13.37 to 13.54, an ancillary service agent may—

(i) submit revised reserve offers in respect of any instantaneous reserve already subject to a reserve offer before the grid emergency so that the total instantaneous reserve offered by the ancillary service agent for that trading period is increased; and

(ii) submit new reserve offers in respect of any instantaneous reserve not subject to a reserve offer before the grid emergency; and

(f) despite clause 13.46(1A), an ancillary service agent may submit a new price band or bands for new reserve offers or revised reserve offers in respect of the increased instantaneous reserve made under paragraph (e), but may not revise the type of instantaneous reserve or the price band or bands in respect of the instantaneous reserve offered before the notice of the grid emergency.

Compare: Electricity Governance Rules 2003 rule 8.3 section III part G

Clause 13.98(a): amended, on 29 June 2017, by clause 36(1)(a), (b) and (c) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 13.98(b): amended, on 29 June 2017, by clause 36(2)(a) and (b) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.
Clause 13.98(d): amended, on 29 June 2017, by clause 36(4)(a), (b) and (c) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.
Clause 13.98(f): amended, on 29 June 2017, by clause 36(6)(a), (b) and (c) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.

13.99 Effect of grid emergency on total quantities bid

Despite clauses 13.19A to 13.27, if the system operator has declared a grid emergency—
(a) a purchaser may not increase the aggregate quantity of electricity specified in all of the nominated bids made by the purchaser for the trading periods and GXPs affected by the grid emergency unless the purchaser has a bona fide physical reason that necessitates the increase; and
(b) the system operator must accept any revision made under paragraph (a).

Compare: Electricity Governance Rules 2003 rule 8.4 section III part G


13.99A Effect of grid emergency on nominated dispatch bids

(1) This clause applies—
(a) if the system operator has declared a grid emergency; and
(b) to each nominated dispatch bid that is for—
   (i) a GXP that is in the affected electrical or geographical region as specified in the formal notice issued by the system operator; and
   (ii) a trading period that is specified in the formal notice issued by the system operator.

(2) If this clause applies, a purchaser must immediately change each bid to which this clause applies from a nominated dispatch bid to a nominated non-dispatch bid.


13.100 Purchasers may change other parameters

Despite clause 13.99, during a grid emergency, a purchaser may—
(a) increase a nominated bid's quantities, or submit nominated bids at GXPs that were not subject to nominated bids before the grid emergency, if equivalent decreased quantities are, in substitution, bid for GXPs in the affected electrical or geographical region, as specified in the formal notice issued by the system operator, which were the subject of nominated bids made by the purchaser; and
(b) decrease a nominated bid's quantities.

Compare: Electricity Governance Rules 2003 rule 8.5 section III part G

Clause 13.100(a): substituted, on 28 June 2012, by clause 43(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clause 13.100(b): amended, on 28 June 2012, by clause 43(2) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clause 13.100(b): substituted, on 15 May 2014, by clause 40(b) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.101 Reporting requirements in respect of grid emergencies

(1) If the system operator declares a grid emergency,—

(a) the system operator must, within 12 hours of the conclusion of the grid emergency, publish a written report that describes the basis on which the system operator decided to declare the grid emergency; and

(b) a generator that reduced the MW specified in any price band in any offer, and an ancillary service agent that reduced the instantaneous reserve specified in any reserve offer, made by that person in respect of the point of connection with the grid and trading periods affected by the grid emergency must report the reduction to the Authority in writing together with details of the bona fide physical reason for the reduction claimed by the generator or ancillary service agent. A reduction must be reported to the Authority by 1700 hours on the 1st business day after the trading day on which the reduction was made.

(c) [Revoked]

(2) [Revoked]

Compare: Electricity Governance Rules 2003 rules 8.6 and 8.7 section III part G
Clause 13.101(1)(b): amended, on 29 June 2017, by clause 38(1)(a), (b) and (c) of the Electricity Industry Participation Code Amendment (Shortened Gate Closure and Revised Bid and Offer Provisions) 2017.

13.102 Reporting obligations of system operator

By the 10th business day of each calendar month, the system operator must inform the Authority in writing of any discretionary action the system operator has taken under clause 13.70, in the previous calendar month, that required departure from the dispatch schedule.

Compare: Electricity Governance Rules 2003 rule 9 section III part G.

System operator to publish information

13.103 [Revoked]
13.104 System operator to make information available

(1) As soon as practicable after the system operator has completed preparing a price-responsive schedule and a non-response schedule, the system operator must make available on WITS, for each trading period in the schedule length period,—

(a) the following information in respect of both the price-responsive schedule and the non-response schedule:

(i) forecast prices and forecast reserve prices; and

(ii) scheduled non-dispatch-capable load at each conforming GXP; and

(iii) the aggregate supply curve at each reference point incorporating all offers from generators with offer prices adjusted for forecast marginal location factors; and

(iv) the grid injection points and grid exit points that have no load or generation connected to them in the modelling system; and

(v) the grid injection points and grid exit points where an infeasibility situation has occurred; and

(vi) the scheduled largest single reserve risk for each island as described in clause 13.59(ix); and

(vii) the scheduled levels of fast instantaneous reserve and sustained instantaneous reserve required in each island as described in clause 13.59(x); and

(viii) the reserve offer stacks for each island as described in clause 13.59(xi); and

(ix) the adjusted reserve offer stacks for each island as described in clause 13.59(xii); and

(x) [Revoked]

(xi) the scheduled HVDC component flows; and

(xii) the scheduled HVDC risk offsets; and

(xiii) the expected near-constraint arc flows; and

(xiv) the expected near-group-constraint arc flows; and

(xv) the group constraint formulas relating to the expected near-group-constraint arc flows; and

(xvi) the expected deficit quantities for energy, fast instantaneous reserve, and sustained instantaneous reserve (if any); and

(xvii) whether the HVDC link is out of service; and

(b) in relation to the price-responsive schedule, the aggregate demand curve at each reference point incorporating the forecast prepared under clause 13.7A(1), and all bids from purchasers with bid prices adjusted for forecast marginal location factors; and

(c) in relation to the non-response schedule, the scheduled frequency keeping units for each island.

(2) Subclause (3) applies to—

(a) each price-responsive schedule prepared under clause 13.62(1)(a):
(b) each non-response schedule prepared under clause 13.62(1)(a).

(3) Despite subclause (1), for each schedule to which this subclause applies, the system operator is not required to make available on WITS the information set out in subclause (1) for the trading periods covered by—

(a) the price-responsive schedule prepared under clause 13.62(1)(b);
(b) the non-response schedule prepared under clause 13.62(1)(b).

Compare: Electricity Governance Rules 2003 rule 10.2 section III part G
Clause 13.104(1)(a)(xvi) and (xvii): inserted, on 1 June 2013, by clause 7 of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

13.105A Information to be made available to purchasers, generators, and ancillary service agents

(1) At the same time as the system operator is required to make information available in accordance with clause 13.104, the system operator must make available on WITS—

(a) for each dispatchable load purchaser that has submitted a nominated dispatch bid, information from the current non-response schedule relating to the scheduling of the dispatchable load purchaser's nominated dispatch bids for the trading periods covered in the schedule length period; and

(a) for each purchaser, information from the current price-responsive schedule relating to the scheduling of the purchaser’s bids for the trading periods covered in the schedule length period; and

(b) for each generator, information from the current price-responsive schedule and non-response schedule relating to the scheduling of the generator’s offers for the trading periods covered in the schedule length period; and

(c) for each ancillary service agent who has submitted a reserve offer for the scheduling period, information from the current price-responsive schedule and non-response schedule relating to the scheduling of the ancillary service agent’s reserve offers for the trading periods covered in the schedule length period.

(2) Subclause (3) applies to—

(a) each price-responsive schedule prepared under clause 13.62(1)(a);
(b) each non-response schedule prepared under clause 13.62(1)(a).
(3) Despite subclause (1), for each schedule to which this subclause applies, the **system operator** is not required to make available on **WITS** the information set out in subclause (1) for the **trading periods** covered by—
   (a) the **price-responsive schedule** prepared under clause 13.62(1)(b):
   (b) the **non-response schedule** prepared under clause 13.62(1)(b).

13.106 Transmission of information

(1) [Revoked]

(2) If **WITS** is unavailable for the purposes of making information available under clauses 13.104 to 13.105A, the **system operator** must follow the backup procedures specified by the **WITS manager**.

(3) The **WITS manager** must specify the backup procedures referred to in subclause (2) following consultation with the **Authority**, the **system operator**, the **pricing manager**, the **clearing manager**, **purchasers**, **generators**, and **ancillary service agents**.

Compare: Electricity Governance Rules 2003 rules 10.5 to 10.7 section III part G

**Subpart 3—Must-run dispatch auction**

13.107 Contents of this subpart

This subpart provides for must-run dispatch **auctions**.

Compare: Electricity Governance Rules 2003 rule 1 section IV part G

13.108 Clearing manager to hold must-run dispatch auctions

Each day the **clearing manager** must hold an **auction** as set out in clauses 13.117 to 13.130, at which **generators** may bid for **auction rights** in **time blocks**.

Compare: Electricity Governance Rules 2003 rule 2 section IV part G

13.109 Clearing manager authorises generators

(1) If a **generator**’s bid at an **auction** is successful the **clearing manager** must authorise the **generator** to **offer electricity** at 0 price for the relevant **time block** and **trading period**.

(2) The **clearing manager** must specify in each authorisation—
(a) the quantity of electricity that the generator may offer under the authorisation; and

(b) the trading periods for which the authorisation is valid; and

(c) how much the generator must pay the clearing manager for the auction rights.

Compare: Electricity Governance Rules 2003 rules 2.1 and 2.2 section IV part G

13.110 Clearing manager must calculate amounts owing

(1) The clearing manager must calculate the amount owing by each generator for the auction rights the generator has acquired in the previous billing period.

(2) Any auction revenue owing by a generator in relation to a billing period must be advised to the generator by the clearing manager under subpart 4 of Part 14.

Compare: Electricity Governance Rules 2003 rules 2.3 and 2.4 section IV part G

13.111 Purchasers must receive auction revenue

Each purchaser who purchases electricity at a grid exit point must receive auction revenue from generators in accordance with clause 13.112(1).

Compare: Electricity Governance Rules 2003 rule 2.5 section IV part G

13.112 Clearing manager must calculate amounts receivable

(1) The clearing manager must calculate and credit purchasers for auction revenue for each trading period in accordance with the following formula:

\[ AR_p = \left( \frac{TAR_g}{APB} \right) \times \left( \frac{P_q}{TP_q} \right) \]

where

- \( AR_p \) is the auction revenue receivable by a purchaser
- \( TAR_g \) is the total auction revenue for a time block owing by generators as calculated by the clearing manager in accordance with clause 13.110(1)
- \( APB \) is the number of trading periods in that time block
- \( P_q \) is the total electricity purchased by that purchaser from the clearing manager during the trading period as shown by the reconciliation information calculated by the reconciliation manager under clause 15.21 to 15.26
- \( TP_q \) is the total electricity purchased by all purchasers from the clearing manager during the trading period as shown by reconciliation information calculated by the reconciliation manager under clause 15.21 to 15.26.
(2) Any auction revenue owing to a purchaser in relation to a billing period must be advised to the purchaser by the clearing manager under subpart 4 of Part 14.

Compare: Electricity Governance Rules 2003 rules 2.6 and 2.7 section IV part G

13.113 Generators choose grid injection points at which they will exercise rights conferred
A generator who acquires auction rights may exercise them in respect of any generating plant it owns and at a grid injection point during the relevant time block.

Compare: Electricity Governance Rules 2003 rule 2.8 section IV part G

13.114 Transmission of auction information
(1) Except where specified otherwise in this Part, all information in relation to auctions must be transmitted using WITS.

(2) If WITS is not available to transmit information under this clause, the clearing manager must follow the backup procedures specified by the WITS manager.

(3) The WITS manager must specify the backup procedures referred to in subclause (2) following consultation with the Authority, generators, and the clearing manager.

Compare: Electricity Governance Rules 2003 rules 2.9 to 2.11 section IV part G

13.115 Trading in auction rights permitted
(1) A generator who has acquired auction rights at an auction (the "transferring generator") may transfer all or some of those rights to another generator.

(2) The generator who acquires the rights by transfer takes them on the same terms that apply to the transferring generator.

Compare: Electricity Governance Rules 2003 rule 2.12 section IV part G

13.116 Offers at 0
(1) Subject to subclause (2), a generator may offer electricity to the clearing manager at a 0 price only if the generator has an authorisation from an auction in accordance with clauses 13.108 to 13.115.

(2) A generator may offer electricity to the clearing manager at a 0 price without an authorisation from an auction only in relation to—

(a) generating plant that comes within the scope of clauses 13.24 or 13.26; or
(b) offers submitted before publication of auction results, but, if authorisation from an auction is not granted, such offers are cancelled or revised so that they no longer contain a 0 price before 1300 hours on the day before the trading day for which the offers apply.

Compare: Electricity Governance Rules 2003 rules 2.13 and 2.14 section IV part G
Must-run auction process

13.117 Clearing manager must conduct auctions
(1) The clearing manager must conduct an auction every day.
(2) Each generator is eligible to take part in each auction.
(3) The clearing manager must specify the format for bidding and must accept auction bids only if they are made in that format. Each auction bid must be made in positive numbers.

Compare: Electricity Governance Rules 2003 rules 3.1 to 3.3 section IV part G

13.118 [Revoked]

Compare: Electricity Governance Rules 2003 rule 3.4 section IV part G

13.119 Historic load data
(1) Subject to subclause (3), by 1100 hours on a day that is 2 days before an auction, a grid owner must advise the clearing manager of the information described in subclause (2) by—
   (a) giving written notice to the clearing manager; or
   (b) using WITS.
(2) The information is the total load that was on the grid that is owned or operated by the grid owner, on the day that is 363 days before the date of the auction.
(3) If the trading day following the auction is—
   (a) a national holiday, the day referred to in subclause (2) is deemed to be the Sunday before the day preceding the date of the auction by 363 days; or
   (b) a business day, but the 363rd day before the date of the auction is a national holiday, the day referred to in subclause (2) is deemed to be the next business day after the national holiday.

Compare: Electricity Governance Rules 2003 rule 3.5 section IV part G

13.120 Quantity available for auction
The clearing manager must calculate the quantity of auction rights available in each time block at each auction as follows:

\[
\text{quantity of auction rights available in each time block} = 0.8 \times \text{l df}_{ib}
\]

where

\[
\text{l df}_{ib}
\]

is the lowest demand forecast for a time block, which is the lowest demand in any trading period on the day for which load must be advised under clause 13.119 (in an interval that equates to the time block).

Compare: Electricity Governance Rules 2003 rule 3.6 section IV part G
13.121 Notice of auction and deadline for auction bids
(1) For each auction, by any time up to 1100 hours on the day before the auction, the clearing manager must give written notice or use WITS to advise each generator of the quantity of auction rights available in each time block at the auction to be held the following day and must invite auction bids for those auction rights.

(2) A generator who wishes to bid at an auction must submit auction bids by 0900 hours on the day that the auction is to be held.

Compare: Electricity Governance Rules 2003 rule 3.7 section IV part G

13.122 Revising, cancelling and extending auction bids
(1) A generator may, by giving written notice or using WITS, revise or cancel an auction bid up to 0900 hours on the day of the auction to which the auction bid relates.

(2) Each auction bid is valid for only 1 auction unless the generator expressly states when it makes the auction bid that the auction bid is to remain valid until cancelled.

Compare: Electricity Governance Rules 2003 rule 3.8 section IV part G

13.123 Contents of auction bids
(1) A generator may make up to 5 auction bids for each time block.

(2) Each auction bid must specify for each time block the quantity of auction rights sought and the price that the generator is prepared to pay if its auction bid succeeds.

Compare: Electricity Governance Rules 2003 rule 3.9 section IV part G

13.124 Ranking of auction bids
(1) When bidding closes at 0900 hours each day the clearing manager must rank the auction bids it has received in descending order by price per MWh.

(2) Beside each auction bid the clearing manager must record the quantity of auction rights sought by the relevant generator.

Compare: Electricity Governance Rules 2003 rule 3.10 section IV part G

13.125 Matching auction bids to rights
(1) The clearing manager must match the ranked auction bids against all the auction rights available in each time block until the auction bids equal the quantity of auction rights available.

(2) The auction bids made by a generator succeed if the bids are matched (in whole or part) against the auction rights available.

Compare: Electricity Governance Rules 2003 rule 3.11 section IV part G

13.126 Similar and identical auction bids
(1) If the clearing manager receives more than 1 auction bid at the same price, and there are not enough auction rights available to satisfy the auction bids, the clearing manager must award auction rights to each relevant bidder in the order in which the
clearing manager received the auction bids (as evidenced by the time stamp provided by the clearing manager’s computer system).

(2) If the clearing manager receives more than 1 auction bid at the same price at the same time it will award auction rights to each relevant bidder in proportion to the volume of auction rights the bidders sought in each of their auction bids.

Compare: Electricity Governance Rules 2003 rule 3.12 section IV part G

13.127 Auction payment
The amount owing by a successful bidder in an auction is the quantity of electricity awarded by the clearing manager to that bidder multiplied by the clearing auction price.

Compare: Electricity Governance Rules 2003 rule 3.13 section IV part G

13.128 Results
By 1100 hours on the day of each auction the clearing manager must give written notice or use WITS to advise—
(a) each generator that has bid at an auction of the outcome of the auction; and
(b) all generators and purchasers of the quantity and price of all successful auction bids made at the auction.

Compare: Electricity Governance Rules 2003 rule 3.14 section IV part G

13.129 Authorisation to successful bidders
The clearing manager must give an authorisation, by way of a written notice or using WITS, to each generator that secures auction rights at an auction. The authorisation must set out the auction rights the generators secured at the auction and the price payable for them.

Compare: Electricity Governance Rules 2003 rule 3.15 section IV part G

13.130 Records
The clearing manager must maintain a complete record for 3 years of all quantities of auction rights offered, all auction bids received, and the prices achieved in each time block at each auction. A generator may require the clearing manager to provide, in writing or using WITS, information relating to the generator's auction bids and auction results at any time within that period.

Compare: Electricity Governance Rules 2003 rule 3.16 section IV part G
Subpart 4—Pricing

13.131 Contents of this subpart
This subpart provides for the processes by which the pricing manager receives data and produces provisional prices, provisional reserve prices, interim prices, interim reserve prices, final prices, and final reserve prices.

Compare: Electricity Governance Rules 2003 rule 1 section V part G

13.132 Purpose of the pricing process
The purpose of the pricing process is to achieve an appropriate balance between certainty and accuracy of final prices and final reserve prices for each trading period.

As part of the process—
(a) the system operator, the pricing manager, a grid owner, or a generator must take certain steps under this subpart if a provisional price situation or shortage situation exists; and
(b) after any provisional pricing situation is resolved, but before making the final prices or final reserve prices available on WITS, the pricing manager must make interim prices and interim reserve prices available on WITS; and
(c) if an error claimant claims that a pricing error has been made, the pricing manager must consider the claim and resolve any pricing error that has occurred; and
(d) the pricing manager must produce final prices and send them to the clearing manager, who will then use them in the clearing and settlement processes; and
(e) the pricing manager must produce final reserve prices.

Compare: Electricity Governance Rules 2003 rule 2 section V part G

13.133 Trigger ratio for high spring washer price situation
The value of the high spring washer price trigger ratio is 5.

Compare: Electricity Governance Rules 2003 rule 2A section V part G

13.134 Methodology to resolve high spring washer price situation
(1) This clause applies if the pricing manager, in relation to a trading period,—
(a) gives notice in accordance with clauses 13.144(1), 13.156(1)(e), or 13.159(a)(iii) that a high spring washer price situation exists; or
(b) publishes provisional prices and provisional reserve prices in accordance with clauses 13.149 or 13.150 because the revised data required by clause 13.146 or the notice required by clause 13.147 in relation to a high spring washer price situation have not been given; or
(c) publishes provisional prices and provisional reserve prices in accordance with clause 13.153 because the revised data provided in accordance with clause 13.146 or the notice given in accordance with clause 13.147 have given rise to a high spring washer price situation.
(2) If this clause applies, the system operator must—
   (a) identify each transmission security constraint that has bound in the relevant trading period; and
   (b) identify the constraint price associated with each transmission security constraint identified in accordance with paragraph (a); and
   (c) apply the high spring washer price relaxation factor—
      (i) to the maximum flow limit of the transmission security constraint with the highest associated constraint price; or
      (ii) if 2 or more transmission security constraints have the equal highest associated constraint price, to the maximum flow limit of each of those transmission security constraints.

(2A) [Revoked]

(2B) [Revoked]

(3) [Revoked]

(4) After the system operator has applied the high spring washer price relaxation factor under subclause (2)(c), the system operator must determine whether a high spring washer price situation still exists in the trading period.

(5) If the system operator determines under subclause (4) that a high spring washer price situation still exists in the trading period, the system operator must reapply the high spring washer price situation methodology for that trading period unless subclause (6) applies.

(6) The system operator must not reapply the high spring washer price situation methodology under subclause (5) if doing so would require the system operator to apply the high spring washer price relaxation factor to a maximum flow limit to which the high spring washer price relaxation factor has already been applied for the trading period.

Compare: Electricity Governance Rules 2003 rule 2B section V part G
Clause 13.134(2A), (2B) and (3): revoked, on 21 September 2012, by clause 5(2) of the Electricity Industry Participation (High Spring Washer Price Situation) Code Amendment 2012.

Rules governing the preparation of provisional, interim, and final prices

13.135 Methodology used to prepare provisional, interim, and final prices
Subject to clause 13.135B, to calculate provisional prices, provisional reserve prices, interim prices, interim reserve prices, final prices and final reserve prices the pricing manager must use—
   (a) the input information in clause 13.141; and
   (b) the methodology in Schedule 13.3.
13.135A Notice of scarcity pricing situation

(1) This clause applies if the pricing manager, in relation to a trading period, gives written notice in accordance with clause 13.144(1) that a shortage situation exists.

(2) If this clause applies, the pricing manager must determine whether a scarcity pricing situation exists in the relevant trading period.

(2A) The pricing manager must determine whether a scarcity pricing situation exists in the relevant trading period only after the pricing manager has—

(a) calculated interim prices for the 336 trading periods before the relevant trading period; and

(b) if an infeasibility situation caused by a shortage of instantaneous reserve existed in any of the 336 trading periods before the relevant trading period, either—

(i) recalculated interim prices for that trading period in accordance with clause 13.166A; or

(ii) calculated interim prices for that trading period in accordance with clause 13.164(b).

(3) An island scarcity pricing situation exists for an island if the pricing manager gives notice that an island shortage situation existed and the input information or revised data shows that—

(a) for the relevant trading period, there is no binding constraint in the island (excluding the HVDC link) in which an island shortage situation declaration is made; and

(b) for the relevant trading period—

(i) the HVDC link is in service and—

(A) if the island in which the island shortage situation declaration is made is the South Island, the price at the Benmore node is higher than the price at the Haywards node; or

(B) if the island in which the island shortage situation declaration is made is the North Island, the price at the Haywards node is higher than the price at the Benmore node; or

(ii) the HVDC link is out of service.

(4) A national scarcity pricing situation exists if the pricing manager gives notice that a national shortage situation existed and the input information or revised data shows that, for the relevant trading period,—

(a) there is no binding constraint in either island; and

(b) the HVDC link is in service and there is no binding constraint on the HVDC link.

(5) If the pricing manager determines that a scarcity pricing situation exists, the pricing manager must—

(a) give written notice of the scarcity pricing situation on WITS and to the system operator, relevant grid owner, and any person that has requested notice; and
specify in the notice each **trading period** affected by the **scarcity pricing situation**; and

(c) in relation to each **trading period** affected by the **scarcity pricing situation**, specify in the notice whether the **scarcity pricing situation** is an **island scarcity pricing situation** or a **national scarcity pricing situation**.

(6) If the **pricing manager** determines that a **scarcity pricing situation** does not exist, the **pricing manager** must give written notice of its determination on **WITS** and to the **system operator**, relevant **grid owner**, and any persons that request notice.


**13.135B Methodology to prepare interim prices and interim reserve prices if scarcity pricing situation exists**

(1) Subject to clause 13.135C, if a **scarcity pricing situation** exists in a **trading period**, the **pricing manager** must—

(a) calculate **interim prices** and **interim reserve prices** in the affected **island** or **islands** for that **trading period** in accordance with the methodology set out in Schedule 13.3A; and

(b) make **interim prices** and **interim reserve prices** available on **WITS** for the **trading period** by—

(i) if no notice of a **provisional price situation** is given, 1200 hours in the following **trading day**; or

(ii) if notice of a **provisional price situation** is given, 4 hours after the **provisional price situation** is resolved.

(2) Despite subclause (1), subclause (3) applies if a **scarcity pricing situation** exists in a **trading period**, and there is a change to—

(a) **interim prices** or **interim reserve prices** calculated and made available on **WITS** under subclause (1) for the **trading period**; or

(b) **interim prices** or **interim reserve prices** made available on **WITS** for any of the 336 **trading periods** before the **trading period**.

(3) If this subclause applies, the **pricing manager** must—

(a) recalculate **interim prices** and **interim reserve prices** in the affected **island** or **islands** for the **trading period** in which the **scarcity pricing situation** exists, in accordance with the methodology set out in Schedule 13.3A; and

(b) make the recalculated **interim prices** and **interim reserve prices** available on **WITS** no later than 4 hours after the change to **interim prices** or **interim reserve prices**.

Clause 13.135B: inserted, on 1 June 2013, by clause 10 of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.
13.135C Limitation on application of scarcity pricing provisions

Clause 13.135B does not apply—
(a) in the case of an island scarcity pricing situation, if the average island GWAP in the previous 336 trading periods in the island affected by the scarcity pricing situation exceeds $1,000 per MWh; or
(b) in the case of a national scarcity pricing situation, if the average island GWAP in the previous 336 trading periods in either island exceeds $1,000 per MWh.

Clause 13.135C: inserted, on 1 June 2013, by clause 10 of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

Generators to give grid owner half-hour metering information


13.136 Generators to provide half-hour metering information

(1) Using an approved system or by written notice, each generator must give the relevant grid owner half-hour metering information under clause 13.138 in relation to generating plant that is subject to a dispatch instruction—
(a) that injects electricity directly into a local network or an embedded network; or
(b) if the meter configuration is such that the electricity flows into a local network without first passing through a grid injection point or grid exit point metering installation.

(1A) For the purposes of subclause (1), the relevant grid owner is—
(a) in relation to a generator (other than an embedded generator), the grid owner of the grid to which the generator's generation is connected; and
(b) in relation to a generator that is an embedded generator, the grid owner of the grid to which the local network to which the embedded generator is directly or indirectly connected, is connected.

(2) To avoid doubt, subclause (1) does not apply in respect of—
(a) any unoffered generation; or
(b) electricity supplied from—
   (i) an intermittent generating station; or
   (ii) a type B industrial co-generating station.

Compare: Electricity Governance Rules 2003 rule 3.2.1 section V part G

Clause 13.136(1A)(a) and (b): amended, on 5 October 2017, by clause 389(b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
13.137 Generators to provide half-hour metering information for unoffered and intermittent generation, and type B industrial co-generation

(1) Using an approved system or by written notice, each generator must give the relevant grid owner half-hour metering information for—
   (a) unoffered generation from a generating station with a point of connection to the grid; and
   (b) electricity supplied from an intermittent generating station with a point of connection to the grid; and
   (c) electricity supplied from a type B industrial co-generating station with a point of connection to the grid.

(2) To avoid doubt, each generator must give the relevant grid owner the half-hour metering information required under this clause in accordance with the requirements of Part 15 for the collection of the generator’s volume information.

(3) If the half-hour metering information is not available, the generator must give the relevant grid owner a reasonable estimate of such data using an approved system or by written notice.

Compare: Electricity Governance Rules 2003 rule 3.2.2 section V part G

Clause 13.137 (1) and (3): amended, on 5 October 2017, by clause 390(2)(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

13.138 Generator’s half-hour metering information to be adjusted for losses

(1) Each generator must provide the information required by clauses 13.136 and 13.137—
   (a) adjusted for losses (if any) relative to the grid injection point or, for embedded generators the grid exit point, at which it offered the electricity; and
   (b) in the manner and form that the relevant grid owner stipulates; and
   (c) by 0500 hours on a trading day for each trading period of the previous trading day.

(2) To avoid doubt, each generator must provide the half-hour metering information required under this clause in accordance with the requirements of Part 15 for the collection of that generator’s volume information.

Compare: Electricity Governance Rules 2003 rule 3.2.3 section V part G


13.138A Dispatchable load purchaser’s half-hour metering information to be adjusted for losses
(1) Using an approved system or by written notice, each dispatchable load purchaser must provide half-hour metering information to the relevant grid owner—
(a) for each of its dispatch-capable load stations; and
(b) in accordance with subclause (2).
(2) Each dispatchable load purchaser must provide the half-hour metering information—
(a) adjusted for losses, if any, relative to the grid exit point at which the dispatchable load purchaser purchases electricity for the dispatch-capable load station; and
(b) in the manner and form advised by the relevant grid owner; and
(c) by 0500 hours on a trading day for each trading period of the previous trading day.
(3) To avoid doubt, each dispatchable load purchaser must prepare the half-hour metering information required under this clause in accordance with the requirements of Part 15 for the collection of the dispatchable load purchaser’s volume information.
(4) If the Authority or the system operator requests a copy of the information specified in subclause (2) from a dispatchable load purchaser, the dispatchable load purchaser must comply with the request.


13.138B System operator to give list of trading periods
(1) The system operator must give the pricing manager and the relevant grid owner a list showing, in relation to each dispatch-capable load station, each trading period in the previous trading day for which there is a nominated dispatch bid.
(2) The system operator must give the list to the pricing manager and the relevant grid owner—
(a) by 0500 hours on each trading day; and
(b) in the manner and form agreed by the pricing manager and the system operator.


13.139 Half-hour metering information part of input information
The adjusted half-hour metering information provided under clauses 13.136 to 13.138A forms part of the input information in the formula in clause 13.141(1)(b)(i).

Compare: Electricity Governance Rules 2003 rule 3.2.4 section V part G

13.140 Generators and dispatchable load purchasers to advise grid owner of having provided half-hour metering information
(1) This clause applies to—
(a) a generator; and
(b) a dispatchable load purchaser.
(2) If a participant to which this clause applies provides half-hour metering information to a grid owner under clauses 13.136 to 13.138, or 13.138A, the participant must advise the relevant grid owner by 0500 hours on the day the participant provided the half-hour metering information to the relevant grid owner.

Compare: Electricity Governance Rules 2003 rule 3.2.5 section V part G

13.141 Pricing manager to use certain input information

(1) The pricing manager must use the following input information:

(a) for existing generation configuration—
   (i) data specifying the instantaneous MW injection at the grid injection point at the beginning of each trading period for each generating plant and each generating unit that was the subject of offers for that trading period; or
   (ii) if no such data is available, a reasonable estimate of such data:

(b) for actual demand over the trading period,—
   (i) the demand half-hour metering information described as L_MA below must be calculated as follows:

\[
\begin{align*}
L_{MA} &= G_{EA} + L_{MX} - L_{DCLS} \text{ (for a grid exit point)} \\
L_{MA} &= G_{EA} - L_{MI} - L_{DCLS} \text{ (for a grid injection point)} \\
L_{MA} &= L_{MX} - L_{DCLS} - UIG_{EA} \text{ (for an intermittent generating station with a point of connection to the grid, and/or unoffered generation from a generating station with a point of connection to the grid, and/or a type B industrial co-generating station with a point of connection to the grid)}
\end{align*}
\]

where

- \(L_{MA}\) is the adjusted quantity of electricity measured in MWh by a metering installation at a grid exit point or grid injection point
- \(L_{MX}\) is the unadjusted half-hour metering information for the quantity of electricity measured in MWh at a grid exit point
- \(L_{MI}\) is the unadjusted half-hour metering information for the quantity of electricity measured in MWh at a grid injection point
- \(L_{DCLS}\) is the adjusted half-hour metering information for the quantity of electricity measured in MWh used by a dispatch-capable load station for the trading periods that the system operator listed under clause 13.138B
- \(G_{EA}\) is the adjusted half-hour metering information given to the relevant grid owner under clause 13.136
- \(UIG_{EA}\) is the information given to the relevant grid owner under clause 13.137:
(ii) if any of the **half-hour metering information** is not available, an initial estimate for each **grid exit point** or **grid injection point**;

(iii) to avoid doubt, each **grid owner** must, using an approved system, provide the **half-hour metering information** to the **pricing manager** required under this clause in accordance with Part 15 for the collection of that **grid owner’s volume information**:

(c) the final **offers** for each **trading period** submitted by **generators** and provided to the **pricing manager** by the **system operator** in accordance with clause 13.63:

(ca) the final nominated dispatch bid for each dispatch-capable load station (other than a dispatch-capable load station for which the final nominated bid for the **trading period** was a nominated non-dispatch bid) dispatched in each **trading period** that was provided to the **pricing manager** by the **system operator** in accordance with clause 13.63:

(d) the final reserve offers for each such **trading period** as given by ancillary service agents in accordance with clauses 13.37 to 13.54:

(e) the final information provided to the **system operator** by a **grid owner** under clauses 13.29 to 13.34 for each **trading period** for which the **system operator** makes final information available under clause 13.63.

(1AA) The **pricing manager** must remove all offers from the following participants from the information specified in subclause (1)(c) before using it in the pricing process:

(a) **intermittent generators**; and

(b) **type B co-generators**.

(1A) Each **grid owner** must give the **pricing manager** the information the **pricing manager** is required to use under subclause (1)(a)—

(a) by 0730 hours on each **trading day**; and

(b) for each **trading period** of the previous **trading day**; and

(c) in the manner and form agreed by the **pricing manager** and each **grid owner**.

(2) Each **grid owner** must give the information required by subclause (1)(b) to the **pricing manager** by 0730 hours on a **trading day** for each **trading period** of the previous **trading day**. Each **grid owner** must provide this information in the form specified by the **pricing manager**.

(3) The **pricing manager** must make the information available on WITS, and at no cost on a publicly accessible approved system, by 1000 hours on a **trading day** for each **trading period** of the previous **trading day**.

(4) If the **pricing manager** receives revised demand **half-hour metering information** in accordance with clauses 13.146(1) and 13.154(1A)(b), and if the revised information resolves a **provisional price situation**, the **pricing manager** must make the revised demand **half-hour metering information** available on WITS, and at no cost on a publicly accessible approved system, no later than the time at which it is required to make **interim prices** and interim reserve prices available on WITS.

(5) If the **pricing manager** receives revised information after it has made information available under subclause (3), the **pricing manager** must replace the information previously made available with the revised information.

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Compare: Electricity Governance Rules 2003 rule 3.3 section V part G
Clause 13.141(1)(a) & (b): substituted, on 15 May 2014, by clause 46(a) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.142 Pricing manager to make interim prices available unless notice is given of provisional price situation or shortage situation

(1) The **pricing manager** must implement the process set out in clauses 13.143 to 13.185 and resolve the **provisional price situation** or **shortage situation** if, by 1000 hours on a **trading day**, 1 of the following notices has been given for the previous **trading day**:

(a) a written notice given by a **grid owner**, in accordance with clause 13.143, which specifies that a **SCADA situation** exists:

(b) a written notice given by the **pricing manager**, in accordance with clause 13.144(1), which specifies that an **infeasibility situation** or a **metering situation** or a **high spring washer price situation** or a **shortage situation** exists.

(2) However, if by 1000 hours on a **trading day** a notice specified in subclause (1) has not been given for the previous **trading day**, the **pricing manager** must make **interim prices** and **interim reserve prices** for the previous **trading day** available on **WITS** by 1200 hours.

Compare: Electricity Governance Rules 2003 rule 3.4 section V part G
13.143 Grid owners to give written notice of SCADA situation

(1) If a grid owner gives any input information in accordance with clause 13.141 to the pricing manager, the grid owner must—
   (a) give written notice to the pricing manager and the WITS manager that the grid owner has given the pricing manager input information; and
   (b) specify in the notice whether the input information yields a SCADA situation, and if so each trading period affected; and
   (c) give details in the notice of the relevant grid exit points and grid injection points for which the SCADA situation exists.

(2) A grid owner must give the notice required by subclause (1)(a) by 0730 hours on the day on which it gives the relevant input information.

(3) Despite subclause (2), the grid owner may give further written notices to the pricing manager and the WITS manager advising that the grid owner has found that a SCADA situation exists and the trading periods that are affected by it.

(4) A grid owner must give each written notice under subclause (3) no later than 0900 hours on the same day that it gave notice under subclause (1)(a).

(5) As soon as practicable after receiving a written notice from a grid owner under this clause, the WITS manager must give the notice to any person that has requested it.

Compare: Electricity Governance Rules 2003 rule 3.5 section V part G
Clause 13.143(1), (3) and (4): amended, on 5 October 2017, by clause 395(2)(a) to (c) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

13.144 Pricing manager to give written notice of infeasibility situation, metering situation, high spring washer price situation, or shortage situation

(1) Subject to subclause (2), if the pricing manager receives input information that yields an infeasibility situation, or a metering situation, or a high spring washer price situation, or receives notice of a shortage situation in accordance with clause 5(1A) of Technical Code B of Schedule 8.3, the pricing manager must—
   (a) give to the system operator, relevant grid owner, and any persons that request notice, written notice of the infeasibility situation, or metering situation, or high spring washer price situation, or shortage situation; and
   (b) specify in the notice each trading period affected by the infeasibility situation, or metering situation, or high spring washer price situation, or shortage situation; and
   (c) in relation to each trading period affected by a high spring washer price situation, specify in the notice each transmission security constraint that has bound in the relevant trading period or trading periods; and
   (d) in relation to each trading period affected by a shortage situation, specify in the notice whether the shortage situation is an island shortage situation or a national shortage situation.
(1A) For the purposes of subclauses (1)(b) and (1)(d), a **trading period** affected by a **shortage situation** is a **trading period** in respect of which a **shortage situation** was in effect at the start of the **trading period**.

(2) The **pricing manager** must not give written notice of a **high spring washer price situation** or **shortage situation** in accordance with subclause (1) in relation to a **trading period** if an **infeasibility situation**, or a **metering situation**, or a **SCADA situation** exists in that **trading period** and has not been resolved.

(3) Subject to subclause (4), the **pricing manager** must give written notice of an **infeasibility situation**, **metering situation**, **high spring washer price situation**, or **shortage situation** under subclause (1)(a) no later than 0900 hours on the day that the **pricing manager** receives the relevant **input information** or notice.

(4) If a **shortage situation** exists at the same time as a **provisional price situation**, the **pricing manager** must give written notice of the **shortage situation** as soon as possible after the **pricing manager** resolves—

(a) the **provisional price situation**; and

(b) any subsequent **provisional price situation** that arises from resolving the **provisional price situation**.

(5) Despite subclause (4), if the **pricing manager** cannot resolve a **provisional price situation** that exists at the same time as a **shortage situation**, the **pricing manager** must give written notice of the **shortage situation**—

(a) after the **pricing manager** has given written notice under clause 13.164(a) in relation to the **trading periods** affected by the unresolved **provisional price situation**; but

(b) before the **pricing manager** makes **interim prices** available under clause 13.164(b) for each **trading period** affected by the unresolved **provisional price situation**.

Compare: Electricity Governance Rules 2003 rules 3.6 and 3.6A section V part G
Clause 13.144(1): amended, on 1 June 2013, by clause 12(2)(a) and (b) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.
Clause 13.144(1)(a) and (b): amended, on 1 June 2013, by clause 12(2)(c) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.
Clause 13.144(2), (3), (4) and (5): amended, on 5 October 2017, by clause 396(2)(b) and (c) and (3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 13.144(3), (4) and (5): inserted, on 19 January 2017, by clause 7(3) of the Electricity Industry Participation Code Amendment (Scarcity Pricing) 2016.
13.145 Grid owner to give written notice that estimated data given

(1) If a grid owner gives the pricing manager estimated input information in accordance with clauses 13.141(1)(a)(ii) or (b)(ii), the grid owner must, by 0730 hours on the day the relevant input information is required by clause 13.141—
   (a) give written notice to the pricing manager and the WITS manager of any input information that is estimated; and
   (b) specify in the notice whether the estimated information relates to SCADA or half-hour metering information; and
   (c) give details in the notice of the grid exit points and grid injection points to which the estimated information relates; and
   (d) specify in the notice whether the estimated information relates to a dispatch capable load station or a type B industrial co-generating station; and
   (e) specify in the notice the trading periods for which the input information is estimated for each relevant grid exit point, grid injection point, and dispatch capable load station.

(2) As soon as practicable after receiving a written notice from a grid owner under this clause, the WITS manager must give the notice to any person that has requested it.

Compare: Electricity Governance Rules 2003 rule 3.7 section V part G
Clause 13.145(1)(d) and (e): inserted, on 19 December 2014, by clause 35(2) of the Electricity Industry Participation Code Amendment (Minor Code Amendments) (No 3) 2014.

13.146 Requirements if provisional price situation or shortage situation exists

(1) If notice is given by—
   (a) a grid owner to the pricing manager of a SCADA situation in accordance with clause 13.143; or
   (b) the pricing manager of a metering situation in accordance with clause 13.144(1); or
   (c) the pricing manager of an infeasibility situation in accordance with clause 13.144(1)—
      the relevant grid owner, and, in the case of an infeasibility situation, the system operator, must exercise reasonable endeavours to resolve the provisional price situation and to provide revised data to the pricing manager using an approved system.

(2) If notice is given of a high spring washer price situation in accordance with clause 13.144(1), the system operator must apply the high spring washer price relaxation factor in accordance with the high spring washer price situation methodology and provide revised data to the pricing manager using an approved system.
(2A) If the **pricing manager** gives notice of a **shortage situation** in accordance with clause 13.144(1), the **pricing manager** must determine whether a **scarcity pricing situation** exists in accordance with clause 13.135A and, if a **scarcity pricing situation** does exist, calculate **interim prices** and **interim reserve prices** in accordance with clause 13.135B.

(3) The revised data required by subclauses (1) and (2) must be provided to the **pricing manager**—

(a) if the **provisional price situation** arose on a **business day**, by 1000 hours on that day; and

(b) if the **provisional price situation** arose on a day other than a **business day**, by 1200 hours on the 2nd **business day** after the **provisional price situation** arose.

(4) If a **generator** or a **dispatchable load purchaser** does not give **half-hour metering information** to a **grid owner** in accordance with clauses 13.136 to 13.140, and the **pricing manager** has given notice of a **metering situation** in accordance with clause 13.144(1), the **generator** or the **dispatchable load purchaser** must use reasonable endeavours to assist the **grid owner** to resolve the **provisional price situation**.

Compare: Electricity Governance Rules 2003 rule 3.8 section V part G
Clause 13.146(2A): inserted, on 1 June 2013, by clause 13(2) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

13.147 Revised data to be accompanied by written notice

(1) Subclauses (2) and (3) apply to—

(a) a **grid owner**; and

(b) [Revoked]

(c) the **system operator**.

(d) [Revoked]

(2) If a **participant** listed under subclause (1) gives revised data to the **pricing manager** under clause 13.146, the **participant** must—

(a) give written notice to the following **participants** that the **participant** has given revised data:

(i) if a **grid owner** gave the revised data, the **pricing manager**, **WITS manager**, **system operator**, and any other **grid owners**; or

(ii) if the **system operator** gave the revised data, the **pricing manager**, **WITS manager**, and **grid owners**; and

(b) specify in the notice the revisions that have been made; and

(c) in the case of revised data given in relation to a **SCADA situation**, state in the notice whether a **SCADA situation** continues to exist; and
(d) in the case of revised data given in relation to a high spring washer price situation, state in the notice whether the high spring washer price relaxation factor has been applied.

(3) A participant listed under subclause (1) must comply with subclause (2) within the timeframes specified in clause 13.146(3) as if references to the revised data in clause 13.146(3) are references to a notice under this clause.

(4) As soon as practicable after receiving a written notice under this clause, the WITS manager must give the notice to any person that has requested it.

13.148 Failure to give revised data and notice not breach
A participant that is listed in clause 13.147(1) does not breach clauses 13.146(3) or 13.147(3) if the participant has,—

(a) in the case of a provisional price situation other than a high spring washer price situation, exercised reasonable endeavours to remedy the circumstance giving rise to the provisional price situation; and

(b) in the case of a high spring washer price situation, applied the high spring washer price relaxation factor in accordance with the high spring washer price situation methodology; and

(c) used reasonable endeavours to provide the notice required by clause 13.147.

13.149 Pricing manager to make provisional prices and provisional reserve prices available if revised data and notice not given regarding provisional price situation arising on business day

(1) This clause applies if—

(a) a notice of a provisional price situation is given on a business day; and

(b) a participant that is listed in clause 13.147(1)—

(i) does not comply with the timeframes specified in clause 13.146(3); or

(ii) does not comply with the timeframes specified in clause 13.147(3).

(2) If this clause applies, the pricing manager must—

(a) by 1200 hours on that day, give to the system operator, relevant grid owner, the Authority, and any persons that request notice, written notice of the provisional price situation and each trading period affected; and
13.150 Pricing manager to make provisional prices and provisional reserve prices available if revised data and notice not given regarding provisional price situation arising on day other than business day

(1) This clause applies if—
   (a) a notice of a provisional price situation is given on a day other than a business day; and
   (b) a participant that is listed in clause 13.147(1),—
      (i) does not comply with the timeframes in clause 13.146(3); or
      (ii) does not comply with the timeframes in clause 13.147(3).

(2) If this clause applies, the pricing manager must—
   (a) by 1000 hours on the day that the notice of a provisional price situation was given, give to the system operator, relevant grid owner, the Authority, and any persons that request notice, written notice of the provisional price situation and each trading period affected; and
   (b) by 1000 hours on that day make provisional prices and provisional reserve prices available on WITS.

(c) [Revoked]
13.151 Data to be used by pricing manager to determine provisional prices and provisional reserve prices
The pricing manager must produce provisional prices and provisional reserve prices—
(a) on a business day, by using the latest data given to it by 1000 hours on that day; and
(b) on a day other than a business day, by using the data given to it by 0730 hours on that day.
Compare: Electricity Governance Rules 2003 rule 3.13 section V part G

13.152 Pricing manager to make interim prices and interim reserve prices available if revised data resolves provisional price situation
(1) This clause applies if a participant that is listed in clause 13.147(1)—
(a) gives revised data in accordance with clause 13.146 (that does not itself give rise to a provisional price situation); or
(b) gives written notice in accordance with clause 13.147.
(2) If this clause applies, the pricing manager must make interim prices and interim reserve prices available on WITS for each trading period of the previous trading day.
(3) The pricing manager must make the interim prices and interim reserve prices available on WITS by 1200 hours on the day that the revised data and notice were required to be given.
Compare: Electricity Governance Rules 2003 rule 3.14 section V part G

13.153 Revised data gives rise to provisional price situation
If revised data provided in accordance with clause 13.146 gives rise to a provisional price situation, the pricing manager must make provisional prices and provisional reserve prices available on WITS in accordance with clauses 13.149 and 13.150, as if no data had been received.
Compare: Electricity Governance Rules 2003 rule 3.15 section V part G

13.154 Grid owner, generators, dispatchable load purchasers, and system operator to give revised data if provisional prices and provisional reserve prices have been made available
(1) This clause applies if the pricing manager makes provisional prices and provisional reserve prices available on WITS under clause 13.149 or 13.150.
(1A) If provisional prices and provisional reserve prices are made available on WITS in relation to—
(a) an infeasibility situation or a SCADA situation, the grid owner and, in the case of an infeasibility situation, the system operator, must use reasonable
endeavours to resolve the **provisional price situation** and provide revised data to the **pricing manager** using an **approved system**; or

(b) a **metering situation**, the **grid owner** or the **generator** or the **dispatchable load purchaser** (as the case may be) must provide revised **metering information** in accordance with clause 13.166; or

(c) a **high spring washer price situation**, the **system operator** must apply the **high spring washer price relaxation factor** in accordance with the **high spring washer price situation methodology** and use reasonable endeavours to provide revised data to the **pricing manager** using an **approved system**.

(2) The revised data required by subclause (1A) must be provided to the **pricing manager** by 1200 hours on the 2nd business day after the **pricing manager** makes the **provisional prices** and **provisional reserve prices** available on **WITS**.

Compare: Electricity Governance Rules 2003 rule 3.16 section V part G


### 13.155 Revised data to be accompanied by written notice

(1) If a **participant** that is listed in clause 13.147(1) gives revised data in accordance with clause 13.154 to the **pricing manager**, the **participant** must, by the time prescribed by that clause for giving revised data,—

(a) give written notice to the following **participants** that the **participant** has given revised data:

(i) if a **grid owner** gave the revised data, the **pricing manager**, **WITS manager**, **system operator**, and any other **grid owners**; or

(ii) if the **system operator** gave the revised data, the **pricing manager**, **WITS manager**, and **grid owners**; and

(b) specify in the notice the revisions that have been made; and

(c) in the case of revised data given in relation to a **metering situation** or a **SCADA situation**, state in the notice whether a **metering situation** or a **SCADA situation** continues to exist; and

(d) in the case of revised data given in relation to a **high spring washer price situation**, if the **high spring washer price situation relaxation factor** has been applied, state in the notice that the factor has been applied.

(2) As soon as practicable after receiving a written notice under subclause (1)(a), the **WITS manager** must give the notice to any person that has requested it.

Compare: Electricity Governance Rules 2003 rule 3.17 section V part G

13.156 Pricing manager to make interim prices available after provisional prices and provisional reserve prices are made available unless further provisional price situation arises

(1) Subject to subclause (2), if the **pricing manager**—
   (a) does not receive revised data in accordance with clause 13.154 and notice in accordance with clause 13.155 in relation to a **provisional price situation** (other than a **high spring washer price situation**), the **pricing manager** must make **interim prices** and **interim reserve prices** available on **WITS** for all **trading periods** of the relevant **trading day** in accordance with clauses 13.163 and 13.164; or
   
   (b) does not receive revised data in accordance with clause 13.154 and notice in accordance with clause 13.155 in relation to a **high spring washer price situation**, the **pricing manager** must, by 1400 hours on the 2nd **business day** after the **provisional prices** and **provisional reserve prices** were made available on **WITS**, make **interim prices** and **interim reserve prices** available on **WITS** for all **trading periods** of the relevant **trading day** as if the **high spring washer price situation** did not exist; or
   
   (c) receives revised data in accordance with clause 13.154 (that does not itself give rise to a **provisional price situation**) and notice in accordance with clause 13.155, the **pricing manager** must, by 1400 hours on the 2nd **business day** after the **provisional prices** and **provisional reserve prices** were made available on **WITS**, make **interim prices** and **interim reserve prices** available on **WITS** for all **trading periods** of the relevant **trading day**; or
   
   (d) receives revised data in accordance with clause 13.154 and notice in accordance with clause 13.155 and an **infeasibility situation** arises from that data, the **pricing manager** must, by 1400 hours on the 2nd **business day** after the **provisional prices** and **provisional reserve prices** were made available on **WITS**, give to the **system operator**, relevant **grid owner**, and any person that has requested notice, written notice that an **infeasibility situation** exists, specifying in the notice each **trading period** affected by the **infeasibility situation**; or
   
   (e) receives revised data in accordance with clause 13.154 and notice in accordance with clause 13.155 and a **high spring washer price situation** arises from that data, the **pricing manager** must, by 1400 hours on the 2nd **business day** after the **provisional prices** and **provisional reserve prices** were made available on **WITS**, give to the **system operator**, relevant **grid owner**, and any person that has requested notice, written notice that a **high spring washer price situation** exists, specifying in the notice—
(i) each trading period affected by the high spring washer price situation; and
(ii) each transmission security constraint that has bound in the relevant trading period or trading periods.

(2) The pricing manager must not give written notice of a high spring washer price situation in accordance with subclause (1)(e) in relation to a trading period if—
(a) an infeasibility situation exists in that trading period and it has not been resolved; or
(b) the pricing manager has previously given written notice that a high spring washer price situation exists in that trading period.

13.157 Requirements if infeasibility situation or high spring washer price situation exists

(1) If the pricing manager gives notice of an infeasibility situation in accordance with clause 13.156(1)(d), the relevant grid owner and the system operator must, by 1600 hours on the 2nd business day after the provisional prices and provisional reserve prices were made available on WITS, exercise reasonable endeavours to resolve the provisional price situation and provide revised data to the pricing manager using an approved system.

(2) If the pricing manager gives notice of a high spring washer price situation in accordance with clause 13.156(1)(e), the system operator must, by 1600 hours on the 2nd business day after the provisional prices and provisional reserve prices were made available on WITS, apply the high spring washer price relaxation factor in accordance with the high spring washer price situation methodology and provide revised data to the pricing manager using an approved system.

13.158 Revised data to be accompanied by written notice

(1) If a grid owner or the system operator gives revised data to the pricing manager in accordance with clause 13.157, the grid owner or system operator (as the case may be) must, by the time prescribed by that clause for giving revised data,—
(a) give written notice to the following participants that it has given revised data:
   (i) if a grid owner gave the revised data, the pricing manager, system operator, and any other grid owners; or
   (ii) if the system operator gave the revised data, the pricing manager, and grid owners; and
(b) specify in the notice the revisions that have been made; and
(c) in the case of revised data given in relation to an infeasibility situation, state in the notice whether the infeasibility situation has been resolved; and
(d) in the case of revised data given in relation to a **high spring washer price situation**, if the **high spring washer price situation relaxation factor** has been applied, state in the notice that the factor has been applied.

(2) As soon as practicable after receiving a written notice under subclause (1)(a), the **WITS manager** must give the notice to any person that has requested it.

Compare: Electricity Governance Rules 2003 rule 3.20 section V part G

13.159 Pricing manager to make interim prices available or give written notice that high spring washer price situation exists

Subject to clause 13.160, if the **pricing manager**—

(a) receives revised data in accordance with clause 13.157 and written notice in accordance with clause 13.158, the **pricing manager** must,—

(i) if the revised data does not itself give rise to a **provisional price situation**, by 1800 hours on the 2nd **business day** after the **provisional prices** and **provisional reserve prices** were published, make **interim prices** and **interim reserve prices** available on **WITS** for all **trading periods** of the relevant **trading day**; or

(ii) if an **infeasibility situation** arises from that data, make **interim prices** and **interim reserve prices** available on **WITS** in accordance with clauses 13.163 and 13.164; or

(iii) if a **high spring washer price situation** arises from that data, by 1800 hours on the 2nd **business day** after the **provisional prices** and **provisional reserve prices** were made available on **WITS**, give to the **system operator** and any person that has requested notice, written notice that a **high spring washer price situation** exists, specifying in the notice—

(A) each **trading period** affected by the **high spring washer price situation**; and

(B) each **transmission security constraint** that has **bound** in the relevant **trading period** or **trading periods**; and

(b) does not receive revised data in accordance with clause 13.157 and does not receive a written notice in accordance with clause 13.158,—

(i) in relation to an **infeasibility situation**, the **pricing manager** must make **interim prices** and **interim reserve prices** available on **WITS** in accordance with clauses 13.163 and 13.164; or

(ii) in relation to a **high spring washer price situation**, the **pricing manager** must make **interim prices** and **interim reserve prices** available on **WITS** by 1800 hours on the 2nd **business day** after the **provisional prices** and **provisional reserve prices** were made available on **WITS**, as if the **high spring washer price situation** did not exist.

Compare: Electricity Governance Rules 2003 rule 3.21 section V part G
13.160 Prohibition on notice of high spring washer price situation

The **pricing manager** must not give notice of a **high spring washer price situation** in accordance with clause 13.159(a)(iii) in relation to a **trading period** if—

(a) an **infeasibility situation** exists in that **trading period** and has not been resolved; or

(b) the **pricing manager** has previously given notice that a **high spring washer price situation** exists in that **trading period**.

Compare: Electricity Governance Rules 2003 rule 3.21A section V part G

13.161 System operator to apply high spring washer price relaxation factor and give notice

(1) If the **pricing manager** gives written notice of a **high spring washer price situation** in accordance with clause 13.159(a)(iii), the **system operator** must, by 1000 hours on the 3rd **business day** after the **provisional prices** and **provisional reserve prices** were made available on WITS,—

(a) apply the **high spring washer price relaxation factor** in accordance with the **high spring washer price situation methodology**; and

(b) exercise reasonable endeavours to provide revised data to the **pricing manager** using an **approved system**.

(2) If the **system operator** gives revised data to the **pricing manager** in accordance with subclause (1), the **system operator** must, by the time prescribed by that subclause for giving revised data,—

(a) give written notice to the **pricing manager** and the **WITS manager** that the **system operator** has given revised data; and

(b) specify in the notice the revisions that have been made; and

(c) if the **high spring washer price relaxation factor** has been applied, state in the notice that the factor has been applied.

(3) As soon as practicable after receiving a written notice under subclause (2)(a), the **WITS manager** must give the notice to any person that has requested it.

Compare: Electricity Governance Rules 2003 rule 3.21B section V part G


13.162 Pricing manager to make interim prices available

If the **pricing manager**—

(a) receives revised data in accordance with clause 13.161(1) and notice in accordance with clause 13.161(2), the **pricing manager** must, by 1200 hours on the 3rd **business day** after the **provisional prices** and **provisional reserve prices**
were made available on WITS, make **interim prices** and **interim reserve prices** available on WITS for all **trading periods** of the relevant **trading day**; or

(b) does not receive revised data in accordance with clause 13.161(1) and does not receive a notice in accordance with clause 13.161(2), the **pricing manager** must, by 1200 hours on the 3rd **business day** after the **provisional or provisional reserve price** was made available on WITS, make **interim prices** and **interim reserve prices** available on WITS for all **trading periods** of the relevant **trading day** as if the **high spring washer price situation** did not exist.

Compare: Electricity Governance Rules 2003 rule 3.21C section V part G
Clause 13.162(a) and (b): amended, on 5 October 2017, by clause 411(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

13.163 Revised data cannot be given or revised data gives rise to provisional price situation (other than high spring washer price situation)
If clause 13.156(1)(a) applies, or the revised data received in accordance with clause 13.157(1) does not resolve an **infeasibility situation** or gives rise to a **provisional price situation** (other than a **high spring washer price situation**), the **pricing manager** must make **interim prices** and **interim reserve prices** available on WITS and must give written notice to **generators** and **purchasers**—

(a) for each **trading period** not affected by a **provisional price situation**; and

(b) on the basis of the information given to it under clause 13.154; and

(c) by 1800 hours of the 2nd **business day** after it makes **provisional prices** and **provisional reserve prices** available on WITS.

Compare: Electricity Governance Rules 2003 rule 3.22 section V part G

13.164 If provisional price situation (other than high spring washer price situation) continues
If clause 13.156(1)(a) applies, or the revised data received in accordance with clause 13.157(1) does not resolve an **infeasibility situation** or gives rise to a **provisional price situation** (other than a **high spring washer price situation**), the **pricing manager** must, for each affected **trading period**,—

(a) no later than the time at which the **pricing manager** would be required to make **interim prices** available under clause 13.163, give to the **system operator**, relevant **grid owner**, and any person that has requested notice, written notice that the **pricing manager** cannot calculate **interim prices** and **interim reserve prices**, specifying the **trading periods** affected; and

(b) on the basis of the information given to the **pricing manager** under clause 13.154, calculate and make **interim prices** available on WITS for all **grid injection points** and all **net grid exit points** for each affected **trading period** by—

(i) assigning a price to all **net grid injection points** for each affected **trading period** equal to the highest price at the point that the **loss adjusted demand** intersects with the **offer stack**; and
(ii) assigning a price to all net grid exit points equal to 1.05 times the price calculated for all grid injection points under subparagraph (i)—by 1800 hours on the 2nd business day after the pricing manager makes provisional prices and provisional reserve prices available on WITS; and

(c) calculate and publish interim reserve prices by taking the mean of the relevant final reserve prices of the corresponding day in each of the 4 previous weeks, by 1800 hours on the 2nd business day after the pricing manager makes provisional prices and provisional reserve prices available on WITS; and

(d) give to any person that has requested notice, written notice of all interim prices and interim reserve prices by 1800 hours on the 2nd business day after the pricing manager makes provisional prices and provisional reserve prices available on WITS.

Compare: Electricity Governance Rules 2003 rule 3.23 section V part G
Clause 13.164(a) to (d): amended, on 5 October 2017, by clause 413(a) to (d) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

13.165 System operator or grid owner to give written notice to Authority if provisional price situation not resolved

(1) If a grid owner or the system operator receives notice of an unresolved provisional price situation in accordance with clause 13.164, the grid owner or system operator (as the case may be) must immediately give written notice to the Authority of—

(a) how the unresolved provisional price situation arose; and

(b) the steps taken in attempting to resolve the provisional price situation; and

(c) the reasons for the inability of the grid owner or system operator (as the case may be) to resolve the provisional price situation.

(2) As soon as it receives a notice given under subclause (1), the Authority must consider the unresolved provisional price situation and urgently address the matters raised in the notice.

Compare: Electricity Governance Rules 2003 rules 3.24 and 3.25 section V part G

13.166 Generator, grid owner, or dispatchable load purchaser to give revised metering information following initial estimate

(1) If clause 13.154(1A)(b) applies, the generator, grid owner, or dispatchable load purchaser who gave the initial estimate to the pricing manager in accordance with clause 13.141(1)(b)(ii) must give to the pricing manager—

(a) actual half-hour metering information; or

(b) if actual half-hour metering information is not reasonably available, back-up metering information; or

(c) if back-up metering information is not reasonably available, check metering information (adjusted by the relevant registration factor to achieve accuracy equivalent to actual half-hour metering information); or

(d) if check metering information is not reasonably available, a final estimate.
(2) If a **metering situation** arose, either in whole or in part, from the failure of a **generator** or a **dispatchable load purchaser** to provide **half-hour metering information**, the **generator** or the **dispatchable load purchaser** must use reasonable endeavours to assist the relevant **grid owner** to provide the information required by this clause by the time prescribed in clause 13.154(2).

Compare: Electricity Governance Rules 2003 rule 3.26 section V part G

### 13.166A Pricing manager to recalculate and make interim prices available if infeasibility situation caused by shortage of instantaneous reserve

(1) If an **infeasibility situation** that has been resolved under this subpart was caused by a shortage of **instantaneous reserve**, the **pricing manager** must recalculate and make **interim prices** available on WITS for the relevant **trading period** by adding a virtual provider of **fast instantaneous reserve** and **sustained instantaneous reserve**, at the price as specified in subclause (2), that provides sufficient **fast instantaneous reserve** and **sustained instantaneous reserve** so that prices for **fast instantaneous reserve** and **sustained instantaneous reserve** do not exceed that price.

(2) The price referred to in subclause (1) for a **trading period** is the greater of—

(a) 3 times the highest **offer** scheduled in the relevant **island** during the **trading period** according to the revised data provided to the **pricing manager** under this subpart; and

(b) the highest **reserve offer** scheduled in the relevant **island** during the **trading period** according to the revised data provided to the **pricing manager** under this subpart as follows:

(i) in the case of an **infeasibility situation** caused by a shortage of **fast instantaneous reserve**, the highest **reserve offer** for **fast instantaneous reserve**;

(ii) in the case of an **infeasibility situation** caused by a shortage of **sustained instantaneous reserve**, the highest **reserve offer** for **sustained instantaneous reserve**.


**Interim pricing period**

### 13.167 Pricing manager to make interim prices available

The **pricing manager** must make **interim prices** and **interim reserve prices** available on WITS—

(a) when required to do so by clauses 13.142, 13.152, 13.156(1), 13.159, 13.162, 13.163 or 13.164, by 1200 on each **trading day** for the previous **trading day**; and

(aa) when required to do so by clause 13.135B; and
(b) when required to do so by the Authority under clause 13.177(1)(c); and
(c) before making final prices or final reserve prices available on WITS.

Compare: Electricity Governance Rules 2003 rule 3.26A section V part G

13.168 When pricing error may be claimed

Once the pricing manager has made interim prices and interim reserve prices available on WITS, an error claimant may claim that the prices contain a pricing error.

Compare: Electricity Governance Rules 2003 rule 3.26B section V part G

13.169 Error claimant materially affected by pricing error

(1) Subject to subclause (2), an error claimant may only claim that a pricing error has occurred if it considers it has been materially affected by the pricing error.

(2) Subclause (1) does not apply to—
   (a) the Authority; or
   (b) any person who is not a participant.

Compare: Electricity Governance Rules 2003 rule 3.26C section V part G

13.170 Method and timing for claiming pricing error has occurred

To claim that a pricing error has occurred, an error claimant must—
   (a) complete the form set out in Form 9 of Schedule 13.1; and
   (b) include sufficient information in the form to demonstrate that the error claimant (other than an error claimant described in clause 13.169(2)) has been materially affected by the pricing error; and
   (c) give the completed form to the pricing manager; and
   (d) comply with paragraphs (a) to (c) no later than 1200 on the 1st business day following the trading day on which the pricing manager made the interim price or interim reserve price that contains the pricing error available on WITS.

Compare: Electricity Governance Rules 2003 rule 3.26D section V part G

13.171 Pricing manager must make final prices available if no pricing error claimed

(1) Subclause (2) applies if, by 1200 on the 1st business day following the trading day on which the pricing manager made the interim price or interim reserve price available
on WITS, no **pricing error** is claimed in respect of the **interim prices** or **interim reserve prices**.

(2) The **pricing manager** must make available on WITS the **interim prices** as **final prices**, and **interim reserve prices** as **final reserve prices**, by 1400 hours on the 1st **business day** following the **trading day** on which the **pricing manager** made the **interim prices** or **interim reserve prices** available on WITS.

Compare: Electricity Governance Rules 2003 rule 3.26E section V part G

### 13.172 Effect of pricing error being claimed

If an **error claimant** claims that a **pricing error** is contained in either **interim prices** or **interim reserve prices**, the **pricing manager** must not make **final prices** or **final reserve prices** available on WITS until the **pricing manager** has implemented the Authority's decision in accordance with clause 13.177.

Compare: Electricity Governance Rules 2003 rule 3.26F section V part G

### 13.173 Process when pricing error claimed

If the **pricing manager** receives a claim that an **error claimant** considers that a **pricing error** has occurred, the **pricing manager** must—

(a) check that sufficient information is included in the form as required under clause 13.170; and

(b) confirm to the **error claimant** that it has received the **pricing error** claim; and

(c) by 1400 hours on the 1st **business day** following the **trading day** on which the **pricing manager** made available on WITS the **interim prices** or **interim reserve prices** in respect of which the **pricing error** is claimed, give a written notice on WITS and to the **error claimant**, the **Authority**, any **participant** to which clause 13.173(d) applies, and any person that has requested notice, advising—

(i) that a **pricing error** has been claimed; and

(ii) the name of the **error claimant**; and

(iii) the reason for the **error claimant** believing that a **pricing error** has occurred; and

(iv) the **trading periods** that are claimed to have been affected by the **pricing error**; and

(d) request that the **error claimant**, a **participant**, or the **Authority**, provide the **pricing manager** with any additional information that the **pricing manager** reasonably requires to determine whether a **pricing error** has occurred; and

(e) provide the **Authority** with a copy of all information it has received in relation to the **pricing error** that has been claimed; and

(f) determine whether it agrees that a **pricing error** has occurred.

Compare: Electricity Governance Rules 2003 rule 3.26G section V part G
13.174 Recommendation to Authority

When the **pricing manager** has determined whether it agrees that a **pricing error** has occurred—

(a) if it agrees that a **pricing error** has occurred, it must—
   (i) recommend that the **Authority** uphold the claim; and
   (ii) set out its reasons for agreeing that a **pricing error** has occurred; and
   (iii) recommend the actions that the **pricing manager** considers are required to correct the **pricing error**; or

(b) if it does not agree that a **pricing error** has occurred, it must—
   (i) recommend that the **Authority** not uphold the claim; and
   (ii) set out its reasons for not agreeing that a **pricing error** has occurred.

Compare: Electricity Governance Rules 2003 rule 3.26H section V part G

13.175 Authority to accept or reject recommendations

If the **Authority** receives a recommendation and reasons from the **pricing manager** under clause 13.174, it—

(a) must decide whether to accept the **pricing manager**'s recommendations; and

(b) must immediately give written notice to the **pricing manager** of the **Authority**'s decision; and

(c) may direct the **pricing manager**—
   (i) to take any specified action to resolve the **pricing error**; or
   (ii) to direct, on behalf of the **Authority**, another **participant** to take any specified action to resolve the **pricing error**.

Compare: Electricity Governance Rules 2003 rule 3.26I section V part G


13.176 Pricing manager to give written notice

As soon as practicable after the **Authority** has given written notice to the **pricing manager** of its decision under clause 13.175, the **pricing manager** must give to any person that has requested notice, a written report specifying—

(a) the name of the **error claimant**; and

(b) the reason for the **error claimant** claiming that a **pricing error** has occurred; and

(c) the trading **periods** that are claimed to have been affected by the **pricing error**; and

(d) the **Authority**'s decision made under clause 13.175; and

(e) the **Authority**'s reasons for its decision under clause 13.175; and:

(f) if the **Authority** decided that a **pricing error** had occurred, any actions it has directed be taken to correct the **pricing error**.

Compare: Electricity Governance Rules 2003 rule 3.26J section V part G


13.177 Pricing manager to implement Authority's decision

(1) If the Authority decides that a pricing error has occurred, the pricing manager must—
   (a) take any action directed by the Authority under clause 13.175(c)(i) to resolve the pricing error; and
   (b) give a written direction to a participant to take any action required by the Authority under clause 13.175(c)(ii) to resolve the pricing error; and
   (c) once those actions have been completed, make recalculated interim prices and interim reserve prices available on WITS, using any updated metering information.

(2) If the Authority decides that a pricing error has not occurred, the pricing manager must make the interim prices and interim reserve prices available on WITS as final prices and final reserve prices.

Compare: Electricity Governance Rules 2003 rule 3.26K section V part G
Clause 13.177(1)(a), (c) and (2): amended, on 5 October 2017, by clause 424(a), (c) and (d) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

13.178 Effect of making recalculated interim prices available

If the pricing manager is required to make recalculated interim prices and interim reserve prices available on WITS in accordance with clause 13.177(1)(c)—
   (a) the pricing manager must do so by following the methodology required under clauses 13.135 to 13.179; and
   (b) a further pricing error may be claimed in respect of the recalculated interim prices and interim reserve prices made available on WITS.

Compare: Electricity Governance Rules 2003 rule 3.26L section V part G

13.179 Timing for resolution of pricing error claim process

The pricing manager and the Authority must make reasonable endeavours to ensure that, by 1400 hours on the 2nd business day after the relevant pricing error was claimed, but at least 2 hours after the pricing manager gives the notice under clause 13.176, the pricing manager—
   (a) makes recalculated interim prices and interim reserve prices available in accordance with clause 13.177(1)(c); or
   (b) makes final prices and final reserve prices available in accordance with clause 13.177(2).

Compare: Electricity Governance Rules 2003 rule 3.26M section V part G
13.180 Actions Authority may take to resolve pricing error

(1) To correct a pricing error, the actions that the Authority may take, or that the Authority may direct the pricing manager to take, include—

(a) delaying when interim prices, interim reserve prices, final prices, and final reserve prices are made available under clause 13.184, if the Authority considers that is necessary to allow time for the pricing error to be investigated or corrected; or

(b) giving written directions to any participant to act in a manner that will, in the Authority’s opinion, correct or assist in correcting the pricing error.

(2) However, to avoid any doubt, in resolving a pricing error, the Authority must not—

(a) act inconsistently with this Code, the Act, or any other law; or

(b) require any other participant to act inconsistently with this Code, the Act, or any other law.

Compare: Electricity Governance Rules 2003 rule 3.26N section V part G

13.181 Obligation to comply with pricing manager

(1) If the pricing manager asks a participant or the Authority to provide information in accordance with clause 13.173(d), the participant or the Authority must provide the pricing manager with the requested information in writing, within the reasonable timeframe advised by the pricing manager.

(2) Each participant must comply promptly with any direction given by the pricing manager in accordance with clause 13.175(c)(ii).

(3) To avoid doubt, if an error claimant does not provide the pricing manager with sufficient information to support its claim that a pricing error has occurred, and fails to provide additional information when requested under clause 13.173(d) the pricing manager may recommend under clause 13.174(b) that the Authority not uphold the claim.

Compare: Electricity Governance Rules 2003 rule 3.26O section V part G

13.182 No pricing errors may be claimed after final prices calculated

(1) An error claimant may only claim that a pricing error has occurred in respect of interim prices or interim reserve prices.

(2) Once the pricing manager has made final prices or final reserve prices available on WITS, no further pricing errors can be claimed in respect of those prices.

Compare: Electricity Governance Rules 2003 rule 3.26P section V part G
Electricity Industry Participation Code 2010
Part 13

Making final prices available


13.183 Pricing manager must not make recalculated final prices available

Unless directed to do so by the Authority under clause 5.2, the pricing manager must not make a recalculated final price or final reserve price available on WITS for any trading period despite the fact that the final price or final reserve price may contain an error.

Compare: Electricity Governance Rules 2003 rule 3.27 section V part G

13.184 Authority may order delay in making final prices available

Despite clauses 13.135 to 13.191, the Authority may give a written direction to the pricing manager to delay making interim prices, interim reserve prices, final prices, or final reserve prices available on WITS.

Compare: Electricity Governance Rules 2003 rule 3.28 section V part G

13.185 Final prices for more than 1 trading day

If the pricing manager is required to make 1 or more of the following prices available on WITS for more than 1 trading day at a time, the pricing manager’s deadline for making the price or prices available on WITS is extended by 2 hours for each trading day:

(a) interim prices;
(b) interim reserve prices;
(c) final prices;
(d) final reserve prices.

Compare: Electricity Governance Rules 2003 rule 3.29 section V part G

Miscellaneous requirements relating to calculation of prices

13.186 Revised data for more than 1 trading day

If the system operator or a grid owner is required to give revised data for more than 1 trading day at a time, that system operator’s or grid owner’s deadline is extended by 2 hours for each trading day.

Compare: Electricity Governance Rules 2003 rule 3.30 section V part G
13.187 Daylight saving to be observed

Despite anything in this subpart, if the grid owner gives the pricing manager data for an initial estimate under clause 13.141(1)(b)(ii) or a final estimate under clause 13.166(1)(d), the following provisions apply:

(a) if a grid owner gives data for an initial estimate or a final estimate using an equivalent day and the equivalent day is the day on which daylight saving begins, the grid owner must replicate the actual data from trading periods 5 and 6 of the equivalent day into trading periods 7 and 8 to produce synthetic data for 48 trading periods. This is shown below:

| Used | 1  | 2  | 3  | 4  | 5  | 6  | 7  | 8  | 9  | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|------|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|
| Recorded | 1  | 2  | 3  | 4  | 5  | 6  | 7  | 8  | 9  | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
| Used | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | 43 | 44 | 45 | 46 | 47 | 48 |
| Recorded | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | 43 | 44 | 45 | 46 | 47 | 48 |

(b) if a grid owner gives data for an initial estimate or a final estimate for the day on which daylight saving begins, the grid owner must discard the actual data for trading periods 5 and 6 to produce synthetic data for 46 trading periods. This is shown below:

| Used | 1  | 2  | 3  | 4  | 5  | 6  | 7  | 8  | 9  | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|------|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|
| Recorded | 1  | 2  | 3  | 4  | 7  | 8  | 9  | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 |
| Used | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | 43 | 44 | 45 | 46 | 47 | 48 |
| Recorded | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | 43 | 44 | 45 | 46 | 47 | 48 |

(c) if a grid owner gives data for an initial estimate or a final estimate for the day on which daylight saving ends, the grid owner must replicate the actual data from trading periods 5 and 6 into trading periods 7 and 8 to produce synthetic data for 50 trading periods. This is shown below:

| Used | 1  | 2  | 3  | 4  | 5  | 6  | 7  | 8  | 9  | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|------|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|
| Recorded | 1  | 2  | 3  | 4  | 5  | 6  | 7  | 8  | 9  | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
| Used | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | 43 | 44 | 45 | 46 | 47 | 48 | 49 | 50 |
| Recorded | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | 43 | 44 | 45 | 46 | 47 | 48 | 49 | 50 |

(d) if a grid owner gives data for an initial estimate or a final estimate using an equivalent day and the equivalent day is the day on which daylight saving ends, the grid owner must discard the actual data from trading periods 5 and 6 of the equivalent day to produce synthetic data for 48 trading periods. This is shown below:
13.188 Reconciliation manager to publish annual consumption list

(1) At least once every 6 months, the reconciliation manager must give the Authority an annual consumption list.

(2) The list must rank in descending order the annual consumption of all grid exit points and grid injection points with annual consumption greater than 300 GWh for the 12-month period ended 3 months prior to the date on which the list is due.

(3) The reconciliation manager must publish the list within 1 business day of providing it to the Authority.

Compare: Electricity Governance Rules 2003 rule 3.31 section V part G
Clause 13.188(1) and (3): amended, on 5 October 2017, by clause 434(2) and (3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

13.189 System operator to give pricing manager and Authority list of model variable values

(1) [Revoked]

(2) If the value of the model parameters listed in Schedule 13.2 are to be changed, the system operator must immediately—

(a) give the pricing manager and the Authority an updated list of values in writing; and

(b) advise the Authority, in relation to the price under clause 13.13(1)(c)(ii), or clause 13.13(c)(iii) if there is no price published under clause 13.13(1A), if—

(i) the price remains appropriate; or

(ii) a new price is appropriate.

(2A) If the system operator advises the Authority that a new price is appropriate under subclause (2)(b)(ii), the system operator must give to the Authority in writing the proposed new price, and an explanation for the proposed new price.

(3) The pricing manager and the Authority must acknowledge receipt of the updated list in writing.

(4) Changes specified in any updated list must become effective from a date specified by the system operator, subject to agreement in writing from both the pricing manager and the Authority.

Compare: Electricity Governance Rules 2003 rule 3.33 section V part G
Clause 13.189(2): amended, on 3 November 2016, by clauses 5(3) and 5(4) of the Electricity Industry Participation Code Amendment (Dispatchable Demand During Tight Market Conditions) 2016.
Clause 13.189(4): amended, on 3 November 2016, by clause 5(7)(a) and (b) of the Electricity Industry Participation Code Amendment (Dispatchable Demand During Tight Market Conditions) 2016.

13.189A Pricing manager to give clearing manager information about dispatch-capable load station from schedule of final prices

(1) The **pricing manager** must give the **clearing manager** information about the quantity of **electricity** scheduled in the schedule of **final prices** for each **dispatch-capable load station** for each **trading period** that is both—
   (a) a **trading period** for which a **nominated dispatch bid** was submitted for the **dispatch-capable load station**; and
   (b) a **trading period** in the **billing period** that is immediately before the **billing period** in which the information must be provided under subclause (2).

(2) The **pricing manager** must provide the information by 1600 hours on the 7th **business day** of each **billing period**.


13.190 All information and notices to be unconditional and final

(1) [Revoked]

(2) Except as provided for in this Code, **participants** may treat all information and notices given under clauses 13.135 to 13.191 as final.

Compare: Electricity Governance Rules 2003 rule 3.34 section V part G

13.191 Backup procedures if WITS or approved system is unavailable

(1) If WITS or the **approved system** is unavailable for the purposes of giving information or making information available under clauses 13.135 to 13.191, each **grid owner** and the **pricing manager** must follow the backup procedures specified by the **WITS manager**.

(2) The backup procedures referred to in subclause (1) must be specified by the **WITS manager** following consultation with the **Authority**, **generators**, **purchasers**, **ancillary service agents**, the **grid owners** and the **pricing manager**.

(3) [Revoked]

Compare: Electricity Governance Rules 2003 rules 3.35 and 3.36 section V part G
13.192 Constrained off situations may occur

A constrained off situation occurs when—

(a) a generator is not given a dispatch instruction, or is not dispatched by the system operator to the level expected based on the generator’s offer compared to the relevant final price, for a trading period despite the generator having offered electricity at a price below the final price for that trading period at the relevant grid injection point; or

(b) in relation to a block dispatch group or station dispatch group, a generator is not given a dispatch instruction, or is not dispatched by the system operator to the level expected based on the generator’s offer compared to the final price, for the trading period, despite the generator having offered electricity in the trading period at a grid injection point within the block dispatch group or station dispatch group below the final price at the relevant grid injection point in that trading period, and the aggregate quantity of those offers is greater than the dispatched quantity calculated in accordance with clause 13.194; or

(c) in relation to a dispatch-capable load station (except when the final nominated bid for the dispatch-capable load station in a trading period is a nominated non-dispatch bid), the latest dispatch instruction issued by the system operator for the dispatch-capable load station for a trading period is for a MW amount that is less than the MW amount scheduled for the dispatch-capable load station in the schedule of final prices for the trading period.

Compare: Electricity Governance Rules 2003 rule 4.1 section V part G
Clause 13.192(c): amended, on 1 December 2015, by clause 7 of the Electricity Industry Participation Code Amendment (Dispatchable Demand: Late Bid Revisions) 2015.

13.193 Determining affected price bands for block dispatch groups and station dispatch groups

If a constrained off situation occurs for a block dispatch group or station dispatch group during any trading period during a billing period, the clearing manager must determine the affected price bands for that block dispatch group or station dispatch group by—

(a) taking all the offers made by that block dispatch group or station dispatch group in relation to that trading period, calculating the differences between each offer price and final price for each grid injection point, and ranking the differences in ascending order; and

(b) identifying each price band ranked under paragraph (a) in which the aggregate quantity in all previous price bands plus the quantity for that price band is greater than 0 or the dispatched quantity calculated in accordance with clause 13.194, but is less than the aggregate quantity for all the generating plant in that block
dispatch group or station dispatch group calculated by the clearing manager using the methodology set out in Schedule 13.3. The offer prices corresponding to the ranked price bands identified under this paragraph are the affected price bands for the block dispatch group or station dispatch group for the purposes of clauses 13.194 to 13.196.

Compare: Electricity Governance Rules 2003 rule 4.2 section V part G

13.194 Clearing manager to calculate constrained off amounts

(1) Despite clause 13.193, if a constrained off situation occurs, in relation to a generator, during a trading period, the clearing manager must calculate the constrained off amounts for each generator, for each affected price band, using the following formula:

\[ \text{COF}_g = Q_{cof} \times (P_f - P_o) \]

where

- \( \text{COF}_g \) is the constrained off amount for a generator
- \( Q_{cof} \) is the dispatched quantity in MWh (calculated as set out below) from that price band in the offer that was constrained off during a trading period, or the positive difference between the reconciliation information and the scheduled quantity, whichever is less
- \( P_o \) is the price offered for that price band by that generator for the quantity of electricity from the generating plant that was constrained off
- \( P_f \) is the final price for that trading period at the grid injection point.

(1A) If a constrained off situation occurs in relation to a dispatch-capable load station during a trading period, the clearing manager must calculate the constrained off amounts for each dispatch-capable load station, for each affected nominated dispatch bid price band, using the following formula:

\[ \text{ConOffAmtdisp} = \text{ConOffQ} \times (P_b - P_f) \]

where

- \( \text{ConOffAmtdisp} \) is the constrained off amount for a dispatch-capable load station for the nominated dispatch bid price band
- \( \text{ConOffQ} \) is the amount in MWh by which \( Q_{fp} \) exceeds the highest of \( Q_{disp} \) and \( Q_{rec} \)

where

- \( Q_{fp} \) is the quantity, in MWh, scheduled for the nominated dispatch bid price band in the schedule of final prices
- \( Q_{disp} \) is the latest quantity, in MWh, dispatched for the nominated dispatch bid price band in the trading period
- \( Q_{rec} \) is the reconciled quantity provided by the reconciliation manager under clause 15.20C allocated by the clearing manager to the nominated dispatch bid price band in the trading period

Compare: Electricity Governance Rules 2003 rule 4.2 section V part G
Electricity Industry Participation Code 2010
Part 13

Pb  is the price bid for the nominated dispatch bid price band for the dispatch-capable load station that was constrained off.

Pr  is the final price for the trading period at the grid exit point.

(2) For the purposes of clauses 13.192 to 13.201, dispatched quantity must be calculated taking into account—

(a) the quantity in MW recorded in the log kept by the system operator in accordance with clause 13.76 and, if required, the clearing manager must aggregate such quantities for—

(i) generating stations or generating units in the relevant station dispatch group; or

(ii) generating units, if the clearing manager requires the dispatched quantity to be determined on a grid injection point basis; and

(b) for an offer, the ramp rate applying to that constrained off situation that is specified in the offer submitted by that generator, or—

(i) for a block dispatch group or a station dispatch group; or

(ii) for generating units, if the clearing manager requires the dispatched quantity to be determined on a grid injection point basis—

the fastest of the ramp rates applying to that constrained off situation that are specified in the offers submitted by the generator in that block dispatch group, that station dispatch group or those generating units electrically connected to the relevant grid injection point (as the case may be); and

(c) plus or minus the MW bandwidth applicable for each generator affected by a frequency keeping requirement as advised by the system operator to the clearing manager, and, if required, the clearing manager must aggregate the MW bandwidth applicable to determine the MW bandwidth on a grid injection point basis.

Compare: Electricity Governance Rules 2003 rule 4.3.1 section V part G

13.195 Constrained off amount for block dispatch groups and station dispatch groups
The constrained off amounts for a block dispatch group or station dispatch group must equal the sum of the amounts calculated in accordance with clause 13.194 for the generating plant in block dispatch group or station dispatch group.

Compare: Electricity Governance Rules 2003 rule 4.3.2 section V part G
13.196 Calculation of constrained off amounts attributable to system operator

If a constrained off situation occurs during any trading period in the previous billing period, and the clearing manager receives notice of the constrained off situation under clauses 13.76 to 13.80, the clearing manager must determine the portion of the constrained off amounts calculated under clause 13.194 that is attributable to the system operator for each generator as follows:

(a) if the system operator has advised the clearing manager that a voltage support or other constrained off situation occurred (including, but not limited to, over frequency reserve and instantaneous reserve) the system operator must be allocated the total constrained off amount:

(b) if the system operator has advised the clearing manager that a non-security constrained off situation occurred, the system operator must be allocated a constrained off amount calculated in accordance with the following formula:

\[
SOCOFNS_{so} = TCOFP * \left( \frac{SOQcoffns}{TQcoff} \right)
\]

where

\(SOCOFNS_{so}\) is the constrained off amount attributable to the system operator for that non-security constrained off situation

\(TCOFP\) is the total constrained off payment for that trading period

\(SOQcoffns\) is the non-security quantity that was constrained off and advised to the clearing manager by the system operator under clauses 13.76 to 13.80 or the total quantity constrained off, whichever is less

\(TQcoff\) is the total quantity constrained off:

(c) if the system operator has advised the clearing manager that a frequency keeping situation occurred in a trading period the system operator must be allocated a constrained off amount calculated in accordance with the following formula:

\[
SOCOFFK_{so} = TCOFP * \left( \frac{SOQcofffk}{TQcoff} \right)
\]

where

\(SOCOFFK_{so}\) is the constrained off amount attributable to the system operator for that frequency keeping constrained off situation

\(TCOFP\) is the total constrained off payment for the generator for the trading period

\(SOQcofffk\) is the frequency keeping quantity advised to the clearing manager by the system operator under clauses 13.76 to 13.80 or
the total quantity constrained off for the *generator*, whichever is the less

\[ TQcoff \]

is the total quantity constrained off for the *generator*.

Compare: Electricity Governance Rules 2003 rule 4.3.3 section V part G

### 13.197 Timeframe for calculating constrained off amounts

Each billing period, the *clearing manager* must calculate constrained off amounts for the previous billing period in accordance with clauses 13.194 to 13.196 by the later of—

(a) 1600 hours on the 8th business day of the billing period after the previous billing period; and

(b) 1600 hours on the 1st business day after the clearing manager receives the information required to calculate constrained off amounts.

Compare: Electricity Governance Rules 2003 rule 4.4 section V part G

### 13.198 Clearing manager to send constrained off information to system operator

1. The *clearing manager* must, at the time specified in clause 13.197, send to the *system operator* the details of constrained off amounts that are attributable to the *system operator* (but limited to information about those constrained off amounts that is in the possession of the clearing manager) and the constrained off quantities (in MW) calculated in accordance with clause 13.196 for the previous billing period.

2. The information must be provided to the system operator in the manner and format agreed between the clearing manager and the system operator from time to time.

Compare: Electricity Governance Rules 2003 rule 4.5 section V part G

### 13.199 Clearing manager to make details of constrained off amounts available

The *clearing manager* must, at the time specified in clause 13.197, make the details of constrained off amounts available on WITS for each *generator* and each dispatched purchaser for the previous billing period as follows:

(a) the constrained off amounts calculated in accordance with clauses 13.194 to 13.196;

(b) the *generator* or dispatched purchaser (as the case may be) that was constrained off;

(c) the applicable grid injection point, or grid exit point, or block dispatch group, or station dispatch group.

Compare: Electricity Governance Rules 2003 rule 4.6 section V part G

13.200 Authority, generators and purchasers have rights to constrained off information
(1) In addition to the information the clearing manager makes available under clause 13.199, a generator or purchaser who reasonably believes it was adversely affected by a constrained off situation occurring, or the Authority, may request information from the system operator about the cause of the constrained off situation.
(2) The system operator must comply with any reasonable request made for such information provided that the information does not include any information that is confidential in respect of any other generator or purchaser.
Compare: Electricity Governance Rules 2003 rule 4.7 section V part G

13.201 Generators do not get paid constrained off compensation
(1) A generator is not entitled to be paid compensation in respect of any constrained off situation except as provided for in an ancillary service arrangement entered into by the system operator and the generator.
(2) This clause does not affect the rights that a participant has under this Code against the system operator for a failure by the system operator to comply with this Code.
Compare: Electricity Governance Rules 2003 rule 4.8 section V part G

13.201A Dispatched purchasers entitled to constrained off compensation and purchasers to pay constrained off compensation
(1) A dispatched purchaser in respect of whose dispatch-capable load station there was a constrained off situation as described in clause 13.192(c) is owed constrained off amounts calculated under clause 13.194(1A).
(2) A purchaser that purchases electricity at a grid exit point incurs an amount owing to the clearing manager for constrained off compensation, calculated under subclause (6).
(2A) The clearing manager must advise each purchaser of the amount owing by the purchaser for constrained off compensation for a billing period when the clearing manager advises amounts owing under subpart 4 of Part 14.
(3) The clearing manager owes constrained off compensation received under subclause (2), for each dispatch-capable load station, to the dispatched purchaser that purchased electricity for the dispatch-capable load station.
(4) The clearing manager must advise each dispatched purchaser of the amount owing to the dispatched purchaser for constrained off compensation for a billing period when the clearing manager advises amounts owing under subpart 4 of Part 14.
(5) [Revoked]
(6) The clearing manager must calculate constrained off compensation owing by a purchaser under subclause (2) for each trading period using the following formula:
ConOffC_p = ConOffC_DLPs * (Puri / TotPur)

where

ConOffC_p is the constrained off compensation owing by a purchaser
ConOffC_DLPs is the sum of constrained off compensation owing to all dispatched purchasers for the trading period
Puri is the total quantity in MWh of all purchases by the purchaser from the clearing manager during the trading period, as shown by reconciliation information calculated by the reconciliation manager under Part 15
TotPur is the quantity in MWh of all purchases by all purchasers from the clearing manager during the trading period, as shown by reconciliation information calculated by the reconciliation manager under Part 15.


Calculation of constrained on amounts

13.202 Constrained on situations may occur

(1) Subject to subclause (2), a constrained on situation occurs when—

(a) a generator is given a dispatch instruction by the system operator and the price offered by the generator for that dispatched quantity of electricity at the relevant grid injection point and trading period is higher than the final price at that grid injection point in the relevant trading period; or

(b) in relation to a block dispatch group or station dispatch group, a generator is given a dispatch instruction by the system operator and the price offered by the generator for that aggregate dispatched quantity of electricity from that block dispatch group or station dispatch group in the relevant trading period is higher than the final price in the relevant trading period; or

(c) an ancillary service agent is given a dispatch instruction by the system operator and the price offered by the ancillary service agent for the dispatched instantaneous reserve in the relevant trading period is higher than the final reserve price of the dispatched instantaneous reserve in the relevant trading period; or
(d) in relation to a dispatch-capable load station (except when the final nominated bid for the dispatch-capable load station in a trading period is a nominated non-dispatch bid), the latest dispatch instruction issued by the system operator for the dispatch-capable load station for a trading period is for a MW amount that is more than the MW amount scheduled for the dispatch-capable load station in the schedule of final prices for the trading period.

(2) If the pricing manager calculates interim prices and interim reserve prices in accordance with clause 13.135B for a trading period, and the scarcity pricing factor in that calculation is determined under clause 1(3)(c) or clause 2(3)(c) of Schedule 13.3A, a constrained on situation is deemed not to have occurred in that trading period in the island or islands in which the scarcity pricing situation occurred.

Compare: Electricity Governance Rules 2003 rule 5.1 section V part G

13.203 Determining affected price bands for block dispatch groups or station dispatch groups

If a constrained on situation occurred for a block dispatch group or station dispatch group during any trading period during the previous billing period, the clearing manager must determine the affected price bands for that block dispatch group or station dispatch group by—

(a) taking all the offers made by that block dispatch group or station dispatch group in relation to that trading period, calculating the differences between each offer price and final price for each grid injection point and ranking the differences in ascending order; and

(b) identifying each price band ranked under paragraph (a) in which the aggregate quantity for that price band plus all the quantity in all previous price bands exceeds the aggregate quantity for all the generating plant in that block dispatch group or station dispatch group calculated by the pricing manager using the methodology set out in Schedule 13.3. The offer prices corresponding to the ranked price bands identified under this paragraph are the affected price bands for that block dispatch group or station dispatch group for the purposes of clause 13.204.

Compare: Electricity Governance Rules 2003 rule 5.2 section V part G

13.204 Calculation of constrained on amounts

(1) If a constrained on situation occurs during any trading period during a previous billing period,—
(a) the clearing manager must calculate the constrained on amounts for a constrained on situation described in clause 13.202(1)(a) or (b) for each generator for each affected price band in accordance with the following formula:

\[ COC = Q_{\text{con}} \times (P_o - P_f) \]

where

- \( COC \) is the constrained on amount for a generator
- \( Q_{\text{con}} \) is the dispatched quantity in MWh (calculated as set out below) from that price band in the offer that was constrained on during a trading period, or the positive difference between the reconciliation information and the scheduled quantity, whichever is less
- \( P_o \) is the price offered for that price band by the generator for the quantity of electricity from the generating plant which was constrained on
- \( P_f \) is the final price for that trading period at the grid injection point; and

(aa) the clearing manager must calculate the constrained on amounts for a constrained on situation described in clause 13.202(1)(d) for each dispatch-capable load station for each affected nominated dispatch bid price band, using the following formula:

\[ \text{ConOnAmt} = \text{ConOnQ} \times (P_f - P_b) \]

where

- \( \text{ConOnAmt} \) is the constrained on amount for a dispatch-capable load station for the nominated dispatch bid price band
- \( \text{ConOnQ} \) is the amount in MWh by which the lowest of \( Q_{\text{disp}} \) and \( Q_{\text{rec}} \) exceeds \( Q_{\text{fp}} \)

where

- \( Q_{\text{disp}} \) is the latest quantity in MWh, dispatched for the nominated dispatch bid price band in the trading period
- \( Q_{\text{rec}} \) is the reconciled quantity provided by the reconciliation manager under clause 15.20C allocated by the clearing manager to the nominated dispatch bid price band in the trading period
- \( Q_{\text{fp}} \) is the quantity, in MWh, scheduled for the nominated dispatch bid price band in the schedule of final prices
- \( P_f \) is the final price for the trading period at the grid exit point
- \( P_b \) is the price bid for the nominated dispatch bid price band for the dispatch-capable load station that was constrained on; and

(b) for the purposes of clauses 13.202 to 13.211 dispatched quantity must be calculated taking into account—
(i) the quantity in MW recorded in the log kept by the system operator in accordance with clause 13.76; and if required, the clearing manager must aggregate such quantities for—

(A) generating stations or generating units in the relevant station dispatch group; or

(B) generating units, if the clearing manager requires a dispatched quantity to be determined on a grid injection point basis; and

(ii) for an offer, the ramp rate applying to that constrained on situation that is specified in the offer submitted by the generator, or—

(A) for a block dispatch group or a station dispatch group; or

(B) for generating units, if the clearing manager requires the dispatched quantity to be determined on a grid injection point basis—

the fastest of the ramp rates applying to that constrained on situation that are specified in the offers submitted by the generator in that block dispatch group, that station dispatch group or those generating units electrically connected to the relevant grid injection point (as the case may be); and

(iii) plus or minus the MW bandwidth applicable for each generator affected by a frequency keeping requirement as advised by the system operator to the clearing manager under clauses 13.76 to 13.80 and, if required, the clearing manager must aggregate the MW bandwidth applicable to determine the MW bandwidth on a grid injection point basis; and

(c) the clearing manager must calculate the constrained on amounts for a constrained on situation described in clause 13.202(c) for each ancillary service agent for each affected price band in accordance with the following formula:

\[ \text{COC} = Q_{\text{con}} \times (P_o - P_f) \]

where

COC is the constrained on amount for an ancillary service agent

\( Q_{\text{con}} \) is the dispatched quantity of instantaneous reserve in MW (calculated as set out below) from that price band in the reserve offer that was constrained on during a trading period

\( P_o \) is the price offered for that price band by that ancillary service agent for the quantity \( Q_{\text{con}} \)

\( P_f \) is the final reserve price for that trading period at the point of connection on the grid; and

(d) for the purposes of paragraph (c), in determining the dispatched quantity, the clearing manager must take into account the quantity in MW of instantaneous reserve dispatched for the ancillary service agent recorded in the log kept by the system operator in accordance with clause 13.76; and
(e) the constrained on amounts for a block dispatch group or station dispatch group equal the sum of the amounts calculated in accordance with paragraphs (a) and (b) for the generating plant in that block dispatch group or station dispatch group (as the case may be); and

(f) in relation to any 2 adjacent trading periods, a generator is entitled to be paid for the 2nd trading period at the final price for the grid injection point if the generator—

(i) was in a constrained on situation in the 1st trading period; and

(ii) continues to generate in the 2nd trading period as a result of a dispatch instruction given for the 1st trading period; but

(iii) has not made an offer in the 2nd trading period.

(2) To avoid doubt, nothing in this clause entitles the system operator to issue any instruction to a generator in relation to unoffered generation.

Compare: Electricity Governance Rules 2003 rule 5.3 section V part G
Clause 13.204(1)(aa): inserted, on 15 May 2014, by clause 64(a) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.205 Calculation of constrained on amounts attributable to system operator

If a constrained on situation occurs during a trading period in a previous billing period, and the clearing manager receives notice of the constrained on situation under clauses 13.76 to 13.80, the clearing manager must determine the portion of the constrained on amounts calculated under clause 13.204 attributable to the system operator for each generator or each ancillary service agent as follows:

(a) if the system operator has advised the clearing manager that a voltage support or other constrained on situation occurred (including but not limited to over frequency reserve and instantaneous reserve) the system operator must be allocated the total constrained on amount for that trading period:

(b) if the system operator has advised the clearing manager that a non-security constrained on situation occurred the system operator must be allocated a constrained on amount calculated in accordance with the following formula:

\[ \text{SOCONNS}_{go} = T\text{CONP} \times (\frac{\text{SOQconns}}{TQcon}) \]

where

\[ \text{SOCONNS}_{go} \] is the constrained on amount attributable to the system operator for that non-security constrained on situation

\[ T\text{CONP} \] is the total constrained on payment for that trading period
SOQconns is the non-security quantity that was constrained on and advised to the clearing manager by the system operator under clauses 13.76 to 13.80, or the total quantity constrained on, whichever is less.

TQcon is the total quantity constrained on:

(c) if the system operator has advised the clearing manager that a frequency keeping situation occurred the system operator must be allocated a constrained on amount calculated in accordance with the following formula:

\[ \text{SOCONFK}_{go} = \text{TCONP} \times (\frac{\text{SOQconfk}}{\text{TQcon}}) \]

where

\( \text{SOCONFK}_{go} \) is the constrained on amount attributable to the system operator for that frequency keeping constrained on situation

\( \text{TCONP} \) is the total constrained on payment for the generator for the trading period

\( \text{SOQconfk} \) is the frequency keeping quantity that was advised to the clearing manager by the system operator under clause 13.76 to 13.80, or the total quantity constrained on for the generator, whichever is less

\( \text{TQcon} \) is the total quantity constrained on for the generator.

Compare: Electricity Governance Rules 2003 rule 5.4 section V part G

13.206 Timeframe for calculating constrained on amounts

Each billing period, the clearing manager must calculate constrained on amounts for the previous billing period in accordance with clauses 13.204 and 13.205 by the later of—

(a) 1600 hours on the 8th business day of the billing period after the previous billing period; and

(b) 1600 hours on the 1st business day after the clearing manager receives the information required to calculate constrained on amounts.

Compare: Electricity Governance Rules 2003 rule 5.5 section V part G
13.207 Clearing manager to send constrained on information to system operator
(1) The clearing manager must, at the time specified in clause 13.206, send to the system operator the details of constrained on amounts that are attributed to the system operator (but limited to information about those constrained on amounts that is in the possession of the clearing manager) and the constrained on quantities (in MW) calculated in accordance with clause 13.205 for the previous billing period.

(2) The information must be provided to the system operator in the manner and format agreed between the clearing manager and the system operator from time to time.

Compare: Electricity Governance Rules 2003 rule 5.6 section V part G

13.208 Clearing manager to make details of constrained on amounts available
The clearing manager must, at the time specified in clause 13.206, make the details of constrained on amounts available on WITS in relation to each generator, ancillary service agent, and dispatched purchaser for the previous billing period calculated in accordance with clauses 13.204 and 13.205 as follows:

(a) the aggregate constrained on amounts calculated under clauses 13.204 and 13.205:

(b) the generator, ancillary service agent, or dispatched purchaser (as the case may be) that was constrained on:

(c) the applicable grid injection point, grid exit point, block dispatch group, or station dispatch group.

Compare: Electricity Governance Rules 2003 rule 5.7 section V part G


13.209 Authority, generators, ancillary service agents, and purchasers have rights to constrained on information
(1) In addition to the information the clearing manager makes available under clause 13.208, the Authority, or a generator, ancillary service agent, or purchaser who reasonably believes it was adversely affected by a constrained on situation occurring, may request information from the system operator about the cause of the constrained on situation.

(2) The system operator must comply with any reasonable request for such information except that the information must not include any information that is confidential in respect of any other generator, ancillary service agent, or purchaser.

Compare: Electricity Governance Rules 2003 rule 5.8 section V part G


13.210 [Revoked]

Compare: Electricity Governance Rules 2003 rule 5.9 section V part G

13.211 Backup procedures if WITS is unavailable

(1) If WITS is unavailable for the purposes of making information available under clauses 13.199 and 13.208, the clearing manager must follow the backup procedures specified by the WITS manager from time to time.

(2) The WITS manager must specify the backup procedures referred to in subclause (1) following consultation with the Authority, generators, ancillary service agents, purchasers, and the clearing manager.

Compare: Electricity Governance Rules 2003 rules 5.10 and 5.11 section V part G

13.212 Payment of constrained on compensation

(1) For each trading period,—
   (a) a generator or ancillary service agent is owed constrained on compensation for constrained on amounts determined under clauses 13.204 and 13.205; and
   (b) a dispatched purchaser is owed constrained on compensation for constrained on amounts determined under clause 13.204.

(1A) Constrained on compensation for each dispatch-capable load station is an amount owing to the dispatched purchaser that purchased electricity for the dispatch-capable load station.

(2) The system operator must pay to a generator, or ancillary service agent any constrained on amount calculated under clause 13.205.

(3) The clearing manager must advise each generator, ancillary service agent, and dispatched purchaser of the amount owing to the generator, ancillary service agent, or dispatched purchaser for constrained on compensation for a billing period when the clearing manager advises amounts owing under subpart 4 of Part 14.

(4) [Revoked]

(5) Each purchaser that purchases electricity at a grid exit point incurs an amount owing to the clearing manager for constrained on compensation, calculated under subclause (7).

(5A) [Revoked]

(6) Instantaneous reserve constrained on compensation is an instantaneous reserve cost that must be allocated in accordance with clauses 8.59 to 8.66.

(7) The clearing manager must calculate constrained on compensation for each trading period using the following formula:

\[ \text{COC}_p = (\text{COC}_g - \text{COC}_{so}) \times \frac{P_q}{TP_q} \]

where

\( \text{COC}_p \) is the constrained on compensation owing by a purchaser
\( \text{COC}_g \) is the sum of constrained on compensation owing to all generators and all dispatched purchasers for the trading period calculated in accordance with clause 13.204(1)(a) and 13.204(1)(aa)

\( \text{COC}_{so} \) is the sum of constrained on compensation for that trading period payable by the system operator to generators under subclause (2)
P_q is the total electricity purchased by that purchaser from the clearing manager during the trading period as shown by the reconciliation information calculated by the reconciliation manager under Part 15.

TP_q is the total electricity purchased by all purchasers from the clearing manager during the trading period as shown by reconciliation information calculated by the reconciliation manager under Part 15.

(8) The clearing manager must advise each purchaser of the amount owing by the purchaser for constrained on compensation for a billing period when the clearing manager advises amounts owing under subpart 4 of Part 14.

Compare: Electricity Governance Rules 2003 rule 6 section V part G
Clause 13.212(3) & (4): amended, on 15 May 2014, by clause 67(b) & (c) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

No payment of constrained on and off compensation for frequency keeping

Cross heading: inserted, on 1 May 2016, by clause 4 of the Electricity Industry Participation Code Amendment (Removal of In-band Frequency Keeping Compensation) 2015.

13.212A No payment of constrained on and off compensation for frequency keeping

(1) Despite clause 13.192 to clause 13.212, the system operator must not pay a frequency keeping ancillary service agent—
   (a) constrained on compensation in respect of any constrained on situation; or
   (b) constrained off compensation in respect of any constrained off situation.

(2) Subclause (1) applies in respect of any reconciled quantity of electricity the frequency keeping ancillary service agent produces—
   (a) while providing frequency keeping; and
   (b) between—
(i) the level of **active power** (expressed in MW) dispatched in a **trading period** to the **ancillary service agent’s generating plant**; and

(ii) the level of **active power** (expressed in MW) generated by the **ancillary service agent’s generating plant** in a **trading period**, measured by a **metering installation**.


**Pricing manager's reporting obligations**

13.213 [Revoked]

Compare: Electricity Governance Rules 2003 rule 7.1 section V part G

13.214 [Revoked]

Compare: Electricity Governance Rules 2003 rule 7.2 section V part G

13.215 Generators and purchasers have right to information concerning pricing manager’s action

(1) A **generator** or **purchaser** may, by giving written notice to the **pricing manager**, request further information related to—

   (a) any alleged breach of this Code by the **pricing manager**;

   (b) any alleged breach of this Part by a **participant**, if the alleged breach has materially affected the **generator** or **purchaser** requesting the information.

(2) In such cases, the **pricing manager** must provide the requested information to that **generator** or **purchaser** except that such information must not include any information that is confidential in respect of any other person.

Compare: Electricity Governance Rules 2003 rule 7.3 section V part G

13.216 Daily situation report

On the day after the **pricing manager** makes **final prices** and **final reserve prices** available on **WITS** in respect of the **trading day** to which the prices relate, the **pricing manager** must give the **Authority** a report containing—

(a) a statement of whether flows on any **branches** were at their maximum capacity and each **trading period** affected; and
(b) a statement of whether the status of circulating HVDC link and branch flows was abnormal and each trading period affected.

Compare: Electricity Governance Rules 2003 rule 7.4 section V part G

Subpart 5—Hedge arrangement disclosure

13.217 Contents of this subpart
This subpart provides for the disclosure of information about risk management contracts, which may be contracts for differences, fixed-price physical supply contracts or options contracts, in order to—
(a) facilitate the ready comparison of electricity prices and other key terms of risk management contracts; and
(b) address the lack of information available to persons to formulate their own historic contract curves for electricity; and
(c) provide a more informed basis for persons to assess the competitiveness of the market for risk management contracts in respect of electricity.

Compare: Electricity Governance Rules 2003 rule 1 section VI part G

13.218 Parties required to submit information
The following parties to risk management contracts are required to submit the information specified in clauses 13.219, 13.222 and 13.223 using an approved system:
(a) the seller, if the seller is a participant; or
(b) the buyer, if the buyer is a participant and the seller is not a participant.

Compare: Electricity Governance Rules 2003 rule 2 section VI part G

13.219 Information that must be submitted
(1) The following information must be submitted to the approved system in relation to every options contract:
(a) the trade date:
(b) the effective date:
(c) the end date:
(d) the quantity.

(2) The following information must be submitted to the approved system in relation to each contract for differences or fixed-price physical supply contract:
(a) whether the contract is a contract for differences or a fixed-price physical supply contract:
(b) the trade date:
(c) the effective date:
(d) the end date:
(e) the quantity:
(f) whether or not the contract applies to all trading periods within its term:

(g) whether there is an adjustment clause:

(h) whether there is a force majeure clause:

(i) whether there is a suspension clause:

(j) whether there are any other clauses providing for the pass-through of certain costs, levies or tax or some form of carbon-related cost.

(3) In addition to the information that must be submitted in accordance with subclause (2), the following information must be submitted to the approved system in relation to each contract for differences:

(a) whether there is a special credit clause:

(b) whether the volume of electricity, in respect of which payments are required to be made by the floating-price payer, is flat or varies for different trading periods:

(c) whether the contract has been traded on the EnergyHedge platform. The EnergyHedge platform is a centralised trading platform for standardised derivative contracts on electricity prices in New Zealand:

(d) whether the contract has been prepared based on the standardised schedule, which can be adopted in conjunction with the International Swaps and Derivatives Association Master Agreement, as may be available on EnergyHedge.

(4) In addition to the information that must be submitted in accordance with subclauses (2) and (3), the following information must be submitted to the approved system in relation to each contract for differences that has a term of less than 10 years and each fixed-price physical supply contract that has a term of less than 10 years:

(a) the contract price calculated in accordance with clause 13.220:

(b) the grid zone area in which the contract price is determined or applies.

(5) The information specified in this clause must be submitted in the form specified by the Authority and in accordance with clause 13.225(1).

(6) If a seller and a buyer enter into a contract for differences or fixed-price physical supply contract that includes more than 1 contract price schedule, the party required to submit information in accordance with clause 13.218 must do so in accordance with 1 of the following methods:

(a) if the contract includes contract price schedules relating to more than 1 grid zone area, by combining the information relating to all contract price schedules within each grid zone area and submitting that combined information to the approved system as if there were 1 contract for each grid zone area:

(b) if the contract includes contract price schedules relating to more than 1 node, by combining the information relating to all contract price schedules at each node and submitting the combined information to the approved system as if there were 1 contract for each node:

(c) if the party does not wish to combine the information in accordance with paragraphs (a) and (b), by submitting the information for each contract price schedule to the approved system individually, as though each contract price schedule was a separate contract.

(7) To avoid doubt, if a contract for differences or fixed-priced physical supply contract includes an adjustment clause,—
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(a) the information that must be disclosed in accordance with this clause, in relation to the contract, must only be disclosed once; and

(b) the contract price to be disclosed in accordance with subclause (4) is that which first applies under the contract.

Compare: Electricity Governance Rules 2003 rule 3 section VI part G

13.220 Calculation of contract price

(1) The contract price to be submitted for the purposes of clause 13.219(4)(a) and (6) is to be calculated in accordance with the following formula:

\[
CP = \left( \frac{\sum_{i=1}^{n} P_i \times TP_i}{\sum_{i=1}^{n} TP_i} \right) / LF \times LAF
\]

where

CP is the contract price

n is the number of different prices within the contract

P\textsubscript{i} is the price specified in the contract

TP\textsubscript{i} is the number of trading periods during which each price in the contract applies

LF is the location factor, for the relevant node at which the price is set in the contract, as published by the Authority in accordance with clause 13.221

LAF means a loss adjustment factor, which is,—

(a) if the contract price for the contract is referenced to a point of connection on the grid, 1; or

(b) for all other contracts, 0.937 (being the difference between 1 and the loss factor of 0.063).

(2) The Authority may issue guidelines on the approved system to provide assistance to sellers and buyers in determining what information must be submitted to the approved system, which may include clarification as to how to apply the formula in subclause (1) in the circumstances covered by clause 13.219(6).

Compare: Electricity Governance Rules 2003 rule 4 section VI part G

13.221 Node and grid zone area information

(1) The **WITS manager** must publish annually,—

(a) a list of all **nodes** at which the **pricing manager** makes **final prices** available on **WITS**; and

(b) a corresponding **location factor** for each such **node**; and

(c) a corresponding **grid zone area** for each such **node**; and

(d) a list of nominated **zone nodes**, being 1 **node** at which the **pricing manager** makes **final prices** available on **WITS**, within each **grid zone area**.

(2) For the purposes of subclause (1)(b), the **location factor** for each such **node** must be calculated as follows:

\[ LF = \frac{A}{B} \]

where

A is the average **final price** made available on **WITS** at that **node** over the 12 month period preceding the month before the date on which the **location factors** are published

B is the average **final price** made available on **WITS** at the relevant nominated **zone node**, as published in accordance with subclause (1)(d), for the 12 month period preceding the month before the date on which the **location factors** are published

LF is the **location factor** to be published in accordance with subclause (1)(b).

Compare: Electricity Governance Rules 2003 rule 5 section VI part G


13.222 Other information that must be submitted

(1) The following information must be submitted to the **approved system** in relation to every **risk management contract**:

(a) each party’s legal name:

(b) each party’s email address for notice.

(2) The information must be submitted in accordance with clause 13.225(1).

Compare: Electricity Governance Rules 2003 rule 6 section VI part G


13.223 Modified or amended information

(1) If a modification or amendment is made to a **risk management contract**, after the information referred to in clauses 13.219 or 13.222 has been submitted to the **approved system**, and the effect of the modification or amendment is that the information submitted to the **approved system** is no longer correct or complete, the modified or amended information must be submitted to the **approved system**.
The information submitted under subclause (1) must—
(a) identify in each case the information that has been modified or amended; and
(b) be in the form specified by the Authority; and
(c) be submitted in accordance with clause 13.225(2).

Compare: Electricity Governance Rules 2003 rule 7 section VI part G

13.224 Correction of information
Except when clause 13.223 applies, if a party to a risk management contract discovers that information previously submitted to the approved system about that risk management contract is incorrect or incomplete, that party must—
(a) seek to agree with the other party to the risk management contract that the information is incorrect or incomplete and how it should be corrected; and
(b) when both parties have agreed that the incorrect or incomplete information should be corrected, submit the corrected information to the approved system in accordance with clause 13.225(3).

Compare: Electricity Governance Rules 2003 rule 8 section VI part G

13.225 Timeframes for submitting information
(1) The information specified in clauses 13.219 and 13.222 must be submitted to the approved system—
(a) in respect of a contract for differences or an options contract, no later than 5pm, 5 business days after the trade date; and
(b) for any other type of risk management contract, no later than 5pm, 10 business days after the trade date.

(2) The modified or amended information submitted under clause 13.223(1) must be submitted to the approved system no later than 5pm, 5 business days after the amendment or modification to the risk management contract is made.

(3) A participant that discovers under clause 13.224 that information it submitted to the approved system is incorrect or incomplete must submit the corrected information to the approved system no later than 5pm, 2 business days after both parties to the risk management contract have agreed how the incorrect or incomplete information should be corrected.

(4) The corrected information submitted in accordance with clause 13.227(8) must be submitted to the approved system no later than 5pm, 2 business days after the parties to the risk management contract have agreed, in accordance with clause 13.227(5)(b), that the information made available under clause 13.226(1) is not correct, and corrected the information accordingly.

Compare: Electricity Governance Rules 2003 rule 9 section VI part G
13.226 WITS manager must make certain information available to the public

(1) The WITS manager must, as soon as practicable, make the information submitted under clauses 13.219, 13.223(1), and 13.224 available at no cost on a publicly accessible approved system.

(2) At the same time that it makes the submitted information available in accordance with subclause (1), for all information other than that submitted under clause 13.224, the WITS manager must—
   (a) indicate on the approved system that the information is unverified; and
   (b) if the contract is a contract for differences or an options contract, give a written notice to the other party to the contract—
      (i) (if the other party is a participant) requiring the other party to submit a verification notice to the approved system within 2 business days of receiving the notice confirming whether or not the information is correct; or
      (ii) (if the other party is not a participant) giving the other party the option to submit a verification notice to the approved system within 2 business days of receiving the notice confirming whether or not the information is correct; or
   (c) if the contract is a fixed-price physical supply contract, give a written notice to the other party giving the other party the option to submit a verification notice to the approved system within 2 business days confirming whether or not the information is correct.

(3) A participant that receives a verification notice under subclause (2)(b)(i) must comply with the written notice.

Compare: Electricity Governance Rules 2003 rule 10 section VI part G

13.227 Verification of information

(1) If the other party to a risk management contract submits a verification notice to the approved system within 2 business days of receiving notice under clause 13.226(2) confirming that the information made available under clause 13.226(1) is correct, the WITS manager must indicate that the information made available under clause 13.226(1) is verified.

(2) The WITS manager must indicate on the approved system that the information made available under clause 13.226(1) is not disputed, if—
   (a) the other party to a contract for differences or an options contract is not a participant and does not submit a verification notice to the approved system within 2 business days of receiving notice under clause 13.226(2)(b)(ii); or
   (b) the other party to a fixed-price physical supply contract does not submit a verification notice to the approved system within 2 business days of receiving notice under clause 13.226(2)(c).
(3) If the other party to a risk management contract submits a verification notice to the WITS manager within 2 business days of receiving notice under clause 13.226(2) advising that the information made available under clause 13.226(1) is not correct, the approved system must indicate that the information is disputed.

(4) If the other party to a contract for differences or an options contract is a participant but does not submit a verification notice within 2 business days of receiving notice in accordance with clause 13.226(2)(b)(i), the WITS manager must—
   (a) indicate on the approved system that the information made available in accordance with clause 13.226(1) is pending verification; and
   (b) give the other party a written reminder notice requiring the other party to submit a verification notice as soon as possible.

(5) If the information made available under clause 13.226(1) is disputed, the WITS manager must—
   (a) indicate on the approved system that the information is disputed; and
   (b) give the parties to the relevant risk management contract a written notice requiring the parties to use all reasonable endeavours to agree on whether the information submitted in accordance with clause 13.225(1) is correct or not within 10 business days of receiving the notice.

(6) The parties must comply with any notice given under subclauses (4)(b) or (5)(b).

(7) If the parties to the risk management contract agree in accordance with subclause (5)(b) that the information made available in accordance with clause 13.226(1) is correct, the other party must submit a verification notice to the approved system within 1 business day confirming that the information is correct.

(8) If the parties to a risk management contract agree in accordance with subclause (5)(b) that the information made available in accordance with clause 13.226(1) is not correct, the party that submitted that information to the approved system must correct that information in accordance with clause 13.225(4).

(9) If, within 10 business days of receiving the notice sent in accordance with subclause (5)(b), the parties to the relevant risk management contract are not able to agree whether or not the information made available in accordance with clause 13.226(1) is correct, despite using all reasonable endeavours, the WITS manager must indicate on the approved system that the information is subject to a long term dispute.

Compare: Electricity Governance Rules 2003 rule 11 section VI part G

13.228 Confirmation of information submitted through approved system

(1) The WITS manager must, using the approved system, confirm receipt of any information received by it under clauses 13.21, or 13.222 to 13.224.

(2) Each confirmation under subclause (1) must contain a copy of the information received using the approved system, together with the date and time of receipt.

Compare: Electricity Governance Rules 2003 rule 12 section VI part G


13.229 Submitting party to check if no confirmation received

(1) If a party that submits information to the approved system does not receive confirmation from the WITS manager under clause 13.228(1) that the approved system has received the party's information within 6 hours of submitting the information, that party must, within 1 business day of that 6 hour period ending, contact the WITS manager to check whether the approved system has received the information.

(2) If the approved system has not received the information, the party must resubmit the information.

(3) This process must be repeated until the WITS manager has confirmed receipt of the information from the party in accordance with clause 13.228.

Compare: Electricity Governance Rules 2003 rule 13 section VI part G
Clause 13.229(2) and (3): amended, on 5 October 2017, by clause 463(b) and (c) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

13.230 Certification of information

(1) Each participant that has submitted information in accordance with clause 13.225 in a particular year ending 31 March must, within 3 months of the end of the year ending 31 March, certify to the Authority that the information submitted was correct.

(2) The certification provided under subclause (1) must be—

(a) [Revoked]

(b) in the form specified by the Authority; and

(c) signed and dated by either—

(i) a director of the participant; or

(ii) the participant's chief financial officer, or person holding an equivalent position; or

(iii) the participant's chief executive officer, or person holding an equivalent position.

Compare: Electricity Governance Rules 2003 rule 14 section VI part G
13.231 Audit of information

(1) The Authority may, in its discretion, carry out an audit as to whether a participant has complied with this subpart.

(2) If the Authority decides under subclause (1) that a participant should be subject to an audit, the Authority must first give written notice to the participant requiring the participant to nominate an appropriate auditor. The participant must provide that nomination in writing to the Authority within a reasonable timeframe. The Authority must appoint the auditor nominated by the participant. If the participant fails to nominate an appropriate auditor within a reasonable timeframe, the Authority may appoint an auditor of its own choice.

(3) A participant subject to an audit under this clause must, on request from the auditor, provide the auditor with a copy of every risk management contract that it has entered into in the previous 12 months or within such other period specified by the auditor. The participant must provide this audit information no later than 20 business days after receiving a request from the auditor for the information.

(4) The participant must ensure that the auditor provides the Authority with an audit report on the participant’s compliance with this subpart that has been prepared in accordance with subclauses (4A) and (5).

(4A) The audit report must include any comments from the participant on any non-compliance found by the auditor if the participant provided comments to the auditor within a time specified by the auditor.

(5) The audit report must not contain any risk management contract that the participant has provided to the auditor in accordance with subclause (3), unless the Authority has specifically requested that the auditor do so.

Compare: Electricity Governance Rules 2003 rule 15 section VI part G

13.232 Payment of costs relating to audits

(1) If an audit establishes, to the reasonable satisfaction of the Authority, that a participant may not have complied with this subpart (whether or not the Authority appoints an investigator to investigate the alleged breach), the participant must pay for the audit.
(2) If the Authority considers that the non-compliance of the participant is minor or relates to some (but not all) of the clauses in this subpart, the Authority may, in its discretion, make an assessment regarding the proportion of the costs of the audit that are to be paid by the participant, and those costs must be paid by the participant.

(3) If an audit establishes to the reasonable satisfaction of the Authority that the participant has complied with this subpart, the participant is not required to pay any of the auditor’s costs.

Compare: Electricity Governance Rules 2003 rule 16 section VI part G

13.233 WITS manager and Authority must not publish certain information and may use information only under this subpart

(1) The Authority must keep, and ensure that the WITS manager and each auditor appointed under clause 13.231(2) keep, information submitted to the approved system under clauses 13.219, or 13.222 to 13.224 and copies of any risk management contract provided to the auditor under clause 13.231 confidential, unless—

(a) the information is provided by the Authority to subcontractors or service providers that the Authority appoints to provide services for the purposes of this subpart, and those subcontractors or service providers have agreed to keep that information confidential, on the same terms as apply to the Authority under this clause; or

(b) the information is required to be disclosed by law; or

(c) the party or parties to whom the information relates have provided written consent to the disclosure; or

(d) any of the information in a risk management contract is made available in accordance with clause 13.226(1).

(2) The Authority may use the information submitted under clause 13.222 and copies of a risk management contract provided to the Authority by an auditor appointed under clause 13.231(2) only for purposes related to this subpart and the enforcement of this subpart.

Compare: Electricity Governance Rules 2003 rule 17 section VI part G


Clause 13.233(1) and (2): amended, on 5 October 2017, by clause 466(2)(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

13.234 No misleading information

A party may not submit any information that, at the time the information was submitted, was misleading or deceptive or likely to mislead or deceive.

Compare: Electricity Governance Rules 2003 rule 18 section VI part G

13.235 Risk management contracts must be lawful

A party may not submit information if that party knows or ought reasonably to know that the risk management contract to which that information applies would contravene any law.

Compare: Electricity Governance Rules 2003 rule 19 section VI part G
13.236 Availability of information
The information that is submitted under clauses 13.219, 13.223, or 13.224 may only be removed from the approved system after 12 months following the termination of the risk management contract.

Compare: Electricity Governance Rules 2003 rule 20 section VI part G

Subpart 5A—Spot price risk disclosure

13.236A Disclosing participants must prepare and submit spot price risk disclosure statements
(1) Each disclosing participant must prepare a spot price risk disclosure statement for each quarter beginning 1 January, 1 April, 1 July, and 1 October in each year.
(2) Each participant who will be a disclosing participant in the next quarter must prepare a spot price risk disclosure statement for that quarter in accordance with this subpart.
(3) The disclosing participant must submit the spot price risk disclosure statement to the person appointed by the Authority to receive spot price risk disclosure statements no later than 5 business days before the beginning of the quarter to which the statement relates.
(4) A participant is not required to comply with this clause for a quarter if it is a disclosing participant in relation to the quarter only because it is subject to a wash-up in that quarter.


13.236B Authority must appoint a person to receive and analyse spot price risk disclosure statements
(1) The Authority must appoint an independent person to receive and analyse spot price risk disclosure statements.
(2) The Authority must enter into a contract with the person appointed to receive and analyse spot price risk disclosure statements.
(3) The contract with the person appointed to receive and analyse spot price risk disclosure statements must include the following:
   (a) a requirement that the person does not disclose any spot price risk disclosure statement to any other person, including that it does not disclose any spot price risk disclosure statement to the Authority:
   (b) a requirement that the person provide information regarding spot price risk disclosure statements to the Authority in a form that does not identify the disclosing participant to which it relates.

13.236C Authority may approve consolidated spot price risk disclosure statements
On application by 1 or more disclosing participants, the Authority may approve those disclosing participants preparing and submitting a consolidated spot price risk disclosure statement.

13.236D Authority must publish base case, stress test, and method for calculating target cover ratio
(1) The Authority must publish a notice setting out the following:
   (a) a base case:
   (b) 1 or more stress tests:
   (c) 1 or more methods for calculating a disclosing participant's target cover ratio.
(2) If the Authority has not published a notice under subclause (1) at least 30 business days before the start of a quarter in respect of which a spot price risk disclosure statement is required to be prepared, a disclosing participant is not required to prepare or submit a spot price risk disclosure statement for the next quarter.
(3) If the Authority publishes an amendment to a notice, or revokes and replaces a notice, within 30 business days before the start of a quarter in respect of which a spot price risk disclosure statement is required to be prepared, disclosing participants must prepare spot price risk disclosure statements for the immediately following quarter in accordance with the notice as in force immediately before the amendment or replacement was made and not in accordance with the notice as amended or replaced.

13.236E Content of spot price risk disclosure statements
(1) A spot price risk disclosure statement submitted under this subpart must include the following:
   (a) the disclosing participant's annual net cash flow from operating activities as set out in the disclosing participant's most recent set of audited annual financial statements:
   (b) the disclosing participant's level of shareholders equity as set out in the disclosing participant's most recent set of audited annual financial statements:
   (c) the disclosing participant's estimate of the value of electricity that it expects to sell to the clearing manager during the period to which the stress test relates when the stress test is applied, minus the disclosing participant's estimate of the value of that electricity under the base case for that period:
   (d) the disclosing participant's estimate of the value of electricity that it expects to purchase from the clearing manager during the period to which the stress test relates when the stress test is applied, minus the disclosing participant's estimate of the value of that electricity under the base case for that period:
(e) the disclosing participant's estimate of the projected net cash flows from operating activities of the disclosing participant during the period to which the stress test relates when the stress test is applied, minus the disclosing participant's estimate of those cash flows under the base case for that period:

(f) a statement as to whether the disclosing participant has an explicit risk management policy in respect of its exposure to the wholesale market:

(g) if the disclosing participant has an explicit risk management policy, the disclosing participant's target cover ratio, for each stress test, calculated in accordance with the relevant method published by the Authority under clause 13.236D for the quarter to which the statement relates.

(1A) Despite subclause (1), a disclosing participant is not required to include the information in subclause (1) in its spot price risk disclosure statement for a quarter if—

(a) the disclosing participant expects that a change in spot prices would not affect the disclosing participant's cash flow from operating activities in the quarter; and

(b) the disclosing participant’s spot price risk disclosure statement for the quarter includes a statement that the disclosing participant expects that a change in spot prices would not affect the disclosing participant's cash flow from operating activities in the quarter.

(2) For the purposes of subclause (1),—

(a) electricity is deemed to be sold to the clearing manager by a disclosing participant if it is sold to the clearing manager on the disclosing participant's behalf; and

(b) electricity is deemed to be purchased from the clearing manager by a disclosing participant if it is purchased from the clearing manager on the disclosing participant's behalf.

(3) The disclosing participant must ensure that a spot price risk disclosure statement is signed and dated by a director, or the chief executive officer, or the chief financial officer, or a person holding a position equivalent to one of those positions, of the disclosing participant no earlier than 20 business days and no later than 5 business days before the beginning of the quarter to which the statement relates.

(4) In preparing a spot price risk disclosure statement, a disclosing participant must have regard to all relevant factors, including (without limitation)—

(a) any financial instruments in which the disclosing participant has an interest; and

(b) any other measures that the disclosing participant has in effect to manage the risk arising from its exposure to the wholesale market; and

(c) any other arrangements that the disclosing participant has in place to manage that risk; and

(d) any amounts of electricity that the disclosing participant expects to buy from, or sell to, the clearing manager.

13.236F Certification of spot price risk disclosure statement
(1) A disclosing participant who has submitted a spot price risk disclosure statement in accordance with this subpart must certify to the Authority—
   (a) that the board of the disclosing participant has considered—
      (i) every spot price risk disclosure statement submitted under this subpart by the disclosing participant in the period to which the certification relates; and
      (ii) the projected change in net cash flows from operating activities of the disclosing participant as a result of applying the stress test or stress tests that relate to each period to which each spot price risk disclosure statement relates; and
   (b) that the disclosing participant has provided to each of the disclosing participant's customers who, in the period to which the certification relates, has entered into or renewed a contract with the disclosing participant that results in any electricity supplied to the customer being determined directly by reference to the final price at a GXP, information to enable the customer to consider the outcomes of applying the stress test or stress tests to the customer.

(2) Each certification must be submitted as follows:
   (a) in the case of the first certification submitted by a disclosing participant, no later than the end of the fourth quarter following the quarter in which the first spot price risk disclosure statement is submitted by that disclosing participant (in which case the certification must relate to every spot price risk disclosure statement made by the disclosing participant in the preceding quarters):
   (b) in the case of every subsequent certification, no later than the end of the fifth quarter following the quarter in which the last certification was submitted (in which case the certification must relate to every spot price risk disclosure statement made by the disclosing participant since the last certification was submitted).

(3) Each certification submitted under subclause (2) must be—
   (a) in the form specified by the Authority; and
   (b) signed and dated by a director of the disclosing participant and either—
      (i) another director of the disclosing participant; or
      (ii) the disclosing participant's chief executive officer, or person holding an equivalent position; or
      (iii) the disclosing participant's chief financial officer, or person holding an equivalent position.
13.236G Authority may require disclosing participant to submit new spot price risk disclosure statement

(1) The Authority may, by notice in writing to a disclosing participant who submitted a spot price risk disclosure statement, require the disclosing participant to submit a new spot price risk disclosure statement.

(2) If a disclosing participant receives a request from the Authority under subclause (1), the disclosing participant must submit a new spot price risk disclosure statement to the person appointed by the Authority to receive spot price risk disclosure statements within 10 business days after the date on which the disclosing participant received the request.

(3) Clause 13.236E applies to a spot price risk disclosure statement submitted under this clause.


13.236H Authority may require independent audit of spot price risk disclosure statement or certification

(1) The Authority may, in its discretion, on the recommendation of the person appointed to receive and analyse spot price risk disclosure statements or on its own motion, require an audit of 1 or more of the following:

(a) a spot price risk disclosure statement;
(b) part of a spot price risk disclosure statement;
(c) the information set out in the certification given under clause 13.236F.

(2) If the Authority requires an audit under subclause (1), the Authority must require the relevant disclosing participant to nominate an appropriate auditor.

(3) The disclosing participant must provide that nomination within a reasonable timeframe.

(4) The Authority may direct the disclosing participant to appoint the auditor nominated by the disclosing participant.

(5) If the disclosing participant fails to nominate an appropriate auditor within 5 business days, the Authority may direct the disclosing participant to appoint an auditor of the Authority's choice.

(6) The disclosing participant must appoint an auditor in accordance with a direction made under subsection (4) or subsection (5).

(7) A disclosing participant subject to an audit under this clause must, on request from the auditor, provide the auditor with such information as the auditor reasonably requires in order to audit the spot price risk disclosure statement or the information set out in the certification given under clause 13.236F (as the case may be).

(8) The disclosing participant must provide the information no later than 10 business days after receiving a request from the auditor for the information.

(9) The disclosing participant must ensure that the auditor produces an audit report on the spot price risk disclosure statement or the information set out in the certification.
given under clause 13.236F (as the case may be) and submits the audit report to the Authority.

(10) Before the audit report is submitted to the Authority, any failure of the spot price risk disclosure statement or the information set out in the certification given under clause 13.236F (as the case may be) to comply with this subpart must be referred back to the disclosing participant for comment.

(11) The comments of the disclosing participant must be included in the audit report.

(12) The disclosing participant may require that the auditor does not provide the Authority with a copy of any information that the disclosing participant has provided to the auditor in accordance with subclause (7).


Clause 13.236H(1), (5), (7), (8), (9) and (10): amended, on 5 October 2017, by clause 473(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

### 13.236I Payment of auditor's costs

(1) If an audit establishes, to the Authority's reasonable satisfaction, that a disclosing participant's spot price risk disclosure statement or the information set out in the certification given under clause 13.236F (as the case may be) has not complied with this subpart (whether or not the Authority appoints an investigator to investigate the alleged breach), the disclosing participant must pay the auditor's costs.

(2) If the Authority considers that the disclosing participant's non-compliance is minor, the Authority may, in its discretion, determine the proportion of the auditor's costs that the disclosing participant must pay, and the disclosing participant must pay those costs.

(3) If an audit establishes to the Authority's reasonable satisfaction that a disclosing participant's spot price risk disclosure statement or the information set out in the certification given under clause 13.236F (as the case may be) has complied with this subpart, the Authority must pay the auditor's costs.


### Subpart 6—Financial transmission rights


### 13.237 Contents of this subpart

This subpart provides for the processes by which—

(a) the FTR manager prepares and publishes the FTR allocation plan; and

(b) the Authority approves the FTR allocation plan; and

(c) the FTR manager allocates and creates FTRs; and
(d) the FTR manager operates the FTR register and collects information from the grid owner and clearing manager; and

(e) FTRs may be assigned; and

(f) the clearing manager collects and allocates FTR auction revenue and collects information from the FTR manager; and

(g) the Authority may direct the FTR manager to suspend the allocation of FTRs.


13.238 Preparation and publication of FTR allocation plan

(1) The FTR manager must prepare and publish an FTR allocation plan that complies with Schedule 13.5.

(2) The FTR manager must keep the FTR allocation plan published at all times.

(3) Subject to subclause (4), if Schedule 13.5 is amended, the FTR manager must, no later than 3 months after the date on which the amendment comes into force, submit to the Authority for approval under clause 13.241(4), a variation to the FTR allocation plan to make the FTR allocation plan consistent with Schedule 13.5.

(4) The FTR manager is not required to comply with subclause (3) if no amendment is necessary to make the FTR allocation plan consistent with Schedule 13.5.


13.239 FTR manager gives draft FTR allocation plan to Authority

(1) The FTR manager must submit to the Authority for approval a draft FTR allocation plan by the date specified in the market operation service provider agreement between the FTR manager and the Authority.

(2) In preparing the draft FTR allocation plan, the FTR manager must—

(a) consult with persons that the FTR manager thinks are representative of the interests of persons likely to be substantially affected by the plan; and

(b) consider submissions made on the plan.

(3) The FTR manager must provide a copy of each submission received under subclause (2) to the Authority.


13.240 Authority approves FTR allocation plan

(1) The Authority must, as soon as practicable after receiving the draft FTR allocation plan, by notice in writing to the FTR manager—

(a) approve the plan; or
(b) decline to approve the plan.

(2) If the Authority declines to approve the draft FTR allocation plan, the Authority must publish the changes that the Authority wishes the FTR manager to make to the draft plan.

(3) When the Authority publishes the changes that the Authority wishes the FTR manager to make to the draft FTR allocation plan under subclause (2), the Authority must give written notice to the FTR manager and interested parties of the date by which submissions on the changes must be received by the Authority.

(4) Each submission on the changes to the draft FTR allocation plan must be made in writing to the Authority and be received on or before the date specified by the Authority under subclause (3).

(5) The Authority must—
(a) provide a copy of each submission received to the FTR manager; and
(b) publish the submissions.

(6) The FTR manager may make its own submission on the changes to the draft FTR allocation plan and the submissions received in relation to the changes. The Authority must publish the FTR manager's submission when it is received.

(7) The Authority must consider the submissions made to it on the changes to the draft FTR allocation plan.

(8) Following the consultation required by subclauses (3) to (7), the Authority may approve the FTR allocation plan subject to the changes that the Authority considers appropriate being made by the FTR manager.


13.241 Variations to FTR allocation plan

(1) A participant or the Authority may submit a proposal for a variation to the FTR allocation plan to the FTR manager.

(2) The FTR manager must provide a copy of each proposed variation received from a participant under subclause (1) to the Authority.

(3) The FTR manager must consider a proposed variation to the FTR allocation plan submitted under subclause (1).

(4) The FTR manager may submit a request for a variation to the FTR allocation plan to the Authority.

(5) The consultation and approval requirements under clause 13.239(2) and (3) and clause 13.240 apply to a request for a variation submitted under subclause (4) as if references to the draft plan were a reference to the requested variation.

(6) If the FTR manager does not submit a request for a variation submitted under subclause (1) to the Authority under subclause (4), the Authority may consider the proposal and require the FTR manager to submit a request for a variation based on the proposal to the Authority, and subclause (5) applies accordingly.

(7) The Authority may approve a variation requested under subclause (4) or subclause (6) without complying with the provisions referred to in subclause (5) if—
(a) the Authority considers that it is necessary or desirable in the public interest that the requested variation be made urgently; and
(b) the Authority publishes a notice of the variation and a statement of the reasons why the urgent variation is needed.

(8) Every variation made under subclause (7) expires on the date that is 9 months after the date on which the variation is made.


Allocation, creation and reconfiguration of FTRs


13.242 FTR manager must allocate and create FTRs

(1) The FTR manager must conduct an FTR auction in accordance with the FTR allocation plan approved under clause 13.240 to—

(a) allocate FTRs; and
(b) create FTRs; and
(c) reconfigure FTRs.

(2) Every FTR must relate to—

(a) a minimum amount of electricity (in MW) of 0.1 MW; and
(b) an amount of electricity (in MW) that is a multiple of 0.1 MW.


13.242A FTR manager to adjust offered FTR and FTR acquisition cost after FTR reconfiguration auction

After each FTR reconfiguration auction, the FTR manager must—

(a) reduce the amount of electricity (in MW) to which each offered FTR relates by the amount of electricity (in MW) to which the relevant reconfigured FTR relates; and
(b) adjust the FTR acquisition cost of the offered FTR by subtracting the FTR reconfiguration amount of the relevant reconfigured FTR from the FTR acquisition cost of the offered FTR.

13.243 Participation in FTR auction

The FTR manager must not allow a person to participate in an FTR auction unless the FTR manager is satisfied that the person complies with prudential requirements in Part 14A.


13.244 Acceptance of bids and offers in FTR auction

(1) The FTR manager must not accept a bid or an offer in an FTR auction if the FTR manager considers that the bid or the offer, if accepted, would cause the person making the bid or the offer to incur an obligation for which it does not have sufficient acceptable security under Part 14A.

(2) For the purposes of subclause (1), the FTR manager must, based on information received from the clearing manager, determine the maximum liability that each person can incur in respect of its bids or offers in the FTR auction.

Clause 13.244(1): amended, on 1 November 2014, by clause 9(b) and (c) of the Electricity Industry Participation (FTR Reconfiguration Auctions) Code Amendment 2014.

Auction revenue and FTR receipts and payments


13.245 Clearing manager must collect and allocate auction revenue

The clearing manager must collect the FTR auction revenue and allocate it in accordance with Part 14.


13.246 Clearing manager must deal with FTR receipts and payments

The clearing manager must deal with all receipts and payments in respect of FTRs in accordance with Part 14.

13.247 FTR manager must operate FTR register

(1) The **FTR manager** must create and operate an **FTR register** that records—
   (a) the **holdings of FTRs**; and
   (b) the **FTR acquisition cost** for each **FTR**; and
   (c) assignments of **FTRs** including any price disclosed under clause 13.249; and
   (d) the **amount of electricity** (in MW) to which each **FTR** relates; and
   (e) the reconfiguration of each **offered FTR**.

(2) The **FTR register** must contain an account for each holder of an **FTR**.

(3) The **FTR manager** must assign a registered number to each **FTR** recorded in the **FTR register**.

(4) The **FTR manager** must maintain, **publish**, and keep **published** at all times, an up to date copy of the **FTR register**.


Assignment of FTRs


13.248 Assignment of FTRs

(1) If a person ("assignor") wishes to assign an **FTR** or part of an **FTR** to another person ("assignee"), the assignor and assignee must complete and sign Form 1 in Schedule 13.6 and provide it to the **FTR manager**.

(2) The completed form may be provided to the **FTR manager** under subclause (1) in electronic form if—
   (a) both the assignor and assignee consent to completing and signing the form electronically; and
   (b) the electronic form contains all of the information required by Form 1 in Schedule 13.6; and
   (c) the notification of assignment to the **FTR manager** is in a format specified by the **FTR manager**.

(3) The **FTR manager** must not register an assignment in the **FTR register** unless the **FTR manager** is satisfied that the assignee complies with prudential requirements in Part 14A.

(4) The **FTR manager**, on being satisfied that all requirements for an assignment are met, must register the assignment on the **FTR register**.
(4A) If an assignment is made under this clause in respect of part of an FTR, the FTR manager must register the assignment as follows:

(a) create a new record for an FTR in respect of the amount of electricity (in MW) to which the assignment relates; and

(b) amend the record for the FTR retained by the assignor by reducing the amount of electricity (in MW) to which the FTR relates so as to reflect the assignment.

(5) An assignment of an FTR or part of an FTR is not effective unless it is registered on the FTR register by the FTR manager.

(6) The FTR manager must not register an assignment that is expressed to have effect after the end of the billing period to which the FTR relates.


13.249 Liability for FTR acquisition cost when FTR assigned and price disclosed

(1) This clause applies if—

(a) an FTR is assigned under clause 13.248; and

(b) the notification of assignment discloses the price (being an amount that may be positive or negative) at which the FTR has been assigned.

(2) The FTR manager must provide a copy of the notification of assignment to the clearing manager.

(3) The assignee owes the clearing manager the amount disclosed under subclause (1)(b) when it becomes due on settlement of the FTR.

(4) If the price disclosed in the notification is less than the FTR acquisition cost in respect of the FTR that would, if the assignment had not taken place, become owing on settlement of the FTR, the assignor owes the clearing manager an amount equal to the difference between the FTR acquisition cost and the price at which the FTR has been assigned.

(5) The clearing manager must advise the assignor of the amount owing under subclause (4) when the clearing manager advises amounts owing under subpart 4 of Part 14 for the billing period in which the assignment took place.

(6) The clearing manager must apply any amount owing by a participant to the clearing manager under this clause to the settlement of FTRs, but an amount must not be applied to the settlement of an FTR until the billing period in which the FTR is settled.

(7) If the price disclosed in the notification is more than the FTR acquisition cost in respect of the FTR that would, if the assignment had not taken place, become owing on settlement of the FTR, the clearing manager owes the assignor on settlement of the FTR an amount equal to the difference between the price at which the FTR has been assigned and the FTR acquisition cost.
13.250 Liability for FTR acquisition cost when FTR assigned and price not disclosed

(1) This clause applies if—
   (a) an FTR is assigned under clause 13.248; and
   (b) the notification of assignment does not disclose the price at which the FTR has been assigned.

(2) The FTR manager must provide a copy of the notification of assignment to the clearing manager.

(3) The assignee owes the clearing manager the FTR acquisition cost in respect of the FTR that has been assigned when it becomes due on settlement of the FTR.

Provision of information to the FTR manager and clearing manager


13.251 Information to be provided to FTR manager

(1) Each grid owner must provide a written forecast of the configuration and capacity of the grid owner's grid for the FTR period (as advised to each grid owner by the FTR manager) to the FTR manager for use in determining the FTRs to be offered in each FTR auction.

(2) The information that each grid owner must provide must include relevant planned outages.

(3) Except as otherwise agreed with the FTR manager, each grid owner must provide the information to the FTR manager no later than 1 month before the date (as advised to each grid owner by the FTR manager) on which an FTR auction is to be held.

(4) The clearing manager must advise the FTR manager in writing—
(a) whether a person who has applied to participate in an FTR auction complies with prudential requirements in Part 14A; and
(b) the amount of security that a person who has applied to participate in an FTR auction has provided that exceeds that person's other obligations under Parts 14 and 14A.

(5) Except as otherwise agreed with the FTR manager, the clearing manager must provide the information to the FTR manager no later than 2 business days before the date (as advised to the clearing manager by the FTR manager) on which an FTR auction is to be held.

(6) If the information referred to in subclause (4) changes, the clearing manager must, if requested by the person who has applied to participate in an FTR auction, provide the updated information in writing to the FTR manager.

(7) The clearing manager must inform the FTR manager in writing, as soon as practicable after receiving a request from the FTR manager, whether an assignee of an FTR meets the prudential security requirements in Part 14A.

13.252 Information to be provided to clearing manager

(1) The FTR manager must provide the following information to the clearing manager in writing in relation to each successful bidder in an FTR auction:
(a) the details of each FTR allocated under an FTR auction, including—
   (i) the period to which the FTR applies; and
   (ii) whether the FTR is an option FTR or an obligation FTR; and
   (iii) the formula under which the FTR hedge value is to be calculated for the settlement of the FTR:
(b) the FTR acquisition cost in respect of each FTR.

(2) The FTR manager must provide the information specified in subclause (1) to the clearing manager as soon as practicable and no later than 1 week after each FTR auction.

13.253 [Revoked]

13.254 Publication of results of FTR auctions

The FTR manager must, as soon as practicable after each FTR auction, publish and keep published the results of each FTR auction in accordance with the FTR allocation plan.


Suspension of FTR allocation


13.255 Authority may direct FTR manager to suspend allocation of FTRs

The Authority may direct the FTR manager to suspend the allocation of FTRs if there is any situation that—

(a) threatens, or may threaten, confidence in, or the integrity of, the allocation or settlement of FTRs; and

(b) in the reasonable opinion of the Authority, cannot satisfactorily be resolved by any other mechanism available under this Code.


Schedule 13.1  
Forms 1 to 9

cls 13.9, 13.13, 13.38, 13.64, and 13.170

Form 1  
Generator offer

Date:  _______________________________________

Generator Participant Identifier:  __________________________

Generator Name:  _______________________________________

Grid Injection Point:  ______________________________________

Generator Category (clause 13.10 of the Code):  
☐ Unit  ☐ Station  
☐ Generator block (clauses 13.60 and 13.61 of the Code)

Block Name (if applicable):  ______________________________________

Generator Maximum Output (including overload):  
____________________________________________________MW

Trading Period:  _______ Starting at ________ : _______ 0 hours

Maximum Generator Ramp Up Rate:  
_____________________________________________________MW/hr

Maximum Generator Ramp Down Rate:  
_____________________________________________________MW/hr

Offer to sell electricity

Band 1:  From 0 MW to ____________ MW @ $ ____________ per MWh

Band 2:  plus ____________ MW @ $ ____________ per MWh

Band 3:  plus ____________ MW @ $ ____________ per MWh

Band 4:  plus ____________ MW @ $ ____________ per MWh

Band 5:  plus ____________ MW @ $ ____________ per MWh

Compare: Electricity Governance Rules 2003 form 1 schedule G1 part G
Form 2
Intermittent Generator Offer

Date: _______________________________________

Intermittent Generator Participant Identifier: _______________________________________

Intermittent Generator Name: _______________________________________

Grid Injection Point: _______________________________________

Generator category (clause 13.10 of the Code): □ Station

Generator Installed Capacity: ________________________________________ MW

Trading Period: _______ Starting at ________ : _______ 0 hours

Maximum Generator Ramp Up Rate: ________________________________________ MW/hr

Maximum Generator Ramp Down Rate: ________________________________________ MW/hr

Offer to sell electricity

Band 1: From 0 MW to __________ MW @ $ __________ per MWh

Compare: Electricity Governance Rules 2003 form 2 schedule G1 part G
Form 3
Type A or Type B Co-generator Offer

Date: ________________________________

Type A/Type B Co-generator Participant Identifier: ________________________________

Type A/Type B Co-generator Name: ________________________________

Grid Injection Point: ________________________________

Generator Category (clause 13.10 of the Code): □ Unit □ Station

Type A/Type B Co-generator Maximum Output (including overload):

____________________________________ MW

Trading Period: _____ Starting at ________ : ________ 0 hours

Maximum Generator Ramp Up Rate:

____________________________________ MW/hr

Maximum Generator Ramp Down Rate:

____________________________________ MW/hr

Offer to sell electricity

Band 1: From 0 MW to ___________ MW @ $ ___________ per MWh

Band 2: plus ___________ MW @ $ ___________ per MWh

Compare: Electricity Governance Rules 2003 form 2A schedule G1 part G
Form 4

Purchaser’s nominated bid for electricity

Date:  _______________________________________

Purchaser:  _______________________________________

Grid Exit Point:  _______________________________________

Trading Period:  ____ starting at _________ : _________ 0 hours

Type of bid:  Nominated dispatch bid □

Nominated non-dispatch bid □

Dispatch-capable load station identifier (if applicable):  __________

Nominated bid to buy electricity

Band 1:  From 0 MW to  _  MW below $  ____  per MWh
Band 2:  plus  _______  MW below $  ____  per MWh
Band 3:  plus  _______  MW below $  ____  per MWh
Band 4:  plus  _______  MW below $  ____  per MWh
Band 5:  plus  _______  MW below $  ____  per MWh
Band 6:  plus  _______  MW below $  ____  per MWh
Band 7:  plus  _______  MW below $  ____  per MWh
Band 8:  plus  _______  MW below $  ____  per MWh
Band 9:  plus  _______  MW below $  ____  per MWh
Band 10:  plus  _______  MW below $  ____  per MWh

Compare: Electricity Governance Rules 2003 form 3 schedule G1 part G
Form 4A
Purchaser’s difference bid for electricity

Date:  
_______________________________________

Purchaser:  
_______________________________________

Grid Exit Point:  
_______________________________________

Trading Period:  ________ starting at _________ : _________ 0 hours

Difference bid to increase/ decrease use of electricity

Increase electricity

Band 1: Increase _______ MW below $ ____________ per MWh
Band 2: plus _______ MW below $ ____________ per MWh
Band 3: plus _______ MW below $ ____________ per MWh
Band 4: plus _______ MW below $ ____________ per MWh
Band 5: plus _______ MW below $ ____________ per MWh

Decrease electricity

Band 1: Decrease _______ MW above $ ____________ per MWh
Band 2: plus _______ MW above $ ____________ per MWh
Band 3: plus _______ MW above $ ____________ per MWh
Band 4: plus _______ MW above $ ____________ per MWh
Band 5: plus _______ MW above $ ____________ per MWh

Form 5
Generation Reserve Offer

Date: ________________________________________________________

Ancillary Service Agent:  

Generator Name:  ________________________________________________________

Grid Injection Point:  ________________________________________________________

Trading Period: ______________ Starting at _____________________ 0 hours

Offer to provide reserve

1 Partly Loaded Spinning Reserve

Band 1:  
____% of electricity (MW), up to a maximum of ____ MW as Fast Instantaneous Reserve  
____% of electricity (MW), up to a maximum of ____ MW as Sustained Instantaneous Reserve  

____% of electricity (MW), up to a maximum of ____ MW as Fast Instantaneous Reserve  
____% of electricity (MW), up to a maximum of ____ MW as Sustained Instantaneous Reserve

Band 2:

Band 3:

2 Tail water depressed reserve

Band 1:
Up to a maximum of ________ MW @ $ ________ per MW as Fast Instantaneous Reserve

Up to a maximum of ________ MW @ $ ________ per MW as Sustained Instantaneous Reserve
Band 2:
Up to a maximum of _______ MW @ $ _______ per MW as Fast Instantaneous Reserve
Up to a maximum of _______ MW @ $ _______ per MW as Sustained Instantaneous Reserve

Band 3:
Up to a maximum of _______ MW @ $ _______ per MW as Fast Instantaneous Reserve
Up to a maximum of _______ MW @ $ _______ per MW as Sustained Instantaneous Reserve

Compare: Electricity Governance Rules 2003 form 4 schedule G1 part G
Form 6
Interruptible Load Offer

Date: _______________________________________________________

Ancillary Service Agent: __________________________________________

Grid Exit Point or interruptible load group GXP: ___________________________

**Instantaneous reserve capability**

Holds a Reserve Contract with the System Operator □ Yes

Fast Instantaneous Reserve Interruptible Load Available □ Yes

Sustained Interruptible Load Available □ Yes

Trading Period: ___________ Starting at __________ : ____________ 0 hours

**Offer to provide reserve**

1 Interruptible load

**Band 1:**
Up to a maximum of ______ MW @ $ ______ per MW as Fast Instantaneous Reserve

Up to a maximum of ______ MW @ $ ______ per MW as Sustained Instantaneous Reserve

**Band 2:**
Up to a maximum of ______ MW @ $ ______ per MW as Fast Instantaneous Reserve

Up to a maximum of ______ MW @ $ ______ per MW as Sustained Instantaneous Reserve

**Band 3:**
Up to a maximum of ______ MW @ $ ______ per MW as Fast Instantaneous Reserve

Up to a maximum of ______ MW @ $ ______ per MW as Sustained Instantaneous Reserve

Compare: Electricity Governance Rules 2003 form 5 schedule G1 part G
Form 7
Instantaneous Reserve Parameters

Date: _________________________________________________________

Trading Period:______________ Starting at __________ : __________ 0 hours

North Island Fast Instantaneous Reserve Adjustment Factor

________________________________________________________________

North Island Sustained Instantaneous Reserve Adjustment Factor

________________________________________________________________

South Island Fast Instantaneous Reserve Adjustment Factor

________________________________________________________________

South Island Sustained Instantaneous Reserve Adjustment Factor

________________________________________________________________

Minimum Risk

North Island Minimum Risk _____________________ MW

South Island Minimum Risk _____________________ MW

Compare: Electricity Governance Rules 2003 form 6 schedule G1 part G
Form 8
Notice of Station Dispatch Group

Date:

Generator:
[Insert name of generator] hereby gives the system operator notice pursuant to clause 13.64 of the Code that the following group of generating units and/or generating stations are to be treated as a station dispatch group:

Name of Station Dispatch Group:
Station Identifier:
Constituent units:

<table>
<thead>
<tr>
<th>Grid Injection Point (GIP)</th>
<th>Station/ generating unit name</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>

This notice is to be effective from 0000 hours on [insert date], being at least 15 business days after the date of this notice, and remains in force until cancelled in writing by [insert name of generator].

Generator Control centre:

Name: _________________________
Contact Number: Ph: ________________ Ph: _____________________
Address: __________________________________________________
________________________________________________

Yours sincerely

[Name of sender]

[Generator name]

Compare: Electricity Governance Rules 2003 form 7 schedule G1 part G
Form 9
Claim of pricing error

CLAIM OF PRICING ERROR

Please email the completed form to the pricing manager

Contact Details (all fields are mandatory)
Claimant: ____________________________________________
Organisation: ___________________________________________
Role at organisation: _____________________________________
E-mail: _________________________________________________
Phone: _________________________________________________
Mobile: _________________________________________________
Fax: _________________________________________________

Pricing Error Summary Details (all fields are mandatory)
Date: ___________ Trading period(s) affected: ______________________
Node: ____________________________ Energy: Yes/No Reserve: Yes/No

Summary of pricing error:

Section 1 - Basis of claim (only question 1 is mandatory)
1. What is the nature of the pricing error?
2. Has the pricing error been caused by a Code breach? Yes/No

If yes, please specify the clause that has been breached:

Section 2 – Materiality of pricing error and solution sought by applicant (all questions are mandatory)

1. Describe the effect of this pricing error for your organisation? (if possible please provide financial information to demonstrate the materiality of the claimed pricing error)

2. Describe how, in your view, the claimed pricing error should be resolved.

Compare: Electricity Governance Rules 2003 form 8 schedule G1 part G
1 Model parameters

The system operator must, in accordance with clause 13.189 of the Code, provide the pricing manager with a list specifying the values for the following model parameters:

(a) deficit bus generation:
(b) surplus bus generation:
(c) deficit 6s reserve for a contingent event as defined in clause 12.3 of the Policy Statement:
(d) deficit 6s reserve for an extended contingent event as defined in clause 12.3 of the Policy Statement:
(e) deficit 60s reserve for a contingent event as defined in clause 12.3 of the Policy Statement:
(f) deficit 60s reserve for an extended contingent event as defined in clause 12.3 of the Policy Statement:
(g) deficit branch group constrained:
(h) surplus branch group constrained:
(i) deficit bus group constrained:
(j) surplus bus group constrained:
(k) deficit ramp rate:
(l) surplus ramp rate:
(m) market node/trader capacity deficit:
(n) deficit branch flow:
(o) surplus branch flow:
(p) deficit M-node constrained:
(q) surplus M-node constrained.

Compare: Electricity Governance Rules 2003 schedule G2 part G


**Schedule 13.3**

**The Modelling System**


**Inputs into the modelling system**

1 Purpose of modelling system

(1) The purpose of the modelling system is to provide schedules of quantities and prices that maximise the gross purchaser benefit from purchases of electricity from the clearing manager less the total cost of production of electricity and instantaneous reserves as specified in this Schedule.

(2) Schedules covering more than 1 trading period must be prepared for each trading period independently of the previous trading period unless otherwise specified in this Schedule.

(2A) Despite subclause (2), a price-responsive schedule and non-response schedule must use the scheduled generation at the end of the previous trading period as the expected output for the purpose of clause 9A(b).

(3) The modelling system must provide prices for electricity and instantaneous reserve that are consistent with the above purpose and the scheduled quantities of electricity and instantaneous reserve.

(4) The modelling system must be used, using different inputs, to produce—

(a) price-responsive schedules; and
(b) non-response schedules; and
(c) dispatch schedules; and
(d) schedules of real time prices; and
(e) schedules of provisional prices; and
(f) schedules of interim prices; and
(g) schedules of final prices.

Compare: Electricity Governance Rules 2003 clause 1.1 schedule G6 part G


Clause 1(3): amended, on 28 June 2012, by clause 54(2) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 1(4): substituted, on 28 June 2012, by clause 54(3) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

2 Contents of each schedule

Each schedule must contain the information specified in—

(a) clause 13.59, for a price-responsive schedule and a non-response schedule; and
Electricity Industry Participation Code 2010
Schedule 13.3

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(b) [Revoked]

(c) clauses 13.71 to 13.86, for a dispatch schedule; and

(d) clause 13.135, for a schedule of provisional prices or a schedule of interim prices or a schedule of final prices; and

(e) clause 13.88, for a schedule of real time prices.

Compare: Electricity Governance Rules 2003 clause 1.2 schedule G6 part G
Clause 2(a), (c), (d) and (e): amended, on 28 June 2012, by clause 55(2) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Inputs used at each stage

3 Specific inputs must be used in schedules
The schedules must be prepared using the following inputs:

(a) for each price-responsive schedule, the inputs set out in clause 13.58A(1); and

(b) for each non-response schedule, the inputs set out in clause 13.58A(2); and

(c) for each dispatch schedule, the inputs set out in clause 7; and

(d) for each schedule of provisional prices, each schedule of interim prices and each schedule of final prices, the inputs set out in clause 13.141; and

(e) for each schedule of real time prices, the inputs set out in clause 6.

Compare: Electricity Governance Rules 2003 clause 1.3 schedule G6 part G

4 [Revoked]

Clause 4: revoked, on 28 June 2012, by clause 57 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

5 [Revoked]

Clause 5: revoked, on 28 June 2012, by clause 57 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

6 Schedule of real time prices
For a schedule of real time prices, the schedule must use—

(a) the final information for each real time pricing period provided to the system operator under subpart 1 of Part 13, including—

(i) offers revised under clause 13.19; and

(ii) nominated dispatch bids revised under clause 13.19A; and

(iii) reserve offers revised under clause 13.47; and

(iv) information updated under clause 13.34(1); and

(b) existing generation configuration specifying the instantaneous MW injection at each grid injection point at the beginning of the relevant real time pricing period for generating plant or generating units that were the subject of offers
for the relevant trading period, or, if no such information is available, a reasonable estimate of such data; and

(c) existing demand configuration, specifying the average MW demand at each grid exit point, excluding the MW demand at each dispatch-capable load station for which a nominated dispatch bid is submitted at the grid exit point, during the relevant real time pricing period, or if no such information is available, a reasonable estimate of such data.

Compare: Electricity Governance Rules 2003 clause 1.3.3 schedule G6 part G
Clause 6 Heading: amended, on 28 June 2012, by clause 58(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clause 6(a): substituted, on 15 May 2014, by clause 71(1) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.
Clause 6(c): amended, on 15 May 2014, by clause 71(2) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

7 Dispatch schedule

For a dispatch schedule, the schedule must use—

(a) offers and reserve offers, excluding the following:
   (i) offers made by an intermittent generator under clause 13.6(3):
   (ii) revised offers made by an intermittent generator under clause 13.17(3):
   (iii) offers made by a type B co-generator under clause 13.6(1) or (2):
   (iv) revised offers made by a type B co-generator under clause 13.17(1) or (2);

(b) the quantities specified in nominated bids (clause 13.7 and 13.7AA) and the quantities specified in revised nominated bids (clause 13.19A); and

(c) the expected profile of demand until the next dispatch schedule is produced by the system operator; and

(d) the ramp rates agreed for intermittent generators under clause 13.71(c); and

(e) any additional information regarding the future output of an intermittent generator, submitted by an intermittent generator in agreement with the system operator for the period until the next dispatch schedule is produced (clause 13.71(e)); and

(f) the current output levels of each generator; and

(g) information from the grid owner (clauses 13.29 to 13.34) and revised information from the grid owner (clause 13.33) about—
   (i) the AC transmission system configuration, capacity and losses; and
   (ii) the capability of the HVDC link including its configuration, capacity, losses, the direction of any transfer limit, and any minimum or maximum transfer limits; and
   (iii) transformer configuration, capacity and losses; and

(h) information about voltage support; and

(i) adjustments required to meet the dispatch objective must be incorporated in each schedule prepared and this method repeated until the system operator is satisfied that the schedule meets the requirements of the dispatch objective.
Compare: Electricity Governance Rules 2003 clause 1.3.4 schedule G6 part G
Clause 7 Heading: amended, on 28 June 2012, by clause 59(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clause 7: amended, on 28 June 2012, by clause 59(2) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clause 7(b): substituted, on 28 June 2012, by clause 59(2)(b) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clause 7(b): substituted, on 15 May 2014, by clause 72(a) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.
Clause 7(g)(ii): substituted, on 1 November 2012, by clause 6(1) of the Electricity Industry Participation (HVDC Link Pole 3 Standing Data) Code Amendment 2012.
Clause 7(i): amended, on 15 May 2014, by clause 72(b) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

8 The objective function

(1) The objective function of the modelling system is described mathematically as:

\[
\text{Maximise}
\left\{ \sum_{i,j} D_{i,j} \times BP_{i,j} - \sum_{i,j} G_{i,j} \times OP_{i,j} - \sum_{i,j} R^{PLSr}_{i,j} \times OP^{PLSr}_{i,j} - \sum_{i,j} R^{TWD} \times OP^{TWD}_{i,j} - \sum_{i,j} R^{IL}_{i,j} \times OP^{IL}_{i,j} \right\}
\]

where

- \(i\) is a price band of a bid / offer or a reserve offer
- \(j\) is a generating unit / generating station, or a purchaser
$D_{i,j}$ is the scheduled demand corresponding to price band $i$ of the bid for purchaser $j$ or metered demand, whichever is relevant, and where the relevant bids used here are formed from a combination of the following, as appropriate to the schedule being calculated:

(a) nominated bids:
(b) the forecast prepared under clause 13.7A(1):
(c) difference bids (if difference bids are used, the quantities must be added or subtracted, as appropriate, from the forecast prepared under clause 13.7A(1)):
(d) the system operator’s expectation of the profile of demand during the relevant period covered by the schedule being calculated:
(e) a measure of actual demand during the relevant period

$BP_{i,j}$ is the bid prices corresponding to price band $i$ of the bid for purchaser $j$

$G_{i,j}$ is the scheduled generation corresponding to price band $i$ of the offer for unit / station $j$

$OP_{i,j}$ is the offer price corresponding to price band $i$ of the offer for unit / station $j$

$R_{i,j}^{PLSR,f}$ is the scheduled fast PLSR corresponding to price band $i$ of the fast reserve offer for unit / station $j$

$R_{i,j}^{PLSR,s}$ is the scheduled sustained PLSR corresponding to price band $i$ of the reserve offer for unit / station $j$

$OP_{i,j}^{PLSR,f}$ is the reserve offer price corresponding to price band $i$ of the fast PLSR reserve offer for unit / station $j$

$OP_{i,j}^{PLSR,s}$ is the offer price corresponding to price band $i$ of the sustained PLSR reserve offer for unit / station $j$

$R_{i,j}^{TWD,f}$ is the scheduled fast TWD corresponding to price band $i$ of the reserve offer for unit / station $j$

$R_{i,j}^{TWD,s}$ is the scheduled sustained TWD corresponding to price band $i$ of the reserve offer for unit / station $j$

$OP_{i,j}^{TWD,f}$ is the reserve offer price corresponding to price band $i$ of the fast TWD reserve offer for unit / station $j$

$OP_{i,j}^{TWD,s}$ is the reserve offer price corresponding to price band $i$ of the sustained TWD reserve offer for unit / station $j$

$R_{i,j}^{fIL}$ is the scheduled fast IL corresponding to price band $i$ of the reserve offer for purchaser $j$
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$R_{i,j}^{IL}$ is the scheduled sustained IL corresponding to price band $i$ of the reserve offer for purchaser $j$

$OP_{i,j}^{IL}$ is the reserve offer price corresponding to price band $i$ of the fast IL reserve offer for purchaser $j$

$OP_{i,j}^{sIL}$ is the reserve offer price corresponding to price band $i$ of the sustained IL reserve offer for purchaser $j$

and where

PLSR is partly loaded spinning reserve

TWD is tail water depressed reserve

IL is interruptible load

fast is fast instantaneous reserve

sustained is sustained instantaneous reserve

(2) The objective must be maximised to an accuracy specified in the model formulation. Compare: Electricity Governance Rules 2003 clause 2 schedule G6 part G
Clause 8, definition of $D_{ij}$: amended, on 28 June 2012, by clause 60 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

9 Constraints

In maximising the objective function, the system operator or the pricing manager (as the case may be) must ensure that the following constraints are met to an accuracy specified in the model formulation:

(a) [Revoked]
(b) each constraint relating to generation set out in clause 9A:
(c) the constraint relating to demand set out in clause 10:
(d) each constraint relating to the transmission system set out in clause 11:
(e) each constraint relating to instantaneous reserve set out in clause 12.

Compare: Electricity Governance Rules 2003 clauses 3 and 3.1 schedule G6 part G

9A Constraints relating to generation

The constraints for the purpose of clause 9(b) are that—

(a) for each price band, the modelling system does not schedule electricity generation that would result in the scheduled quantity of electricity to be generated by a generator being greater than the quantity offered by the generator for the price band; and
(b) the modelling system schedules electricity generation for each generating unit or generating station in a trading period within the offered maximum ramp up and ramp down rates of the generating unit or generating station, given the expected (or actual) output at the start of the trading period.


10 Constraint relating to demand

The constraint relating to demand for the purpose of clause 9(c) is that, for each price band, the modelling system does not schedule electricity demand that would result in the scheduled quantity of demand being greater than the quantity bid by the purchaser for the price band.

Compare: Electricity Governance Rules 2003 clause 3.2 schedule G6 part G

11 Constraints relating to transmission system

The final schedule provided by the modelling system must have the following characteristics (all of which must be met to an accuracy to be specified in the model formulation):

(a) the total scheduled flow into and out of a grid injection point or grid exit point must equal 0 for all grid injection points and grid exit points:

(b) the modelling system must calculate losses in transmission lines, the HVDC link, and transformers. Those losses must be approximated using the information provided by grid owners under clauses 13.29 to 13.31, for transmission lines, the HVDC link and transformers respectively:

(c) the modelling system must calculate the electricity flows into individual transmission lines and flows into the connection points of transformers connected at the same grid injection point or grid exit point using an established DC power flow technique within the limitations imposed by the technique that—

(i) correctly adjusts flows for transmission system losses; and

(ii) correctly apportions flows in transmission system loops, whether or not those loops contain transmission constraints—

provided that the capacity of transformers through which electricity is supplied to a grid exit point is not included in the model unless the transformer may carry flows of electricity other than offtakes from that grid exit point.

Compare: Electricity Governance Rules 2003 clause 3.3 schedule G6 part G
Clause 11(b) and (c): amended, on 1 February 2016, by clause 88 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.
12 Constraints relating to instantaneous reserve

(1) The modelling system must simultaneously calculate the amount of **fast instantaneous reserve** and **sustained instantaneous reserve** to be provided by each **ancillary service agent** in each **island** to meet the requirements of the **dispatch objective** in each **island**.

(2) In making the calculation in subclause (1), the modelling system must identify the risk (in **MW**) associated with the largest “Contingent Event” as the largest of—
   (a) the transfer on a single pole of the HVDC link; or
   (b) the generation from a single generating unit (whether or not this is a generator’s generating unit); or
   (c) any other risk specified in the dispatch objective.

(3) The modelling system must calculate the total amount of **fast instantaneous reserve** and **sustained instantaneous reserve** required to meet the requirements of the dispatch objective. The amount of **fast instantaneous reserve** and **sustained instantaneous reserve** to be provided by each **ancillary service agent** is this amount less any instantaneous reserve being provided by any other person who is not an **ancillary service agent** (as advised by the system operator).

(4) The modelling system must not schedule instantaneous reserve at a generating unit or generating station that would result in the scheduled quantity of electricity to be generated plus the scheduled quantity of instantaneous reserve to be provided that is greater than the maximum generator effective reserve capacity of that generating unit or generating station as specified in the reserve offer for that generating unit or generating station.

Compare: Electricity Governance Rules 2003 clause 3.4 schedule G6 part G

13 Adjustments to schedules to meet dispatch objective

(1) As soon as practicable after each **non-response schedule** and each **dispatch schedule** has been completed, the **system operator** must give notice on **WITS** to **participants** of any changes required to the non-response schedule or dispatch schedule (as the case may be) to meet the dispatch objective, including adjustments for—
   (a) voltage support; and
   (b) frequency keeping reserves; and
   (c) over-frequency arming; and
   (d) additional transmission constraints; and
   (e) instantaneous reserve.

(2) The adjustments identified in subclause (1) must be made by setting 1 or a combination of the following parameters:
   (a) minimum generation (in **MW**) required at a grid injection point or group of grid exit points:
   (b) maximum generation (in **MW**) required at a grid injection point or group of grid exit points:
(c) minimum flow limits (in MW) on a transmission line or a transformer:
(d) maximum flow limits (in MW) on a transmission line or a transformer:
(e) minimum flow limits (in MW) on a group of transmission lines or transformers:
(f) maximum flow limits (in MW) on a group of transmission lines or transformers:
(g) the reserve modelling parameters as contained in Form 7 in Schedule 13.1.

(3) For a non-response schedule or a dispatch schedule, the adjustments must be made by the system operator. For a dispatch schedule, this method must be repeated to produce a new schedule. This must continue until the system operator is satisfied that the requirements of the dispatch objective have been met.

(4) For a schedule of provisional prices or a schedule of interim prices or a schedule of final prices, the adjustments must be made using the adjustments that were used in the non-response schedule that applied at the beginning of the trading period.

Compare: Electricity Governance Rules 2003 clauses 4.1 and 4.2 schedule G6 part G
Clause 13 Heading: substituted, on 28 June 2012, by clause 63(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clauses 13(1), (3) and (4); substituted, on 28 June 2012, by clause 63(2) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clause 13(2)(e) and (f); amended, on 1 February 2016, by clause 89 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

14 Principles to be followed by system operator
In suggesting changes and making adjustments under clause 13, the system operator must have regard to the following principles:
(a) constraints must be imposed on generating plant only if the system operator has a specific requirement from the generating plant to meet the requirements of the dispatch objective:
(b) constraints must be imposed on a transmission line or transformer only if the system operator has a specific requirement from the line or the transformer to meet the requirements of the dispatch objective:
(c) adjustments must be made to instantaneous reserve modelling parameters only if the system operator has a specific requirement for instantaneous reserve to meet the requirements of the dispatch objective.

Compare: Electricity Governance Rules 2003 clause 4.3 schedule G6 part G

15 Schedule of prices
A schedule of provisional prices or interim prices or final prices must use —
(a) the information specified in generator offers (clause 13.6(1) to (3)); and
(aa) the final submitted nominated dispatch bid for each trading period as specified in clause 13.141(1)(ca); and
(b) the information specified in ancillary service agent reserve offers (clause 13.38(1)); and
(c) the metered demand within the current trading period (clause 13.141(1)(b)), including any adjustments made for an embedded generator; and
(d) the information from the system operator and a grid owner (clauses 13.29 to 13.34) that was used in the first dispatch schedule prepared for that trading period about—
(i) the AC transmission system configuration, capacity and losses; and
(ii) the capability of the HVDC link including its configuration, capacity, losses, the direction of any transfer limit, and any minimum or maximum transfer limits, weighted by time for any changes within the trading period (clause 13.30); and
(iii) transformer configuration, capacity and losses; and
(iv) voltage support; and
(v) instantaneous reserves; and
(e) adjustments that were made to the dispatch schedule and the non-response schedule, which were required to meet the dispatch objective (clause 13.57).

Compare: Electricity Governance Rules 2003 clause 5 schedule G6 part G

16 Calculation of prices, marginal location factors and reserve prices

(1) The modelling system must calculate the following set of prices:
(a) prices for electricity at each grid injection point and grid exit point, and at each reference point;
(b) reserve prices for each island;
(c) marginal location factors for each grid injection point and each grid exit point. Those factors must be determined by dividing the price at that grid injection point or grid exit point by the price at the reference point relevant to that grid injection point or grid exit point.

(2) The modelling system must assign a 0 price for electricity at each grid injection point and grid exit point that has no load or generation connected to it in the modelling system.

(3) The prices described in subclause (1) must be used—
(a) for a price-responsive schedule or a non-response schedule, as—
(i) forecast prices; and
(ii) forecast reserve prices; and
(iii) forecast marginal location factors;
(b) for a schedule of provisional prices, or a schedule of interim prices, or a schedule of final prices, as—
(i) provisional prices, interim prices, or final prices, as the case may be; and
(ii) provisional reserve prices, interim reserve prices, or final reserve prices, as the case may be; and
(iii) provisional marginal location factors, interim marginal location factors, or final marginal location factors, as the case may be:
(c) [Revoked]

(d) if this schedule is used as a schedule of real time prices, as real time prices.

Compare: Electricity Governance Rules 2003 clauses 6 to 6.2 schedule G6 part G
Clause 16(c): revoked, on 28 June 2012, by clause 66(d) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

17 What modelling system must take into account when calculating prices

The modelling system must calculate the prices in clause 16 consistent with the objective function, and consistent with the quantities of electricity and instantaneous reserve scheduled, while meeting all constraints, and in particular—

(a) prices for electricity at each grid injection point or grid exit point must be consistent with the treatment of transmission system losses and the transmission system power flow; and

(b) subject to the rights of the system operator described in clause 13, a generator at a grid injection point must be scheduled to generate a quantity of electricity from a price band if the price determined by the modelling system at the reference point multiplied by the marginal location factor at that grid injection point is greater than or equal to the price offered in that price band; and

(c) subject to the rights of the system operator described in clause 13, a generator at a grid injection point must not be scheduled to generate a quantity of electricity from a price band if the price determined by the modelling system at the reference point multiplied by the relevant marginal location factor at that grid injection point is less than the price offered in that price band; and

(d) for nominated bids, subject to the obligations of the system operator described in clause 13, a purchaser at a grid exit point—

(i) must be scheduled to purchase a quantity of electricity from a price band if the price determined by the modelling system at the reference point multiplied by the relevant marginal location factor at the grid exit point is less than the price bid for the price band; and

(ii) must not be scheduled to purchase a quantity of electricity from a price band if the price determined by the modelling system at the reference point multiplied by the relevant marginal location factor at the grid exit point is greater than the price bid for the price band; and

(e) for positive difference bids, subject to the obligations of the system operator described in clause 13, a purchaser at a grid exit point—

(i) must be scheduled to increase a quantity of electricity if the price determined by the modelling system at the reference point multiplied by the relevant marginal location factor at the grid exit point is less than the price bid for the price band; and

(ii) must not be scheduled to increase a quantity of electricity if the price determined by the modelling system at the reference point multiplied by
the relevant marginal location factor at the **grid exit point** is greater than the price bid for the price band; and

(ea) for negative **difference bids**, subject to the obligations of the **system operator** described in clause 13, a **purchaser** at a **grid exit point**—

(i) must be scheduled to decrease a quantity of **electricity** if the price determined by the modelling system at the **reference point** multiplied by the relevant marginal location factor at that **grid exit point** is greater than the price bid for the price band; and

(ii) must not be scheduled to decrease a quantity of **electricity** if the price determined by the modelling system at the **reference point** multiplied by the relevant marginal location factor at that **grid exit point** is less than the price bid for the price band; and

(f) subject to the rights of the **system operator** described in clause 13, an **ancillary service agent** who has made a **reserve offer** must be scheduled to provide a quantity of **instantaneous reserve** from a reserve price band only if the reserve price determined by the modelling system is greater than or equal to the total price offered for that reserve price band. In the case of a **reserve offer** for a **generating unit**, the total price offered for a price band must be equal to the amount required to ensure that that **ancillary service agent** is indifferent as to whether it generates **electricity** or provides **instantaneous reserve** plus the price **offered** in that reserve price band; and

(g) subject to the rights of the **system operator** described in clause 13, an **ancillary service agent** who has made a **reserve offer** must not be scheduled to provide a quantity of **instantaneous reserve** from a price band if the reserve price determined by the modelling system is less than the total price offered for that price band. In the case of a **reserve offer** for a **generating unit**, the total price offered for a price band is equal to the amount required to ensure that that **ancillary service agent** is indifferent as to whether it generates **electricity** or provides **instantaneous reserve** plus the price offered in that reserve price band.

Compare: Electricity Governance Rules 2003 clause 6.3 schedule G6 part G
Clause 17(d) and (e): substituted, on 28 June 2012, by clause 66A(a) and (b) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Clause 17(ea): inserted, on 28 June 2012, by clause 66A(c) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.
Calculation of interim prices and interim reserve prices in island scarcity pricing situation


1 Calculation of interim prices and interim reserve prices in island scarcity pricing situation

(1) If the pricing manager determines under clause 13.135A that an island scarcity pricing situation exists in a trading period, the pricing manager must calculate interim prices and interim reserve prices in the relevant island for that trading period in accordance with the following:

(a) calculate initial interim prices and interim reserve prices for the relevant island for that trading period in accordance with clause 13.135:
(b) calculate the island GWAP in accordance with subclause (2):
(c) calculate the scarcity pricing factor in accordance with subclause (3):
(d) calculate interim prices by multiplying the initial interim prices calculated under paragraph (a) by the scarcity pricing factor:
(e) calculate interim reserve prices by multiplying the initial interim reserve prices calculated under paragraph (a) by the scarcity pricing factor.

(2) The pricing manager must calculate the island GWAP in accordance with the following formula:

\[
GWAP_{ISL} = \sum_{g=1}^{n} (Q_g \times P_g) / \sum_{g=1}^{n} Q_g
\]

where

GWAP_{ISL} is the island GWAP

Q_g is the scheduled quantity of generation for generator g in the island

P_g is the initial interim price at the node where generator g injects electricity in the island

(3) The scarcity pricing factor is determined as follows:

(a) if the island GWAP is greater than or equal to $10,000/MWh and less than or equal to $20,000/MWh, the scarcity pricing factor is 1:
(b) if the island GWAP is less than $10,000/MWh, the scarcity pricing factor is calculated in accordance with the following formula:
\[ X = \frac{10,000}{\text{GWAP}_{\text{ISL}}} \]

where

\[ X \] is the scarcity pricing factor

\[ \text{GWAP}_{\text{ISL}} \] is the island GWAP

(c) if the island GWAP is greater than $20,000/MWh, the scarcity pricing factor is calculated in accordance with the following formula:

\[ X = \frac{20,000}{\text{GWAP}_{\text{ISL}}} \]

where

\[ X \] is the scarcity pricing factor

\[ \text{GWAP}_{\text{ISL}} \] is the island GWAP


2 Calculation of interim prices in national scarcity pricing situation

(1) If the pricing manager determines under clause 13.135A that a national scarcity pricing situation exists in a trading period, the pricing manager must calculate interim prices and interim reserve prices for that trading period in accordance with the following:

(a) calculate initial interim prices and interim reserve prices for that trading period in accordance with clause 13.135:

(b) calculate the national GWAP in accordance with subclause (2):

(c) calculate the scarcity pricing factor in accordance with subclause (3):

(d) calculate interim prices by multiplying the initial interim prices calculated under paragraph (a) by the scarcity pricing factor:

(e) calculate interim reserve prices by multiplying the initial interim reserve prices calculated under paragraph (a) by the scarcity pricing factor.

(2) The pricing manager must calculate the national GWAP in accordance with the following formula:

\[
\text{GWAP}_{\text{NAT}} = \frac{\sum_{g=1}^{n} \left( Q_g \times P_g \right)}{\sum_{g=1}^{n} Q_g}
\]
where

\[ \text{GWAP}_{\text{NAT}} \] is the \textbf{national GWAP}

\[ Q_g \] is the scheduled quantity of generation for \textbf{generator} \( g \) in both \textbf{islands}

\[ P_g \] is the initial \textbf{interim price} at the \textbf{node} where \textbf{generator} \( g \) injects \textbf{electricity} in both \textbf{islands}

\[ (3) \] The scarcity pricing factor is determined as follows:

\[ (a) \] if the \textbf{national GWAP} is greater than or equal to \$10,000/MWh and less than or equal to \$20,000/MWh, the scarcity pricing factor is 1:

\[ (b) \] if the \textbf{national GWAP} is less than \$10,000/MWh, the scarcity pricing factor is calculated in accordance with the following formula:

\[ X = \frac{\$10,000}{\text{GWAP}_{\text{NAT}}} \]

where

\[ X \] is the scarcity pricing factor

\[ \text{GWAP}_{\text{NAT}} \] is the \textbf{national GWAP}

\[ (c) \] if the \textbf{national GWAP} is greater than \$20,000/MWh, the scarcity pricing factor is calculated in accordance with the following formula:

\[ X = \frac{\$20,000}{\text{GWAP}_{\text{NAT}}} \]

where

\[ X \] is the scarcity pricing factor

\[ \text{GWAP}_{\text{NAT}} \] is the \textbf{national GWAP}

Schedule 13.4

Approval as type A or type B industrial co-generating station


1 Generators to apply to Authority for approval
A generator may apply to the Authority to have 1 or more generating units approved as—
(a) a type A industrial co-generating station; or
(b) a type B industrial co-generating station.

Compare: Electricity Governance Rules 2003 clause 1 schedule G9 part G

2 Application requirements
(1) An application must—
(a) be in writing; and
(b) specify each generating unit that the applicant wants to have approved; and
(c) include information related to any seasonal operation of each generating unit; and
(d) specify whether the applicant wants each generating unit to be approved as a—
(i) type A industrial co-generating station; or
(ii) type B industrial co-generating station.

(2) An applicant may include any supporting information that the applicant considers may assist the Authority with the application.

Compare: Electricity Governance Rules 2003 clause 2 schedule G9 part G

3 Authority must publish each application for approval
On receipt of an application, the Authority must—
(a) publish the application; and
(b) provide a copy of the application to the system operator.

Compare: Electricity Governance Rules 2003 clause 3 schedule G9 part G

4 Factors that Authority must consider
Before the Authority approves an application, it must take into account—
(a) the system operator’s views as to the effect an approval would have on the system operator’s ability to meet the PPOs; and
(b) the cumulative effects, if the approval were granted, of all approvals granted under this Schedule on the system operator’s ability to meet the PPOs; and
(c) any views that may be made known to the Authority when it published the application in accordance with clause 3(a); and
(d) whether each generating unit that is the subject of the application is as described
in paragraphs (b) and (c) of the definition of **industrial co-generating station** set out in Part 1; and
(da) the implications of each **generating unit** that is the subject of the application being approved in accordance with the applicant's preference specified under clause 2(1)(d), having regard to the obligations of **type A co-generators** and **type B co-generators**; and
(e) section 15 of the **Act**.

Compare: Electricity Governance Rules 2003 clause 4 schedule G9 part G

5 **Authority may require extra information**
The **Authority** may require the provision of additional information at any stage during the application process and, if the Authority’s requirements are reasonable, the applicant must provide that information to the **Authority**.

Compare: Electricity Governance Rules 2003 clause 5 schedule G9 part G

6 **Authority may seek independent expert advice**
In considering an application for approval, the **Authority** may seek technical advice from an independent person who is familiar with co-generation.

Compare: Electricity Governance Rules 2003 clause 6 schedule G9 part G

7 **Applicant may withdraw or amend application at any time**
(1) The applicant may, at any time, withdraw or amend an application being considered by the **Authority**.
(2) An amendment or withdrawal—
(a) must be made in writing; and
(b) must be submitted to the **Authority**; and
(c) takes effect from the date of receipt by the **Authority**.

Compare: Electricity Governance Rules 2003 clause 7 schedule G9 part G

8 **Authority's decision**
(1) The **Authority** must, no later than 6 months after receiving an application,—
(a) approve each **generating unit** that is the subject of the application as either—
   (i) a **type A industrial co-generating station**; or
   (ii) a **type B industrial co-generating station**; or
(b) decline to approve the application.

(2) The **Authority** must consult with an applicant before making a decision if the **Authority**—
(a) proposes to approve an application for a type of **industrial co-generating station**
Schedule 13.4

9 Decision must be recorded

(1) The Authority must keep a register of all current approvals granted under this Schedule available for public inspection free of charge during normal office hours at the offices of the Authority and on the Authority’s website at all reasonable times.

(2) The register must state, for each approval on the register,—

(a) whether the applicant's generating units have been approved as a type A co-generating station or a type B co-generating station; and
(b) the name of the type A co-generator or the type B co-generator; and
(c) the name of the type A industrial co-generating station or the type B industrial co-generating station; and
(d) the date of the approval; and
(e) the duration of the approval; and
(f) whether the approval includes any conditions and if so, a description of the conditions.

Compare: Electricity Governance Rules 2003 clause 9 schedule G9 part G

10 Effect of approval

Approval of 1 or more generating units as a type A industrial co-generating station or a type B industrial co-generating station takes effect from the date specified in the approval, which may be no earlier than 10 business days after the date of the notice of decision published by the Authority under clause 8(3).

Compare: Electricity Governance Rules 2003 clause 10 schedule G9 part G

11 Authority may impose conditions

The Authority may impose conditions on any approval it grants. Such conditions may include 1 or more of the following:

(a) requirements to assist the system operator in meeting the PPOs:
(b) requirements as to seasonal co-generation, including limitations on when the approval applies:
(c) requirements that a type A co-generator or type B co-generator comply with specific instructions from the system operator during a grid emergency or during a system constraint that directly affects the type A co-generator or type B co-generator.

12 [Revoked]

Compare: Electricity Governance Rules 2003 clause 12 schedule G9 part G

13 Authority may rescind or amend approval

(1) If the Authority considers a change of circumstance has led to a situation in which the continuation of an approval would significantly adversely impact on the system operator’s ability to meet the PPOs, it may amend or rescind the approval.

(2) The Authority may, at the request of a type A co-generator or a type B co-generator, amend an approval to change a type A industrial co-generating station to a type B co-generating station, or vice-versa.

(3) The Authority must consult with the system operator before amending an approval under subclause (2).

14 Notice and reasons for rescinding or amending approval

If the Authority amends or rescinds an approval, it must—

(a) give the type A co-generator or type B co-generator 3 months' notice before rescinding or amending the approval; and

(b) advise the type A co-generator or type B co-generator of the reasons for rescinding or amending the approval.

Compare: Electricity Governance Rules 2003 clause 14 schedule G9 part G
Clause 14(a) and (b): substituted, on 27 May 2015, by clause 29 of the Electricity Industry Participation Code Amendment (Industrial Co-generation Dispatch Arrangements) 2015.
Schedule 13.5

Requirements for FTR allocation plan


1 Purpose
The purpose of this Schedule is to set out the requirements for the FTR allocation plan prepared by the FTR manager under subpart 6 of Part 13.

2 Requirements for design of FTRs
(1) FTRs must be allocated by auction.
(2) At a minimum, the FTRs allocated under the FTR allocation plan must be FTRs between a hub in the South Island and a hub in the North Island that would provide a reasonable match with the trading points for exchange–traded futures products or the equivalent electricity futures products, and which would enable the volumes of FTRs available to reflect inter-island grid capacity.
(3) The FTR manager must offer option FTRs and obligation FTRs.
(4) The FTRs offered must include FTRs for which the FTR period is 1 month.
(5) Subclause (4) does not prevent the FTR manager from offering FTRs relating to a shorter FTR period in addition to FTRs for which the FTR period is 1 month.

3 Requirements for FTR auction design
(1) The number and nature of the FTRs allocated under the FTR allocation plan and available for auction must be—
   (a) supported by a reasonable estimate of the capacity of the grid for the relevant period; and
   (b) set so as to achieve a reasonable balance between the following:
       (i) ensuring that there is revenue available that is sufficient to settle the FTRs:
       (ii) ensuring that sufficient FTRs are available so that participants who wish to purchase FTRs are able to obtain them.
(2) The FTR auction must be designed to—
   (a) maximise the value of trade in the auction as determined by the bids made in the auction; and
   (b) maximise competition in the auction; and
   (c) minimise costs of participation in the auction.
(3) The FTR allocation plan must include FTR auction procedures.
(4) The initial FTR allocation plan must specify a plan that seeks to—
   (a) ensure that, no later than 1 year after the first FTR auction, FTRs are available in each FTR auction relating to an initial month and to at least each of the 11 months following the initial month; and
   (b) ensure that the availability of FTRs is progressively increased so that, no later than 3 years after the first FTR auction, FTRs are available in each FTR auction
relating to an initial month and to at least the 23 months following the initial month.

4 Requirements for FTR grid design

The FTR grid must—
(a) be based on each grid owner's forecast of the configuration and capacity of its grid for the FTR period; and
(b) make allowance for relevant planned and unplanned outages in accordance with reasonable transmission operating practice.
Schedule 13.6


Form 1
Assignment of FTR

Date: 

FTR registered number: 

If part of the FTR is to be assigned, specify the amount of electricity (in MW) to which the assigned part of the FTR relates: 

Price*: 

Assignor: 

Assignee: 

* Parties are only required to specify the price if they wish clause 13.249 to apply.
Methodology for Determining Conforming and Non-Conforming GXPs

1 Methodology for determining whether GXP is conforming GXP or non-conforming GXP

In making a determination under clause 13.27A or clause 13.27B(4), the Authority must use the following method:

(a) use the input data described in clause 2 to determine the adjusted reconciled half hour demand data (in MW) for the GXP for each trading period during the most recent 12 consecutive months for which data is available; and

(b) using the results from paragraph (a), determine the mean demand (in MW) for the GXP over the most recent 12 consecutive months for which data is available; and

(c) determine the unpredictability measure for the GXP in accordance with clause 3; and

(d) apply the results from paragraphs (b) and (c) to the table below, to determine whether the GXP is either a conforming GXP or a non-conforming GXP.

Table 1: Determining whether GXP is conforming or non conforming

<table>
<thead>
<tr>
<th>Category for mean demand (in MW) for a GXP over relevant 12 months (clause 1(b)) (d)</th>
<th>Category for unpredictability measure (clause 1(c)) (p)</th>
<th>Resulting classification of the GXP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Where d &lt; 10MW</td>
<td>For all p</td>
<td>Conforming GXP</td>
</tr>
<tr>
<td>Where 10MW ≤ d &lt; 20MW</td>
<td>For p &lt; 0.15</td>
<td>Conforming GXP</td>
</tr>
<tr>
<td></td>
<td>For p ≥ 0.15</td>
<td>Non-conforming GXP</td>
</tr>
<tr>
<td>Where 20MW ≤ d &lt; 250 MW</td>
<td>For p &lt; 0.10</td>
<td>Conforming GXP</td>
</tr>
<tr>
<td></td>
<td>For p ≥ 0.10</td>
<td>Non-conforming GXP</td>
</tr>
<tr>
<td>Where d ≥ 250 MW</td>
<td>For all p</td>
<td>Non-conforming GXP</td>
</tr>
</tbody>
</table>

2 Input data

(1) For the purpose of determining the adjusted reconciled half hour demand data for a GXP under clause 1(a), the Authority must use the following data from the most recent 12 consecutive months for which data is available:

(a) reconciled half hour demand data for the GXP representing purchases of electricity at the GXP aggregated across all purchasers at the GXP, and with each half hour figure in MWh converted to an average demand in MW over that half hour; and

(b) information about the impact of demand switching on the GXP; and
(c) information from distributors, purchasers and the system operator about any one-off events that have affected demand but which would not be expected to affect demand in the future.

(2) If the Authority identifies, under subclause (1)(b), that 2 or more adjacent GXPs are significantly affected by demand switching, the Authority must—

(a) combine the GXPs’ reconciled half hour demand data as described in subclause (1)(a) and follow the method set out in clause 1 for the combined GXPs as if they were a single GXP; or

(b) follow such other method of addressing the impact of demand switching as the Authority may determine is appropriate in the circumstances.

(3) In applying the methodology under clause 1, the Authority must remove one-off events identified under this clause from the input data.

(4) A one-off event includes, but is not limited to, the following:

(a) a transmission outage that has caused a GXP to be unable to be supplied with electricity:

(b) a consumer ceasing to consume at a GXP, if over the proportion of the relevant 12 month period for which the consumer was consuming electricity, the reconciled demand attributed to the consumer (in MW) was on average at least 40% of the total demand (in MW) at the GXP.

3 Calculate unpredictability measures

(1) For the purpose of determining the unpredictability measure of a GXP under clause 1(c), the Authority must use the following method:

(a) the Authority must fit an appropriate statistical predictive model as described in subclause (2), to the adjusted reconciled half hour demand data (in MW) which is produced in accordance with clause 1(a); and

(b) the Authority must calculate the residuals (in MW for each half hour) of the statistical predictive model (representing the simulated predictive errors of such a model); and

(c) the Authority must calculate the unpredictability measure as the ratio of the standard deviation of the residuals calculated under paragraph (b) to the mean demand at the GXP (calculated under clause 1(b)).

(2) The statistical predictive model under subclause (1)(a) must achieve the approximate level of predictive accuracy that should be able to be achieved by the system operator when preparing the forecast under clause 13.7A several hours in advance in the absence of forecast information from purchasers and electricity users.

(3) To avoid doubt, the statistical predictive model may include a variable representing weather forecast information.


4 Data for most recent 12 months unavailable

(1) If the data required under clauses 1 to 3 is not available for the most recent 12 consecutive months, the Authority must use reasonable endeavours to make a
determination in accordance with the methodology set out in this Schedule using the data it has available.

(2) If the available data is insufficient to enable the Authority to make a determination in accordance with subclause (1), the Authority must make a determination by—
   (a) using all available data; and
   (b) using its own reasonable expectations of the future activities at the GXP; and
   (c) taking into account, to the extent practicable, the methodology set out in clauses 1 to 3.
Schedule 13.8  cl 1.1, 13.3A, 13.3B

Approval of dispatch-capable load station


1  Applications for approval
Each application for approval for a dispatch-capable load station must—
(a) be in writing; and
(b) list a device or a group of devices that the applicant wishes to have approved as a dispatch-capable load station; and
(c) include information to enable the system operator to determine the application.

2  System operator to provide application to Authority and advise others of application
On receipt of an application, the system operator must—
(a) provide a copy of the application to the Authority; and
(b) advise the following participants that it has received the application:
   (i) the relevant grid owner:
   (ii) each distributor that has a network from which a device that comprises or forms part of the proposed dispatch-capable load station draws electricity:
   (iii) the pricing manager:
   (iv) the clearing manager:
   (v) the reconciliation manager:
   (vi) the WITS manager.

Clause 2(b)(ii) substituted, on 1 February 2016, by clause 90 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

3  Factors that system operator must consider
(1) Before the system operator approves a device or a group of devices to be a dispatch-capable load station, it must consider—
(a) the effect an approval would have on the system operator’s ability to comply with the PPOs; and
(b) whether the applicant—
   (i) is able to provide real time indications and measurements to the satisfaction of the system operator; and
   (ii) has in place communication systems that meet the system operator’s requirements; and
   (iii) is able to receive dispatch instructions; and
(c) whether there is a substantial risk that a dispatch instruction that changes the level of load of the device or group of devices that is the subject of the application may be offset by changes in demand in the same trading period from other load controlled by the applicant; and
(d) whether the device or group of devices is technically capable of complying with a dispatch instruction so that it does not adversely affect the system operator’s ability to comply with the PPOs; and
(e) any other matter the system operator reasonably considers relevant.
(2) In making a decision under subclause (1), the system operator must—
(a) ask the Authority for the Authority’s view; and
(b) consider the Authority’s view.

4 System operator may request additional information
(1) Subclauses (2) and (3) apply to—
(a) a participant that has applied to the system operator to have a device or a group of devices approved as a dispatch-capable load station; and
(b) a purchaser that has a dispatch-capable load station that has been approved.
(2) The system operator may request a participant to which this clause applies to provide additional information.
(3) The participant must provide the requested information to the system operator.
(4) As soon as practicable after receiving the requested information, the system operator must provide a copy of the information to the Authority.

5 Applicant may withdraw or amend application at any time
(1) An applicant may, at any time, amend or withdraw an application.
(2) An applicant must make an amendment or withdrawal—
(a) in writing; and
(b) by submitting it to the system operator.
(3) An amendment or a withdrawal takes effect from the date of receipt by the system operator.
(4) As soon as practicable after receiving an amendment or a withdrawal, the system operator must—
(a) provide the amendment or withdrawal to the Authority; and
(b) advise all participants listed in clause 2(b) of the amendment or withdrawal.

6 System operator’s decision
(1) The system operator must decide whether to—
(a) approve an application; or
(b) decline an application.
(2) If the system operator decides to approve an application, the system operator must assign a dispatch-capable load station identifier to each approved dispatch-capable load station.
(3) The system operator must, as soon as practicable after making a decision, advise the parties listed in subclause (4) in writing of—
(a) the decision; and
(b) if the decision is to approve the application, any conditions that apply to the approval; and
(c) the system operator’s reasons for the decision.
(4) For the purpose of subclause (3), the system operator must advise the following parties:
(a) the applicant:
(b) the Authority:
(c) all participants listed in clause 2(b).
7 System operator may impose conditions
(1) The system operator may impose conditions on any approval it grants under this Schedule.
(2) Conditions may include, but are not limited to, 1 or more of the following:
   (a) a requirement that the applicant has in place real time indications and measurements to the satisfaction of the system operator:
   (b) a requirement that the applicant has in place a system for communicating with the system operator to the satisfaction of the system operator:
   (c) a requirement that the applicant performs tests of load controlling systems on a regular basis.

8 Timeframe for decision
(1) The system operator must make a decision under clause 6(1)—
   (a) within 20 business days after—
      (i) the date on which the system operator receives the application; or
      (ii) if the application is amended under clause 5, the date on which the system operator receives the amendment; or
   (b) within any other period of time that has been agreed by the applicant and the system operator.
(2) Despite subclause (1), if the system operator requests additional information from the applicant under clause 4, the timeframes in subclause (1) are extended by the number of days the applicant takes to provide the additional information.

9 Effect of approval
(1) When approving an application for a dispatch-capable load station, the system operator must specify a date from which the approval takes effect.
(2) The system operator must not set a date from which an approval takes effect that is earlier than 10 business days after the date on which the approval was granted.
(3) An approval of a dispatch-capable load station takes effect from the date specified in the approval.

10 System operator may amend, revoke, or suspend approval
(1) The system operator may, at its own discretion or on the request of the Authority or a dispatchable load purchaser,—
   (a) amend an approval; or
   (b) revoke an approval; or
   (c) suspend an approval.
(2) An amendment takes effect from—
   (a) the date it is made; or
   (b) a later date specified by the system operator.
(3) A revocation takes effect from—
   (a) the date it is made; or
   (b) a later date specified by the system operator.
(4) A suspension—
   (a) takes effect from—
      (i) the date it is made; or
      (ii) a later date specified by the system operator; and
   (b) remains in effect until a date specified by the system operator.
11 **System operator to give reasons for amending, revoking, or suspending approval**
As soon as practicable after the system operator amends, revokes, or suspends a dispatchable load purchaser's approval, the system operator must advise the purchaser, the Authority, and all participants listed in clause 2(b) of—
(a) the revocation, suspension, or amendment; and
(b) the reasons for the revocation, suspension, or amendment.

12 **Authority to keep register of all current approvals**
(1) The Authority must keep a register of all current approvals—
(a) granted under this Schedule; and
(b) of which the system operator has advised the Authority.
(2) The Authority must keep the register available for public inspection free of charge—
(a) at its offices, during normal office hours; and
(b) on its website, at all reasonable times.
(3) The register must state, for each approval granted,—
(a) the name of the applicant; and
(b) the name of the dispatch-capable load station; and
(c) the dispatch-capable load station identifier; and
(d) the date from which the approval takes effect; and
(e) any conditions.

Electricity Industry Participation Code 2010

Part 14
Clearing and settlement


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14.1 Contents of this Part
This Part provides for—
(a) the sale and purchase of electricity to and from the clearing manager; and
(b) the calculation and invoicing of amounts owing to and by the clearing manager for electricity, ancillary services, extended reserve, FTRs, and other payments that may be received or paid by the clearing manager; and
(c) the settlement of amounts payable under this Part; and
(d) processes and remedies for an event of default; and
(e) obligations of the clearing manager in relation to clearing and settlement, including reporting obligations and requirements for the operating account that must be established and held by the clearing manager.

Subpart 1—Sale and purchase of electricity

14.2 Sale and purchase of electricity
(1) The clearing manager must—
(a) purchase electricity sold to the clearing manager in accordance with clauses 14.3 to 14.5; and
(b) sell electricity purchased from the clearing manager in accordance with clause 14.6.
(2) Each generator must sell electricity in accordance with clauses 14.3 and 14.4.
(3) Each purchaser must purchase electricity in accordance with clause 14.6.
(4) Each participant that sells or purchases electricity through a local network or embedded network must sell and purchase the electricity in accordance with clauses 14.4, 14.5, and 14.7.
(5) The amount owing for electricity purchased under this Part must be determined in accordance with clause 14.10.

14.3 Sale by generators with point of connection to grid
(1) This clause applies to each generator that has a generating station or generating unit with a point of connection to the grid.
(2) Each generator to which this clause applies must sell to the clearing manager all electricity generated by the generator's generating station or generating unit injected through a point of connection to the grid.

14.4 Sale by generators with point of connection to local network or embedded network
(1) This clause—
(a) applies to each generator that has an embedded generating station; but
(b) does not apply to a generator in respect of an embedded generating station in relation to a point of connection for which a notice under clause 15.14 is in force.
(2) Each generator to which this clause applies must sell all electricity generated by the embedded generating station and injected through a point of connection with the
local network or embedded network to—
(a) the clearing manager; or
(b) a participant trading on the local network or embedded network.

(3) Despite anything to the contrary in this Code, the relevant point of connection to the grid is, for the purposes of reconciliation under this Code, deemed to be a grid injection point.


14.5 On sale by participants
If an embedded generator sells electricity to a participant under clause 14.4, the participant must at the same time on-sell that electricity to the clearing manager.

14.6 Purchase of offtake through point of connection to grid
Each purchaser must purchase from the clearing manager the electricity allocated to the purchaser under Part 15 in respect of a point of connection to the grid.

14.7 Purchase of offtake through local network by embedded generator
(1) A generator that purchases electricity at the same point of connection with a local network at which it sells electricity in accordance with clause 14.4 must purchase the electricity from the same participant to which it sold its electricity under clause 14.4.
(2) The participant from which electricity is purchased under subclause (1) must sell the electricity as set out in this Code.

Subpart 2—Hedge settlement agreements

14.8 Hedge settlement agreement lodgement
(1) If a hedge settlement agreement that is signed by 2 participants is submitted to the clearing manager, subject to subclauses (2) and (3), it is validly lodged when it is signed by the clearing manager.
(2) A hedge settlement agreement must be in 1 of the forms set out in Schedule 14.4, or in an alternative form approved by the Authority.
(3) The clearing manager may only sign a hedge settlement agreement submitted under subclause (1) if the clearing manager is satisfied that, after the hedge settlement agreement is lodged, at least 1 participant to the hedge settlement agreement will have a physical position in MW that is 33% or more of its hedge settlement agreement position in MW in any month calculated under paragraph (b) of subclause (4).
(4) For the purposes of subclause (3),—
(a) a participant's physical position in MW is the greater of the following:
   (i) the average of the participant's generation in MW over the last 12 months based on reconciled quantities:
   (ii) the average of the participant's generation in MW over the last month based on reconciled quantities:
   (iii) the average of the participant's purchases in MW over the last 12 months based on reconciled quantities:

14.9 Cancellation of hedge settlement agreement

(1) A hedge settlement agreement may be cancelled only in the following situations:
   (a) if an event of default has occurred and is continuing in relation to a party to the hedge settlement agreement, in accordance with clause 14.48;
   (b) if no event of default is continuing in relation to either of the parties to the hedge settlement agreement, in accordance with subclause (2).

(2) A party to a hedge settlement agreement may cancel the hedge settlement agreement under subclause (1)(b) if both parties to the hedge settlement agreement agree in writing to the cancellation and either—
   (a) the parties give the clearing manager at least 90 days' notice of the cancellation; or
   (b) the parties give the clearing manager less than 90 days' notice of the cancellation and the clearing manager agrees to the cancellation in accordance with subclause (3).

(3) The clearing manager may agree to the cancellation of a hedge settlement agreement under subclause (2)(b) only if the clearing manager is satisfied that—
   (a) immediately following the cancellation of the hedge settlement agreement, each party will—
       (i) continue to meet the requirements in clause 14A.4(1); or
       (ii) meet the requirements in clause 14A.3; and
   (b) the cancellation of the hedge settlement agreement is not otherwise contrary to the interests of participants to which an amount is payable under this Part.

(4) In deciding whether to agree to the cancellation of a hedge settlement agreement, the clearing manager may consult with the Authority.

Subpart 3—Amounts owing

14.10 Amounts owing for electricity

(1) The clearing manager must determine the amount owing for electricity purchased under clauses 14.2 to 14.7 using the following formula:
\[ Q \times P_f \]

where

- \( Q \) is the quantity of electricity allocated to the participant for each trading period for each point of connection to the grid determined in accordance with reconciliation information and summarised and loss adjusted dispatchable load information.
- \( P_f \) is the final price determined by the pricing manager for each relevant point of connection to the grid for each trading period.

(2) The clearing manager must determine the amount owing for electricity sold under clauses 14.2 to 14.7 using the following formula:

\[ Q \times P_f \]

where

- \( Q \) is the quantity of electricity allocated to the participant for each trading period for each point of connection to the grid determined in accordance with reconciliation information.
- \( P_f \) is the final price determined by the pricing manager for each relevant point of connection to the grid for each trading period.

(3) The quantity of electricity bought by a purchaser or sold by a generator under subpart 1 must be determined in accordance with clauses 15.20A to 15.26.

(4) The final price of electricity bought by a purchaser or sold by a generator under subpart 1 must be determined in accordance with clauses 13.135 and 13.171 to 13.185.

### 14.11 Amounts owing for constrained off compensation and constrained on compensation

The clearing manager must determine amounts owing in respect of constrained off compensation and constrained on compensation in accordance with clauses 13.192 to 13.212.

### 14.12 Amounts owing for washup amounts

The clearing manager must determine amounts owing in respect of washup amounts in accordance with subpart 6.

### 14.13 Amounts owing for auction revenue

The clearing manager must determine amounts owing in respect of auction revenue in accordance with clauses 13.110 to 13.112.

### 14.14 Amounts owing for ancillary services

The clearing manager must determine amounts owing in respect of ancillary services in accordance with clauses 8.6, 8.31, 8.55(1), and 8.68(1).

14.14A Amounts owing for extended reserve
The clearing manager must determine amounts owing in respect of extended reserve in accordance with clauses 8.55(2), 8.67A, and 8.68(3) and (4).

14.15 Amounts owing for hedge settlement agreements
The clearing manager must calculate amounts owing under a hedge settlement agreement in respect of the current billing period in accordance with the terms of the hedge settlement agreement.

14.16 Calculation of loss and constraint excess
(1) A loss and constraint excess accrues for a billing period when the total of the amounts owing by the clearing manager to generators for that billing period for the electricity sold and purchased in accordance with clause 14.3 is less than the total amount owing to the clearing manager for that billing period for the electricity sold and purchased in accordance with clause 14.6.

(2) The FTR manager must—
(a) determine the amount of loss and constraint excess that must be applied to the settlement of FTRs in accordance with Schedule 14.3; and
(b) advise the clearing manager of that amount no later than—
(i) 1600 hours on the 7th business day of the month following the relevant billing period; or
(ii) if publication of final prices is delayed for any trading period in the relevant billing period, so that final prices for a trading period in the billing period are published later than 1600 hours on the 6th business day of the month following the relevant billing period, 1 business day after all final prices for the billing period are published.

(3) Each grid owner and the pricing manager must provide information to the FTR manager in accordance with Schedule 14.3.

(4) Subject to subpart 8, the clearing manager must apply the amount advised under subclause (2) to the settlement of FTRs.

(5) Subject to subpart 8, if the amount that the FTR manager advises the clearing manager under subclause (2) exceeds the amount of the loss and constraint excess for the billing period, the clearing manager must apply all of the loss and constraint excess to the settlement of FTRs.

(6) The Authority must advise the clearing manager of the proportion of the loss and constraint excess and residual loss and constraint excess owing to each grid owner.

(7) Unless the Authority has directed otherwise under this clause, the amount owing to each grid owner in the proportions advised under subclause (6) is—
(a) the amount of any loss and constraint excess less the amount to be applied to the settlement of FTRs under subclause (4) or (5); and
(b) the amount of any residual loss and constraint excess.
14.17 Amounts owing for FTRs

(1) The clearing manager must calculate, for each billing period, the amount owing—
   (a) by a participant to the clearing manager in respect of each FTR for which the participant is registered as the holder of the FTR; and
   (b) by the clearing manager to a participant in respect of each FTR for which the participant is registered as the holder of the FTR; and
   (c) by a participant to the clearing manager in respect of the assignment of an FTR under clause 13.249(4); and
   (d) by the clearing manager to a participant in respect of the assignment of an FTR under clause 13.249(7).

(2) The amount owing by a participant to the clearing manager in respect of an FTR is the net amount of the FTR acquisition cost for the FTR minus the FTR hedge value for the FTR, if that net amount is positive.

(3) The amount owing by the clearing manager to a participant in respect of an FTR is the net amount of the FTR hedge value for the FTR minus the FTR acquisition cost for the FTR, if that net amount is positive.

(4) The clearing manager must publish, for each billing period,—
   (a) the amount owing by a participant to the clearing manager for each FTR; and
   (b) the amount owing by the clearing manager to a participant for each FTR.

(5) Subclause (6) applies if, in respect of a billing period, the total amount to be advised as owing by the clearing manager under paragraphs (b) and (d) of subclause (1) exceeds the sum of the following amounts:
   (a) the total amount to be advised as owing to the clearing manager under subclause (1)(a):
   (b) any amount available under clause 13.249(6) for the settlement of FTRs in the billing period:
   (c) the amount of the loss and constraint excess to be applied to the settlement of FTRs under clause 14.16(4) or (5).

(6) The clearing manager must, in calculating the amount owing in respect of each FTR under paragraph (a) or (b) of subclause (1), use an amended FTR hedge value scaled according to the formula specified in Schedule 14.1.

Subpart 4—Notice of amounts owing and payable

Information about amounts owing and payable

14.18 Clearing manager to advise participant of amounts owing and payable

(1) The clearing manager must advise each participant, for which the clearing manager has determined that the participant owes or is owed an amount under subpart 3, the following:
   (a) amounts owing by the participant to the clearing manager in accordance with clause 14.19:
   (b) amounts owing by the clearing manager to the participant in accordance with
clause 14.20:
(c) the amount of the settlement retention amount calculated in accordance with the methodology published by the clearing manager under clause 14.21:
(d) any amount payable by the participant to the clearing manager and any amount payable by the clearing manager to the participant under subpart 5 in accordance with clause 14.22.

(2) The clearing manager must advise each participant of each amount owing and each amount payable as follows:
(a) no later than the 9th business day of the month following the billing period; but
(b) if the clearing manager has not received any information required to determine an amount payable in respect of the prior billing period in time to advise each participant by that date,—
   (i) if the clearing manager receives the information in time to advise each participant of each amount owing and each amount payable 2 business days or more before the 20th day of the month, the clearing manager must advise each participant no later than 2 business days before the 20th day of the month; or
   (ii) if the clearing manager does not receive, or considers that it is not likely to receive, the information in time to advise each participant of each amount owing and each amount payable 2 business days before the 20th day of the month,—
      (A) the clearing manager must refer the matter to the Authority; and
      (B) the Authority must direct the clearing manager as to the time by which the clearing manager must advise each participant of each amount owing and each amount payable; and
      (C) the clearing manager must advise each participant by the time directed by the Authority.

(3) A participant must not issue a GST invoice for supplies of electricity, ancillary services, extended reserve, or ancillary service administrative costs to the clearing manager.

Clause 14.18(2): substituted, on 24 March 2015, by clause 5 of the Electricity Industry Participation Code Amendment (Late and Revised Data) 2015.

14.19 Amounts owing by participant to clearing manager
(1) When advising a participant of amounts owing under clause 14.18(1)(a), the clearing manager must specify any amount owing by the participant to the clearing manager for—
   (a) the relevant billing period, to the extent that the clearing manager has received the necessary information; and
   (b) any prior billing period if the clearing manager receives the necessary information for that billing period after the date that amounts owing for that billing period were required to be advised by the clearing manager.

(2) The clearing manager must specify any amount owing by the participant to the
clearing manager in respect of the periods referred to in subclause (1) for the following:

(a) electricity purchased under clauses 14.2 to 14.7:
(b) constrained off compensation under clause 13.201A:
(c) constrained on compensation under clause 13.212:
(d) a washup amount and any interest on that amount under subpart 6:
(e) auction revenue under clause 13.110:
(f) ancillary services under clauses 8.6, 8.31(1)(a), and 8.68(1):
(fa) extended reserve under clauses 8.67A, and 8.68(3):
(g) payment of an amount under any hedge settlement agreement:
(h) for each FTR in respect of which the participant is registered as the holder of the FTR, the net amount of the FTR acquisition cost for the FTR minus the FTR hedge value for the FTR, if that net amount is positive:
(i) any amount owing in respect of the assignment of any FTR under clause 13.249(4):
(j) GST.

(3) The clearing manager must specify the sum of the amounts referred to in subclause (2).


14.20 Amounts owing by clearing manager to participant

(1) When advising a participant of amounts owing under clause 14.18(1)(b), the clearing manager must specify any amount owing by the clearing manager to the participant for—

(a) the relevant billing period, to the extent that the clearing manager has received the necessary information; and

(b) any prior billing period if the clearing manager receives the necessary information for that billing period after the date that amounts owing for that billing period were required to be advised by the clearing manager.

(2) The clearing manager must specify any amount owing by the clearing manager to the participant in respect of the periods referred to in subclause (1) for the following:

(a) electricity sold under clauses 14.2 to 14.7:
(b) constrained off compensation under clause 13.201A:
(c) constrained on compensation under clause 13.212:
(d) a washup amount and any interest on that amount under subpart 6:
(e) auction revenue under clause 13.112:
(f) ancillary services under clause 8.55(a):
(fa) extended reserve under clause 8.68(4):
(g) payment of an amount under any hedge settlement agreement:
(h) for each FTR in respect of which the participant is registered as the holder of the FTR, the net amount of the FTR hedge value for the FTR minus the FTR acquisition cost for the FTR, if that net amount is positive:
(i) any amount owing in respect of the assignment of any FTR under clause 13.249(7):
(j) GST:
(k) loss and constraint excess and residual loss and constraint excess under clause 14.16(7).

(3) The clearing manager must specify the sum of the amounts referred to in subclause (2).


14.21 Methodology for determining settlement retention amount

(1) The clearing manager must formulate and publish a methodology for determining the settlement retention amount to be advised to a participant in accordance with clause 14.18(1)(c).

(2) The methodology formulated by the clearing manager under subclause (1) must comply with the principle that the settlement retention amount is set to ensure that the clearing manager has sufficient funds to pay each non-defaulting participant the amount payable to that participant under subpart 5 if both of the following occur:
(a) a settlement default that results in the largest percentage reduction in payments that would be made in the absence of the settlement retention amount in respect of amounts other than FTRs; and
(b) a settlement default that results in the largest percentage reduction in payments that would be made in the absence of the settlement retention amount in respect of FTRs (other than in respect of the residual loss and constraint excess).

(3) For the purposes of subclause (2), multiple settlement defaults by parties related in any way specified in the methodology must be treated as 1 settlement default.

(4) The consultation and approval requirements set out in Schedule 14.2 apply to the methodology.

14.22 Calculation of amount payable

(1) The amount payable by a participant to the clearing manager under clause 14.31 is determined in accordance with the following formula:

\[
APP = \text{Max} \{0, AOP - AOCM + SRA\}
\]

where

APP is the amount payable by the participant to the clearing manager
AOP is the sum of the amounts owing by the participant to the clearing manager, calculated under clause 14.19
AOCM is the sum of the amounts owing by the clearing manager to the participant, calculated under clause 14.20
SRA is the settlement retention amount, calculated in accordance with the methodology published by the clearing manager under clause 14.21

(2) Subject to subpart 8, the amount payable by the clearing manager to a participant in
accordance with clause 14.34 is determined in accordance with the following formula:

\[ \text{APCM} = \text{AOCM} - \text{AOP} + \text{APP} \]

where

\( \text{APCM} \) is the amount payable by the clearing manager to the participant

\( \text{AOCM} \) is the sum of the amounts owing by the clearing manager to the participant, calculated under clause 14.20

\( \text{AOP} \) is the sum of the amounts owing by the participant to the clearing manager, calculated under clause 14.19

\( \text{APP} \) is the amount payable under subclause (1) (if any)

Procedure for advising participants of amounts owing and payable

14.23 Procedure for advising participant of amounts owing and payable

(1) When advising a participant of amounts owing and payable under this subpart, the clearing manager must—
(a) submit the information to each relevant participant through WITS; and
(aa) publish the information; and
(b) if the participant requests, post or hand deliver the information to the participant.

(2) Proof of submitting the information to WITS is deemed to be proof of the advice under subclause (1), despite the procedures set out in this clause and in clause 14.24.


14.24 Participant to confirm receipt

(1) Each participant that receives information from the clearing manager under this subpart must immediately confirm, through WITS, receipt of the information sent by the clearing manager under clause 14.23(1)(a) or (b).

(2) If, by 1200 hours on the business day after submitting the information under clause 14.23(1), the clearing manager has not received confirmation from a participant that the participant has received the information, the clearing manager must check whether the participant has received the information.

(3) If the participant has not received the information, the clearing manager must resubmit the information through WITS.

(4) Delayed confirmation by a participant that the information has been received does not extend the payment period set out in clause 14.31.


14.25 Participant may dispute amount
(1) A participant may dispute information about an amount that is provided by the clearing manager under this subpart by notice in writing to the clearing manager.
(2) A participant may not—
(a) dispute the information under subclause (1) after the expiry of 2 years after the date that the information is provided; or
(b) commence a dispute under subclause (1) if the participant has commenced a dispute in relation to the volume information on which the information is based under clause 15.29, and the dispute remains unresolved.
(3) The clearing manager must advise all participants materially affected by the dispute and the Authority of the dispute no later than 1 business day after the clearing manager receives notice of the dispute under subclause (1).
(4) On receiving advice of a dispute that relates to volume information under subclause (3), the Authority may direct that no further action be taken in respect of the dispute.
(5) If the Authority gives a direction under subclause (4), clauses 14.26 to 14.28 cease to apply to the dispute.
(6) A direction under subclause (4) does not affect the validity of information provided under clause 14.26(2) or clause 14.37 before the direction was given.

14.26 Resolution of dispute about amount
(1) The disputing participant and the clearing manager must attempt to resolve the dispute.
(2) The clearing manager must revise the disputed amount and any other affected amount if, in time for the clearing manager to advise each participant of each amount owing and each amount payable 2 business days or more before the disputed amount is due to be paid or received by the disputing participant—
(a) the dispute is resolved by the parties advised of the dispute agreeing that information used to determine the amount is incorrect; and
(b) [Revoked]
(c) the clearing manager has received all information necessary to revise the amount and any other affected amount (including revised volume information if necessary).
(3) Subject to clause 14.28, if the participant and the clearing manager do not resolve the dispute by the time referred to in subclause (2), the disputing participant must pay or receive the amount in accordance with clauses 14.31 and 14.34.
Clause 14.26(2)(b): revoked, on 24 March 2015, by clause 7(2) of the Electricity Industry Participation Code Amendment (Late and Revised Data) 2015.
Clause 14.26(3): amended, on 24 March 2015, by clause 7(3) of the Electricity Industry Participation Code Amendment (Late and Revised Data) 2015.
14.27 Dispute about amount may be referred to Rulings Panel
(1) If the dispute is not resolved within 15 business days after the date on which the
 clearing manager received notice of the dispute under clause 14.25(1), the disputing
 participant or the clearing manager may refer the dispute to the Rulings Panel for
 resolution.
(2) The Rulings Panel may make such determination as it thinks fit.
(3) The Rulings Panel must give notice of its determination to the parties to the dispute and
 affected participants.
Clause 14.27(1): amended, on 1 November 2018, by clause 101 of the Electricity Industry Participation Code

14.28 Correction of information about amount as result of dispute
(1) If a dispute (other than a dispute resolved by the time referred to in clause 14.26(2)) is
 resolved by the parties to the dispute agreeing, or the Rulings Panel determining, that
 information used to determine the amount is incorrect, the clearing manager and the
 reconciliation manager must correct the information as follows:
(a) if the information to be corrected is volume information, the information must be
 corrected in accordance with subclause (2):
(b) if the information to be corrected is not volume information—
(i) the clearing manager must either correct the information, or advise the
 appropriate market operation service provider or the Authority so that
 the information may be corrected; and
(ii) if a market operation service provider or the Authority corrects the
 information, the market operation service provider or the Authority, as
 the case may be, must provide the corrected information to the clearing
 manager.
(2) The reconciliation manager must correct volume information as follows:
(a) if a revised seasonal adjustment shape must be issued in order for the volume
 information to be corrected—
(i) the reconciliation manager must provide each reconciliation participant
 whose submission information is required to be corrected with a revised
 seasonal adjustment shape; and
(ii) each reconciliation participant must provide corrected submission
 information to the reconciliation manager no later than 4 business days
 after being provided with the revised seasonal adjustment shape:
(b) if a revised seasonal adjustment shape is not required to be issued in order for
 the volume information to be corrected, each reconciliation participant whose
 submission information or dispatchable load information is required to be
 corrected must provide corrected submission information or dispatchable load
 information to the reconciliation manager no later than 4 business days after
 receiving notice of the resolution of the dispute:
(c) the reconciliation manager must provide the corrected volume information to
 the clearing manager.
(3) If information is corrected under subclause (1) or (2), the clearing manager must
 advise the Authority and comply with any direction given by the Authority on the
Subpart 5—Payments

14.29 Payment of amounts payable

(1) If the calculation under clause 14.22 provides for a participant to pay an amount to the clearing manager, the participant must pay that amount to the clearing manager in accordance with clauses 14.31 and 14.32.

(2) If the calculation under clause 14.22 provides for the clearing manager to pay an amount to a participant, the clearing manager must pay that amount to the participant in accordance with clause 14.34.

14.30 Prepayment of amounts payable

(1) A participant may elect to pay an amount to the clearing manager before the participant incurs the amount owing to the clearing manager.

(2) If a participant prepays an amount to the clearing manager under subclause (1),—

(a) the participant must advise the clearing manager of 1 or more billing periods to which the payment relates; and

(b) the clearing manager must deduct the amount paid by the participant from the amount advised to the participant as owing by the participant to the clearing manager under subpart 4.

(3) Any amount paid to the clearing manager under this clause must not be returned to the participant, except as provided in subclause (4).

(4) If an amount prepaid by a participant is more than the actual amount payable by the participant to the clearing manager for the relevant billing periods, the clearing manager must—

(a) apply the amount to the amount payable in the next billing period; or

(b) if the participant requests the clearing manager to pay the residual amount to the participant and satisfies the clearing manager that it will continue to comply with prudential requirements in Part 14A, pay the residual amount to the participant in accordance with clause 14.34.

(5) The clearing manager must credit to a participant that has prepaid an amount under this clause all interest received by the clearing manager on the prepaid amount, less any applicable deduction for tax purposes.
14.31 Deadlines for payments
(1) Subject to subclauses (3) and (4), each participant must pay the clearing manager the amount advised to the participant under subpart 4 as payable by the participant to the clearing manager by—
(a) 1300 hours on the 20th day of the month following the billing period in respect of which the amount was advised; or
(b) if that day is not a business day, 1300 hours on the next business day.
(2) If the clearing manager does not advise a participant of an amount payable by the time specified in clause 14.18(2)(b)(i), payment may, if the participant so elects, be delayed for a period corresponding to the period of delay in advising the participant of the amount payable.
(3) In the case of advice of an amount payable being delayed, the clearing manager must advise the participant of the new payment date.
(4) If the clearing manager revises an amount advised to the participant 2 business days or more before the amount is due to be paid, the participant must pay the amount by the date for payment under subclause (1).

14.32 Methods of payment
(1) Subject to subclause (2), each participant must pay the clearing manager in cleared funds into the operating account.
(2) A participant may instruct the clearing manager to pay all or part of an amount payable by the participant under clause 14.31 from a cash deposit held by the clearing manager in respect of the participant in accordance with clause 14A.13.
(3) The clearing manager is not required to comply with an instruction given under subclause (2) unless it is received at least 2 business days before the participant is required under clause 14.31 to pay the clearing manager the amount to which the instruction relates.
(4) However, the participant may request that the clearing manager comply with an instruction received later than provided for in subclause (3), and the clearing manager may agree to comply with such an instruction.

14.33 Allocation of payments
(1) Subject to subpart 8, the allocation by the clearing manager of a payment received from a participant under this Part must be dealt with in accordance with this clause.
(2) The clearing manager must hold each amount paid into the operating account by or on behalf of a participant in payment or part payment of an amount payable under this subpart upon trust for those persons that are entitled to receive payment from the clearing manager.
(3) A participant may not direct the clearing manager to apply any funds paid under this Part other than in accordance with this clause.
(4) The clearing manager must separately account for any amount received under clause 14.31 in respect of an amount referred to in clause 14.19(2)(h) and (i).

14.34 Payments by clearing manager
(1) Subject to subparts 7 and 8, the clearing manager must pay each participant the amount advised to the participant under subpart 4 as payable by the clearing manager to the participant by 1600 hours on the final business day for payment under clause 14.31.
(2) The clearing manager must pay each participant in cleared funds.
(3) A participant may instruct the clearing manager to treat all or part of an amount payable to the participant under this clause as a cash deposit under Part 14A.
(4) The clearing manager is not required to pay a participant under this clause if a settlement default is continuing in relation to the participant.
(5) The clearing manager is not required to comply with an instruction given under subclause (3) unless it is received at least 2 business days before the participant is required under clause 14.31 to pay the clearing manager the amount to which the instruction relates.
(6) However, the participant may request that the clearing manager comply with an instruction received later than provided for in subclause (5), and the clearing manager may agree to comply with such an instruction.


14.35 Payment of residual loss and constraint excess
Each grid owner must treat residual loss and constraint excess paid to it under this Part as loss and constraint excess.

Subpart 6—Washups

14.36 Clearing manager to conduct washups
If the clearing manager receives corrected information in accordance with clauses 8.68, 8.69, 15.20C(b), 15.26(4), or clause 28 of Schedule 15.4, it must conduct washups and advise participants of amounts owing in accordance with this subpart.

14.37 Clearing manager to advise participants of washup amounts
The clearing manager must advise relevant participants of amounts owing in respect of washup amounts in accordance with subpart 4 and clauses 14.38 to 14.40, except that the clearing manager must, if requested by a participant affected by the washup, issue corrected information covered by the washup to the participant.

14.38 Washup amounts
(1) All washup amounts and interest accrued in accordance with subclause (2) must be expressed as an amount owing by the participant to the clearing manager or an amount owing by the clearing manager to the participant in respect of the current
billing period.

(2) Daily interest (less any deduction for resident withholding tax) on the washup amount, calculated at the bank bill bid rate, accrues from the date that payment of the amount based on the incorrect information to which the washup relates was due as set out in clauses 14.31 and 14.34 (as applicable) until the date of advice of the revised washup amount in accordance with clause 14.18, and must be compounded at the end of each calendar month.

14.39 Washups for grid owners

If a washup has occurred due to incorrect consumption information being used to determine amounts owing in accordance with subpart 4 that affects grid owners, the clearing manager must credit or debit a washup amount to or from each grid owner as follows:

(a) if a grid owner’s washup amount is a credit, the clearing manager must add the credit to any amount owing to the grid owner in accordance with clause 14.16(7) in respect of the current billing period:

(b) if a grid owner’s washup amount is a debit, the clearing manager must subtract the debit from any amount owing to the grid owner in accordance with clause 14.16(7) in respect of the current billing period:

(c) if the washup amount is greater than the amount owing, the clearing manager must advise the grid owner of any amount owing for the washup amount concurrently with advising participants of any amount owing under clause 14.18, and payment of the washup amount must be made by the grid owner by the time for payment set out in clause 14.31:

(d) daily interest (less any deduction for resident withholding tax) on the washup amount, calculated at the bank bill bid rate, must be debited or credited (as the case may be) to the amount owing to the grid owner in accordance with clause 14.16(7), and accrues from the date that payment based on the incorrect information to which the washup relates was made until the date of advice in accordance with clause 14.18 resulting in the grid owner's washup amount, and must be compounded at the end of each calendar month.

14.40 Payment where no longer participant

(1) Despite clauses 14.38 and 14.39, if a washup amount affects a person that is no longer a participant, the clearing manager must advise the person of the washup amount owing and payable in accordance with clauses 14.31 and 14.32.

(2) The person remains liable for outstanding obligations in accordance with section 30(3) of the Act.

(3) Daily interest (less any deduction for resident withholding tax) on the washup amount, calculated at the bank bill bid rate, must be added to the washup amount and accrues from the date that payment of the amount based on the incorrect information to which the washup relates was due as set out in 14.31 and 14.34 (as applicable) until the date of advice of the revised washup amount in accordance with clause 14.18, and must be compounded at the end of each calendar month.
Subpart 7—Events of default

Types of default

14.41 Definition of an event of default

(1) Each of the following events constitutes an event of default:

(a) failure of a participant to provide security for the minimum amount required in accordance with clause 14A.6:

(b) a settlement default:

(c) any action taken for, or with a view to, the declaration of a participant that is required to comply with Part 14A as a corporation at risk under the Corporations (Investigation and Management) Act 1989:

(d) appointment of a statutory manager in respect of participant that is required to comply with Part 14A under the Corporations (Investigation and Management) Act 1989 (or a recommendation or submission is made by a person to the Financial Markets Authority supporting such an appointment):

(e) appointment of a person under section 19 of the Corporations (Investigation and Management) Act 1989 to investigate the affairs or run the business of a participant that is required to comply with Part 14A:

(f) if a participant that is required to comply with Part 14A is (or admits that it is or is deemed under any applicable law to be) unable to pay its debts as they fall due or is otherwise insolvent, or stops or suspends, or threatens to stop or suspend, or a moratorium is declared on, payment of its indebtedness generally, or makes or commences negotiations or takes any other steps with a view to making any assignment or composition with, or for the benefit of, its creditors, or any other arrangement for the rescheduling of its indebtedness or otherwise with a view to avoiding, or in expectation of its inability to pay, its debts:

(g) a holder of a security interest or other encumbrancer taking possession of, or a receiver, manager, receiver and manager, liquidator, provisional liquidator, trustee, statutory or official manager or inspector, administrator or similar officer being appointed in respect of the whole or any part of the assets of a participant that is required to comply with Part 14A or if the participant requests that such an appointment be made:

(h) termination of a trader’s use-of-system agreement with a distributor because of a serious financial breach if—

(i) the trader continues to have a customer or customers purchasing electricity from the trader on the distributor's local network or embedded network; and

(ii) there are no unresolved disputes between the trader and the distributor in relation to the termination; and

(iii) the distributor has not been able to remedy the situation in a reasonable time; and

(iv) the distributor gives notice to the Authority that this subclause applies.

(2) If a distributor, having given notice under subclause (1)(h)(iv), considers that an event
of default no longer exists, the distributor must advise the Authority that it considers that the event of default has been remedied.


Clause 14.41(1)(h)(i) and (iv): amended, on 1 February 2016, by clause 91(1) and (2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.


**Procedure for event of default**

14.42 Clearing manager to advise Authority of anticipated event of default

(1) If the clearing manager believes that an event of default is likely to occur, the clearing manager must advise the Authority so that the Authority can consider an appropriate course of action.

(2) If the clearing manager, having advised the Authority under subclause (1), no longer believes that an event of default is likely to occur, the clearing manager must advise the Authority that it no longer believes that the event of default is likely to occur.


14.43 Procedure upon event of default

(1) If an event of default occurs in relation to a participant, the participant must immediately advise the clearing manager and the Authority of the event of default.

(2) Despite subclause (1), a participant is not required to advise the clearing manager or the Authority if the participant would breach section 36 of the Corporations (Investigation and Management) Act 1989 by advising the clearing manager or the Authority.

(3) If subclause (2) applies, the participant must seek the consent of the Registrar of Companies or the Financial Markets Authority (as applicable) to disclose the matter to the clearing manager and the Authority.

(3A) If a participant, having advised of an event of default under subclause (1), considers that the event of default has been remedied, the participant must advise the clearing manager that it considers that the event of default has been remedied.

(3B) If the clearing manager has been advised under subclause (3A) that the participant considers that an event of default has been remedied, the clearing manager must—

(a) decide whether it agrees that the event of default has been remedied; and

(b) if it agrees, advise the Authority that it considers that the event of default has been remedied.

(4) If the clearing manager becomes aware that an event of default under paragraphs (a) to (g) of clause 14.41 has occurred and is continuing in relation to a participant, the clearing manager must—

(a) advise the Authority that the event of default has occurred; and

(b) if the participant has not advised the clearing manager of the event of default, advise the defaulting participant that the event of default has occurred.
(4A) If the clearing manager, having advised of an event of default under subclause (4), considers that the event of default has been remedied, the clearing manager must advise the Authority that it considers that the event of default has been remedied.

(5) [Revoked]
Clause 14.43(3A) and (3B): inserted, on 1 February 2016, by clause 93(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

Remedies and rights of recovery

14.44 Event of default gives clearing manager remedies

(1) If an event of default has occurred, the clearing manager has the power to exercise, as appropriate, all or any of the following remedies without prejudice to any other remedy it may have at law:
(a) apply the balance of the cash deposit of the defaulting participant in accordance with clause 14A.13(a):
(b) make a demand under a guarantee, letter of credit, or bond provided under Part 14A in respect of the defaulting participant:
(c) if the defaulting participant has not paid an amount due under this Part by the due date for payment, set-off any amount payable by the clearing manager to the defaulting participant against the unpaid amount payable by the defaulting participant to the clearing manager:
(d) take possession of any FTR held by the defaulting participant in accordance with clause 14.47.

(2) If an event of default is continuing at the expiry of the participant's post-default exit period registered under clause 14A.22,—
(a) the clearing manager must cancel a hedge settlement agreement to which the defaulting participant is a party in accordance with clause 14.48:
(b) the Authority may direct a grid owner or distributor to exercise any contractual right the grid owner or distributor has to electrically disconnect a defaulting participant that is a direct purchaser in accordance with clause 14.49.

14.45 Remedies for settlement default

If the clearing manager elects to exercise any of the remedies specified in clause 14.44 in the event of a settlement default, the clearing manager must exercise the remedies in the following order:
(a) set-off the amount payable by the clearing manager to the defaulting participant against any amount that is payable by the defaulting participant to the clearing manager in respect of the current billing period or any other billing period:
(b) apply the balance of the cash deposit of the defaulting participant:
(c) if the amounts set-off or applied under paragraphs (a) and (b) are not sufficient to
remedy the default,—

(i) make a demand under a guarantee, letter of credit, or bond provided under Part 14A in respect of the defaulting participant:

(ii) take possession of any FTR held by the defaulting participant in accordance with clause 14.47.

14.46 Remedies for other types of default
If an event of default other than a settlement default occurs in relation to a participant, the clearing manager must exercise all or any of the remedies specified in clause 14.44 to ensure that it has sufficient funds for the next settlement date.

14.47 Application to take possession of FTR
(1) The clearing manager on application to the FTR manager is entitled to be registered on the FTR register as the holder of any FTR that the clearing manager takes possession of under clause 14.44(1)(d) without any further authorisation than this subclause.

(2) If the FTR hedge values or estimated FTR hedge values of the FTRs held by the defaulting participant exceed the amount required to remedy the event of default, the clearing manager may exercise its discretion in deciding which FTRs are transferred to the clearing manager.

(3) If the amount received by the clearing manager on settlement or sale of an FTR taken possession of under clause 14.44(1)(d) exceeds the amount required to remedy the event of default, the clearing manager must repay the excess amount to the defaulting participant.

(4) If the clearing manager holds an FTR in respect of which an amount would be owing if the FTR was held by another person, no amount is owing by the clearing manager.

14.48 Cancellation of hedge settlement agreement in event of default
(1) If the defaulting participant is a party to a hedge settlement agreement and the event of default is continuing at the expiry of the participant's post-default exit period registered under clause 14A.22, the clearing manager must cancel the hedge settlement agreement on the first business day after the expiry of the participant's post-default exit period.

(2) The clearing manager must give written notice to the parties to the hedge settlement agreement if a hedge settlement agreement is cancelled under this clause.

14.49 Electrical disconnection of direct purchaser
(1) Each direct purchaser must at all times ensure that the terms of each of its contracts that provide for the electrical connection of the direct purchaser to a network permit the relevant grid owner or distributor to electrically disconnect the direct purchaser on the direction of the Authority if an event of default occurs in relation to the direct purchaser and is continuing at the expiry of its post-default exit period registered under clause 14A.22.

(2) Each grid owner or distributor must at all times ensure that the terms of each of its contracts that provide for the electrical connection of a direct purchaser to a network
permit the grid owner or distributor to electrically disconnect the direct purchaser on the direction of the Authority if an event of default occurs in relation to the direct purchaser and is continuing at the expiry of its post-default exit period registered under clause 14A.22.

(3) If an event of default occurs in relation to a direct purchaser and is continuing at the expiry of the direct purchaser's post-default exit period registered under clause 14A.22, the Authority may direct a grid owner or distributor to exercise any contractual right the grid owner or distributor has to electrically disconnect the defaulting direct purchaser.

(4) A grid owner or distributor that receives a direction under subclause (3) must comply with the direction.


14.50 Clearing manager to exercise rights to recover amounts outstanding
The clearing manager must exercise such rights, including those rights under the Act and this Code, as is reasonable to recover any amounts outstanding from a defaulting participant.

14.51 Participants assigned or subrogated to all clearing manager’s rights of recovery
(1) If a participant’s default means that the clearing manager is unable to pay participants the full outstanding amount that would otherwise be payable to them so that any amount paid to participants is reduced under subpart 8, the participants are entitled to be assigned or subrogated to the rights of the clearing manager in respect of amounts payable to the clearing manager by the relevant defaulting participant which, if paid, would have been required to be held on trust by the clearing manager for the participants in accordance with this Code.

(2) The clearing manager must do all that is reasonably necessary, including the granting of a power of attorney in favour of the participants, to assist the participants in the exercise of the rights.

(3) The participants may, in the name of the clearing manager (if requested),—
(a) take any step to enforce repayment or exercise any other rights of the clearing manager in respect of money for the time being due to the clearing manager—
   (i) from a defaulting participant; or
   (ii) from a guarantor of the defaulting participant; or
   (iii) from any person that has provided a letter of credit or bond in favour of the clearing manager in respect of the defaulting participant; or
   (iv) in respect of any other security held by the clearing manager in respect of the defaulting participant; and
(b) directly or indirectly, prove in, claim, share in, or receive the benefit of any distribution, dividend, or payment arising out of—
(i) any insolvency of a defaulting participant; or
(ii) a guarantor of the defaulting participant; or
(iii) any person that has provided a letter of credit or bond in favour of the clearing manager in respect of the defaulting participant; or
(iv) any other security held by the clearing manager in respect of the defaulting participant.

14.52 Rights of participants to exercise rights
(1) Any 1 or more participants is entitled to exercise rights under clause 14.51, if—
   (a) the clearing manager has not, within 3 business days of receiving notice of, or otherwise becoming aware of, the occurrence of an event of default, taken any action under clauses 14.44 to 14.46; or
   (b) the clearing manager has failed within 2 months of an event of default to collect all amounts due from the defaulting participant.
(2) Nothing in subclause (1) or this subpart limits the statutory right of the clearing manager to apply to the Court for the appointment of a receiver, interim liquidator, or liquidator.

Publication of information about event of default

14.53 Authority may publish information about event of default
(1) The Authority may publish information about an event of default if the Authority considers it is appropriate.
(2) If an event of default results in a reduction in payments under subpart 8, the Authority must publish information about the following:
   (a) the nature of the event of default;
   (b) the extent of the event of default;
   (c) the identity of the defaulting participant.


Subpart 8—Payments in event of settlement default

14.54 Application of this subpart
(1) This subpart applies if—
   (a) a participant commits a settlement default; and
   (b) the amount received from the defaulting participant and recovered or set-off under clause 14.44 by 1500 hours on the final day for payment under clause 14.31 is less than the amount payable by the participant to the clearing manager.
(2) In this subpart a reference to 1 or more general amounts is a reference to any amount that is not required to be applied to the settlement of FTRs or paid to the grid owner as residual loss and constraint excess.
14.55 Allocation of shortfall to settlement of general amounts and FTRs

(1) The clearing manager must allocate any shortfall as a result of a settlement default to adjust the settlement of general amounts and FTRs in accordance with this clause.

(2) The shortfall is—

(a) the amount payable by the defaulting participant to the clearing manager under subpart 5; minus

(b) any amount received from the defaulting participant and recovered or set-off under clause 14.44.

(3) In respect of each defaulting participant, the amount of the shortfall that must be allocated to adjust the settlement of general amounts is the total shortfall, less the amount of the shortfall that must be allocated to adjust the settlement of FTRs in accordance with subclause (4).

(4) In respect of each defaulting participant, the amount of the shortfall that must be allocated to adjust the settlement of FTRs is determined in accordance with the following formula:

\[
X_{\text{FTR}} = X_{\text{TOT}} \times \left( \frac{O_{\text{FTR}}}{O_{\text{TOT}}} \right)
\]

where

\(X_{\text{FTR}}\) is the amount of the shortfall that must be allocated to adjust the settlement of FTRs

\(X_{\text{TOT}}\) is the amount of the total shortfall

\(O_{\text{FTR}}\) is the total amount owing by the defaulting participant to the clearing manager in respect of FTRs as specified under clause 14.19(2)(h) and (i)

\(O_{\text{TOT}}\) is the total amount owing by the defaulting participant to the clearing manager as specified under clause 14.19(3)

(5) If the total amount owing by a defaulting participant as specified under clause 14.19(3) includes an amount owing in respect of the assignment of any FTR under clause 14.19(2)(i) that relates to a future billing period or billing periods, a portion of the amount of the shortfall that must be allocated to adjust the settlement of FTRs under subclause (4) must be allocated to each future billing period in accordance with the following formula:

\[
F_{\text{FTR}} = X_{\text{FTR}} \times \left( \frac{O_{\text{FTR}} \text{ (future)}}{O_{\text{FTR}}} \right)
\]

where

\(F_{\text{FTR}}\) is the amount of the shortfall that must be allocated to adjust the settlement of FTRs in the future billing period

\(X_{\text{FTR}}\) is the amount of the shortfall that must be allocated to adjust the settlement of FTRs, calculated under subclause (4)

\(O_{\text{FTR}} \text{ (future)}\) is the amount owing by the defaulting participant to the clearing manager in respect of the assignment of an FTR under clause 14.19(2)(i) that relates to the future billing period
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14.56 Calculation of revised amount owing for general amounts

(1) The clearing manager must apply any amount available for the settlement of general amounts in accordance with the following order of priority:

(a) to satisfy any liability to pay GST and other governmental charges or levies, that are payable by the clearing manager in respect of the amounts owing and payable under subparts 4 to 6, taking into account any GST input tax credits available to the clearing manager in respect of payments under paragraphs (b) to (e):

(ab) [Revoked]

(b) to satisfy any amounts owing to the following parties, pro rata according to the amounts owing to them for ancillary services or extended reserve (as the case may be):

(i) the system operator for ancillary services under clauses 8.6, 8.31(1)(a), and 8.55 to 8.67:

(ii) an extended reserve provider for extended reserve under clauses 8.55(2) and 8.68(4):

(c) to satisfy any amount of loss and constraint excess to be applied to the settlement of FTRs under clause 14.16(4) or (5):

(d) to satisfy any amount owing to each grid owner for any loss and constraint excess in accordance with clause 14.16(7)(a):

(e) to satisfy any other general amount owing by the clearing manager to a participant.

(2) If there is an insufficient amount available for the settlement of general amounts, the clearing manager must calculate the revised amounts owing by the clearing manager to participants in respect of general amounts as follows:

(a) first apply the full amount available to satisfy each amount owing in the order of priorities in subclause (1):

(b) if there is an insufficient amount to satisfy the full amount owing under any of paragraphs (a) to (e) of subclause (1), calculate the revised amount owing to each participant under that paragraph according to the following formula:

\[ AO_{CM}^{(revised)} = AO_{CM}^{(general)} \times \left( \frac{A_{general}}{R_{general}} \right) \]

where

\[ AO_{CM}^{(revised)} \] is the revised amount owing by the clearing manager to the participant in respect of the general amounts

\[ AO_{CM}^{(general)} \] is the amount owing by the clearing manager to the participant in respect of that billing period under the relevant paragraph in subclause (1)

\[ A_{general} \] is the total amount available for the settlement of amounts owing by
the clearing manager in the relevant billing period under the relevant paragraph in subclause (1)

\[ R_{\text{general}} \text{ is the sum of all amounts required to settle those amounts in respect of the billing period} \]


14.57 Calculation of revised amount owing for FTR amounts

(1) The clearing manager must apply any amount available for the settlement of FTRs in accordance with the following order of priority:

(a) to satisfy any amount owing to a participant in respect of FTRs:
(b) to satisfy any amount owing to each grid owner for any residual loss and constraint excess under clause 14.16(7)(b).

(2) If there is an insufficient amount available for the settlement of FTRs, the clearing manager must calculate the revised amount owing in respect of FTRs as follows:

(a) first apply the amount available for the settlement of FTRs in the relevant billing period to satisfy each amount owing to a participant in respect of an FTR:
(b) if there is an amount remaining for the settlement of FTRs in the relevant billing period after the clearing manager has satisfied each amount owing to a participant in respect of an FTR, the clearing manager must allocate that amount to each grid owner under clause 14.16(7)(b):
(c) if there is an insufficient amount to satisfy each amount owing under paragraph (a), the clearing manager must adjust each amount owing to a participant in respect of an FTR according to the following formula:

\[ \text{AO}_{\text{CM}} (\text{revised}) = \text{AO}_{\text{CM}} (\text{FTRs}) \times \left( \frac{C_{\text{FTR}}}{\text{FTR}_{\text{required}}} \right) \]

where

\[ \text{AO}_{\text{CM}} (\text{revised}) \text{ is the revised amount owing by the clearing manager to the participant in respect of FTRs} \]
\[ \text{AO}_{\text{CM}} (\text{FTRs}) \text{ is the amount advised to the participant under clause 14.20 as being owing to the participant in respect of that billing period in respect of an amount specified in clause 14.20(2)(h) or (i)} \]
\[ C_{\text{FTR}} \text{ is the total amount available for the settlement of FTRs in the relevant billing period} \]
\[ \text{FTR}_{\text{required}} \text{ is the sum of all amounts required to settle FTRs in respect of the billing period} \]
14.58 Calculation of scaled amount payable

The clearing manager must calculate the scaled amount payable for each participant to which an amount is payable by the clearing manager under subpart 5 in accordance with the following formula:

\[ AP_{CM} \text{ (scaled)} = AO_{CM} \text{ (revised)} - AO_{P} + P \]

where

- \( AP_{CM} \text{ (scaled)} \) is the scaled amount payable by the clearing manager to the participant
- \( AO_{CM} \text{ (revised)} \) is the sum of the revised amounts owing by the clearing manager to the participant, calculated under clauses 14.56 and 14.57
- \( AO_{P} \) is the sum of the amounts owing by the participant to the clearing manager, calculated under clause 14.19
- \( P \) is any amount payable by the participant under clause 14.31 and, in the case of a defaulting participant, that amount minus any amount set-off under clause 14.44(1)(c)


14.59 Calculation of revised amount payable

(1) If the application of the formula in clause 14.58 results in a scaled amount payable that is positive or 0 for every participant to which an amount is payable by the clearing manager, the scaled amount payable by the clearing manager to a participant is the revised amount payable by the clearing manager under clause 14.60.

(2) [Revoked]

(3) [Revoked]

(4) If the application of the formula in clause 14.58 results in a scaled amount payable that is negative for 1 or more participants to which an amount is payable by the clearing manager, the clearing manager must calculate the revised amount payable by the clearing manager under clause 14.60 as follows:

(a) for each participant for which the scaled amount payable is negative, set the revised amount payable for the participant to 0:

(b) for each participant for which the scaled amount payable is positive, calculate the revised amount payable to the participant in accordance with the following formula:

\[ AP_{CM} \text{ (revised)} = AP_{CM} \text{ (scaled)} + AP_{negative} \left( \frac{AO_{CM} \text{ (revised)}}{AO_{positive}} \right) \]

where

- \( AP_{CM} \text{ (revised)} \) is the revised amount payable by the clearing manager to the participant
- \( AP_{CM} \text{ (scaled)} \) is the scaled amount payable by the clearing manager to the participant, calculated under clause 14.58
AP_{\text{negative}} \text{ is the sum of all scaled amounts payable by the clearing manager to the participant for every participant for which the scaled amount payable is negative}

AO_{\text{CM (revised)}} \text{ is the sum of the revised amounts owing by the clearing manager to the participant, calculated under clauses 14.56 and 14.57}

AO_{\text{positive}} \text{ is the sum of all revised amounts owing by the clearing manager to a participant for every participant for which the scaled amount payable is positive}

(5) If the application of the formula in subclause (4)(b) results in a participant having a revised amount payable that is negative, the clearing manager must recalculate the revised amount payable for each participant under subclause (4) using the revised amount payable by the clearing manager to the participant as the scaled amount payable by the clearing manager to the participant.

Clause 14.59(2) and (3): revoked, on 24 March 2015, by clause 12(1) of the Electricity Industry Participation Code Amendment (Late and Revised Data) 2015.
Clause 14.59(4)(b): amended, on 24 March 2015, by clause 17(2) and (3) of the Electricity Industry Participation Code Amendment (Settlement and Prudential Security) 2014.

14.60 Payment of revised amount payable
The clearing manager must pay each participant the revised amount payable in accordance with clause 14.34 as if references to the amount payable were references to the revised amount payable.

14.61 Payment by participant with negative scaled amount payable
(1) If the application of the formula in clause 14.58 results in a scaled amount payable for a participant that is negative, the participant must pay an amount that is equal to the absolute value of the scaled amount payable with this clause.

(2) The clearing manager must advise the participant of the amount payable.

(3) The participant must pay the amount payable to the clearing manager by 1300 hours on the next business day after the day on which the clearing manager advises the participant of the amount.

(4) Clause 14.32 applies to a payment under this clause.

(5) If the clearing manager receives further funds from the defaulting participant, the clearing manager may revise or cancel the amount payable under this clause to reflect the need for the amount payable.

14.62 Application of payment by participant with negative scaled amount payable
(1) The clearing manager must allocate the funds received under clause 14.61 to each participant for which the scaled amount payable is positive.

(2) The amount allocated to each participant under this clause is the difference between the scaled amount payable and revised amount payable for the participant.
(3) The clearing manager must pay each participant the amount allocated under this clause by 1600 hours on the day that funds are received under clause 14.61.

(4) If there are insufficient funds to pay each participant the amount allocated under this clause, the clearing manager must adjust the amount payable for each participant based on the proportion that the amount payable by the clearing manager to the participant bears to the total amount payable to all participants under this clause.

14.63 Further funds paid according to priority

(1) As further funds are received or recovered from a defaulting participant by the clearing manager, those funds must be allocated to the settlement of general amounts and FTRs and paid in accordance with this subpart as if—
   (a) the further funds had been paid by the defaulting participant on the final day for payment under clause 14.31; but
   (b) with the amount already paid by the clearing manager to a participant under this subpart deducted from the amount calculated as payable by the clearing manager to the participant.

(2) If funds received or recovered by the clearing manager are identifiable as relating to a specific billing period, the clearing manager must apply those funds in satisfaction or part satisfaction of amounts payable by the clearing manager in respect of that billing period.

(3) If it is not clear to which billing period the funds relate, the funds must be applied in satisfaction or part satisfaction of amounts payable by the clearing manager in respect of the earliest billing period in respect of which amounts are outstanding to the extent that full payment has not been received by the relevant participants in respect of that billing period.

14.64 Interest payable to participants

(1) If a participant does not receive the full amount payable under this Part, the clearing manager is liable to pay interest on the unpaid amount.

(2) The interest must be calculated daily from the date payment would otherwise have been due, at the default interest rate, until the date that payment is actually made by the clearing manager to the participant and compounded at the end of each calendar month.

(3) If a participant has not paid any amount payable under this Part after the due date for payment, the participant must pay interest on the unpaid amount.

(4) The interest must be calculated daily from the date on which the payment was due, at the default interest rate, until the date that full payment is received in cleared funds and compounded at the end of each calendar month.

14.65 Participant to remain in default

Despite anything else in this Code, the application of money under this Part that does not satisfy the full amount payable by a participant does not—
   (a) satisfy the obligation of the participant to pay the full amount payable together with the interest due on that amount to the clearing manager or to a participant acting in accordance with clause 14.51; or
(b) prejudice any remedy available to the clearing manager in an event of default or to a participant under clause 14.51.

Subpart 9—Administrative obligations of clearing manager

Clearing manager operating account

14.66 Clearing manager to establish operating account
(1) The clearing manager must establish, in its name, an operating account with a bank.
(2) The operating account must—
   (a) be held by the clearing manager as a trust account for the benefit of the persons who are entitled to receive payment from the clearing manager under this Part; and
   (b) be clearly identified as such; and
   (c) subject to this Code, be entirely separate from the cash deposit accounts and any other account of the clearing manager.
(3) The clearing manager must obtain an acknowledgement from the bank with which the operating account is held that—
   (a) the funds in that account are held on trust for the purposes set out in clause 14.33; and
   (b) the bank has no right of set-off or combination in relation to the funds.

14.67 Payment by clearing manager
(1) Each payment required to be made by the clearing manager to the person entitled to the payment must be made by direct payment to the bank account that the person entitled to the payment may advise the clearing manager in writing from time to time.
(2) Any payment by the clearing manager under this Part must be made from the operating account.
(3) Except as expressly permitted by this Code or as required by law, all payments by the clearing manager under this Part must be free and clear of any withholding or deduction and without any set-off or counter claim.

Reporting obligations of the clearing manager

14.68 Monthly divergence reports to be prepared by clearing manager
(1) The clearing manager must report to the Authority in writing under this clause.
(2) The clearing manager must give the report to the Authority—
   (a) on the 10th business day of each calendar month; or
   (b) if exceptional circumstances prevent the clearing manager from providing the report by that day, as soon as reasonably practicable after that day.
(3) The report must include—
   (a) [Revoked]
   (b) [Revoked]
   (c) [Revoked]
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(d) [Revoked]
(e) situations in which information about an amount owing was or will be issued late and whether or not the delay was caused by the clearing manager; and
(f) if there is a delay in the clearing manager advising a participant of an amount owing under clause 14.18, the part of the process that was delayed.

Clause 14.68(3)(a), (b), (c) and (d): revoked, on 1 November 2018, by clause 104(a) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

14.69 [Revoked]

14.70 [Revoked]

14.71 Clearing manager to make block dispatch settlement differences available
(1) By 0900 hours on the 2nd business day after the clearing manager has advised participants of amounts owing under clause 14.18, the clearing manager must make the following information available for participants on WITS:
(a) the maximum block dispatch settlement difference for each block dispatch group for the previous billing period as determined by the following formula:

\[
\text{Settlement Difference} = \max \left\{ \sum_{\text{gip}} \left\{ P_{\text{gip}} \left\{ \frac{\text{Gen}_{\text{gip}} - \text{Set}_{\text{gip}}}{\sum_{\text{gip}} \text{Set}_{\text{gip}}} \right\} \right\} \right\}
\]

(b) the total block dispatch settlement differences for each block dispatch group for the previous billing period as determined by the following formula:

\[
\text{Settlement Difference} = \sum_{i=1}^{i} \left\{ \sum_{\text{gip}} \left\{ P_{\text{gip},i} \left\{ \frac{\text{Gen}_{\text{gip},i} - \text{Set}_{\text{gip},i}}{\sum_{\text{gip},i} \text{Set}_{\text{gip},i}} \right\} \right\} \right\}
\]

where
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\( P_{gip} \) is the final price at the relevant grid injection point for the generating plant or generating unit that forms part of the block dispatch group for the relevant trading period of the billing period.

\( \text{Gen}_{gip} \) is the final quantity of electricity sold by that generator to the clearing manager at the relevant grid injection point for the generating plant or generating unit that forms part of the block dispatch group, obtained from the reconciliation information for the relevant trading period of the billing period.

\( \text{Set}_{gip} \) is the generation quantity at the relevant grid injection point for the generating plant or generating unit that forms part of the block dispatch group for the relevant trading period of the billing period.

\( P_{gip,i} \) is the final price at the relevant grid injection point for the generating plant or generating unit that forms part of the block dispatch group for the relevant trading period of the billing period.

\( \text{Gen}_{gip,i} \) is the final quantity of electricity sold by that generator to the clearing manager at the relevant grid injection point for the generating plant and generating units that form part of the block dispatch group, obtained from the reconciliation information for the relevant trading period of the billing period.

\( \text{Set}_{gip,i} \) is the generation quantity at the relevant grid injection point for the generating plant and generating units that form part of the block dispatch group for the relevant trading period of the billing period.

(2) For the purposes of this clause “generation quantity” means the time-weighted average quantity of electricity for that generating plant or generating unit for the relevant trading period, taking into account—

(a) the quantity in MW provided to the clearing manager by the system operator in accordance with clauses 13.76 to 13.80; and

(b) the ramp rate applying to the relevant trading period that is specified in the offer submitted by that generator.


14.72 Clearing manager to make block dispatch settlement differences available later if WITS unavailable

(1) If WITS is unavailable to make the information set out in clause 14.71 available, the clearing manager is not obliged to follow any backup procedures in respect of making the information available.

(2) The clearing manager must make the information available on WITS as soon as reasonably possible after WITS becomes available.


14.73 Clause 14.71 applies to block dispatch groups only

The calculation of the block dispatch settlement differences under clause 14.71 must be completed on a block dispatch group basis, even if a block dispatch group has been divided into sub-block dispatch groups during one or more trading periods of the relevant billing period.

14.74 No washup calculation under clause 14.71 if revised reconciliation information is received

Following the calculation and publication of the information relating to block dispatch settlement differences in a billing period under clause 14.71, the clearing manager is not required to recalculate any block dispatch settlement differences as a result of subsequently receiving revised reconciliation information.

Notices

14.75 Notices

(1) Except as expressly provided in this Code, a notice or demand given or required to be given under this Part may be given by being delivered or transmitted to the intended recipient at its address or electronic address as last advised in writing to the sender and may be posted to such address by prepaid post.

(2) Subject to subclause (3),—
   (a) a notice or demand delivered by hand is deemed to be delivered on the date of such delivery; and
   (b) a notice or demand delivered by post is deemed to be delivered on the 2nd business day following the date of posting; and
   (c) a notice or demand transmitted through the WITS is deemed to be delivered on the date it was transmitted.

(3) Any notice or demand delivered, or deemed to be delivered, on a day that is not a business day, or after 1600 hours on a business day, is deemed to have been delivered on the next business day.

Formula for scaling amount owing in respect of FTRs

1 Purpose of this Schedule
The purpose of this Schedule is to set out the formula for scaling the amount owing in respect of FTRs if clause 14.17(6) applies.

2 Formula
(1) The formula for scaling the FTR hedge value under clause 14.17(6) is as follows:

\[ H_{\text{Scaled}} = H \times \left( \frac{C}{D} \right) \]

where

\( H_{\text{Scaled}} \) is the scaled FTR hedge value
\( H \) is the original FTR hedge value that would be owing if this subclause did not apply
\( C \) is the amount calculated in accordance with the formula in subclause (2)
\( D \) is the amount calculated in accordance with the formula in subclause (3)

(2) The value for \( C \) in the formula in subclause (1) is as follows:

\[ C = LCE_{\text{FTR}} + ACP + AP - ACCM - ACM \]

where

\( LCE_{\text{FTR}} \) is the amount of the loss and constraint excess to be applied to the settlement of FTRs under clause 14.16(4) or (5)
\( ACP \) is the sum of any FTR acquisition costs owing to the clearing manager
\( AP \) is the sum of any amounts owing to the clearing manager under clause 13.249(4)
\( ACCM \) is the sum of any FTR acquisition costs owing by the clearing manager
\( ACM \) is the sum of any amounts owing by the clearing manager under clause 13.249(7)

(3) The value for \( D \) in the formula in subclause (1) is as follows:

\[ D = H_{\text{CM}} - H_{P} \]

where

\( H_{\text{CM}} \) is the sum of any FTR hedge values owing by the clearing manager
\( H_{P} \) is the sum of any FTR hedge values owing to the clearing manager
Schedule 14.2
Consultation and approval requirements for methodologies

1 Purpose of this Schedule
This Schedule sets out the consultation and approval requirements that apply to the following methodologies formulated and published by the clearing manager:
(a) the methodology for determining the settlement retention amount under clause 14.21;
(b) the methodology for determining the forward estimate of the minimum amount for which security will be required to be provided by a participant under clause 14A.5;
(c) the methodology for determining the general prudential requirement under clause 8 of Schedule 14A.1;
(d) the methodology for determining the minimum security required in respect of FTRs under clause 12 of Schedule 14A.1.

2 Approval of methodology
(1) The clearing manager must submit to the Authority for approval a draft methodology.
(2) In preparing the draft methodology, the clearing manager must—
(a) consult with persons that the clearing manager thinks are representative of the interests of persons likely to be substantially affected by the methodology; and
(b) consider submissions made on the methodology.
(3) The clearing manager must provide a copy of each submission received under subclause (2) to the Authority.
(4) The Authority must, as soon as practicable after receiving the draft methodology, by notice in writing to the clearing manager—
(a) approve the methodology; or
(b) decline to approve the methodology.
(5) If the Authority declines to approve the draft methodology, the Authority must publish the changes that the Authority wishes the clearing manager to make to the draft methodology.

3 Consultation on proposed changes to methodology
(1) When the Authority publishes the changes that the Authority wishes the clearing manager to make to the draft methodology under clause 2(5), the Authority must publish the date by which submissions on the changes must be received by the Authority.
(2) Each submission on the changes to the draft methodology must be made in writing to the Authority and be received on or before the date specified by the Authority under subclause (1).
(3) The Authority must—
(a) provide a copy of each submission received to the clearing manager; and
(b) publish the submissions.
(4) The clearing manager may make its own submission on the changes to the draft methodology and the submissions received in relation to the changes.

(5) The Authority must publish the clearing manager’s submission when it is received.

(6) The Authority must consider the submissions made to it on the changes to the draft methodology.

(7) Following the consultation required by subclauses (1) to (6), the Authority may approve the methodology subject to the changes that the Authority considers appropriate being made by the clearing manager.


4 Variations to methodology

(1) A participant or the Authority may submit a proposal for a variation to the methodology.

(2) The clearing manager must provide a copy of each proposed variation received from a participant under subclause (1) to the Authority.

(3) The clearing manager must consider a proposed variation to the methodology submitted under subclause (1).

(4) The clearing manager may submit a request for a variation to the methodology to the Authority.

(5) The consultation and approval requirements under clauses 2 and 3 apply to a request for a variation submitted under subclause (4) as if references to the draft methodology were a reference to the requested variation.

(6) If the clearing manager does not submit a request for a variation submitted under subclause (1) to the Authority under subclause (4), the Authority may consider the proposal and require the clearing manager to submit a request for a variation based on the proposal to the Authority, and subclause (5) applies accordingly.

(7) The Authority may approve a variation requested under subclause (4) or subclause (6) without complying with the provisions referred to in subclause (5) if—

(a) the Authority considers that it is necessary or desirable in the public interest that the requested variation be made urgently; and

(b) the Authority publishes a notice of the variation and a statement of the reasons why the urgent variation is needed.

(8) Every variation made under subclause (7) expires on the date that is 9 months after the date on which the variation is made.
Schedule 14.3
Calculation of amount of loss and constraint excess to be applied to the settlement of FTRs

1 Purpose
The purpose of this Schedule is to set out the formulae and process for the calculation under clause 14.16(2) of the amount of the loss and constraint excess to be applied to the settlement of FTRs.

2 Interpretation
(1) In this Schedule, unless the context otherwise requires,—
AC line means any AC branch
balanced, in relation to an FTR injection pattern, means that the total positive and negative hub injections sum to 0. A balanced FTR injection pattern is consistent with a grid in which losses are not modelled
binding, in relation to a constraint, means that the constraint has a non-zero shadow price
branch constraint means a constraint in which all the LHS variables are branch flows
canonical form means a linear programming problem that is expressed in the following form:
maximise $c^T x$
subject to $Ax \leq b$
where
$x$ is the vector of variables to be determined
c and $b$ are vectors of constants
$A$ is a matrix of coefficients
$c^T x$ is the objective function to be maximised
$Ax \leq b$ is the set of constraints, each row of $Ax$ being the LHS of a constraint and each element of $b$ being the corresponding RHS
Minimum constraints are assumed to have been multiplied through by $-1$ to form an equivalent maximum constraint
Equality constraints are assumed to have initially been represented by a pair of minimum and maximum constraints with the same LHS and RHS, and then the resulting minimum constraint is assumed to have been multiplied through by $-1$ to form an equivalent maximum constraint
closed, in relation to a branch, means that the branch is electrically connected at both ends.

feasible region, in relation to an n-dimensional linear programming problem, means the n-dimensional solution space filled by the set of all possible feasible solutions.

final pricing schedule means the schedule that the pricing manager uses to produce the interim prices on which final prices are based.

FTR injection pattern means the combination of positive or negative net hub injections implied by a combination of FTRs.

hub injection means the actual or notional flow of electricity into the grid, if positive, or out of the grid, if negative, at any hub.

HVDC link has the same meaning as in the model formulation.

LHS means the left hand side of a constraint expressed in canonical form.

mixed constraint has the same meaning as in the model formulation.

open, in relation to a branch, means that the branch is electrically disconnected at 1 or both ends.

operational system split means an instance where a grid owner chooses to operate with a switch or branch open for reasons such as—
(a) breaking loops that would otherwise constrain flows; or
(b) reducing the size of the maximum fault duty that switchgear needs to withstand.

RHS means the right hand side of a constraint when expressed in canonical form.

scheduled, in relation to a variable, means the value of the variable in the final pricing schedule.

shadow price, in relation to an AC line capacity, branch constraint or mixed constraint, means the absolute value of the shadow price in $/MWh for the AC line or constraint reported in the final pricing schedule.

simultaneously feasible, in relation to an FTR injection pattern, means that the implied flows can be carried by the transmission system, subject to the constraints as defined by clause 5(2).

(2) For the purposes of this Schedule, constraints that are not expressed in canonical form in the model formulation must be translated into the equivalent canonical form.


3 Amount of loss and constraint excess to be applied to settlement of FTRs.
The amount of the loss and constraint excess that must be applied to the settlement of FTRs under clause 14.16(4) is the amount calculated under clause 9(6)(b).
4 Grid owner must determine normal grid configuration

(1) Each grid owner must determine a normal grid configuration for the grid owner’s grid.

(2) The normal grid configuration determined under subclause (1) must be a grid configuration with all existing branches and switches closed except where the grid owner has implemented operational system splits and the grid owner considers that the normal state of those operational system splits is for the relevant branch or switch to be open.

(3) Each grid owner must provide to the FTR manager the information describing the normal grid configuration for the grid owner’s grid determined under subclause (1).

(4) Each grid owner must determine a new normal grid configuration for the grid owner’s grid if the grid owner considers it necessary because, for example, any of the following occur:
   (a) some grid equipment is commissioned or decommissioned;
   (b) there is a change in the capacity or impedance of some grid equipment;
   (c) the grid owner considers that the normal state of any operational system split has changed.

(5) Each grid owner must provide new information to the FTR manager if the grid owner determines a new normal grid configuration for the grid owner’s grid under subclause (4), unless otherwise agreed with the FTR manager.


5 FTR manager must determine FTR injection patterns

(1) The FTR manager must determine a set of balanced extreme FTR injection patterns.

(2) Each balanced extreme FTR injection pattern determined under subclause (1) must be simultaneously feasible assuming—
   (a) the normal grid configuration determined under clause 4; and
   (b) the absence of all other grid flows; and
   (c) all AC line and HVDC link capacity limits applied; and
   (d) all risk and reserve constraints disabled; and
   (e) all branch variable losses set to 0; and
   (f) all branch fixed losses set to 0.

(3) The set of balanced extreme FTR injection patterns determined under subclause (1) must, in the reasonable opinion of the FTR manager, be the set of FTR injection patterns that best represents the extreme limits of the feasible region of FTR injection patterns as defined by the assumptions listed under subclause (2).

(4) The FTR manager must determine a new set of balanced extreme FTR injection patterns if—
   (a) a grid owner provides the FTR manager with new information under clause 4(5) that results in a change to the feasible region of FTR injection patterns; or
   (b) there is a change to the hubs or set of hubs specified in the FTR allocation plan.

6 FTR manager must determine matrix of lossless shift factors

(1) For each trading period of the relevant billing period, following the publication of final prices, the FTR manager must determine a matrix of lossless shift factors referenced to a set of reference nodes, from the input information or revised data used to produce the final pricing schedule, in accordance with the following:

(a) one reference node must be chosen within each electrical island:
(b) nodes are in the same electrical island if a transmission path exists between them.

(2) The matrix of lossless shift factors determined under subclause (1) must be calculated in accordance with the following matrix formula:

\[
[\text{ShiftFactor}] = [\text{AdmittancePrimitive}] \times [\text{Inc}] \times [\text{Impedance}]
\]

where

- \([\text{ShiftFactor}]\) is the \(m \times n\) matrix of lossless shift factors, which defines the increment in flow in the conventional forward flow direction on any branch in the transmission network resulting from an increment in net injection at any node together with an equal decrement in net injection at the reference node in the electrical island in which the node resides, while neglecting the effect of losses

- \([\text{AdmittancePrimitive}]\) is the \(m \times m\) diagonal matrix formed from the set of \(m\) branch susceptances

- \([\text{Inc}]\) is the \(m \times n\) lossless branch-node incidence matrix, which denotes the conventional from and to nodes for a branch by matrix entries of 1 and \(-1\) respectively

- \([\text{Impedance}]\) is the \(n \times n\) matrix formed from the inverse of \([\text{AdmittanceNodal}]\) with the columns and rows
associated with the reference nodes reinserted and filled with zeroes

\[ \text{[AdmittanceNodal]} \]

is the \( n-r \) by \( n-r \) matrix obtained from \[ \text{[AdmittanceNodalComplete]} \] by deleting the column and row associated with each of the reference nodes

\[ \text{[AdmittanceNodalComplete]} \]

is the \( n \) by \( n \) matrix = \[ \text{[Inc}^T\] \] \times \[ \text{[AdmittancePrimitive]} \] \times \[ \text{[Inc]} \]

\[ \text{[Inc}^T\] \]

is the \( n \) by \( m \) matrix transpose of \[ \text{[Inc]} \]

(3) For the purposes of subclauses (1) and (2) —

(a) the set of inter-island HVDC links must be replaced by a single AC line with a nominal susceptance value between the Benmore and Haywards HVDC terminal nodes, whether or not any HVDC link is actually in service during the relevant trading period; and

(b) the nominal susceptance value determined under paragraph (a) may be any suitable value that will avoid numerical difficulties; and

(c) any switches between the Benmore HVDC terminal node and other Benmore nodes operating at the same nominal voltage that are normally closed must be treated as closed; and

(d) any switches between the Haywards HVDC terminal node and other Haywards nodes operating at the same nominal voltage that are normally closed must be treated as closed; and

(e) in any trading period in which any of the hubs reside in different electrical islands (as defined in subclause (1)(b)), the shift factor matrix for the previous trading period in which all the hubs resided in the same electrical island must be used.

7 FTR manager must determine branch participation loading and constraint participation loading

(1) For each trading period of the relevant billing period, the FTR manager must determine a branch participation loading for each AC line \( k \).

(2) Each branch participation loading determined under subclause (1) must be calculated—

(a) in accordance with the following formula if the scheduled flow on the AC line is in the conventional forward flow direction:

\[
\max \left( \sum_{hub} SF_{k,h} \times \text{Inj}_{k,p} : p \in 1,...P \right) ; \text{ and}
\]
(b) in accordance with the following formula if the scheduled flow on the AC line is in the conventional reverse flow direction:

\[- \min \left( \sum_{h \in \text{Hubs}} SF_{k,h} \times \text{Inj}_{h,p} : p \in 1, \ldots, P \right)\]

where

\(SF_{k,h}\) is the shift factor relating flows on AC line \(k\) to injections at hub \(h\), determined under clause 6(1)

\(\text{Inj}_{h,p}\) is the positive or negative hub injection at hub \(h\) in FTR injection pattern \(p\) in the set of \(P\) balanced extreme FTR injection patterns determined under clause 5(1)

(3) For each trading period of the relevant billing period, for each binding branch constraint \(v\) involving AC line flows, the FTR manager must determine a constraint participation loading in accordance with the following formula:

\[
\max \left( \sum_{k \in \text{ACLineGroup}_v} \sum_{h \in \text{Hubs}} \text{weight}_{k,v} \times SF_{k,h} \times \text{Inj}_{h,p} : p \in 1, \ldots, P \right)
\]

where

\(SF_{k,h}\) and \(\text{Inj}_{h,p}\) are as defined in subclause (2)

\(\text{ACLineGroup}_v\) is the set of AC lines involved in branch constraint \(v\) (any HVDC link flow terms in the constraint must be excluded from this calculation)

\(\text{weight}_{k,v}\) is the weight associated with AC Line \(k\) in branch constraint \(v\) expressed in canonical form

(4) For each trading period of the relevant billing period, for each binding mixed constraint \(v\) (if any) involving AC line flow terms or AC line variable loss terms, the FTR manager must determine a constraint participation loading in accordance with the following formula:

\[
\max \left( \sum_{k \in \text{ACLineGroup}_v} \left( \text{flowweight}_{k,v} \times \text{flow}_{k,p} + \text{lossweight}_{k,v} \times \text{loss}_{k,p} \right) : p \in 1, \ldots, P \right)
\]

where

\(\text{ACLineGroup}_v\) is the set of AC lines whose flows or variable losses are involved in mixed constraint \(v\) (all other terms in the mixed constraint must be excluded
from this calculation)

\[ \text{flowweight}_{k,v} \]

is the weight associated with the flow on AC Line \( k \) in mixed constraint \( v \) expressed in canonical form

\[ \text{lossweight}_{k,v} \]

is the weight associated with the variable losses on AC Line \( k \) in mixed constraint \( v \) expressed in canonical form

\[ \text{flow}_{k,p} \]

is the flow on AC Line \( k \) due to FTR injection pattern \( p \), which equals \( \sum_{h \in \text{Hubs}} \text{SF}_{k,h} \times \text{Inj}_{h,p} \)

\[ \text{loss}_{k,p} \]

is the variable losses on AC Line \( k \) due to \( \text{flow}_{k,p} \)

\( \text{SF}_{k,h} \) and \( \text{Inj}_{h,p} \) are as defined in subclause (2)

(5) For the purposes of this clause, if hub \( h \) is a group of nodes, the positive or negative hub injection at hub \( h \) must be split into its individual nodal components in a manner consistent with the hub definition in the FTR allocation plan, and each nodal component must be treated as a separate hub injection.

8 FTR manager must assign portions of capacities

(1) For each trading period of the relevant billing period, the FTR manager must assign a portion of the capacity of each AC line, AC line loss curve block, binding branch constraint RHS and binding mixed constraint RHS (if any) for the purpose of determining amounts to be applied to the settlement of FTRs under clause 9(3) to (5).

(2) The portion of the capacity of each AC line to be assigned under subclause (1) must be the minimum of—

(a) the line capacity applicable in the trading period in the final pricing schedule; and

(b) the relevant branch participation loading determined under clause 7(1).

(3) The portion of the capacity of each AC line loss curve block to be assigned under subclause (1) must be the portion of the loss curve block that would be utilised by a flow at the level of the capacity of the associated AC line assigned, as determined under subclause (2), assuming that loss curve blocks are utilised in order from lowest to highest loss factor, in the direction of flow.

(4) Subject to subclause (5), the portion of the capacity of each binding branch constraint RHS or binding mixed constraint RHS (if any) to be assigned under subclause (1) must be the minimum of—

(a) the constraint RHS applicable in the trading period in the final pricing schedule, minus the contribution of any LHS terms not involving AC line flows
or AC line variable losses, calculated assuming the values of the relevant variables applicable in the trading period in the final pricing schedule; and

(b) the relevant constraint participation loading determined under clause 7(3) or clause 7(4).

(5) If the capacity determined under subclause (4) for any constraint is negative, the capacity to be assigned for that constraint must be 0.

9 FTR manager must calculate amounts to be applied to settlement of FTRs

(1) The amounts calculated under this clause must be calculated using the flow quantities, nodal prices and shadow prices from the final pricing schedule.

(2) The HVDC loss and constraint excess to be applied to the settlement of FTRs for each trading period of the relevant billing period must be calculated in accordance with the following formula:

\[
\text{max} \left\{ 0, \sum_{n \in n(NI)} \text{price}_n \times \left( \sum_{l \in n(SI)} (\text{HVDCLinkFlow}_l - \text{HVDCLinkLosses}_l) - \sum_{l \in n(SI)} \text{HVDCLinkFlow}_l \right) \right\} + \sum_{n \in n(\text{NI})} \text{price}_n \times \left( \sum_{l \in n(SI)} (\text{HVDCLinkFlow}_l - \text{HVDCLinkLosses}_l) - \sum_{l \in n(SI)} \text{HVDCLinkFlow}_l \right) \leq 2
\]

where

\(\text{price}_n\) is the energy price at AC node \(n\)

\(n(NI)\) is the set of North Island AC nodes to which any HVDC links are connected

\(n(SI)\) is the set of South Island AC nodes to which any HVDC links are connected

\(\text{HVDCLinkFlow}_l\) is the MW flow at the sending end scheduled for HVDC link \(l\)

\(\text{HVDCLinkLosses}_l\) is the variable MW losses for HVDC link \(l\)

\(S_{HVDC}(n)\) is the set of HVDC links for which \(n\) is the sending AC node
R_{HVDC(n)} is the set of HVDC links for which \( n \) is the receiving AC node.

(3) The amount of the loss and constraint excess generated by each AC line that is to be applied to the settlement of FTRs must be calculated in accordance with the following formula:

\[
\text{AssignedCapacity}_k \times \text{ShadowPrice}_k \div 2
\]

where

\( \text{AssignedCapacity}_k \) is the portion of the capacity of AC line \( k \) assigned under clause 8(1)

\( \text{ShadowPrice}_k \) is the shadow price of the line capacity on AC line \( k \)

(4) The amount of the loss and constraint excess generated by each binding branch constraint and binding mixed constraint (if any) involving AC line flow terms or AC line variable loss terms to be applied to the settlement of FTRs must be calculated in accordance with the following formula:

\[
\text{AssignedCapacity}_v \times \text{ShadowPrice}_v \div 2
\]

where

\( \text{AssignedCapacity}_v \) is the portion of the capacity of the RHS of branch constraint or mixed constraint \( v \) assigned under clause 8(1)

\( \text{ShadowPrice}_v \) is the shadow price of branch constraint or mixed constraint \( v \)

(5) The amount of the loss and constraint excess generated by each AC line loss curve block that is to be applied to the settlement of FTRs must be calculated in accordance with the following formula:

\[
\min\left( A\text{LineFlowBlock}_{k,j}, \text{AssignedCapacity}_{k,j} \right) \times \text{ReceivingEndPrice}_k \\
\times \left( A\text{LineLossFactor}_{k,marg} - A\text{LineLossFactor}_{k,j} \right) \div 2
\]
where

\[
ACL_{\text{LineLossFactor}}_{k,m_{\text{arg}}} = \min\left(ACL_{\text{LineLossFactor}}_{k,j}\right) \quad \text{for which}
\]

\[
ACL_{\text{LineFlowBlock}}_{k,j} < ACL_{\text{LineLossMW}}_{k,j}
\]

\(ACL_{\text{LineFlowBlock}}_{k,j}\) is the MW flow on the \(j^{th}\) block of the loss curve of AC line \(k\) in the direction of scheduled positive flow, assuming that loss curve blocks are utilised in order from lowest to highest loss factor, in each direction.

\(Assigned\text{Capacity}_{k,j}\) is the portion of the capacity of the \(j^{th}\) block of the loss curve of AC line \(k\) assigned under clause 8(1).

\(Receiving\text{EndPrice}_{k}\) is the nodal energy price at the receiving end of the scheduled flow on AC line \(k\).

\(ACL_{\text{LineLossFactor}}_{k,j}\) is the loss factor of the \(j^{th}\) block of the loss curve of AC line \(k\).

\(ACL_{\text{LineLossMW}}_{k,j}\) is the MW capacity of the \(j^{th}\) block of the loss curve of AC line \(k\).

(6) The FTR manager must calculate the amount of the loss and constraint excess that must be applied to the settlement of FTRs for each billing period by—

(a) determining the sum of the amounts calculated in accordance with subclauses (2) to (5) for each trading period of the billing period; and

(b) determining the sum of the amounts calculated in accordance with paragraph (a) for all trading periods of the billing period.
Schedule 14.4
Forms of hedge settlement agreement

Form 1

Date: [Enter date]

<table>
<thead>
<tr>
<th>Party A</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Party B</td>
<td></td>
</tr>
</tbody>
</table>

1 Lodging of hedge settlement agreement
(1) Party A and Party B (the parties) submit this hedge settlement agreement to the clearing manager, as contemplated by clause 14.8 of the Electricity Industry Participation Code 2010 (the Code). Terms that are used in this agreement but not defined bear the meaning given to them in the Code.

(2) By submitting this hedge settlement agreement to the clearing manager in accordance with clause 14.8 of the Code, the parties agree to be bound by the terms set out below from the time at which the clearing manager counter-signs it.

(3) If the clearing manager counter-signs this document then, from the time it counter-signs, it has obligations relating to it under the Code. However, the parties acknowledge the clearing manager is not bound by this document and that its obligations in relation to it are limited to those set out in the Code.

2 Definitions
The following definitions apply in this document:

aggregate fixed amount means, in relation to a billing period, the sum of the fixed amounts for each calculation period in that billing period

aggregate floating amount means, in relation to a billing period, the sum of the floating amounts for each calculation period in that billing period

calculation period means a trading period during the term

commencement date means the date specified as such in the schedule

expiry date means the date specified as such in the schedule

fixed amount means, in relation to a calculation period, an amount calculated using the following formula:

fixed amount = notional quantity x fixed price

fixed price means, in relation to a calculation period, the amount specified as such for that calculation period in the schedule

fixed price payer means, in relation to a hedge settlement agreement, the party specified as such in the schedule
**floating amount** means, in relation to a **calculation period**, an amount calculated using the following formula:

\[
\text{floating amount} = \text{notional quantity} \times \text{floating price}
\]

**floating price** means, in relation to a **calculation period**, the **final price** per MWh for that **calculation period** by reference to the **hedge reference point** [rounded to two decimal places]

**floating price payer** means, in relation to a **hedge settlement agreement**, the party specified as such in the schedule

**hedge reference point** means the **grid exit point** specified as such in the schedule

**hedge settlement amount** means, in relation to a **billing period**, the absolute value of the amount calculated by subtracting the **aggregate floating amount** from the **aggregate fixed amount**

**notional quantity** means, in relation to a **calculation period**, the number of MWhs specified as such in the schedule for that **calculation period**

**settlement date** means the date on which payments are due under clause 14.31 of the Code

**term** means the period from 00.00 hours on the **commencement date** until 23.59 hours on the date on which the **hedge settlement agreement** terminates.

3 Payment of hedge settlement amounts

In relation to a **billing period**:

(a) if the **aggregate floating amount** exceeds the **aggregate fixed amount**:

(i) the **floating price payer** must pay the **clearing manager** an amount equal to the **hedge settlement amount** in relation to that **billing period**; and

(ii) the **clearing manager** must pay the **fixed price payer** an amount equal to the **hedge settlement amount** in relation to that **billing period**, on the relevant **settlement date**; and

(b) if the **aggregate fixed amount** exceeds the **aggregate floating amount**:

(i) the **fixed price payer** must pay the **clearing manager** an amount equal to the **hedge settlement amount** in relation to that **billing period**; and

(ii) the **clearing manager** must pay the **floating price payer** an amount equal to the **hedge settlement amount** in relation to that **billing period**, on the relevant **settlement date**.

4 Termination

This **hedge settlement agreement** terminates on the earlier of:

(a) the **expiry date**; and

(b) the date on which it is cancelled under the **Code**.
5 Other provisions

The **fixed price** is inclusive of any additional costs arising due to carbon charges.

EXECUTION

[Execution Block Party A]

[Execution Block Party B]

The clearing manager accepts the lodgement of this **hedge settlement agreement** by counter-signing it.

[Execution Block Clearing Manager]

---

**SCHEDULE**

**TERMS OF HEDGE SETTLEMENT AGREEMENT**

<table>
<thead>
<tr>
<th>Hedge settlement agreement terms</th>
</tr>
</thead>
<tbody>
<tr>
<td>Commencement Date</td>
</tr>
<tr>
<td>Expiry Date</td>
</tr>
<tr>
<td>Fixed Price Payer</td>
</tr>
<tr>
<td>Floating Price Payer</td>
</tr>
<tr>
<td>Notional Quantity</td>
</tr>
<tr>
<td>Fixed Price</td>
</tr>
<tr>
<td>Hedge Reference Point</td>
</tr>
</tbody>
</table>

Form 2: Cap/Floor Calculation Period Price

[Note (not for inclusion in form): This form can be used to achieve both a capped price and a floor price.]

Date: [Enter date]

<table>
<thead>
<tr>
<th>Party A</th>
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1 Lodging of hedge settlement agreement

(1) Party A and Party B (the parties) submit this hedge settlement agreement to the clearing manager, as contemplated by clause 14.8 of the Electricity Industry Participation Code 2010 (the Code). Terms that are used in this agreement but not defined bear the meaning given to them in the Code.

(2) By submitting this hedge settlement agreement to the clearing manager in accordance with clause 14.8 of the Code, the parties agree to be bound by the terms set out below from the time at which the clearing manager counter-signs it.

(3) If the clearing manager counter-signs this document then, from the time it counter-signs, it has obligations relating to it under the Code. However, the parties acknowledge the clearing manager is not bound by this document and that its obligations in relation to it are limited to those set out in the Code.

2 Definitions

The following definitions apply in this document:

calculation period means a trading period during the term
calculation period premium means, in relation to a calculation period, the amount specified as such in the schedule for that calculation period
calculation period settlement amount means, in relation to a calculation period, an amount calculated using the following formula:

\[
\text{calculation period settlement amount} = \text{notional quantity} \times \text{strike price differential}
\]
cash settlement amount means, in relation to a billing period, the sum of the calculation period settlement amounts for each calculation period in that billing period

commencement date means the date specified as such in the schedule
expiry date means the date specified as such in the schedule

floating price means, in relation to a calculation period, the final price per MWh for that calculation period by reference to the hedge reference point [rounded to two decimal places]
hedge reference point means the grid exit point specified as such in the schedule

notional quantity means, in relation to a calculation period, the number of MWhs specified as such in the schedule for that calculation period

option buyer means, in relation to a hedge settlement agreement, the party specified as such in the schedule

option premium means, in relation to a billing period, the sum of the calculation period premiums for each calculation period in that billing period

option seller means, in relation to a hedge settlement agreement, the party specified as such in the schedule

option type means either a put option or a call option as specified in the schedule

settlement date means the date on which payments are due under clause 14.31 of the Code

strike price means, in relation to a calculation period, the amount specified as such in the schedule

strike price differential means, in relation to a calculation period, an amount equal to:
(a) if the option type is a put option, the greater of the strike price minus the floating price and zero:
(b) if the option type is a call option, the greater of the floating price minus the strike price and zero

term means the period from 00.00 hours on the commencement date until 23.59 hours on the date on which the hedge settlement agreement terminates.

3 Payment of hedge settlement amounts
In relation to a billing period:
(a) the option buyer must pay the clearing manager an amount equal to the option premium for that billing period; and
(b) the clearing manager must pay the option seller an amount equal to the option premium for that billing period; and
(c) the option seller must pay the clearing manager an amount equal to the cash settlement amount for that billing period; and
(d) the clearing manager must pay the option buyer an amount equal to the cash settlement amount for that billing period, on the relevant settlement date.

4 Termination
This hedge settlement agreement terminates on the earlier of:
(a) the expiry date; and
(b) the date on which it is cancelled under the Code.
5 Other provisions

The strike price is inclusive of any additional costs arising due to carbon charges.

EXECUTION

[Execution Block Party A]

[Execution Block Party B]

The clearing manager accepts the lodgement of this hedge settlement agreement by counter-signing it.

[Execution Block Clearing Manager]

SCHEDULE

terms of hedge settlement agreement

<table>
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<tr>
<th>Hedge settlement agreement terms</th>
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<tbody>
<tr>
<td>Commencement Date</td>
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<tr>
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<tr>
<td>Option Buyer</td>
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<tr>
<td>Option Seller</td>
</tr>
<tr>
<td>Option Type</td>
</tr>
<tr>
<td>Notional Quantity</td>
</tr>
<tr>
<td>Strike Price</td>
</tr>
<tr>
<td>Calculation Period Premium</td>
</tr>
<tr>
<td>Hedge Reference Point</td>
</tr>
</tbody>
</table>

Form 3: Cap/Floor Average Price

[Note (not for inclusion in form): This form can be used to achieve both a capped average price over a defined period and a floor average price over a period.]

Date: [Enter date]

<table>
<thead>
<tr>
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1 **Lodging of hedge settlement agreement**

(1) Party A and Party B (the **parties**) submit this **hedge settlement agreement** to the **clearing manager**, as contemplated by clause 14.8 of the Electricity Industry Participation Code 2010 (the **Code**). Terms that are used in this agreement but not defined bear the meaning given to them in the **Code**.

(2) By submitting this **hedge settlement agreement** to the **clearing manager** in accordance with clause 14.8 of the **Code**, the **parties** agree to be bound by the terms set out below from the time at which the **clearing manager** counter-signs it.

(3) If the **clearing manager** counter-signs this document then, from the time it counter-signs, it has obligations relating to it under the **Code**. However, the **parties** acknowledge the **clearing manager** is not bound by this document and that its obligations in relation to it are limited to those set out in the **Code**.

2 **Definitions**

The following definitions apply in this document:

**average floating price** means, in relation to an **option period**, an amount calculated using the following formula:

\[
\text{average floating price} = \frac{\text{option period floating amount}}{\text{option period notional quantity}}
\]

**calculation period** means a **trading period** during the term

**calculation period floating amount** means, in relation to a **calculation period**, an amount calculated using the following formula:

\[
\text{calculation period floating amount} = \text{notional quantity} \times \text{floating price}
\]

**calculation period notional quantity** [Revoked]

**calculation period premium** means, in relation to a **calculation period**, the amount specified as such in the schedule for that **calculation period**

**cash settlement amount** means, in relation to a **billing period**, the sum of the **option period settlement amounts** for each **option period** in that **billing period**

**commencement date** means the date specified as such in the schedule
expiry date means the date specified as such in the schedule

floating price means, in relation to a calculation period, the final price in dollars per MWh for that calculation period by reference to the hedge reference point [rounded to two decimal places]

hedge reference point means the grid exit point specified as such in the schedule

notional quantity means, in relation to a calculation period, the amount of electricity (measured in MWh) specified as such in the schedule for that calculation period

option buyer means, in relation to a hedge settlement agreement, the party specified as such in the schedule

option period means each period during the term specified as such in the schedule

option period floating amount means, in relation to an option period, an amount equal to the aggregate of the calculation period floating amounts for each calculation period in that option period

option period notional quantity means, in relation to an option period, the sum of the notional quantities for each calculation period in the option period

option period premium means, in relation to an option period, the sum of the calculation period premium for each calculation period in the option period

option period settlement amount means, in relation to an option period, an amount calculated using the following formula:

\[
\text{option period settlement amount} = \text{option period notional quantity} \times \text{strike price differential}
\]

option premium means, in relation to a billing period, the sum of the option period premiums for each option period in that billing period

option seller means, in relation to a hedge settlement agreement, the party specified as such in the schedule

option type means either a put option or a call option as specified in the schedule

settlement date means the date on which payments are due under clause 14.31 of the Code

strike price means, in relation to an option period, the amount specified as such in the schedule

strike price differential means, in relation to an option period, an amount equal to:

(a) if the option type is a put option, the greater of the strike price minus the average floating price and zero:

(b) if the option type is a call option, the greater of the average floating price minus the strike price and zero

term means the period from 00.00 hours on the commencement date until 23.59 hours on the date on which the hedge settlement agreement terminates.
3 Payment of hedge settlement amounts
In relation to a billing period:
(a) the option buyer must pay the clearing manager an amount equal to the option premium for that billing period; and
(b) the clearing manager must pay the option seller an amount equal to the option premium for that billing period; and
(c) the option seller must pay the clearing manager an amount equal to the cash settlement amount for that billing period; and
(d) the clearing manager must pay the option buyer an amount equal to the cash settlement amount for that billing period, on the relevant settlement date.

4 Termination
This hedge settlement agreement terminates on the earlier of:
(a) the expiry date; and
(b) the date on which it is cancelled under the Code.

5 Other provisions
The strike price is inclusive of any additional costs arising due to carbon charges.

EXECUTION

[Execution Block Party A]

[Execution Block Party B]

The clearing manager accepts the lodgement of this hedge settlement agreement by counter-signing it.

[Execution Block Clearing Manager]

SCHEDULE
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</tr>
<tr>
<td>Option Seller</td>
</tr>
<tr>
<td>Option Type</td>
</tr>
</tbody>
</table>
Option Period | [Each day] [From 00.00 hours until immediately before 00.00 hours on the next day] [first period being nn and last period being mm] [during the term.]
---|---
Notional Quantity | [insert number MWh] [Table of Notional Quantities (in MWh per calculation period) to be inserted]
Strike Price | $[insert amount/MWh] – [Table of Strike Prices to be inserted]
Calculation Period Premium | $[insert amount] for each calculation period of option period. [Table of Premiums to be inserted]
Hedge Reference Point | [insert grid exit point]

Schedule 14.4, Form 3, clause 2, definition of option period notional quantity: substituted, on 24 March 2015, by clause 22(1)(g) of the Electricity Industry Participation Code Amendment (Settlement and Prudential Security) 2014.
Electricity Industry Participation Code 2010

Part 14A

Prudential requirements


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14A.2 Participants to comply with prudential requirements
14A.3 Acceptable credit rating
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14A.6 Participant to provide minimum security required
14A.7 Participant may change form of security
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14A.12 Cash deposits to be paid into cash deposit accounts
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14A.23 Disputes regarding prudential requirements

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14A.24 Notices

Schedule 14A.1
Acceptable security

Schedule 14A.2
Guarantee

Schedule 14A.3
Deed of guarantee and indemnity
14A.1 Purpose of prudential requirements
   The purpose of this Part is to impose prudential requirements on each participant that
   has incurred or will incur financial obligations under this Code to ensure that the
   participant can meet those obligations.

14A.2 Participants to comply with prudential requirements
   (1) Before incurring any financial obligations under this Code, a participant must comply
   with prudential requirements in this Part.
   (2) A participant complies with prudential requirements in this Part in 1 of the following
   ways:
      (a) by maintaining an acceptable credit rating under clause 14A.3;
      (b) by providing acceptable security that complies with clause 14A.4.

14A.3 Acceptable credit rating
   (1) For the purposes of this Part, a person has an acceptable credit rating if—
      (a) the person has a long-term credit rating no lower than—
         (i) A3 (Moody's Investor Services Inc.); or
         (ii) A– (Standard & Poor's Rating Group); or
         (iii) B+ (AM Best); or
         (iv) A– (Fitch Ratings); and
      (b) in the case of a person who has a credit rating at the minimum level required
         under paragraph (a), the person is not subject to negative credit watch (or any
         equivalent arrangement) by the agency that gave the credit rating.
   (2) The clearing manager may require a participant whose compliance with prudential
   requirements in this Part depends on the credit rating of a person to provide evidence of
   the person's credit rating.
   (3) The participant must provide the evidence required by the clearing manager.

14A.4 Acceptable security
   (1) A participant provides acceptable security by—
      (a) providing an acceptable form of security in accordance with Part 1 of Schedule
         14A.1; and
      (b) providing security for an amount that is no less than the amount required under
         clause 14A.6.
   (2) A participant that provides acceptable security must do anything the Authority
   requires to ensure that the security is valid, enforceable, and effective.
14A.5 Clearing manager to determine estimate of minimum security
(1) At least once in every business day, the clearing manager must estimate the minimum amount for which security will be required to be provided by a participant under this Part on that business day and on each of the following 3 business days in accordance with Part 2 of Schedule 14A.1.
(2) The clearing manager must formulate and publish a methodology for estimating the amounts under subclause (1).
(3) The consultation and approval requirements set out in Schedule 14.2 apply to the methodology.

14A.6 Participant to provide minimum security required
(1) Each participant that is required to provide acceptable security under this Part on a business day must provide security for an amount that is the lowest of all of the estimates determined by the clearing manager for the participant for that business day.
(2) The participant must provide security for the amount required under subclause (1) no later than 1600 hours on the relevant business day.

14A.7 Participant may change form of security
The clearing manager must release a participant’s existing security when the participant provides a different form of security under this clause, if—
(a) the participant gives the clearing manager notice of its intention to substitute a different form of security for any security provided by it to the clearing manager; and
(b) no event of default is continuing in relation to the participant; and
(c) the participant satisfies the clearing manager that—
(i) the proposed new form of security is an acceptable form of security under Part 1 of Schedule 14A.1; and
(ii) the security provided by the participant will continue to be for an amount that is no less than the amount required under clause 14A.6.


14A.8 Reductions and releases
The clearing manager must reduce or release a participant’s existing security to the extent requested by the participant, if—
(a) the participant gives the clearing manager notice that it seeks a partial or complete reduction or release of any security provided by it to the clearing manager; and
(b) no event of default is continuing in relation to the participant; and
(c) the participant satisfies the clearing manager that, following the reduction or release of the security, the participant will—
(i) continue to meet the requirements in clause 14A.4; or
(ii) meet the requirements in clause 14A.3.
14A.9 Release of security on ceasing to be participant

The clearing manager must release a participant’s existing security if the participant—
(a) gives the clearing manager notice of it ceasing to be a participant; and
(b) ceases to be a participant and the Authority advises the clearing manager that the person has ceased to be a participant; and
(c) has paid all amounts that it owes under this Code (excluding any washup amount that has not yet been invoiced).

14A.10 Clearing manager to release security within 1 business day

(1) If a participant becomes entitled under clause 14A.7 or 14A.8 or 14A.9 or 14A.23 to a reduction or release of any security, the clearing manager must reduce or release that security within 1 business day of the participant becoming entitled to the reduction or release.

(2) If a cash deposit is to be reduced or refunded under subclause (1), the clearing manager must pay the amount of the reduction or refund to a bank account nominated by the participant for that purpose.

Cash deposits to be held on trust

14A.11 Cash deposit accounts

(1) The clearing manager must establish, in the clearing manager's name, 2 or more interest bearing cash deposit accounts.

(2) The cash deposit accounts must be—
(a) held with more than 1 bank that each has and maintains an acceptable credit rating in accordance with clause 14A.3(1); and
(b) clearly identified as such and be entirely separate from any other bank account of the clearing manager.

(3) The clearing manager must obtain acknowledgement from each bank with which it has a cash deposit account that—
(a) the cash deposits are held on trust in the cash deposit accounts for participants (including the clearing manager) that become entitled to receive money from the clearing manager from time to time under clause 14A.13; and
(b) the bank has no right of set-off or right of combination in relation to the cash deposits.

14A.12 Cash deposits to be paid into cash deposit accounts

(1) Every cash deposit received by the clearing manager must be paid by the clearing manager immediately into the cash deposit accounts.

(2) Each cash deposit must be held between cash deposit accounts in approximately equal amounts.

(3) If a cash deposit is debited under this Part, the clearing manager must ensure that approximately equal amounts of the cash deposit are debited from each cash deposit account.
14A.13 Cash deposits to be applied subject to conditions

The clearing manager must hold each cash deposit in the cash deposit accounts on trust to be applied, subject to this Code, only in accordance with the following:

(a) following any event of default, the clearing manager must use such amount of the defaulting participant's cash deposit as is necessary or available in order to satisfy (to the extent possible) any amounts that may be due and owing by the defaulting participant to the clearing manager under this Code:

(b) if no event of default is continuing in relation to the participant that provided the cash deposit, the participant is entitled to be paid the part of the cash deposit that has not been transferred under paragraph (a) in accordance with clause 14A.7 or 14A.8 or 14A.9 or 14A.23:

(c) to satisfy an amount payable under clause 14.31 if the participant satisfies the clearing manager that, immediately following the application of the cash deposit, it will continue to comply with prudential requirements in this Part:

(d) the participant is not entitled to receive back any part of its cash deposit, other than in accordance with this clause, even if the participant is in liquidation, receivership, or subject to statutory management or other analogous situation.

14A.14 Interest on cash deposits

(1) Subject to clauses 14A.13 and 14A.15, the clearing manager must credit to each participant on behalf of which the clearing manager holds a cash deposit all interest received by the clearing manager on the cash deposit, less any applicable deduction for tax purposes.

(2) Subject to subclause (3), if a participant does not wish the interest to accumulate in the cash deposit accounts, the clearing manager must, at the request of the participant, pay the interest (less any applicable deduction for tax purposes) within 2 business days of the end of the month to a bank account nominated by the participant for this purpose.

(3) Subclause (2) does not apply if an event of default has occurred in relation to the participant and is continuing.

14A.15 Fees and taxes payable by participants

(1) A participant is liable to reimburse the clearing manager for all bank fees in relation to its cash deposit and any taxes that may from time to time be imposed either on its cash deposit or on interest earned on such cash deposit.

(2) Such payments must be deducted by the clearing manager from any amounts paid to the participant under clause 14A.14(2).

(3) If the amounts are less than the payments owed by the participant under this clause, the shortfall must be invoiced separately by the clearing manager.
Information, monitoring, and reporting

14A.16 Information required from new purchasers
Before a new purchaser purchases electricity, it must submit to the clearing manager—
(a) historical records of the quantity of electricity purchased and sold by that person before that person became a purchaser; or
(b) if the clearing manager is not satisfied with records provided under paragraph (a), or if there are no such records, a bona fide business plan prepared in good faith to permit a realistic estimate of the purchaser’s future trading.

14A.17 Participants subject to prudential requirements must provide information to clearing manager
(1) The clearing manager may require a participant that is required to comply with prudential requirements in this Part to provide, by any date specified by the clearing manager, any information that the clearing manager requires for the purposes of carrying out its functions under this Part.
(2) A participant that is required to provide information to the clearing manager under subclause (1) must provide the information to the clearing manager by the date specified by the clearing manager.
(3) Each participant that is required to comply with prudential requirements under this Part must provide the following information to the clearing manager immediately upon the participant becoming aware of the situation:
(a) if the participant is a purchaser, any significant change to that purchaser’s business, including a merger or acquisition, loss or gain of a customer, or sale or purchase of assets, that could significantly affect the quantity of electricity purchased or generated by the participant in its capacity as a purchaser or generator:
(b) any change or likely change to the participant’s credit rating (if the participant has a credit rating), regardless of whether or not the participant is relying on a credit rating as a prudential requirement in terms of clause 14A.3:
(c) if a letter of credit or guarantee or bond is provided in respect of the participant in accordance with Part 1 of Schedule 14A.1—
   (i) any change or likely change to the credit rating of the provider of the guarantee, letter of credit, or bond such that the provider’s credit rating would, as a result, not be an acceptable credit rating as defined in clause 14A.3; or
   (ii) any claim by the provider of the guarantee, letter of credit, or bond that the guarantee, letter of credit, or bond has ceased to be valid and enforceable.
(4) If, at any time, a participant believes that its ability to pay an amount owing to the clearing manager under this Code is or is likely to be materially adversely affected, the participant must provide the clearing manager with details of that fact immediately.
14A.18 System operator to provide information
The system operator must provide the clearing manager with the following information immediately upon becoming aware of the information:
(a) any likely significant change to any amount to be allocated to a participant in respect of ancillary services or extended reserve;
(b) the amount incurred by a participant as a result of the participant causing an under-frequency event.

14A.19 Clearing manager to keep information confidential
The clearing manager must keep all information received by it under clauses 14A.16 to 14A.18 confidential and must not disclose it to any other person except—
(a) with the written consent of the person who provided the information; or
(b) if the information is required to be disclosed to or by the Rulings Panel or the Authority under this Code, regulations made under section 112 of the Act, or any other law.

14A.20 Clearing manager to provide information about cash deposits
Each month the clearing manager must provide each participant that has provided a cash deposit with a statement regarding the balance of the participant's cash deposit.

14A.21 Clearing manager to provide information about required security
(1) The clearing manager must provide each participant that is required to comply with prudential requirements under this Part with information about the amount for which security is required to be provided by the participant under clause 14A.6.
(2) The clearing manager must—
(a) provide the information to the participant through WITS; and
(b) publish the information.

14A.22 Clearing manager to keep register of specified time periods
(1) The clearing manager must keep a register of the following time periods for each participant that is required to comply with prudential requirements in this Part (except a participant to which subclause (2) applies):
(a) a prudential exit period determined in accordance with subclause (3);
(b) a post-default exit period determined in accordance with subclause (4).
(2) The clearing manager is not required to keep a register of time periods for a participant that is required to comply with prudential requirements in this Part only because the participant has an obligation in relation to 1 or more FTRs.
(3) The prudential exit period for a participant is the number of trading days that elapse over the sum of the following:
(a) 1 trading day:
(b) the post-default exit period for the participant.
(4) The post-default exit period for a participant is as follows, unless the Authority has
approved a shorter period requested by the participant:
(a) for a retailer, 18 trading days:
(b) for a direct purchaser, 7 trading days:
(c) for a participant that is not a retailer or a direct purchaser, 7 trading days.

(5) The post-default exit period for a participant begins from the day on which the participant advises the clearing manager or the clearing manager advises the participant under clause 14.43 that an event of default has occurred in relation to the participant.

(6) A participant that has a shorter post-default exit period approved by the Authority may increase the period to no more than the number of business days set out in subclause (4) by giving 20 business days' notice to the clearing manager.

(7) A shorter post-default exit period approved by the Authority takes effect 20 business days after the date of the Authority's approval.

(8) If the Authority has approved a shorter post-default exit period for a participant—
(a) the participant must immediately advise the Authority if the participant's circumstances change such that the criteria against which the Authority approved the shorter post-default exit period may no longer be met:
(b) the clearing manager must immediately advise the Authority if the clearing manager becomes aware that the participant's circumstances have changed such that the criteria against which the Authority approved the shorter post-default exit period may no longer be met:
(c) if the Authority considers the participant's circumstances have changed such that the criteria against which the Authority approved the participant having a shorter post-default exit period are no longer met, the Authority may—
(i) amend the participant's post-default exit period; or
(ii) rescind its approval of the shorter post-default exit period for the participant.

(9) If the Authority amends or rescinds its approval of a participant's shorter post-default exit period, the Authority must—
(a) give the participant at least 1 month's notice in writing before the amendment or the rescission comes into effect; and
(b) advise the participant of the reasons for amending or rescinding the approval.

Clause 14A.22(8) and (9): inserted, on 1 November 2018, by clause 109(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

Disputes

14A.23 Disputes regarding prudential requirements
(1) A participant that disputes a decision of the clearing manager under this Part may refer the dispute to the Rulings Panel.
(2) Until such time as the Rulings Panel makes a decision on the dispute, all participants must comply with the relevant decision of the clearing manager.
(3) If a dispute is referred to it under subclause (1), the Rulings Panel must, after hearing from the participant that disputed the clearing manager’s decision and from the clearing manager, make a decision in accordance with this Part.
(4) If the Rulings Panel overturns or varies a decision by the clearing manager, the clearing manager’s original decision, and the process that led to that decision, is not a breach of this Code by the clearing manager, unless the Rulings Panel determines that the clearing manager’s decision was made negligently or in bad faith.

Notices

14A.24 Notices

(1) Except as expressly provided in this Code, a notice or demand given or required to be given under this Part may be given by being delivered or transmitted to the intended recipient at its address or electronic address as last advised in writing to the sender and may be posted to such address by prepaid post.

(2) Subject to subclause (3),—
   
   (a) a notice or demand delivered by hand is deemed to be delivered on the date of such delivery; and
   
   (b) a notice or demand delivered by post is deemed to be delivered on the 2nd business day following the date of posting; and
   
   (c) a notice or demand transmitted through WITS is deemed to be delivered on the date it was transmitted.

(3) Any notice or demand delivered, or deemed to be delivered, on a day that is not a business day, or after 1600 hours on a business day, is deemed to have been delivered on the next business day.

Schedule 14A.1

Acceptable security

Part 1

Acceptable forms of security

1 Acceptable forms of security
A participant may provide acceptable security in any of the following forms:
(a) a cash deposit (see clause 2):
(b) an unconditional guarantee or letter of credit (see clause 3):
(c) a security bond (see clause 4):
(d) another form of security (see clause 5):
(e) a combination of the forms of security listed in paragraphs (a) to (d) that in aggregate secures the required amount.

2 Cash deposit
(1) A participant must pay a cash deposit into the cash deposit accounts or to the clearing manager.
(2) The participant must provide and maintain an acceptable participant's security agreement in respect of the cash deposit.
(3) A participant's security agreement must—
   (a) be a security agreement as defined in section 16(1) of the Personal Property Securities Act 1999; and
   (b) create a first ranking security interest in respect of the cash deposit; and
   (c) secure the participant's payment and performance obligations to the clearing manager under this Code; and
   (d) be in a form approved by the Authority.

3 Guarantee or letter of credit
(1) A guarantee or letter of credit must be given in favour of the clearing manager.
(2) A letter of credit is an acceptable form of security only if it is given by a bank.
(3) A guarantee or letter of credit must be given on terms as follows, or as otherwise approved by the Authority:
   (a) for a guarantee given by a bank, the terms in Schedule 14A.2:
   (b) for a guarantee given by another person, the terms in Schedule 14A.3:
   (c) for a letter of credit, the terms in Schedule 14A.4.
(4) A guarantee or letter of credit is an acceptable form of security only while the person giving it has an acceptable credit rating as defined in clause 14A.3.

4 Security bond
(1) A security bond must be given in favour of the clearing manager.
(2) A security bond must be given on the terms in Schedule 14A.5 or as otherwise approved by the Authority.
(3) A security bond is an acceptable form of security only while the surety has an
acceptable credit rating as defined in clause 14A.3.

5 Other security

(1) Any other form of security is an acceptable form of security only if it has been approved by the Authority.

(2) The Authority may approve another form of security if the Authority is satisfied that the form of security ensures that the relevant participant can meet its financial obligations under the Code to the same extent as if the participant provided a form of security specified in paragraphs (a) to (d) of clause 1.

Part 2
Minimum security

6 Determining minimum security

(1) The minimum amount for which security is required to be provided by a participant under clause 14A.6 is—

(a) the sum of the following amounts:

(i) the general prudential requirement calculated in accordance with clause 7;

(ii) the FTR prudential requirement calculated in accordance with clause 11;

minus

(b) any amount prepaid by the participant under clause 14.30 that is specified by the participant as being for a billing period—

(i) that has commenced but remains unsettled on the day for which the minimum security is being determined; or

(ii) any part of which falls within the prudential exit period for the participant (if any).

(2) If the sum of the amounts under subclause (1) is negative, the minimum amount for which security is required to be provided is 0.


7 General prudential requirement

The general prudential requirement is the sum of the following amounts calculated in accordance with the methodology approved under clause 8:

(a) the expected amount of the clearing manager's outstanding financial exposure to the participant; and

(b) the exit period prudential margin for the participant.

8 Methodology for determining general prudential requirement amounts

(1) The clearing manager must formulate and publish a methodology for determining the amounts specified in clause 7.

(2) The methodology must comply with the requirements specified in clauses 9 and 10.

(3) The consultation and approval requirements set out in Schedule 14.2 apply to the methodology.
9 Calculating clearing manager's outstanding financial exposure to participant

(1) The expected amount of the clearing manager's outstanding financial exposure to a participant on any trading day is an estimate of all unsettled amounts owing by the participant to the clearing manager and by the clearing manager to the participant to the end of the previous trading day, including the clearing manager's estimate of the following amounts:

(a) the amount owing to or by the participant for purchasing and selling electricity;

(b) the amount owing to or by the participant in relation to extended reserve:

(c) the net amount owing to or by the participant in relation to ancillary services:

(d) the amount of any GST payable by the participant in respect of the above amounts.

(2) The clearing manager must use final prices in calculating amounts under subclause (1) unless—

(a) final prices are not available, in which case the clearing manager must use interim prices; or

(b) neither final prices nor interim prices are available, or an undesirable trading situation has been claimed in respect of a trading period or trading day that is included in the clearing manager's estimate, in which case the clearing manager must use the price calculated in accordance with clause 10(2)(c) that is used in the methodology for determining the exit period prudential margin.

(3) The clearing manager must take washup amounts that have been advised as owing under Part 14 into account in estimating the amounts described in this clause.


10 Exit period prudential margin

(1) The exit period prudential margin for a participant is the clearing manager's estimate of the amount that the participant will incur and earn during the prudential exit period for the participant in respect of the following:

(a) the sale and purchase of electricity:

(ab) extended reserve:

(b) ancillary services:

(c) any hedge settlement agreement lodged with the clearing manager under clause 14.8:

(d) any GST payable in respect of the above amounts.

(2) The estimated amounts to be incurred and earned by the participant in respect of the sale and purchase of electricity under subclause (1)(a) are based on—

(a) the number of trading days in the prudential exit period for the participant determined under clause 14A.22(3); and

(b) the expected value of electricity to be purchased by the participant minus the expected value of electricity to be sold by the participant during that period.
based on the prices in paragraph (c); and

(c) the sum of the following amounts:
   (i) the prices of electricity expected to apply during the quarter to which the calculation relates in accordance with subclauses (3) and (4):
   (ii) an amount determined as set out in subclause (5).

(3) In determining the prices under subclause (2)(c)(i), the clearing manager must use prices of electricity futures products that are available and that the clearing manager considers provide a reasonable estimate of the average price of electricity for the relevant quarter.

(4) The clearing manager must determine the prices under subclause (2)(c)(i)—
   (a) for each quarter beginning 1 January, 1 April, 1 July, and 1 October; and
   (b) no later than 2 months before the beginning of each quarter.

(5) The amount determined under subclause (2)(c)(ii) must—
   (a) be an amount expressed in $/MWh of not less than $0/MWh; and
   (b) be determined on the basis that the exit period prudential margin for a hypothetical purchaser that purchases a constant proportion of total electricity purchased from the clearing manager for every trading period is greater than the general exit period exposure for the purchaser on 75% of the days in a modeling period of 3 to 10 years selected by the clearing manager.

(6) The clearing manager must determine the amount under subclause (2)(c)(ii)—
   (a) once for each calendar year; and
   (b) no later than 2 months before the beginning of each calendar year.

(7) The methodology must specify how the clearing manager will estimate the initial amount of security for ancillary services for a new participant.

(8) The expected amounts to be incurred and earned by the participant in respect of a hedge settlement agreement must be based on the price determined by the clearing manager under subclause (2)(c).


11 FTR prudential requirement
The FTR prudential requirement for a participant is the sum of the following amounts:

(a) the clearing manager's estimate of an amount to be incurred or earned by the participant in respect of any FTR in respect of which the participant is named in the FTR register, calculated in accordance with the methodology approved by the Authority under clause 12:

(b) the amount of any FTR acquisition cost in respect of an FTR held by the participant:

(c) any amount payable by the participant to the clearing manager under clause 13.249(4) minus any amount payable by the clearing manager to that participant under clause 13.249(7).
12 Methodology for determining minimum security required in respect of FTRs

(1) The clearing manager must formulate and publish a methodology for determining the minimum amount for which security is required to be provided in relation to a matter set out in clause 11(a).

(2) The methodology formulated by the clearing manager under subclause (1) must comply with the principle that the amount taken into account under clause 11(a) is an estimate of the FTR hedge value (being an amount that may be positive or negative) of the FTR at the time that the estimate is made and the potential for that value to change before the clearing manager is able to realise the value of the FTR following an event of default occurring in relation to the holder of the FTR.

(3) The consultation and approval requirements set out in Schedule 14.2 apply to the methodology.

13 Information to be considered by clearing manager

In estimating the amounts described in this Part, the clearing manager may take into account a substantial change to a participant’s business.
Schedule 14A.2
Guarantee

To: [Clearing manager] (the "Clearing Manager")
[address]

Attention: [name]

Dear Sir/Madam

1. [Bank] (the "Bank") refers to each obligation of [Participant] (the "Principal") to pay amounts the Principal, now or at any time, owes to, and is invoiced by, the Clearing Manager (whether as principal or agent) together with default interest, if any, in relation to such amounts (the "Obligations") under the Electricity Industry Participation Code 2010 (the "Code").

2. The Bank unconditionally guarantees to pay the Clearing Manager an amount specified in each such demand provided that—

[(a) [the Bank's liability under this guarantee will not exceed $[insert amount] (the "Maximum Amount"); and]

[Note: Bank to elect either this paragraph or the following paragraph].

[(a) the Bank's liability under this guarantee will not exceed the Maximum Amount as defined below—

(i) The sum of the amounts calculated for all trading periods to which this guarantee applies in any period to which a demand under this guarantee relates in accordance with the following formula:

\[ A \times B \]

where

A is [X] MWh
B is the final price for the trading period at the [specify] [grid injection point/grid exit point/reference point]; and

(ii) For the purposes of paragraph 2(a)(i), this guarantee applies to every trading period within any period to which a demand under this guarantee relates as follows:

A. From the "Starting Date", being the later of—

1. the start of the period; and

2. [date]; and

B. Until the "Final Date", being the earlier of—

1. the end of the period; and
2. the Final Date as notified to the Clearing Manager under paragraph 2(a)(iii); and

3. [date]; and

(ii) Despite anything in this guarantee or in the Code, the Bank may give the Clearing Manager notice of the Final Date for the purposes of paragraph 2(a)(ii)B. The Final Date is the later of the date specified in the notice or two business days after the date on which the Clearing Manager receives the notice; and

(b) the Clearing Manager's demand is made in writing and is signed by or purported to be signed by an authorised signatory; and

(c) a certificate signed by or purported to be signed by the Clearing Manager's authorised signatory and certifying that the Principal has failed, in whole or in part, to fulfil the Obligations accompanies the demand, such certificate will be conclusive proof of such failure.

3. The Bank's liability under this guarantee will not be affected, discharged, or diminished by any act, omission, or matter, which, but for this provision, would have affected, discharged, or diminished a guarantor's liability, but would not have affected, discharged, or diminished the Bank's liability had it been a principal debtor, including:

(a) the insolvency, liquidation, or dissolution of the Principal or any other person, the appointment of any receiver, manager, inspector, trustee, statutory manager, or other similar person in respect of the Principal or any other person, or any change in the Principal's status, function, control, or ownership; and

(b) any of the Obligations, or the obligations of any person under any security or guarantee held in relation to any of the Obligations, being or becoming in whole or in part void, voidable, defective, illegal, invalid, or unenforceable in any respect or ranking after any other security; and

(c) any time, credit or other indulgence or other concession being granted or agreed to be granted by the Clearing Manager to, or any composition or other arrangement made with or accepted from, the Principal in respect of any of the Obligations or the obligations of any person under any security or guarantee held in relation to the same; and

(d) any variation of the terms of any of the Obligations or of any security or guarantee (including under this guarantee) held in relation to the same; and

(e) any failure to realise or fully realise the value of, or any release, discharge, exchange, or substitution of, any security or guarantee held in relation to any of the Obligations; and

(f) any failure (whether intentional or not) to take, fully take or perfect any security now or in the future agreed to be taken by the Clearing Manager in relation to any of the Obligations; and

(g) any other act, event or omission that, but for this clause 3, would or might operate or discharge, impair, or otherwise affect any of the obligations of the
Guarantor under this guarantee or any of the rights, powers, or remedies conferred upon the Clearing Manager by the rules or by law.

4. Subject to paragraph 5 below, this guarantee will continue in force until the date at which the Principal ceases to be bound by the Code and has discharged its obligations to the Clearing Manager under the Code, at which time the Clearing Manager will return this guarantee to the Bank.

[5. Despite anything else in this guarantee, the Bank may at any time pay the Clearing Manager the Maximum Amount less any amount or amounts the Bank may previously have paid under this guarantee or such lesser sum as the Clearing Manager may require. Upon payment of that sum, this guarantee shall be cancelled and the Bank shall have no further liability.]

[Note: Bank to elect either this paragraph or the following paragraph as a method of cancellation.]

[5. Despite anything else in this guarantee, the Bank may cancel this guarantee by giving 90 days’ notice in writing to the Clearing Manager. Following cancellation of this guarantee, the Bank remains liable for any Obligations incurred before the effective date of cancellation, but shall not be liable for any Obligations incurred after that date.]

6. This guarantee may be assigned by the Clearing Manager without the Bank’s consent. It will bind the successors and assigns of the Bank.

7. This guarantee is governed by New Zealand law and the parties irrevocably submit to the non-exclusive jurisdiction of the courts of New Zealand.

[insert execution block for Bank]

Schedule 14A.3
Deed of guarantee and indemnity

DATED

BY

1. [Guarantor] (the "Guarantor")

IN FAVOUR OF

2. [Clearing manager] (the "Beneficiary")

1. Guarantee and indemnity

1.1 The Guarantor—

(a) unconditionally and irrevocably guarantees to the Beneficiary the due
performance and observance by [Participant] (the "Debtor") of each obligation the
Debtor may now or in the future have to the Beneficiary to pay amounts it owes
to, and is invoiced by, the Beneficiary (whether as principal or agent) together
with default interest, if any, in relation to such amounts (the "Obligations") under
the Electricity Industry Participation Code 2010 (the "Code"); and

(b) indemnifies the Beneficiary against any loss incurred by the Beneficiary as a
result of any failure by the Debtor to fulfil the Obligations. This indemnity shall
apply to any of the Obligations (or any amount which, if recoverable, would have
formed part of the Obligations) which is not or may not be enforceable,
recoverable, or recovered for any reason; and

(c) shall pay the Obligations (and any other amounts owing under this Deed) on
demand.

1.2 The total amount payable by the Guarantor under this Deed must not exceed the
aggregate of $[insert amount] (the “Maximum Amount”) and any sums payable under
clauses 1.3 and 9 of this Deed.

1.3 If any moneys payable by the Guarantor under this Deed are not paid on demand, the
Guarantor must pay to the Beneficiary interest on such unpaid moneys (both before and
after judgment) at the rate determined in accordance with clause 1.4 of this Deed from
the date of demand to the date of their actual receipt by the Beneficiary calculated on a
daily basis and capitalised as the Beneficiary will determine.

1.4 The interest rate will be 5% per annum plus the then prevailing settlement bid rate for
90 day bills displayed on Reuters Screen BKBM at 10:45am on the date of demand or,
if for any reason that rate is not displayed, the rate determined by the Beneficiary to be
the nearest practicable equivalent.
2. **Preservation of rights**

2.1 The obligations of the Guarantor and the rights, powers and remedies conferred on the Beneficiary under this Deed are in addition to, and not in substitution for, any other security or guarantee that the Beneficiary may at any time hold in respect of the Obligations and may be enforced without the Beneficiary first having recourse to any such security and without the Beneficiary first taking steps or proceedings against the Debtor.

2.2 The Guarantor's liability and the rights, powers, and remedies conferred on the Beneficiary under this Deed will not be affected, discharged, or diminished by (and the Guarantor waives notice of) any act, omission or matter which, but for this clause 2.2, would have affected, discharged or diminished the Guarantor's liability to the Beneficiary or the Beneficiary's rights, powers and remedies with respect to the Guarantor or would have otherwise provided a defence to the Guarantor (in each case, in whole or in part), including—

(a) the insolvency, liquidation, or dissolution of the Debtor or any other person, the appointment of any receiver, manager, inspector, trustee, statutory manager, or other similar person in respect of the Debtor or any other person, or any change in the Debtor's status, function, control, or ownership; and

(b) any of the Obligations, or the obligations of any person under any security or guarantee held in relation to any of the Obligations, being or becoming in whole or in part void, voidable, defective, illegal, invalid, or unenforceable in any respect or ranking after any other security; and

(c) any time, credit or other indulgence or other concession being granted or agreed to be granted by the Beneficiary to, or any composition or other arrangement made with or accepted from, the Debtor in respect of any of the Obligations or the obligations of any person under any security or guarantee held in relation to the same; and

(d) any variation of the terms of any of the Obligations or of any security or guarantee (including under this Deed) held in relation to the same; and

(e) any failure to realise or fully realise the value of, or any release, discharge, exchange, or substitution of, any security or guarantee held in relation to any of the Obligations; and

(f) any failure (whether intentional or not) to take, fully take or perfect any security now or in the future agreed to be taken by the Beneficiary in relation to any of the Obligations; and

(g) any other act, event or omission that, but for this clause 2.2, would or might operate or discharge, impair, or otherwise affect any of the obligations of the Guarantor under this Deed or any of the rights, powers, or remedies conferred upon the Beneficiary by the rules or by law.

2.3 If any payment to the Beneficiary under this Deed is avoided by law, the Guarantor’s obligation to make the payment will not be affected, discharged, or diminished, and the Guarantor must on demand indemnify the Beneficiary against all costs sustained or incurred by the Beneficiary as a result of it being required for any reason to refund all or part of any amount received or recovered by it in respect of such payment and must in
any event pay to the Beneficiary on demand the amount so refunded by it. The Beneficiary and the Guarantor will, in any such case, be deemed to be restored to the position in which each would have been and will be entitled to exercise the rights they respectively would have had if that payment had not been made.

2.4 After a demand has been made by the Beneficiary under this Deed, and so long as the Guarantor is under any actual or contingent liability under this Deed, the Guarantor must not—

(a) exercise in respect of any amount paid by the Guarantor under this Deed any right of subrogation or any other right or remedy that the Guarantor may have in respect of such amount paid; or

(b) except with the Beneficiary’s consent in writing, claim or receive payment of any other moneys for the time being due to the Guarantor by the Debtor or exercise any other right or remedy that the Guarantor may have in respect of the same; or

(c) unless so required by the Beneficiary, prove in the liquidation of the Debtor in competition with the Beneficiary for any moneys owing to the Guarantor by the Debtor on any account.

Any moneys obtained by the Guarantor from the Debtor with such consent or as so required or in breach of this clause must, in each case, be held by the Guarantor upon trust to pay such moneys to the Beneficiary in or towards discharge of the Guarantor’s obligations under this Deed.

2.5 Any moneys received by the Beneficiary that may be applied in or towards discharge of any of the obligations of the Guarantor under this Deed must be regarded as a payment in gross so that, in the event of the liquidation of the Guarantor, the Beneficiary may prove in the liquidation for the whole of such moneys.

3. **Representations and warranties**

The Guarantor represents that—

(a) it is duly incorporated and validly existing under the laws of the jurisdiction in which it was incorporated, capable of suing and being sued and has the power to enter into and perform this Deed, and has taken all necessary corporate action to authorise it to enter into, execute, deliver, and perform its obligations under this Deed; and

(b) its entry into, execution, delivery, and performance of this Deed will not contravene any law or regulation to which the Guarantor is subject or any provision of its constitutional documents and all things (including the obtaining of consents) requisite for such entry, execution, delivery, and performance have been taken, fulfilled, and done, and are in full force and effect; and

(c) no obligation of the Guarantor under this Deed is secured by, and the execution, delivery and performance of this Deed will not result in the existence of, or oblige it to create, any mortgage, charge, pledge, lien or other encumbrance over any of its present or future revenues or assets; and

(d) the execution, delivery of and performance of the Guarantor’s obligations under this Deed will not cause the Guarantor to be in breach of or in default under any agreement binding on the Guarantor or any of its assets and no material litigation
or administrative proceeding before any court or governmental authority is pending or (so far as the Guarantor knows) threatened against the Guarantor or any of its assets which, if decided against the Guarantor, would have a material adverse effect on the ability of the Guarantor to meet any or all of the obligations in this Deed.

4. **Payments**
   All payments to be made by the Guarantor to the Beneficiary under this Deed must be made without set-off or counterclaim and without any deduction or withholding. If the Guarantor is obliged by law to make any deduction or withholding from any such payment, the amount due from the Guarantor in respect of such payment will be increased to the extent necessary to ensure that, after the making of such deduction or withholding, the Beneficiary receives a net amount equal to the amount the Beneficiary would have received had no such deduction or withholding been required to be made.

5. **Continuing security**
   This Deed will be a continuing security to the Beneficiary in respect of each Obligation and must not be (or be construed so as to be) discharged by any intermediate discharge or payment of or on account of the Obligations or any settlement of accounts between the Beneficiary and the Debtor or anyone else.

6. **Cancellation**
   [Despite anything else in this Deed, the Guarantor may at any time pay to the Beneficiary the Maximum Amount less any amount or amounts the Guarantor may previously have paid under this Deed or such lesser sum as the Beneficiary may require. Upon payment of that sum, this Guarantee shall be cancelled and the Guarantor shall have no further liability.]
   [Note: Guarantor to elect either this clause or the following clause as a method of cancellation.]
   [The Guarantor may cancel this Deed by giving 90 days’ notice in writing to the Beneficiary. Following cancellation of this Guarantee, the Guarantor remains liable for any Obligations incurred before the effective date of cancellation but shall not be liable for any Obligations incurred after that date.]

7. **Assignment**
   This Deed may be assigned by the Beneficiary without the Guarantor’s consent. It will bind the successors and assigns of the Guarantor.

8. **Notices**
   8.1 Any demand made on the Guarantor by the Beneficiary under this Deed must be in writing and delivered to the registered office of the Guarantor or to any other address in New Zealand from time to time notified by the Guarantor to the Beneficiary in writing.
   8.2 The Guarantor must immediately notify the Beneficiary of any change in the above address.

9. **Costs and expenses**
The Guarantor indemnifies the Beneficiary for all costs and expenses (including legal fees and any taxes or duties) incurred by the Beneficiary in the enforcement and protection of its rights under this Deed.

10. **Governing law**

This Deed is governed by New Zealand law, and the Guarantor irrevocably submits to the non-exclusive jurisdiction of the courts of New Zealand.

[insert execution block for Guarantor]

Letter of credit

To: [Clearing manager] (the "Clearing Manager")
    (to be advised through [Bank], SWIFT: [Code])
    [address]
Attention: [name]

Dear Sir/Madam

IRREVOCABLE TRANSFERABLE STANDBY LETTER OF CREDIT NO. [number]
DATED [date]

We, [Bank] (the "Bank") issue in favour of the Clearing Manager this irrevocable transferable standby letter of credit (the "Letter of Credit") as follows:

The Account Party: [Participant] (the "Account Party")
Beneficiary: The Clearing Manager (the "Beneficiary")

Issued in Connection With: Each obligation of the Account Party to pay the amounts it, now or at any time, owes to, and is invoiced by, the Beneficiary (whether as principal or agent) together with default interest, if any, in relation to such amounts (the "Obligations") under the Electricity Industry Participation Code 2010 (the "Code").

Maximum Amount: $[insert amount] (the "Maximum Amount").

Expiry: This Letter of Credit expires on the earliest of—

(a) the date at which the Account Party has ceased to be bound by the Code and has discharged its obligations to the Beneficiary under the Code; or
(b) the date of satisfaction of this Letter of Credit in accordance with its terms; or
(c) [the date on which the Bank makes payment to the Beneficiary of the Maximum Amount either at its sole discretion or following demand by the Beneficiary under this Letter of Credit in accordance with its terms.]

[Note: Bank to elect either this clause or the following clause as a method of cancellation.]

(c) [90 days after notice in writing of cancellation of this Letter of Credit has been given by the Bank to the Clearing Manager, provided that the Bank remains liable for any Obligations incurred before the effective date of cancellation but shall not be liable for any Obligations incurred after that date.](the "Expiry Date").
Payable at: [Sight or by demand using SWIFT]
Available at: [address]
By demand on: The Bank.
Enfaced: Drawn under [Bank] Irrevocable Transferable Standby Letter of Credit No. [number] dated [date].
Returnable to: The Bank upon expiry.

The proceeds of this Letter of Credit are transferable by the Beneficiary. A claim may be made under this Letter of Credit by delivering to the address at which this Letter of Credit is expressed to be available, by no later than [time] New Zealand time on or before the Expiry Date, a draft drawn on the Bank (enfaced as specified above) accompanied by—

(a) this Letter of Credit; and
(b) a certificate signed by an authorised signatory of the Beneficiary in the following form:

To [Bank] [date]

[Clearing manager] of [address] (the "Beneficiary") hereby makes claim under the [Bank] Irrevocable Transferable Standby Letter of Credit No. [number] (the "Letter of Credit"). Words and expressions defined in the Letter of Credit will have the same meaning in this Certificate.

[Participant] (the "Account Party") has failed, in whole or in part, to fulfil the Obligations.

As at the date of this Certificate, the amount owed to the Beneficiary by the Account Party in respect of the Obligations is the sum of $[amount outstanding].

Accordingly, the Beneficiary is entitled to claim and requests payment by [date] of the amount of $[amount claimed] to be credited to:

Bank: [Beneficiary’s bank]
Account number [Beneficiary’s trust account number]
Bank’s SWIFT Code [Bank’s SWIFT Code]

The signatory or signatories is/are authorised by the Beneficiary to make the statements in this Certificate on behalf of the Beneficiary.

Signed……………………………………

Authorised Signatory
This Letter of Credit is subject to the Uniform Customs and Practice for Documentary Credits (2007 Revision) International Chamber of Commerce Publication No. 600 [and the Supplement to the Uniform Customs and Practice for Documentary Credits for Electronic Presentation 2007], except as otherwise provided in this Letter of Credit. Subject to that, this Letter of Credit will be governed by New Zealand law, and the parties irrevocably submit to the non-exclusive jurisdiction of the courts of New Zealand.

The Bank agrees with the Beneficiary that drafts drawn under, and in compliance with, this Letter of Credit and up to the Maximum Amount will be paid on presentation in the manner provided in this Letter of Credit.

[insert execution clause for Bank]

To: [Clearing manager] (the "Clearing Manager")
    [address]

From: [Surety] (the “Surety”)
    [address]

Bond Number: [number]

1. [Participant] (the "Principal") has obligations under the Electricity Industry Participation Code 2010 (the "Code") to pay the Clearing Manager amounts invoiced to the Principal by the Clearing Manager ("Obligations").

2. On written demand by the Clearing Manager, the Surety agrees to pay to the Clearing Manager any outstanding amounts invoiced to the Principal, together with any default interest payable in respect of those invoiced amounts. Such written demand must be delivered to the Surety at its above address and certify that the Principal has failed, in whole or in part, to fulfil the Obligations.

3. The Surety's total liability under this Bond shall not exceed $[insert maximum amount] ("Maximum Amount").

4. [The Surety may at any time pay to the Clearing Manager the Maximum Amount less any amount or amounts the Surety may previously have paid under this Bond or such lesser sum as the Clearing Manager may require. Upon payment of that sum, this Bond will be cancelled and the Surety shall have no further liability.]

[Note: Surety to elect either this proviso or the following proviso as a method of cancellation.]

4. [The Surety may cancel this Bond by giving 90 days’ written notice to the Clearing Manager. Following cancellation of this Bond, the Surety remains liable for any Obligations incurred before the effective date of cancellation but shall not be liable for any Obligations incurred after that date.]

5. This Bond is not affected, discharged, or diminished by any act or omission that would, but for this provision, have released a surety but would not have affected, discharged, or diminished the Surety’s liability had it been a principal debtor.

6. This Bond may be transferred or assigned by the Clearing Manager without the Surety’s consent.

7. Upon cancellation, the Bond will be returned to the Surety.

8. This Bond is governed by New Zealand law, and the Surety agrees to submit to the non-exclusive jurisdiction of the courts of New Zealand.

[insert execution clause for Surety]
Electricity Industry Participation Code 2010

Part 15
Reconciliation

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15.1 Contents of this Part
This Part provides for the following:
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(b) the correction of information to remedy errors in information provided:
(c) how reconciliation participants must gather, store and provide information about electricity conveyed:
(d) how reconciliation participants must prepare and provide submission information:
(da) how dispatchable load purchasers must collect volume information in accordance with Schedule 15.2:
(e) how the reconciliation manager must calculate responsibility for electricity among reconciliation participants:
(f) how the reconciliation manager must pass information to the clearing manager, for the calculation of amounts owing under Part 14:
(g) obligations of the reconciliation manager to pass the information to reconciliation participants, the registry manager and the Authority:
(h) requirements for the creation, approval and maintenance of profiles:
(i) requirements for audits, approvals and certifications.

Compare: Electricity Governance Rules 2003 rule 1 part J

15.2 Requirement to provide complete and accurate information
(1) A participant must take all practicable steps to ensure that information that the participant is required to provide to any person under this Part is—
(a) complete and accurate; and
(b) not misleading or deceptive; and
(c) not likely to mislead or deceive.
(2) If a participant becomes aware that the information the participant provided under this Part does not comply with subclause (1)(a) to (c), even if the participant has taken all practicable steps to ensure that the information complies, the participant must, as soon as practicable, provide such further information as is necessary to ensure that the information complies with subclause (1)(a) to (c).

Compare: Electricity Governance Rules 2003 rule 1A part J

15.3 Provision of trading information at point of connection to network
(1) Unless a notice under clause 15.13 is in force, a trader must give the reconciliation manager a notice that complies with this clause at least 5 business days before the trader—
(a) commences trading electricity at a point of connection using a profile with a profile code other than HHR or RPS or UML or EG1 or PV1; or
(b) ceases trading electricity at a point of connection using a profile with a profile code other than HHR or RPS or UML or EG1 or PV1.

(2) A person giving a notice must ensure that the notice complies with any procedures or other requirements specified by the reconciliation manager.

(3) The reconciliation manager must give a copy of every notice to the clearing manager and system operator no later than 1 business day after receiving the notice.

Compare: Electricity Governance Rules 2003 rule 3 part J

Provision of information to the reconciliation manager

15.4 Submission information to be delivered for reconciliation
(1) Each reconciliation participant must, by 1600 hours on the 4th business day of each reconciliation period, ensure that submission information has been delivered to the reconciliation manager for all NSPs for which the reconciliation participant is recorded in the registry as having traded electricity during the consumption period immediately before that reconciliation period, in accordance with Schedule 15.3.

(2) Each reconciliation participant must, by 1600 hours on the 13th business day of each reconciliation period, ensure that submission information has been delivered to the reconciliation manager for all points of connection for which the reconciliation participant is recorded in the registry as trading electricity during any consumption period being reconciled in accordance with clauses 15.27 and 15.28, and in respect of which the reconciliation participant has obtained revised submission information, in accordance with Schedule 15.3.

Compare: Electricity Governance Rules 2003 rules 4.1.1 and 4.1.2 part J

15.5 Preparing and submitting submission information
(1) In preparing and submitting submission information, a reconciliation participant must ensure that volume information for each ICP is allocated to the NSP indicated by the data in the registry for the relevant consumption period at the time the reconciliation participant assembles the submission information.

(2) Each reconciliation participant must derive volume information in accordance with Schedule 15.2.

(3) If a notice under clause 15.13 is in force for an embedded generating station in relation to a point of connection, a reconciliation participant who trades at the point of connection is not required to comply with clause 15.4 or this clause in relation to electricity generated by the embedded generating station to which the notice relates.

Compare: Electricity Governance Rules 2003 rules 4.1.3 and 4.1.4 part J
Clause 15.5(1) and (3): amended, on 5 October 2017, by clause 514(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
15.5A Dispatchable load purchaser must prepare dispatchable load information

(1) Each dispatchable load purchaser must prepare dispatchable load information using volume information prepared in accordance with Schedule 15.2.

(2) If clause 15.5B applies to a dispatch-capable load station's metering installation, the dispatchable load purchaser responsible for the dispatch-capable load station must comply with clause 15.5B in relation to the dispatch-capable load station.


Clause 15.5A(2): substituted, on 1 February 2016, by clause 94(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

15.5B Deriving volume information if metering installation is within premises that are connected to a point of connection

(1) This clause applies if a dispatch-capable load station's metering installation is not at a point of connection but is located within premises that are directly connected to a point of connection.

(2) If this clause applies, the dispatchable load purchaser responsible for the dispatch-capable load station must prepare dispatchable load information using volume information prepared in accordance with Schedule 15.2 and derived from the raw meter data—

(a) obtained from the metering installation; and

(b) that the dispatchable load purchaser has adjusted, using an accurate compensation factor, to compensate for internal site losses between the metering installation and—

(i) if the premises are directly connected to a point of connection to the grid, the point of connection to the grid; or

(ii) if the premises are directly connected to a point of connection to a local network, the point of connection to the local network; or

(iii) if the premises are directly connected to a point of connection to an embedded network, the point of connection to the embedded network.

(3) For the purpose of this clause, a dispatchable load purchaser must have a certified metering installation for each of its dispatch-capable load stations.

Clause 15.5B: inserted, on 15 May 2014, by clause 97 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 15.5B: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 15.5B(1) and (2)(b): amended, on 5 October 2017, by clause 515 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

Clause 15.5B(2): amended, on 1 February 2016, by clause 95(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

15.5C Aggregating and rounding dispatchable load information

(1) When preparing dispatchable load information, a dispatchable load purchaser must—

(a) aggregate volume information to the following level:

(i) NSP code:

(ii) dispatch-capable load station identifier:
(iii) **loss category** code:

(iv) **trading period**; and

(b) round the aggregated **volume information**—

(i) to 2 decimal places; and

(ii) so that if the digit to the right of the second decimal place is—

   (A) greater than or equal to 5, the second digit is rounded up; or

   (B) less than 5, the second digit is unchanged.

(2) When aggregating **volume information** for a **dispatch-capable load station** to the NSP, the **dispatchable load purchaser** must use the NSP code as shown in the registry at the time the **volume information** is derived.

Clause 15.5C: inserted, on 15 May 2014, by clause 97 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.


**15.5D Dispatchable load information to be delivered to reconciliation manager**

(1) Each **dispatchable load purchaser** must provide to the **reconciliation manager**—

(a) **dispatchable load information** for each GXP at which the **dispatchable load purchaser** has purchased **electricity** for a **dispatch-capable load station** during the **consumption period** immediately before each **reconciliation period**; and

(b) if the **dispatchable load purchaser** knows that **dispatchable load information** previously provided has changed, revised **dispatchable load information** for the **consumption period** for which the **dispatchable load information** was initially provided.

(2) Each **dispatchable load purchaser** must provide—

(a) the information described in subclause (1)(a) by 1600 hours on the 4th **business day** of each **reconciliation period**; and

(b) the information described in subclause (1)(b) by 1600 hours on the 13th **business day** of each **reconciliation period**.

Clause 15.5D: inserted, on 15 May 2014, by clause 97 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Additional retailer and direct purchaser information

**15.6 Retailer and direct purchaser ICP days information**

(1) Each **retailer** and **direct purchaser** (excluding **direct consumers**) must deliver a report to the **reconciliation manager** detailing the number of **ICP days** for each **NSP** for each submission file of **submission information** in respect of—

(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**.

(2) The **retailer** or **direct purchaser** must calculate the **ICP days** information in subclause (1) using the data contained in the **retailer’s** or **direct purchaser’s** reconciliation system when it aggregates **volume information** for **ICPs** into **submission information**.

Compare: Electricity Governance Rules 2003 rule 4.2.1 part J
15.7 Retailer electricity supplied information
Each retailer must deliver to the reconciliation manager the retailer’s total monthly quantity of electricity supplied for each NSP, aggregated by invoice month, for which the retailer has provided submission information to the reconciliation manager, including revised submission information for that period as non loss adjusted values in respect of—
(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.

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

15.9 Grid owner volume information
Each grid owner must deliver to the reconciliation manager, for each point of connection for all of its GXP’s, the following:
(a) submission information for the immediately preceding consumption period, by 1600 hours on the 4th business day of each reconciliation period;
(b) revised submission information provided in accordance with clause 15.4(2), by 1600 hours on the 13th business day of each reconciliation period.

15.10 Participants to provide NSP submission information
A participant must provide the following information to the reconciliation manager for each NSP for which the participant has given a notice under clause 25(1) of Schedule 11.1:
(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.
15.11 Grid connected generator

Each generator who has a generating station or generating unit with a point of connection to the grid must deliver to the reconciliation manager for each of its points of connection—

(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.

Compare: Electricity Governance Rules 2003 rule 4.3.3 part J

15.12 Accuracy of submitted information

If a reconciliation participant submits information in accordance with this Code, and the reconciliation participant subsequently obtains more accurate information, the reconciliation participant must provide the most accurate information to the reconciliation manager or participant, as the case may be, at the next available opportunity for submission in accordance with clauses 15.20A, 15.27 and 15.28.

Compare: Electricity Governance Rules 2003 rule 4.4 part J


15.13 Notice by embedded generators

An embedded generator must give a notice to the reconciliation manager for an embedded generating station in relation to a point of connection for the purposes of clauses 15.3 and 15.5(3) if the embedded generator will not receive payment from the clearing manager or any other person for any electricity generated by the relevant embedded generation station through the point of connection to which the notice relates.

Compare: Electricity Governance Rules 2003 rule 4A part J


15.14 Notice of changes to the grid

(1) Each grid owner must give written notice to the reconciliation manager, in accordance with any procedures or other requirements reasonably specified by the reconciliation manager from time to time, of any changes that the grid owner intends to make to the grid that will affect reconciliation.

(2) The grid owner must give the notice at least 1 month before the effective date of the intended change.

(3) No later than 1 business day after receipt of the notice, the reconciliation manager must give a copy of the notice to the extended reserve manager, the clearing manager, and the Authority.
(4) Each grid owner must give notice of an intended change to an existing point of connection to the grid or a new point of connection to the grid to be commissioned. Compare: Electricity Governance Rules 2003 rule 5 part J

Notice of outage constraints or alternative supply

15.15 Notice of points of connection subject to outages or alternative supply
No later than 2 hours after publication of final prices for all trading periods in a consumption period,—
(a) the system operator must give written notice to the reconciliation manager of the following:
   (i) each point of connection to the grid that had no load or generation connected to it in the modelling system in the consumption period:
   (ii) in relation to each point of connection referred to in subparagraph (i), the trading periods in the consumption period during which the point of connection to the grid had no load or generation connected to it in the modelling system; and
(b) each grid owner must give written notice to the reconciliation manager of the following:
   (i) each point of connection to the grid that was supplied from an alternative point of connection in the consumption period:
   (ii) in relation to each point of connection referred to in subparagraph (i), the trading periods in the consumption period during which the point of connection to the grid was supplied from an alternative point of connection.

Compare: Electricity Governance Rules 2003 rule 6.1 part J

15.16 Balancing area NSP grouping changes
If an NSP has been affected by an outage constraint, and the reconciliation manager has determined the notice it receives in accordance with clause 24 of Schedule 11.1 is not compliant with that clause, the reconciliation manager must, no later than 10 business days after the date on which it determines the notice is not compliant, effect, in consultation with the relevant distributor, any changes that are, in the reconciliation manager’s opinion, necessary to balancing area NSP groupings that are to be used during the outage constraint.

Compare: Electricity Governance Rules 2003 rule 6.2 part J
15.17 Submission information to be reviewed in the case of an outage constraint

In the case of an outage constraint, the reconciliation manager must—

(a) review the submission information in accordance with a notice received in accordance with clause 15.15 and satisfy itself that the submission information is consistent with the occurrence of the stated outage constraint; and

(b) reconcile the submission information for the affected NSP within the balancing area identified in accordance with clause 15.15 for the trading periods during which the outage constraint applied; and

(c) as soon as reasonably practicable, but no later than 2 business days after publication of final prices, give written notice to any reconciliation participants who were affected by the outage constraint affecting the NSPs, of the trading periods in the prior consumption period during which the outage constraint applied, and any changes to balancing area NSP groupings made in accordance with clause 15.16; and

(d) if a reconciliation participant’s submission information has been affected by an outage constraint in a consumption period, and the reconciliation participant disputes or queries, in accordance with clause 15.24, the change to balancing area NSP groupings made in accordance with clause 15.16, the reconciliation manager must, no later than 10 business days after it determines that the notice it receives in accordance with clause 24 of Schedule 11.1 is not compliant, in consultation with the distributor, generator or purchaser concerned, assess whether a different balancing area NSP grouping would be more appropriate in the circumstances of the particular outage constraint. The reconciliation manager may change the alternative balancing area NSP grouping for the particular outage constraint and, if the alternative balancing area NSP grouping is changed, the reconciliation manager must update the information changed in accordance with clause 15.16 as necessary.

15.18 Reconciliation manager may request additional information

For the purpose of carrying out its role in accordance with this Code, the reconciliation manager may, in respect of a consumption period, give notice to a reconciliation participant that it requires such additional information from the reconciliation participant as the reconciliation manager reasonably requires, and the reconciliation participant must, as soon as practicable, provide such information to the reconciliation manager.

Compare: Electricity Governance Rules 2003 rule 7 part J
Clause 15.17(c) and (d): amended, on 5 October 2017, by clause 523(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
15.19 Seasonal adjustment and profiling

(1) The reconciliation manager must process submission information derived from non half hour volume information using a profile to allocate the non half hour submission information to trading periods in accordance with Schedule 15.4.

(2) Profiles must be established and changed (if necessary) in accordance with Schedule 15.5.

(3) For each reconciliation revision, the reconciliation manager must—
   (a) subject to paragraph (c), recalculate the seasonal adjustment shape for each reconciliation revision cycle; and
   (b) reconcile submission information using the latest profile shape published, and the most recently supplied profile information; and
   (c) recalculate the residual profile shape and any shapes approved as NSP derived profile shapes under clauses 19 to 24 of Schedule 15.5 for each reconciliation revision cycle and use the shape to allocate non half hour data across the trading periods, in accordance with Schedule 15.5; and
   (d) not recalculate the seasonal adjustment shape after the month 7 reconciliation revision.

(4) Subclause (3)(d) does not prevent the reconciliation manager from recalculating the seasonal adjustment shape following the month 7 reconciliation revision if necessary to resolve a dispute under clauses 14.25 or 15.29, or to correct information under clauses 15.21 to 15.26.

15.20 Calculation and allocation of unaccounted for electricity

The reconciliation manager must, in accordance with Schedule 15.4,—

(a) calculate the scorecard rating of each retailer; and
(b) calculate the unaccounted for electricity; and
(c) allocate the unaccounted for electricity to, and balance, the total electricity supplied, for each NSP.

15.20A Reconciliation manager to update revised dispatchable load information

(1) This clause applies to any revised dispatchable load information provided under clause 15.5D(1)(b).

(2) The reconciliation manager must,—
   (a) if the dispatchable load information to which this clause applies relates to 1 or more consumption periods being 1, 3, 7, or 14 months before the current
reconciliation period, conduct a further update for each applicable consumption period; or
(b) if the dispatchable load information to which this clause applies relates to a consumption period other than the consumption periods set out in paragraph (a),—
(i) store the dispatchable load information until the consumption period becomes 1 of the consumption periods set out in paragraph (a); and
(ii) conduct a further update under paragraph (a).

(3) The reconciliation manager must not update revised dispatchable load information for a consumption period if 14 months have elapsed since the end of the consumption period.

(4) Subclause (3) does not prevent the correction of information under clauses 14.28, 15.26(2), or 15.29.


15.20B Reconciliation manager loss adjusts and summarises dispatchable load information

(1) The reconciliation manager must apply loss factors to dispatchable load information received under clause 15.5D—
(a) for each trading period; and
(b) using the loss category codes advised by the dispatchable load purchaser when submitting dispatchable load information under clause 15.5D.

(2) After applying loss factors under subclause (1), the reconciliation manager must summarise—
(a) into 1 file for each consumption period, dispatchable load information received under clause 15.5D(1)(a); and
(b) into 1 file for each consumption period, dispatchable load information received under clause 15.5D(1)(b) and updated under clause 15.20A.

(3) The Authority may direct the reconciliation manager to apply specified values for loss factors for each loss category for a reconciliation period for which the registry manager does not provide the reconciliation manager with the loss factors for each loss category in accordance with clause 11.26(b).

(4) If the Authority makes a direction under subclause (3), the reconciliation manager must apply the values as loss factors to the relevant dispatchable load information for all reconciliation periods during which the direction applies.


15.20C Reconciliation manager to provide loss adjusted and summarised dispatchable load information to clearing manager

The reconciliation manager must provide to the clearing manager—
(a) the information described in clause 15.20B(2)(a) by 1600 hours on the 7th business day of each reconciliation period; and
(b) the information described in clause 15.20B(2)(b) by 1200 hours on the last business day of each reconciliation period.
15.20D Reconciliation manager to provide loss adjusted and summarised dispatchable load information to dispatchable load purchasers
At the same time the reconciliation manager provides the information described in clause 15.20C to the clearing manager, the reconciliation manager must provide each dispatchable load purchaser with the part of the information that relates to the dispatchable load purchaser.


Reconciliation information produced by reconciliation manager

15.21 Providing information specific to reconciliation participants
The reconciliation manager must provide information specific to each reconciliation participant and the clearing manager in accordance with Schedule 15.4.

Compare: Electricity Governance Rules 2003 rule 10.1 part J

15.22 Providing information to reconciliation participants
The reconciliation manager must provide to a reconciliation participant the information it has concerning the quantity of electricity conveyed at an NSP for each consumption period, by a time agreed between the reconciliation participant and the reconciliation manager (or if no such time can be agreed, by such time as determined by the Authority), if—

(a) the reconciliation participant has requested the information; and
(b) the reconciliation participant has purchased or sold electricity at the NSP during the consumption period or, in the case of a network owner, has a liability as a transporter of electricity in relation to the NSP; and
(c) the reconciliation participant meets the reconciliation manager’s reasonable costs of providing the information; and
(d) the reconciliation participant ensures that all information received in accordance with this clause is kept and maintained confidential to the employees of the reconciliation participant who are required to have access to the information to enable the reconciliation participant to identify errors in the reconciliation information produced for the NSP; and
(e) the reconciliation participant ensures that all information received in accordance with this clause is not used for any purpose other than enabling the reconciliation participant to identify errors in the submission information submitted for the NSP or, in the case of any network owner, other than for a legitimate purpose directly related to the network owner’s liability as a transporter of electricity in relation to that NSP; and
(f) the reconciliation participant implements and maintains best practice internal procedures to meet its obligations in accordance with this clause.

Compare: Electricity Governance Rules 2003 rule 10.2 part J
15.23 Reconciliation information is not final

The reconciliation information provided in accordance with clauses 15.21 and 15.22 is subject to assessment in accordance with clauses 15.24 to 15.26.

Compare: Electricity Governance Rules 2003 rule 10.3 part J

15.24 Reconciliation information checked

(1) The reconciliation participant must check the accuracy of the reconciliation information provided by the reconciliation manager under clauses 15.21 and 15.22.

(2) The reconciliation participant may dispute the volume information on which the reconciliation information provided by the reconciliation manager under clauses 15.21 and 15.22 is based in accordance with clause 15.29.

Compare: Electricity Governance Rules 2003 rules 10.4 and 10.4A part J

15.25 Reconciliation manager must assess information not supplied

(1) If a reconciliation participant fails to provide any information to the reconciliation manager that the reconciliation participant is required to provide under this Part, the reconciliation manager must take all reasonable steps necessary to acquire or estimate the information, and in the case of missing trader data the reconciliation manager must—

(a) estimate a purchaser’s volume information by applying the ICP day scaling factor in accordance with Schedule 15.4; and

(b) estimate a generator’s volume information by using an estimated reading.

(2) Subclause (1) does not apply to information that the reconciliation manager is directed by the Authority to correct under clause 15.26(2).

Compare: Electricity Governance Rules 2003 rules 10.5 and 10.5A part J

15.26 Reconciliation manager to correct information

(1) If the reconciliation manager has, in accordance with clause 15.25(1), acquired or estimated information, or is unable to provide reconciliation information, it must, to the extent it is reasonable, attempt to subsequently establish the correct reconciliation information, provide the updated reconciliation information to the clearing manager and distribute the information to the reconciliation participants entitled to it in accordance with this Code.

(2) If the reconciliation manager considers that information provided by a reconciliation participant or a service provider under this Part is incorrect, the reconciliation manager must refer the issue to the Authority, and, if directed by the Authority to do so, take all reasonable steps to correct the information.

(3) A reconciliation participant or service provider must provide any information to the reconciliation manager that the reconciliation manager requires to correct information under subclause (2).

(4) If the reconciliation manager has corrected information under subclause (2), the reconciliation manager must provide the corrected information to the clearing manager and the reconciliation participants who are entitled to the information under this Code.
(5) The reconciliation manager must not correct information later than 24 months after the date on which information about an amount owing to which the incorrect information relates (if any) has been advised under Part 14.

Compare: Electricity Governance Rules 2003 rules 10.6 to 10.10 part J

Revisions

15.27 Reconciliation manager must reconcile revised information

(1) If the reconciliation manager receives revised NSP information or submission information that has been supplied to it since the previous reconciliation calculation in accordance with clauses 15.4(2) or 15.12, the reconciliation manager must reconcile the information in accordance with the following procedure:

(a) if the submission information received relates to 1 or more consumption periods being 1, 3, 7, or 14 months before the current reconciliation period, a further reconciliation must be conducted for that consumption period or those consumption periods:

(b) if the NSP information or submission information relates to any other consumption period, the reconciliation manager must store the information and wait until the consumption period becomes 1 of the consumption periods described in paragraph (a) before conducting a further reconciliation.

(2) The reconciliation manager must not reconcile revised NSP or submission information arising after month 14.

(3) Subclause (2) does not prevent the correction of information under clauses 14.28, 15.26(2) or 15.29.

Compare: Electricity Governance Rules 2003 rules 11.1 to 11.2A part J

15.28 Transitional provisions concerning revisions

(1) In this clause—

(a) “transitional revisions” means any revision carried out by the reconciliation manager in accordance with this clause, for any reconciliation period that includes a trading period that occurred before 1 May 2008; and

(b) “incumbent retailer” means, for each balancing area, the relevant retailer to be set out in the list of NSPs by balancing area and their corresponding retailers, published from time to time by the reconciliation manager, in accordance with subclause (3).

(2) The intent of this clause is—

(a) as far as practicable, to preserve the effect of the reconciliation provisions concerning revisions that were in effect immediately before 1 May 2008, for all transitional revisions; and

(b) to clarify that volume information and submission information for all transitional revisions (except as provided in this clause) must be submitted by reconciliation participants in accordance with this Part; and
(c) to clarify the application of certain clauses concerning disputes that existed before 1 May 2008.

(3) The **reconciliation manager** must publish a list of the incumbent **retailers** finalised under rule 11.4.3.2 of part J of the **rules** until all transitional revisions are completed.

(4) Despite anything in this Code—

(a) to avoid doubt, clause 8 of Schedule 15.3 applies to **submission information** in relation to all transitional revisions; and

(b) each **reconciliation participant**, including each incumbent **retailer**, must submit the required **submission information** relating to all transitional revisions in accordance with clause 15.4(2); and

(c) if the **submission information** to be supplied for a transitional revision is the first such submission after 1 May 2008, the **reconciliation participant** must provide a full data set as if it were an initial submission in accordance with clause 15.4(1); and

(d) in recognition of the fact that incumbent **retailers** have not, before 1 May 2008, been required to submit the **submission information** referred to in paragraph (b), the **certification** and **audit** requirements of Schedule 15.1 (required for activities in accordance with clauses 2 to 8 and 11 of Schedule 15.3, and clause 17 of Schedule 15.4), do not apply in relation to the non **half-hour metering information** required to be submitted by incumbent **retailers** to the **reconciliation manager** for transitional revisions.

(5) Despite anything in this Code, all transitional revisions must be carried out by the **reconciliation manager** in accordance with this Code, subject to the following:

(a) for the purposes of clause 7 of Schedule 15.4, the **ICP** scaling factor is 1; and

(b) for the purposes of clauses 18(1)(b) and 19 of Schedule 15.4 the **scorecard rating** (SCri) for each **retailer** (other than the incumbent **retailer**) is 1; and

(c) for the purposes of clause 19 of Schedule 15.4, at each **NSP** the market share proportion (MSRi) for the incumbent **retailer** is 1, and, for all other **retailers**, is 0.

(6) Despite anything in this Code, all disputes concerning **metering installations** or **consumption information** in relation to transitional revisions—

(a) that existed before 1 May 2008 are not affected by the coming into effect of part J of the **rules** and this Part; and

(b) must be commenced no later than 2 years after the date of issue of any invoice to which the disputed information relates.

(7) Despite anything in this Code—

(a) as soon as practicable after 16 October 2008, the **reconciliation manager** must publish 1 **seasonal adjustment shape** for each **balancing area** that existed at the beginning of the 1st **trading period** of May 2008; and

(b) the **reconciliation manager** must not publish any further **seasonal adjustment shapes** for the **consumption periods** for which transitional revisions are required; and
(c) no later than 5 business days after the date on which those seasonal adjustment shapes are published, each reconciliation participant must provide submission information to the reconciliation manager based on those seasonal adjustment shapes for the months of February to July 2008; and

(d) as soon as practicable after the expiry of the time referred to in paragraph (c) the reconciliation manager must complete revisions using that submission information for the months of February 2008 to July 2008; and

(e) each reconciliation participant must continue to use the seasonal adjustment shapes published by the reconciliation manager under paragraph (a) for all subsequent transitional revisions for the period for which transitional revisions are required.

Compare: Electricity Governance Rules 2003 rule 11.4 part J

15.29 Volume information disputes

(1) A reconciliation participant may commence a dispute relating to volume information by notice in writing to the reconciliation manager.

(2) A reconciliation participant may not give written notice of a dispute under subclause (1) if information about an amount owing based on the volume information has been advised under Part 14.

(3) The reconciliation manager must give written notice to the Authority and all participants affected by the dispute no later than 1 business day after receiving notice of the dispute under subclause (1).

(4) On receiving a notice of a dispute under subclause (3), the Authority may direct that no further action be taken in respect of the dispute.

(5) If the Authority gives a direction under subclause (4), subclauses (6) to (13) cease to apply to the dispute. However, a direction under subclause (4) does not affect the validity of a washup conducted under clauses subpart 6 of Part 14 before the direction was given.

(6) The disputing reconciliation participant and the reconciliation manager must use reasonable endeavours to resolve the dispute.

(7) A dispute does not excuse anyone from complying with this Code.

(8) Participants must continue to use disputed volume information as if it were not in dispute while the dispute is being resolved.

(9) If a dispute is not resolved within 15 business days after the date on which the reconciliation manager received notice of the dispute under subclause (1), the disputing reconciliation participant or the reconciliation manager may refer the dispute to the Rulings Panel for resolution under the Act.

(10) The Rulings Panel may make such determination as it thinks fit.

(11) The Rulings Panel must give written notice of its determination to the disputing reconciliation participant and affected participants.

(12) If the dispute is resolved by the parties to the dispute agreeing, or the Rulings Panel determining, that the volume information is incorrect, the reconciliation manager must correct the volume information as follows:
(a) if a revised **seasonal adjustment shape** must be issued in order for the **volume information** to be corrected—

(i) the **reconciliation manager** must provide each **reconciliation participant** whose **submission information** is required to be corrected with a revised **seasonal adjustment shape**; and

(ii) each **reconciliation participant** must provide corrected **submission information** to the **reconciliation manager** no later than 4 **business days** after being provided with the revised **seasonal adjustment shape**:

(b) if a revised **seasonal adjustment shape** does not need to be issued in order for the **volume information** to be corrected, each **reconciliation participant** whose **volume information** or **dispatchable load information** is required to be corrected must provide corrected relevant information to the **reconciliation manager** no later than 4 **business days** after receiving notice of the resolution of the dispute.

(13) The **reconciliation manager** must provide the corrected **volume information** to the **clearing manager**.

(14) [Revoked]

Compare: Electricity Governance Rules 2003 rule 12 part J
Clause 15.29(5): amended, on 24 March 2015, by clause 13(1) of the Electricity Industry Participation Code Amendment (Late and Revised Data) 2015.
Clause 15.29(14): revoked, on 24 March 2015, by clause 13(2) of the Electricity Industry Participation Code Amendment (Late and Revised Data) 2015.

**Reporting obligations of the reconciliation manager**

15.30 [Revoked]

Compare: Electricity Governance Rules 2003 rule 13.1 part J

15.31 Right to information concerning reconciliation manager's actions

(1) A **reconciliation participant** may, by giving written notice to the **reconciliation manager**, request further information related to—
(a) any alleged breach of this Code by the **reconciliation manager**:  
(b) any alleged breach of this Part by a **reconciliation participant**, if the alleged breach has materially affected the **reconciliation participant** requesting the information.

(2) The **reconciliation manager** must, no later than 10 business days after receiving such a request, provide the requested information to the **reconciliation participant**, provided that the information does not include any information that is confidential in respect of any other person.

Compare: Electricity Governance Rules 2003 rule 13.2 part J  

**15.32 Reconciliation reports**

The **reconciliation manager** must report to the **Authority** and each **reconciliation participant**, the information determined during the reconciliation process as described in clauses 24 to 28 of Schedule 15.4.

Compare: Electricity Governance Rules 2003 rule 13.3 part J

**15.33 [Revoked]**

Compare: Electricity Governance Rules 2003 rule 14 part J  

**15.34 Use of agents by reconciliation participants**

(1) A **reconciliation participant** who has obligations under this Part may discharge those obligations by way of an agent.

(2) A **reconciliation participant** who utilises an agent to discharge an obligation under this Code remains responsible and liable for, and is not in any way released from, that obligation.

(3) A **reconciliation participant** must not assert, against anyone, that it is not responsible or liable for its obligations because the **reconciliation participant**’s agent has done or not done something or has failed to meet a relevant standard.

Compare: Electricity Governance Rules 2003 rule 15 part J

**15.35 Provision of information**

(1) If an obligation exists to provide information in accordance with this Part, a **participant** must deliver that information to the required person within the timeframe specified in this Code, or, in the absence of any such timeframe, within any timeframe the **Authority** specifies in writing.

(2) Such information must be delivered in the format determined from time to time by the **Authority**.

(3) Unless otherwise specified in this Part, information that must be provided under this Part by the **registry manager** or to the **registry manager**, must be provided using the registry.
15.36 New Zealand Daylight Time adjustment techniques

(1) Submission information provided to, and reconciliation information provided by, the reconciliation manager must, if applicable, be adjusted for NZDT using the technique set out in subclause (3) specified by the Authority.

(2) Any information exchanged between participants that contains trading period specific data must, if applicable, be adjusted for NZDT in accordance with subclause (3).

(3) A daylight savings adjustment must be made by using the “trading period run on technique”, which requires that daylight saving adjustment periods are allocated as consecutive trading periods within the relevant day, in the sequence that they occur.

(4) If no adjustment is made in accordance with subclause (3) to information exchanged between reconciliation participants that contains trading period specific data, the code “NZST” must be used within the data transfer file.

Compare: Electricity Governance Rules 2003 rule 17 part J
15.37C Authority and participant requested audits
(1) The Authority may at any time carry out, or appoint an auditor to carry out, an audit of a participant in respect of the participant's obligations under this Part.
(2) If a participant considers that another participant may not have complied with this Part, the participant may request that the Authority carry out, or appoint an auditor to carry out, an audit of the other participant.
(3) Part 16A applies to an audit carried out under this clause.
Clause 15.37C: inserted, on 1 June 2017, by clause 25 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

Certification

15.38 Functions requiring certification
(1) Subject to clauses 2A and 2B of Schedule 15.1, a reconciliation participant (except an embedded generator selling electricity directly to another reconciliation participant) must obtain and maintain certification in accordance with Schedule 15.1 in order to be permitted to perform, or to have performed by way of an agent or agents, any of the following functions in compliance with this Code:
   (a) maintaining registry information and performing ICP switching (except if the maintenance of registry information is carried out by a distributor in accordance with Part 11);
   (b) gathering and storing raw meter data;
   (c) creating and managing (including validating, estimating, storing, correcting and archiving)—
      (i) half hour volume information; or
      (ii) non half hour volume information; or
      (iii) half hour and non half hour volume information; or
      (iv) dispatchable load information;
   (d) delivery of:
      (i) a report under clause 15.6 and the calculation of the number of ICP days detailed in the report;
      (ii) electricity supplied information under clause 15.7;
      (iii) information from retailer and direct purchaser half hourly metered ICPs under clause 15.8:
      (da) [Revoked]
      (db) [Revoked]
   (e) provision of submission information for reconciliation;
   (f) provision of metering information to the relevant grid owner in accordance with subpart 4 of Part 13.
(1A) A dispatchable load purchaser must obtain and maintain certification in accordance with Schedule 15.1 in order to be permitted to perform, or to have performed by way of an agent or agents, any of the following functions in compliance with this Code:
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(a) gathering and storing raw meter data:
(b) creating and managing (including validating, estimating, storing, correcting, and archiving)—

(i) half hour volume information; or
(ii) non half hour volume information; or
(iii) half hour and non half hour volume information; or
(iv) dispatchable load information:
(c) providing dispatchable load information.

(1B) For the purposes of subclause (1A), each reference to a reconciliation participant in Schedule 15.1 is to be read as a reference to a dispatchable load purchaser.

(2) [Revoked]
Compare: Electricity Governance Rules 2003 rule 19 part J
Clause 15.38(1)(a) and (b): amended, on 1 November 2018, by clause 118(a) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.
Clause 15.38(1)(da) and (db): inserted, on 19 December 2014, by clause 41 of the Electricity Industry Participation Code Amendment (Minor Code Amendments) (No 3) 2014.
Clause 15.38(1)(da) and (db): revoked, on 1 February 2016, by clause 99(3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.
Clause 15.38(1A): inserted, on 1 May 2014, by clause 101(2) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.
Clause 15.38(2): revoked, on 1 June 2017, by clause 26(2) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

**Participant identifiers**


15.39 Participants must use participant identifiers

(1) Each participant must use its participant identifier, when required, to correctly identify that participant’s information.

(2) A participant must apply to the Authority in the prescribed form for a participant identifier at least 5 business days before the participant identifier is required.

(3) The Authority may, by giving written notice to any participant, change the participant identifier for that participant. If the Authority does this, the new participant identifier for that participant will become effective from the date specified in the relevant notice.

Compare: Electricity Governance Rules 2003 rule 20 part J
Schedule 15.1
Certification processes

c1 15.38


1 Contents of this Schedule
This Schedule sets out—
(a) [Revoked]
(b) the requirement for reconciliation participants to be certified to perform the functions specified in clause 15.38, and the process for obtaining and renewing that certification.
(c) [Revoked]

Compare: Electricity Governance Rules 2003 clause 1 schedule J1
Clause 1(a): revoked, on 1 June 2017, by clause 28(1) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Clause 1(b): amended, on 1 June 2017, by clause 28(2) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Clause 1(c): revoked, on 1 June 2017, by clause 28(1) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

2 [Revoked]

Compare: Electricity Governance Rules 2003 clause 1A schedule J1

2A Requirement for certification
(1) Despite clause 15.38(1), a reconciliation participant that is required to obtain certification under clause 15.38 must obtain certification no later than,—
(a) in the case of a reconciliation participant that is recorded in the registry as being responsible for fewer than 100 ICPs of the kind described in subclause (2), 12 months after the reconciliation participant first performs a function specified in clause 15.38(1); or
(b) in every other case, the later of—
(i) 6 months after the date on which the reconciliation participant first performs a function specified in clause 15.38(1); or
(ii) the date on which the reconciliation participant is recorded in the registry as being responsible for 100 or more ICPs of the kind described in subclause (2).

(2) The kind of ICP referred to in subclause (1) is an ICP at which there is—
(a) 1 or more category 1 metering installations and no other kind of metering installation; and
(b) no unmetered load.

Clause 2A: inserted, on 1 June 2017, by clause 29 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
2B Reconciliation participants to obtain Authority approval before performing certain functions

(1) A reconciliation participant that proposes to perform a function listed in clause 15.38(1) without obtaining certification (in reliance on clause 2A) must obtain the Authority's prior approval.

(2) The Authority must give its approval if it is satisfied, on the basis of information provided to it by the reconciliation participant, that the reconciliation participant complies with such of the requirements specified in subclause (3) as are relevant to the reconciliation participant.

(3) The requirements are that the reconciliation participant must—
(a) be capable of producing submission information accurately;
(b) be capable of performing the functions described in clause 15.38(1)(d);
(c) be capable of switching an ICP in accordance with Schedule 11.3;
(d) be capable of managing an ICP in accordance with Schedule 11.1;
(e) understand its obligations under this Code.

Clause 2B: inserted, on 1 June 2017, by clause 29 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

3 Performance of reconciliation participant’s obligations by agent

A reconciliation participant may perform any obligation under this Schedule by an agent, and for that purpose, every act or omission of a reconciliation participant’s agent is deemed to be an act or omission of the reconciliation participant.

Compare: Electricity Governance Rules 2003 clause 1B schedule J1

4 Obtaining certification

(1) A reconciliation participant requiring certification to perform the functions specified in clause 15.38 must apply in writing to the Authority in the prescribed form, at least 2 months before the intended date of certification.

(2) The reconciliation participant must promptly provide such other information as the Authority may reasonably request.

(3) The reconciliation participant must indicate to the Authority the information gathering, processing and management functions it intends to perform and who it intends to use to perform those functions.

Compare: Electricity Governance Rules 2003 clauses 3.1 to 3.1B schedule J1

5 Granting certification

(1) The Authority must grant certification to a reconciliation participant only if—
(a) the Authority is satisfied, on the basis of an audit report provided to the Authority under Part 16A, that the reconciliation participant meets the requirements relevant to the functions specified in clause 15.38 for which the reconciliation participant is seeking certification.

(b) [Revoked]

(2) A reconciliation participant is responsible for appointing an auditor to undertake the audit required by subclause (1).

(3) [Revoked]

Compare: Electricity Governance Rules 2003 clause 3.2 schedule J1
Clause 5(1)(a): amended, on 1 June 2017, by clause 30(1)(a) and (b) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Clause 5(1)(b): revoked, on 1 June 2017, by clause 30(2) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Clause 5(3): revoked, on 1 June 2017, by clause 30(3) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

6 Lists of certified reconciliation participants
The Authority must publish, and keep updated—
(a) a list of certified reconciliation participants that includes, for each reconciliation participant, the date on which the certification expires.
(b) [Revoked]

Compare: Electricity Governance Rules 2003 clause 3A schedule J1

7 Renewal of certification
(1) Certification must not be granted for a term of more than 24 months.
(2) The Authority must renew a reconciliation participant’s certification for a further term of not more than 24 months if the Authority is satisfied on the basis of an audit report provided to the Authority under Part 16A that the reconciliation participant continues to meet the requirements specified in clause 5.

Compare: Electricity Governance Rules 2003 clause 3B schedule J1
Clause 7: amended, on 1 June 2017, by clause 32(1) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Clause 7(2): amended, on 1 June 2017, by clause 32(2) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

8 Changes that affect certification
(1) [Revoked]
(1A) If there is a material change to a reconciliation participant's systems or processes such that an audit is required under clause 16A.11, the Authority must, on receiving the audit report required by that clause, decide whether to continue the reconciliation participant's certification.
(2) The Authority must, by notice to the reconciliation participant, continue the reconciliation participant’s certification if the Authority is satisfied that the reconciliation participant will continue to meet the requirements in clause 5 after the change has come into effect.
(3) A reconciliation participant’s certification is revoked if—
(a) a reconciliation participant fails to provide an audit report to the Authority in accordance with clause 16A.11; or
(b) the Authority gives written notice to the reconciliation participant that the Authority is not satisfied that the reconciliation participant will continue to meet the requirements in clause 5 after the change has come into effect.

Compare: Electricity Governance Rules 2003 clause 3C schedule J1
Clause 8(1A): inserted, on 1 June 2017, by clause 33(2) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

8A [Revoked]
Clause 8A: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

9 [Revoked].
Compare: Electricity Governance Rules 2003 clause 5 Schedule J1
Clause 9: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

10 [Revoked]
Compare: Electricity Governance Rules 2003 clause 6 schedule J1
Clause 10: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

11 [Revoked]
Compare: Electricity Governance Rules 2003 clause 6A schedule J1
Clause 11: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

12 [Revoked]
Compare: Electricity Governance Rules 2003 clauses 8.1 and 8.1A schedule J1
Clause 12: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

13 [Revoked]
Compare: Electricity Governance Rules 2003 clause 8.2 schedule J1
Clause 13: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

14 [Revoked]
Compare: Electricity Governance Rules 2003 clause 8.2A schedule J1
Clause 14: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
15  [Revoked]
Compare: Electricity Governance Rules 2003 clause 8.3 schedule J1
Clause 15: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

16  [Revoked]
Compare: Electricity Governance Rules 2003 clause 8.4 schedule J1
Clause 16: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

17  [Revoked]
Compare: Electricity Governance Rules 2003 clause 8.5 schedule J1
Clause 17: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

18  [Revoked]
Compare: Electricity Governance Rules 2003 clause 8.6 schedule J1
Clause 18: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

19  [Revoked]
Compare: Electricity Governance Rules 2003 clause 8.7 schedule J1
Clause 19: revoked, on 1 June 2017, by clause 34 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Schedule 15.2
Collection of volume information

1 Contents of this Schedule
This Schedule establishes the required processes, in so far as they relate to the reconciliation process, for—
(a) collecting raw meter data, interrogating meters, and deriving validated meter readings; and
(b) creating estimated readings and permanent estimates; and
(c) deriving volume information from validated meter readings, estimated readings, and permanent estimates; and
(d) supporting data processing activities.

Compare: Electricity Governance Rules 2003 clause 1 schedule J2

2 Collection of raw meter data by certified reconciliation participant
(1) This clause applies to each metering installation for which a metering equipment provider is responsible, except for a metering installation—
(a) that only the metering equipment provider can electronically interrogate; or
(b) for which the metering equipment provider has an arrangement with the reconciliation participant, which prevents the reconciliation participant from electronically interrogating the metering installation.

(2) A reconciliation participant must obtain raw meter data used to determine volume information—
(a) from the services access interface of the metering installation; or
(b) if the raw meter data can only be obtained from the metering equipment provider’s back office, from the metering equipment provider.

(3) A reconciliation participant must ensure that the interrogation cycle for each metering installation that it interrogates does not exceed the maximum interrogation cycle in the registry.

(4) A reconciliation participant must interrogate a metering installation at least once in each maximum interrogation cycle for the metering installation.

(5) A reconciliation participant must, when electronically interrogating a metering installation,—
(a) ensure that the interrogation and processing system electronically monitors and corrects its internal clocks against a time source with a verifiable standard at a frequency sufficient, but no longer than 1 week, to ensure the internal clock is accurate, when carrying out an interrogation, to within ±5 seconds of—
   (i) New Zealand standard time; or
   (ii) New Zealand daylight time; and
(b) compare the time on the internal clock of the data storage device with the time on the interrogation and processing system clock; and
(c) calculate the time error for the data storage device; and
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(d) if the time error calculated under paragraph (c) is equal to or less than the applicable time error set out in Table 1, correct the clock of the data storage device; and
(e) if the time error calculated under paragraph (c) is greater than the applicable time error set out in Table 1,—
   (i) correct the clock of the data storage device; and
   (ii) compare the time of the clock with the time of the interrogation and processing system clock; and
   (iii) correct any affected raw meter data; and
(f) download the event log.

(6) The reconciliation participant must record in the interrogation and processing system logs, the time, the date, and the extent of any change in the internal clock setting in the metering installation.

Table 1: Maximum permitted time errors

<table>
<thead>
<tr>
<th>Metering installation category</th>
<th>Half-hour metering installations (seconds)</th>
<th>Non half-hour metering installations (seconds)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>±30</td>
<td>±60</td>
</tr>
<tr>
<td>2</td>
<td>±10</td>
<td>±60</td>
</tr>
<tr>
<td>3</td>
<td>±10</td>
<td>NA</td>
</tr>
<tr>
<td>4</td>
<td>±10</td>
<td>NA</td>
</tr>
<tr>
<td>5</td>
<td>±5</td>
<td>NA</td>
</tr>
</tbody>
</table>

Compare: Electricity Governance Rules 2003 clause 2 schedule J2

3 Source of volume information

(1) A meter reading must, in accordance with the relevant reconciliation participant’s certified processes and procedures, and using its certified facilities, be sourced directly from raw meter data, and if appropriate, be derived and calculated from financial records.

(2) A validated meter reading must be derived from a meter reading. A meter reading that is provided by a consumer may be used as a validated meter reading only if another set of validated meter readings that has not been provided by the consumer is used during the validation process specified in clauses 16 and 17.

(3) An estimated reading and a permanent estimate must be clearly identified as an estimate at source and in an exchange of metering data or volume information between participants (excluding the reconciliation manager).

(4) Volume information must be directly derived, in accordance with this Schedule, from—
   (a) validated meter readings; or
   (b) estimated readings; or
   (c) permanent estimates.
(5) A reconciliation participant must ensure that all raw meter data used to derive volume information in accordance with this Schedule is not rounded or truncated from the stored data from the metering installation.

Compare: Electricity Governance Rules 2003 clause 3 schedule J2

4 Permanence for the purposes of reconciliation
(1) Only volume information created using validated meter readings, or if such values are unavailable, permanent estimates, has permanence within the reconciliation processes (unless subsequently found to be in error).

(2) The relevant reconciliation participant must, at the earliest opportunity, and no later than the month 14 revision cycle, replace volume information created using estimated readings with volume information created using validated meter readings.

(3) If, despite having used reasonable endeavours for at least 12 months, a reconciliation participant has been unable to obtain a validated meter reading, the reconciliation participant must replace volume information created using an estimated reading with volume information created using a permanent estimate in place of a validated meter reading.

Compare: Electricity Governance Rules 2003 clause 4 schedule J2
Clause 4(2) and (3): replaced, on 1 February 2019, by clause 119(1) and (2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

5 Meter interrogation for non half hour metering

A reconciliation participant must, when manually interrogating a non half-hour metering installation, if the relevant parts of the metering installation are visible and it is safe to do so,—

(a) obtain the meter register value; and
(b) ensure seals are present and intact; and
(c) check for phase failure if the meter supports it; and
(d) check for signs of tampering or damage; and
(e) check for electrically unsafe situations, where “electrically unsafe” has the meaning given to it in the Electricity (Safety) Regulations 2010.

Compare: Electricity Governance Rules 2003 clause 5.1 schedule J2

6 When non half hour meter readings apply

Non half hour meter readings are deemed to apply—

(a) if the non half hour meter reading is also a switch event meter reading—
   (i) for the gaining trader, from 0000 hours on the day of the relevant event date; and
   (ii) for the losing trader, at 2400 hours at the end of the day before the relevant event date; or
(b) in all other cases, from 0000 hours on the day after the last meter interrogation up to and including 2400 hours on the day of the meter interrogation. Compare: Electricity Governance Rules 2003 clause 5.2 schedule J2 Clause 6: substituted, on 9 October 2015, by clause 27 of the Electricity Industry Participation Code Amendment (ICP Switching) 2014.

7 Non half hour meter reading during period of supply
(1) Each reconciliation participant must ensure that a validated meter reading is obtained in respect of every meter register for every non half hour metered ICP for which it is responsible, at least once during the period of supply to the ICP by the reconciliation participant, and used to create volume information. This may be a validated meter reading at the time the ICP is switched to, or from, the reconciliation participant.

(2) If exceptional circumstances prevent a reconciliation participant from obtaining the validated meter reading described in subclause (1), the reconciliation participant is not required to comply with subclause (1).

Compare: Electricity Governance Rules 2003 clauses 5.3 and 5.3A schedule J2

8 Non half hour meter reading on 12 monthly basis
(1) Each reconciliation participant must ensure that, at least once every 12 months, a validated meter reading is obtained for every meter register for non half hour metered ICPs that the reconciliation participant trades continuously for each 12 month period. In carrying out this obligation—
(a) each reconciliation participant must report to the Authority, in relation to each NSP, the percentage of the ICPs from which consumption information was collected and reported into the reconciliation process in the previous 12 month period. This report must be submitted no later than 20 business days after the end of each month; and

(b) if the percentage reported in accordance with paragraph (a) is less than 100%, the Authority may, from time to time, require the reconciliation participant to explain why that level was not achieved and to describe the steps that are being taken to achieve a level of performance that, in the Authority’s assessment, is reasonable.

(2) If exceptional circumstances prevent a reconciliation participant from obtaining the validated meter reading described in subclause (1), the reconciliation participant is not required to comply with subclause (1).

Compare: Electricity Governance Rules 2003 clauses 5.4 and 5.4A schedule J2 Clause 8(1): amended, on 5 October 2017, by clause 532(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

9 Non half hour meter reading every 4 months
(1) Each reconciliation participant must ensure, in relation to each NSP, that a validated meter reading is obtained, at least once every 4 months, for 90% of the non half hour metered ICPs at which the reconciliation participant trades continuously for each 4 months for which consumption information is required to be reported into the reconciliation process. In carrying out this obligation—
(a) each reconciliation participant must report to the Authority the percentage, in relation to each NSP, of the ICPs from which consumption information was collected and reported into the reconciliation process in the previous 4 month period. This report must be submitted no later than 20 business days after the end of each month; and

(b) if the percentage reported in accordance with paragraph (a) is less than 90% in relation to any NSP, the Authority may, from time to time, require the reconciliation participant to explain why that level was not achieved and to describe the steps that are being taken to achieve acceptable performance.

(2) If exceptional circumstances prevent a reconciliation participant from obtaining the validated meter reading described in subclause (1), the reconciliation participant is not required to comply with subclause (1).

(3) The reconciliation participant must report to the Authority monthly on a rolling 4 month basis the percentage of non half hour meter interrogations within that period.

Compare: Electricity Governance Rules 2003 clauses 5.5 and 5.5A schedule J2
Clause 9(1) and (3): amended, on 5 October 2017; by clause 553 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

10 Interrogation log
To verify the accuracy of raw meter data collected during interrogation of non half hour metering, a log must be produced consisting of the following as a minimum:

(a) the means to establish the identity of the individual meter reader:

(b) the ICP identifier, and the meter and register identification:

(c) the method being used for this interrogation and the device ID of equipment being used for interrogation of the meter:

(d) the date and time of the meter interrogation.

Compare: Electricity Governance Rules 2003 clause 5.6 schedule J2

11 Metering installation that is electronically interrogated
(1) A reconciliation participant must, as required under clause 2(2), obtain raw meter data from the services access interface for an electronically interrogated metering installation. This may be carried out through the use of portable devices or remotely by the use of a recognised communications medium.

(2) Raw meter data obtained by the electronic interrogation of a metering installation must consist of the following as a minimum:

(a) the unique identifier of the data storage device in the metering installation:

(b) the time from the data storage device at the commencement of the download, unless the time is within specification and the interrogation log automatically records the time of interrogation:

(c) the metering information, which represents the quantity of electricity conveyed at the point of connection, including the date and time stamp or index marker for each half hour period. This may be limited to the metering information accumulated since the last interrogation:

(d) the event log, which may be limited to the events information accumulated since the last interrogation:
(e) for all metering information, an interrogation log generated by the
interrogation software to record details of all interrogations. The
reconciliation participant responsible for collecting the data must peruse the
interrogation log and take appropriate action if problems are apparent.
Alternatively, this process may be an automated software function that flags
exceptions.

(3) For the purposes of subclause (2)(e), the interrogation log must form part of the
interrogation audit trail and must contain the following as a minimum:

(a) the date of interrogation:
(b) the time of commencement of interrogation:
(c) the operator identification (if available):
(d) the unique identifier of the data storage device:
(e) the time errors outside the range specified in Table 1 of clause 2:
(f) the method of interrogation:
(g) the identifier of the reading device used for interrogation (if applicable).

Compare: Electricity Governance Rules 2003 clause 6.1 schedule J2
Clause 11: substituted, on 29 August 2013, by clause 26 of the Electricity Industry Participation (Metering

12 [Revoked]

Compare: Electricity Governance Rules 2003 clause 6.2 schedule J2
Clause 12 and Table 1: revoked, on 29 August 2013, by clause 27 of the Electricity Industry Participation (Metering

13 Trading period
The trading period duration, which is normally 30 minutes, must be within ±0.1% (± 2
seconds).


14 Quantification error

[Revoked]

Compare: Electricity Governance Rules 2003 clause 6.4 schedule J2
Clause 14: amended, on 21 September 2012, by clause 40 of the Electricity Industry Participation (Minor
Clause 14: amended, on 29 August 2013, by clause 28 of the Electricity Industry Participation (Metering
Clause 14: revoked, on 1 February 2016, by clause 103 of the Electricity Industry Participation Code Amendment
(Code Review Programme) 2015.

15 Half hour estimates

(1) If a reconciliation participant is unable to interrogate an electronically interrogated
metering installation before the deadline for providing submission information or
dispatchable load information, the reconciliation participant must submit to the
reconciliation manager its best estimate of the quantity of electricity that was
purchased or sold in each trading period during any applicable consumption period
for that metering installation.

(2) The reconciliation participant must use reasonable endeavours to ensure that
estimated submission information is within the percentage specified by the Authority.
Validation

16 Non half-hour meter readings and estimated readings

(1) All non half-hour meter readings and estimated readings must be checked for validity by the relevant reconciliation participant after each interrogation.

(2) Each validity check of non half-hour meter readings and estimated readings must include the following:
   (a) confirmation that the meter reading or estimated reading relates to the correct ICP, meter, and register;
   (b) checks for invalid dates and times;
   (c) confirmation that the meter reading or estimated reading lies within an acceptable range compared with the expected pattern, previous pattern or trend;
   (d) confirmation that there is no corruption of the data, including unexpected 0 values.

Compare: Electricity Governance Rules 2003 clause 7.1 schedule J2

17 Electronic meter readings and estimated readings

(1) All meter readings obtained by electronic interrogation and estimated readings must be checked for validity by the relevant reconciliation participant.

(2) Each validity check of a meter reading obtained by electronic interrogation and each estimated reading must be at a frequency that will allow a further interrogation of the data storage device before the data is overwritten within the data storage device and before the data can be used for any purpose under this Code.

(3) [Revoked]

(4) Each validity check of a meter reading obtained by electronic interrogation or an estimated reading must include the following:
   (a) checks for missing data:
   (b) checks for invalid dates and times;
   (c) checks of unexpected 0 values:
   (d) comparison with expected or previous flow patterns:
   (e) comparison of meter readings with data on any data storage device registers that are available:
   (f) a review of meter and data storage device event log. Any event that could have affected the integrity of metering data must be investigated.

Compare: Electricity Governance Rules 2003 clause 7.2 schedule J2

Clause 17(1) and (2): substituted, on 29 August 2013, by clause 30(a) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.
Clause 17(3): revoked, on 29 August 2013, by clause 30(b) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.
Clause 17(4): amended, on 29 August 2013, by clause 30(c) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.
18 Archiving and storing of raw meter data

(1) A reconciliation participant who is responsible for interrogating a metering installation under this Part must archive all raw meter data downloaded or collected, and any changes to the raw meter data, for not less than 48 months in accordance with clause 8(6) of Schedule 10.6 with all necessary amendments.

(2) Each reconciliation participant must ensure that procedures are in place to ensure that raw meter data for which it is responsible cannot be accessed by unauthorised personnel.

(3) Each reconciliation participant must ensure that meter readings cannot be modified without an audit trail being created.

19 Correction of meter readings

(1) If a reconciliation participant detects errors while validating non half hour meter readings, the reconciliation participant must—
   (a) confirm the original meter reading by carrying out another meter reading; and
   (b) if the second meter reading confirms that the original meter reading is erroneous, replace the original meter reading with the second meter reading (even if the second meter reading is at a different date).

(1A) If a reconciliation participant detects errors while validating non half hour meter readings, but the reconciliation participant cannot confirm the original meter reading or replace it with a meter reading from another interrogation, the reconciliation participant must—
   (a) substitute the original meter reading with an estimated reading that is marked as an estimate; and
   (b) subsequently replace the estimated reading in accordance with clause 4(2).

(2) If a reconciliation participant detects errors while validating half-hour meter readings, the reconciliation participant must correct the meter readings as follows:
   (a) if the relevant metering installation has a check meter or data storage device, substitute the original meter reading with data from the check meter or data storage device; or
   (b) if the relevant metering installation does not have a check meter or data storage device, substitute the original meter reading with data from another period provided—
      (i) the total of all substituted intervals matches the total consumption recorded on a meter, if available; and
      (ii) the reconciliation participant considers the pattern of consumption to be materially similar to the period in error.

(3) A reconciliation participant may use error compensation and loss compensation as part of the process of determining accurate data. Whatever methodology is used, the reconciliation participant must document the compensation process and comply with audit trail requirements set out in this Code.
(4) In correcting a meter reading in accordance with this clause, a reconciliation participant must not overwrite the raw meter data. If the raw meter data and the meter readings are the same, the reconciliation participant must use the processing or data correction application to—
(a) make an automatic secure backup of the affected data; and
(b) archive the affected data.

(5) If a reconciliation participant corrects or alters data under this clause, the reconciliation participant must generate and archive a journal that contains the following information:
(a) the date of the correction or alteration; and
(b) the time of the correction or alteration; and
(c) the operator identifier for the person within the reconciliation participant who made the correction or alteration; and
(d) the half hour meter reading data or the non half hour meter reading data corrected or altered, and the total difference in volume of such corrected or altered data; and
(e) the technique used to arrive at the corrected data; and
(f) the reason for the correction or alteration.

Compare: Electricity Governance Rules 2003 clause 9 schedule J2
Clause 19(2); amended, on 29 August 2013, by clause 32 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.
Clause 19; replaced, on 1 November 2018, by clause 120 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

20 Data transmission
Transmissions and transfers of data related to metering between reconciliation participants or reconciliation participant’s agents, for the purposes of this Code, must be carried out electronically, using systems that ensure the security and integrity of the data transmitted and received.

Compare: Electricity Governance Rules 2003 clause 10 schedule J2

21 Audit trails
(1) Each reconciliation participant must ensure that a complete audit trail exists for all data gathering, validation and processing functions of the reconciliation participant.
(2) The audit trail must—
(a) include details of information—
(i) provided to and received from the registry manager; and
(ii) provided to and received from the reconciliation manager; and
(iii) provided and received from other reconciliation participants and their agents; and
(b) cover all raw meter data and any changes to the raw meter data archived under clause 18.
(3) Logs of communications and processing activities must form part of the audit trail, including if automated processes are in operation.
(4) Logs must be printed and filed as hard copy or maintained as data files, in a secure form, along with other archived information, and must include (at a minimum) the following:
(a) an activity identifier; and  
(b) the date and time of the activity; and  
(c) the operator identifier for the person within the reconciliation participant who performed the activity.  

(5) A reconciliation participant must collect all relevant data used by the reconciliation participant to determine profile data, including external control equipment operation logs, and archive that data in accordance with clause 18.

Compare: Electricity Governance Rules 2003 clause 11.1 to 11.3 schedule J2
Clause 21(2)(b): substituted, on 29 August 2013, by clause 33(a) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

22 [Revoked]

Compare: Electricity Governance Rules 2003 clause 11.4 schedule J2
Schedule 15.3

Calculation and provision of submission information

1 Contents of this schedule
This Schedule provides for—
(a) the processing of raw meter data and supporting information to create submission information; and
(b) the delivery of submission information to the reconciliation manager.

Compare: Electricity Governance Rules 2003 clause 1 schedule J3

Creation of submission information

2 Reconciliation participants to prepare information
(1) If a reconciliation participant is required to prepare submission information for an NSP for the relevant consumption period in accordance with this Code, the submission information for each ICP about which information is provided under clause 11.7(2)—
   (aa) must comprise all volume information for the ICP:
   (a) must comprise half hour volume information for the total metered quantity of electricity for each category 3 or higher metering installation:
   (ab) must not comprise half hour volume information for a non half-hour metering installation:
   (ac) must comprise either half hour volume information or non half hour volume information for the total metered quantity of electricity for each metering installation that—
      (i) is a category 1 metering installation or category 2 metering installation;
      and
      (ii) is a half-hour metering installation:
   (ad) must comprise non half hour volume information calculated under clauses 4 to 6 (as applicable) for the total metered quantity of electricity for each metering installation that—
      (i) is a category 1 metering installation or category 2 metering installation;
      and
      (ii) contains only non half-hour metering:
   (ae) if a metering installation is a category 1 metering installation or category 2 metering installation, and the metering installation contains half-hour metering and non half-hour metering, may comprise—
      (i) a combination of—
         (A) half hour volume information for the half-hour metering; and
         (B) non half hour volume information calculated under clauses 4 to 6 (as applicable) for the non half-hour metering; or
      (ii) non half hour volume information for the total metered quantity of electricity for the metering installation:
   (b) [Revoked]
   (c) must include unmetered load quantities for each ICP that has unmetered load associated with it, which must be derived from the quantity recorded in the
registry against the relevant ICP and the number of days in the period, the distributed unmetered load database, or other sources of relevant information.

(1A) However, a reconciliation participant need not comply with subclause (1)(a) to (ae) if—
   (a) the reconciliation participant is using a profile approved in accordance with Schedule 15.5; and
   (b) the approved profile allows the reconciliation participant to prepare submission information that does not comply with subclause (1)(a) to (ae); and
   (c) the reconciliation participant complies with the submission information requirements set out in the approved profile.

(2) To create non half hour submission information, a reconciliation participant must only use information that is dependent on a control device if—
   (a) the certification of the control device is recorded in the registry; or
   (b) the metering installation in which the control device is located is an interim certified metering installation.

(3) To create submission information for a point of connection for which it is responsible, a reconciliation participant must use volume information from each metering installation for the point of connection.

(4) For the purposes of subclause (3), the reconciliation participant must calculate the volume information by applying to the raw meter data obtained from each metering installation—
   (a) for each ICP, the compensation factor recorded in the registry for the metering installation; or
   (b) for each NSP, the compensation factor recorded in the metering installation's most recent certification report.

Compare: Electricity Governance Rules 2003 clause 2.1 schedule J3
Clause 2: substituted, on 29 August 2013, by clause 34 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

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 clause 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 and 5, a permanent estimate may be used in place of a validated meter reading.

Compare: Electricity Governance Rules 2003 clause 2.2 schedule J3

4 Historical estimates with seasonal adjustment

The methodology that must be used by each reconciliation participant to prepare an historic estimate of volume information for each ICP when the relevant seasonal adjustment shape is available, 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:

\[ HE_{ICP} = \frac{kWh_p \times A}{B} \]

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:

\[ HE_{ICP} = \frac{kWh_{p1} \times A_1}{B_1} + \frac{kWh_{p2} \times A_2}{B_2} \]

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}.

**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, 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}.

**Forward estimates**

(1) A **forward estimate** is an estimation of the total quantity of electricity that flowed through an ICP during all or part of a consumption period.

(2) A **forward estimate** may be used only for a period for which an historical estimate cannot be calculated.

(3) The methodology used for calculating a forward estimate may be determined at the discretion of the reconciliation participant, and only if the reconciliation participant ensures that the accuracy of its initial submission information against each subsequent revision cycle submission information for each balancing area is within the percentage of error specified and published, from time to time, by the Authority.

Compare: Electricity Governance Rules 2003 clauses 2.2.1 schedule J3
7 Compulsory meter reading after profile change
(1) If a reconciliation participant changes the profile associated with a meter, it must, when determining the volume information for that meter and its respective ICP, use a validated meter reading or permanent estimate on the day on which the profile change is to take effect.
(2) The reconciliation participant must use the volume information from that validated meter reading or permanent estimate to calculate the relevant historical estimates of each profile for that meter.

8 Provision of submission information to reconciliation manager
(1) For each metering installation for which it is responsible that is category 3 or higher, a reconciliation participant must provide half hour submission information to the reconciliation manager.
(2) For each half-hour metering installation for which it is responsible that is a category 1 metering installation or category 2 metering installation, a reconciliation participant must provide to the reconciliation manager—
   (a) half hour submission information; or
   (b) non half hour submission information; or
   (c) a combination of half hour submission information and non half hour submission information if—
      (i) the half-hour metering installation contains a combination of half-hour metering and non half-hour metering; and
      (ii) clause 2(1)(ae) of this Schedule 15.3 applies.
(3) For each non half-hour metering installation for which it is responsible, a reconciliation participant must provide non half hour submission information to the reconciliation manager.
(4) However, a reconciliation participant need not comply with subclause (2) and subclause (3) if—
   (a) the reconciliation participant is using a profile approved in accordance in Schedule 15.5; and
   (b) the approved profile allows the reconciliation participant to provide half hour submission information from a non half-hour metering installation; and
   (c) the reconciliation participant provides submission information that complies with the requirements set out in the approved profile.
(5) For any unmetered load at an ICP for which it is responsible, regardless of the category of any metering installation at the ICP, a reconciliation participant must provide non half hour submission information to the reconciliation manager unless—
   (a) the Authority has approved a profile for the unmetered load that allows the reconciliation participant to provide half hour submission information to the reconciliation manager for the unmetered load; and
   (b) the reconciliation participant provides half hour submission information in accordance with the profile.
(6) The half hour submission information that a reconciliation participant submits under subclause (1), subclause (2), or subclause (4) must be volume information aggregated to the following levels:
Electricity Industry Participation Code 2010
Schedule 15.3

(a) NSP code:
(b) reconciliation type:
(c) profile:
(d) loss category code:
(e) flow direction:
(f) dedicated NSP:
(g) trading period.

(7) The non half hour submission information that a reconciliation participant submits under subclause (2), subclause (3), and subclause (5) must be volume information aggregated to the following levels:
(a) NSP code:
(b) reconciliation type:
(c) profile:
(d) loss category code:
(e) flow direction:
(f) dedicated NSP:
(g) consumption period or day.

Compare: Electricity Governance Rules 2003 clause 3 schedule J3

9 Rounding of submission information
If submission information aggregated by a reconciliation participant under clause 8 is specified to more than 2 decimal places, the reconciliation participant must round the submission information—
(a) to 2 decimal places; and
(b) so that if the digit to the right of the second decimal place is greater than or equal to 5, the second digit is rounded up, and if the digit to the right of the second decimal place is less than 5, the second digit is unchanged.

Compare: Electricity Governance Rules 2003 clause 3A schedule J3

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 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 per NSP, 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 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.

Compare: Electricity Governance Rules 2003 clause 4 schedule J3

11 Distributed unmetered load database

(1) A retailer must ensure that an up-to-date database is maintained for each type of distrubuted unmetered load for which it is responsible. The methodology for deriving submission information in the database must comply with Schedule 15.5.

(2) The database must contain at a minimum—

(a) each ICP identifier for which the retailer is responsible, and to which distributed unmetered load is electrically connected; and

(aa) the item or items of distributed unmetered load associated with each ICP identifier; and

(b) the location of each item; and

(c) a description of load type for each item, including any assumptions made in the assessment of its capacity; and

(d) the capacity of each item in watts.

(2A) Each retailer must ensure that each item of distributed unmetered load for which the retailer is responsible is recorded in the database in accordance with this clause.

(3) The database must track the time of additions and changes in a way that enables the total load in kW to be retrospectively derived for any day.

(4) The database must incorporate an audit trail of all additions and changes identifying the before and after values for changes, date and time of the change or addition, and the person making the change or addition.

(5) [Revoked]

Compare: Electricity Governance Rules 2003 clause 5 schedule J3


Clause 11(2A): inserted, on 1 June 2017, by clause 35(2) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

Clause 11(5): revoked, on 1 June 2017, by clause 35(3) of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Schedule 15.4

Reconciliation procedures

cls 15.19, 15.20 and 15.21

1 Contents of this Schedule

This Schedule relates to the parts of the reconciliation process performed by the reconciliation manager during each reconciliation period and for relevant consumption periods in accordance with the revision cycle. The following steps comprise the reconciliation process. The requirements of each of these steps are detailed in the remainder of this Schedule. The steps are that the reconciliation manager must—

(a) adjust submission information by ICP days scaling; and

(b) apply loss factors to submission information for half hour metered ICPs that have been adjusted for ICP days; and

(c) profile non half hour submission information into trading periods; and

(d) apply loss factors to submission information for non half hour metered ICPs that have been adjusted for ICP days; and

(e) calculate unaccounted for electricity for each balancing area; and

(f) allocate consumed electricity and unaccounted for electricity to purchasers; and

(g) allocate generated electricity to generators; and

(h) produce reports.

Compare: Electricity Governance Rules 2003 clause 1 schedule J4

2 Overview of key reconciliation events

Each reconciliation participant must comply with the timing requirements summarised below:

<table>
<thead>
<tr>
<th>Timing</th>
<th>Reconciliation process</th>
<th>Revisions cycles</th>
</tr>
</thead>
<tbody>
<tr>
<td>Commencement of the 1st day of the reconciliation period</td>
<td>Beginning of reconciliation period.</td>
<td>Beginning of reconciliation period.</td>
</tr>
<tr>
<td>By 1600 hours on the 4th business day of the reconciliation period</td>
<td>The registry manager must make available, and the reconciliation manager must procure, ICP days, loss factor and balancing area and half hour ICP identifiers information, in accordance with clauses 11.24 to 11.27. Each reconciliation participant must submit to the reconciliation manager submission information, retailer information and</td>
<td></td>
</tr>
</tbody>
</table>

45 1 February 2019
<table>
<thead>
<tr>
<th>Timing</th>
<th>Reconciliation process</th>
<th>Revisions cycles</th>
</tr>
</thead>
<tbody>
<tr>
<td>By 1600 hours on the 7th business day of the reconciliation period</td>
<td>The reconciliation manager must complete a reconciliation of the submission information provided by participants and the grid owner in accordance with this Schedule, and must make reconciliation information available to each reconciliation participant who submitted the submission information to which it relates, and the clearing manager for settlement.</td>
<td></td>
</tr>
<tr>
<td>From the 8th business day of the reconciliation period</td>
<td>Each reconciliation participant must seek to resolve all inaccuracies and disputes concerning the reconciliation information.</td>
<td></td>
</tr>
<tr>
<td>By 1600 hours on the 13th business day of the reconciliation period</td>
<td>Each reconciliation participant must submit to the reconciliation manager revised submission information, retailer information and NSP information in accordance with clauses 15.4 to 15.12, 15.27, and 15.28, and clause 10 of Schedule 15.3. The registry manager must make available and the reconciliation manager must procure revised ICP days, loss factor, balancing area and half hour ICP identifiers information, in accordance with clauses 11.24 to 11.27, and clause 10 of Schedule 15.3.</td>
<td></td>
</tr>
</tbody>
</table>
### Calculation by difference for embedded networks

1. A trader may by written notice to the reconciliation manager designate an ICP on an embedded network for which the volume information is to be calculated by difference.

2. A trader must give notice under subclause (1) at least 5 business days before the designation of the ICP takes effect.

3. Not more than 1 ICP on an embedded network may be designated at any time.

4. The reconciliation manager must calculate the volume information by trading period for an ICP to which a designation relates using the following formula:

   \[ i - x = a \]

   where

   - \( i \) is the loss adjusted quantity of electricity injected into the embedded network derived from NSP and submission information
   - \( x \) is the loss adjusted quantity of electricity leaving the embedded network derived from NSP and submission information
   - \( a \) is the differenced volume information for the ICP to which the designation relates.

5. The reconciliation manager must allocate the volume information calculated under subclause (4) to the ICP to which the designation relates.

6. A trader may, by written notice to the reconciliation manager, revoke a designation made under subclause (1).

### Calculation by difference for local networks

1. A trader may apply to the Authority for the Authority to designate part of a local network for which the volume information is to be calculated by difference.

2. A trader must give notice under subclause (1) at least 10 business days before the date the trader intends the designation to take effect.
(3) The trader must comply with any requirements specified by the reconciliation manager within 5 business days of receiving notice of the requirements.

(4) If the Authority grants a designation, the reconciliation manager must calculate the volume information by trading period for an ICP to which the designation relates using the following formula:

\[ i - x = a \]

where

- \( i \) is the loss adjusted quantity of electricity injected into the local network derived from NSP and submission information
- \( x \) is the loss adjusted quantity of electricity leaving the local network derived from NSP and submission information
- \( a \) is the differenced volume information for the ICP to which the designation relates.

(5) The reconciliation manager must allocate the volume information calculated under subclause (4) to the trader who applied for the designation under subclause (1).

(6) The Authority may revoke the approval of a designation granted under subclause (1).

Compare: Electricity Governance Rules 2003 clause 3A schedule J4

5 ICP days scaling of submission information excluding embedded generation information

ICP scaling must be used to adjust each retailer’s submission information (excluding embedded generator information) by a factor determined by the number of ICP days submitted for reconciliation compared to the number of ICP days recorded in the registry.

Compare: Electricity Governance Rules 2003 clause 4 schedule J4

6 ICP days information

(1) Each retailer and each direct purchaser (excluding direct consumers) must deliver to the reconciliation manager, in accordance with clause 15.6, the number of half hour and non half hour ICP days for the NSPs that are recorded in the registry as consuming electricity at any time during the relevant consumption period, upon which the retailer’s or direct purchaser’s submission information is based.

(2) The registry manager must deliver to the reconciliation manager, in accordance with clauses 11.24 to 11.27, the number of half hour and non half hour ICP days per NSP each retailer and direct purchaser (excluding direct consumers) is responsible for during each consumption period.

Compare: Electricity Governance Rules 2003 clause 4.1 schedule J4
7 ICP scaling factor calculation

(1) The reconciliation manager must, using the retailer and direct purchaser reported ICP days and registry reported ICP days, calculate ICP day scaling factors separately in respect of non half hour and half hour metered ICPs according to the following formula:

\[ \text{ICP}_{\text{SF}} = \frac{\text{ICP}_{\text{REG}}}{\text{ICP}_{\text{RTL}}} \]

where

- \( \text{ICP}_{\text{SF}} \) is the ICP scaling factor
- \( \text{ICP}_{\text{REG}} \) is the number of ICP days for that retailer per balancing area as reported by the registry manager
- \( \text{ICP}_{\text{RTL}} \) is the number of ICP days for that retailer for that balancing area as reported by each retailer

provided that if—

(a) the ICP scaling factor is calculated to be less than 1, it must, for the purposes of this clause, be deemed to be 1; and

(b) the ICP scaling factor is calculated to be greater than 1, it must not exceed a figure nominated and published from time to time by the Authority.

(2) The ICP days scaling factor for direct consumers must be 1.

(3) If the ICP days value reported by a retailer or a direct purchaser in respect of a balancing area is 0, or if data is not supplied, but in each case the corresponding ICP days value from the registry manager is not 0, the reconciliation manager must add to that retailer's submission information for that consumption period an amount (designated SIICPD-ADD) that is equal to—

(a) 25 kWh per ICP day, in respect of non half hour ICPs; and

(b) 40 kWh per trading period per ICP day, in respect of half hour ICPs.

(4) The relevant number of ICP days is the value reported by the registry manager.

(5) The reconciliation manager must, when processing 0 ICP days information, and if data is not supplied, use default values for profile, and loss category code, as determined by the Authority from time to time.

Compare: Electricity Governance Rules 2003 clause 4.2 schedule J4
Clause 7(1), (3) and (4); amended, on 5 October 2017, by clause 539 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

8 ICP days scaling of submission information (excluding embedded generator information)

(1) The reconciliation manager must separately apply the ICP scaling factors and any additional amount calculated in clause 7 to the reported half hour and non half hour submission information (excluding embedded generator information) of each retailer or direct purchaser (excluding direct consumers) so as to scale up the
submission information in proportion to any under submission by the retailer or direct purchaser.

(2) The ICP scaling factor and any amount calculated in accordance with clause 7 must be applied to the submission information according to the following formula:

\[ \text{SI}_{\text{ICPD-ADJ}} = (\text{SI} \times \text{ICP}_{\text{SF}}) + \text{SI}_{\text{ICPD-ADD}} \]

where

- \( \text{SI}_{\text{ICPD-ADJ}} \) is submission information adjusted for ICP days
- \( \text{SI} \) is the amount of electricity reported as part of that retailer’s or direct purchaser’s submission information
- \( \text{ICP}_{\text{SF}} \) is the ICP scaling factor determined in accordance with clause 7
- \( \text{SI}_{\text{ICPD-ADD}} \) is the default ICP 0 days volume defined under clause 7(3).

Compare: Electricity Governance Rules 2003 clause 4.3 schedule J4

9 Calculate residual non half hour profile shape
The reconciliation manager must calculate the residual profile shape for each balancing area in accordance with Schedule 15.5.

Compare: Electricity Governance Rules 2003 clause 5 schedule J4

Convert non half hour quantities using profiles

10 Allocation by profile
If submission information is submitted as non half hour quantities to be allocated to trading periods by profile shape, the reconciliation manager must use the appropriate shape for the profile code contained in the submission information, if—
(a) the profile code has been approved by the Authority in accordance with Schedule 15.5; and
(b) the profile owner has given written notice to the reconciliation manager of the approved profile code; and
(c) the profile owner has authorised the reconciliation participant to use the approved profile code.

Compare: Electricity Governance Rules 2003 clause 6.1 schedule J4
Clause 10(a) and (b): amended, on 5 October 2017, by clause 540 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

11 Profile shapes or operation logs
If an engineered, statistically sampled or recorded profile forms part of the submission information, the shape file or operation logs associated with the profile must be provided to the reconciliation manager by the reconciliation participant authorised by the profile owner to use that profile for each relevant NSP in respect of the prior consumption period in accordance with clauses 15.4 to 15.12.

Compare: Electricity Governance Rules 2003 clause 6.2 schedule J4
12 Application of profile shapes

The reconciliation manager must calculate the trading period information by applying the profile shape for the profile code specified in the submission file provided by the reconciliation participant if—
(a) the profile code has been approved by the Authority in accordance with Schedule 15.5; and
(b) the profile owner has given written notice to the reconciliation manager of the approved profile code, and the profile owner has authorised the reconciliation participant to use the approved profile code; and
(c) if a balancing area shape is required as part of the profile, the initial residual or final residual profile shape as defined in Schedule 15.5 must be used.

Compare: Electricity Governance Rules 2003 clause 6.3 schedule J4
Clause 12(a) and (b): amended, on 5 October 2017, by clause 541 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

13 Balancing area derived profiles approved in accordance with Appendix 1 of Schedule 15.5

The reconciliation manager must calculate the trading period information by applying the balancing area derived profile code specified in the submission file provided by the reconciliation participant, if—
(a) the profile code has been approved by the Authority for use as a balancing area derived profile in accordance with Schedule 15.5; and
(b) the profile owner has given written notice to the reconciliation manager of the approved profile code, and that the profile owner has authorised the reconciliation participant to use the approved profile code; and
(c) if the Authority has not approved the profile code, or submitted the profile code to the reconciliation manager in accordance with clause 12(1) of Appendix 1 of Schedule 15.5, the reconciliation manager must use the final residual profile shape as defined in Schedule 15.5.

Compare: Electricity Governance Rules 2003 clause 6.4 schedule J4
Clause 13(a) and (b): amended, on 5 October 2017, by clause 542(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 13(c): replaced, on 5 October 2017, by clause 542(c) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

14 Invalid submission information

If invalid submission information is submitted, and the reconciliation manager cannot obtain corrected information within a reasonable time period from the reconciliation participant, the reconciliation manager must—
(a) use the default values specified in this Code (if any); or
(b) if the default values described in paragraph (a) do not exist, use the default values specified by the Authority (if any); or
(c) if the default values described in paragraph (b) do not exist, temporarily replace the invalid data with an estimate.

Compare: Electricity Governance Rules 2003 clause 6.5 schedule J4
15 Loss factors

(1) The Authority may, from time to time, direct the reconciliation manager to apply certain values for loss factors for each loss category for a reconciliation period for which the registry manager does not, for whatever reason, provide the reconciliation manager with the loss factors for each loss category in accordance with clause 11.26(b).

(2) If the Authority makes such a direction, the reconciliation manager must, after adjustment for ICP days scaling and the application of profiles, apply such loss factors to all submission information for all reconciliation periods during which the Authority’s direction is current.


16 Calculation of unaccounted for electricity

(1) The reconciliation manager must calculate the unaccounted for electricity for each balancing area for each trading period in accordance with the following formula after all relevant quantities have been loss adjusted and scaled for ICP days:

\[ \text{UFE}_{BA} = \text{TOT}_{BA} - \text{Q}_{BA-EN} \]

where

- \( \text{UFE}_{BA} \) is the unaccounted for electricity for each balancing area for the relevant trading period
- \( \text{TOT}_{BA} \) is the net total of all electricity injected into the balancing area less all electricity leaving the balancing area as measured at—
  - (a) the NSPs in respect of the balancing area; and
  - (b) the ICPs for any embedded generators electrically connected to the balancing area
- \( \text{Q}_{BA-EN} \) is all electricity conveyed to consumers connected to the balancing area, being the sum of the consumption parts of submission information, adjusted for losses and ICP days.

(2) The reconciliation manager must calculate the UFE factor in respect of each balancing area for each trading period as follows:

\[ \text{UFE Factor}_{BA} = \frac{\text{TOT}_{BA}}{\text{Q}_{ICPD-LA}} \]

where

- \( \text{UFE Factor}_{BA} \) is the unaccounted for electricity factor in respect of each balancing area for each trading period
Q_{ICPD-LA} is all electricity conveyed to consumers and embedded networks connected to the balancing area, being the sum of the consumption parts of submission information, adjusted for losses and ICP days. TOT_{BA} has the meaning given to it in subclause (1).

17 Scorecard rating
(1) The reconciliation manager must rate each retailer relative to all other retailers using a scorecard rating. The numerical scores must be determined in accordance with this clause and clause 18 and used to weight the portion of unaccounted for electricity to be allocated to each retailer.
(2) Each retailer must provide to the reconciliation manager, in accordance with clause 15.7, the quantity of electricity supplied.
(3) The reconciliation manager must allocate electricity supplied quantities, to reconciliation periods for reporting and calculation purposes and in the event of unusual circumstances that must have been approved beforehand in writing by the Authority, re-allocate quantities on a reasonable basis to reflect the month(s) of actual usage.

18 Calculation of scorecard rating
(1) The reconciliation manager must calculate, publish and apply the scorecard rating for each retailer as follows:
(a) the scorecard rating for each retailer must be calculated and published by the reconciliation manager in respect of each reconciliation period from which the reconciliation manager processes submission information, but must only be applied in respect of the 7 and 14 month revisions;
(b) the scorecard rating for each retailer for each balancing area (SC_{RI}) must, subject to subclause (4), be calculated according to the following formula (provided that if the scorecard rating is calculated through the application of the formula to be less than 1, then SC_{RI} is set to 1):

$$ SC_{RI} = \frac{AES_{RI}}{(ACI_{RI} \times SC_{Thres})} $$

where
SC_{Ri} \quad SC \text{ is the scorecard rating and the subscript “Ri” is a retailer, for each consumption period and each balancing area}

AES_{Ri} \quad \text{is the sum of the electricity supplied quantities for the 12 months up to and including the month of the relevant consumption period}

ACI_{Ri} \quad \text{is the sum of the submission information quantities (ICP days adjusted but non loss adjusted) for the 12 months up to and including the month before the relevant consumption period}

SC_{Thres} \quad \text{is the scorecard threshold (that allows for a degree of expected misalignment between the annualised electricity supplied and submission information quantities) and has the value specified by the Authority from time to time:}

(c) \quad \text{in all cases, the latest electricity supplied and submission information quantities submitted to the reconciliation manager by the retailer must be used.}

(2) \quad \text{The scorecard rating for each retailer must be set to 1.25 if the retailer has not provided the reconciliation manager with any of the required information.}

(3) \quad \text{Despite subclauses (1) and (2), the scorecard rating for direct consumers and direct purchasers must be 1.}

(4) \quad \text{Despite anything else in this Code, the scorecard rating must be set to 1 until such time as the Authority gives written notice to participants that the scorecard rating will be calculated and applied in accordance with this clause.}

Compare: Electricity Governance Rules 2003 clauses 9.2 and 9.3 schedule J4

19 Calculation of unaccounted for electricity

The reconciliation manager must apportion unaccounted for electricity to each retailer and direct purchaser at each NSP and for each trading period using the following formulae:

\[
UF_{E_{Ri}} = UF_{E_{BA}} \times AF_{Ri}
\]

\[
AF_{Ri} = \frac{(SC_{Ri} \times MS_{Ri})}{\sum(SC_{R1} \times MS_{R1}, ..., SC_{Rn} \times MS_{Rn})}
\]

\[
MS_{Ri} = \frac{Q_{ICPD-LA Ri}}{\sum(Q_{ICPD-LA 1}, ..., Q_{ICPD-LA n})}
\]

where, for each trading period

UF_{E_{Ri}} \quad \text{is the quantity of unaccounted for electricity to be allocated to each retailer or direct purchaser}

UF_{E_{BA}} \quad \text{is the quantity of unaccounted for electricity for each balancing area calculated by the reconciliation manager in accordance with clause 16(1)}
Q<sub>ICPD-LA Ri</sub> is the quantity of electricity attributed to each retailer or direct purchaser, which has been adjusted for losses and ICP days at each NSP, determined by the reconciliation manager from that retailer’s or direct purchaser’s submission information.

AF<sub>Ri</sub> is the unaccounted for electricity allocation factor, expressed as a fractional number (not less than 0 or greater than 1), for each retailer or direct purchaser at each NSP, determined by the reconciliation manager.

MS<sub>Ri</sub> is the market share proportion, expressed as a fractional number (not less than 0 or greater than 1), for each retailer or direct purchaser at each NSP to be determined by the reconciliation manager from all submission information at that NSP.

and, for each consumption period

SC<sub>Ri</sub> is the scorecard rating for each retailer or direct purchaser for each balancing area determined by the reconciliation manager in accordance with clauses 17 and 18.

20 Allocation of unaccounted for electricity

The reconciliation manager must add each retailer’s or direct purchaser’s share of unaccounted for electricity to the previously calculated ICP days and loss adjusted submission information at each NSP for each trading period using the following formula:

\[ Q_{ILU Ri} = Q_{ICPD-LA Ri} + UFERi \]

where, for each trading period

Q<sub>ILU Ri</sub> is the quantity of electricity to be attributed to each retailer or direct purchaser that has been ICP days scaled, and loss adjusted and is UFE inclusive.

Q<sub>ICPD-LA Ri</sub> and UFERi have the meaning given to them in clause 19.

21 Parent network UFE allocated to embedded networks

A portion of the UFE from the balancing area to which an embedded network is connected must be allocated by the reconciliation manager to each reconciliation participant trading on the embedded network. The quantity of UFE to be allocated by the reconciliation manager to the embedded network must be allocated in proportion to the ratio of the embedded network’s, and upstream balancing area’s, submission information quantities (that have been adjusted for losses and ICP days).

Compare: Electricity Governance Rules 2003 clause 10.1 schedule J4

Compare: Electricity Governance Rules 2003 clause 10.2 schedule J4

Compare: Electricity Governance Rules 2003 clause 11 schedule J4
22 Balancing

The **reconciliation manager** must balance the **UFE inclusive**, **ICP days** and loss adjusted **submission information** so that the sum of each **reconciliation participant’s quantities** equals each **NSP metered quantity during each trading period**. The following process must be used by the **reconciliation manager**:

(a) for each **retailer** or **direct purchaser**, at each **NSP**, any quantities that have been designated as being attributable to a specific **NSP** within the **balancing area** must be separated off from the remaining non-dedicated quantity and remain allocated to the specific **NSP**. If the sum of each retailer’s dedicated-NSP quantities exceeds the amount of electricity conveyed at the **NSP** in any **trading period**, the **NSP** total must be apportioned to the relevant **retailers or direct purchasers** in proportion to their dedicated-NSP quantities. The net quantities of non-dedicated electricity at each **NSP** must be determined by subtracting the dedicated quantities from the **NSP** totals:

(b) the **NSPs within a balancing area** that have been over-allocated electricity must be identified by comparing the sum of the non-dedicated quantities for each **retailer and direct purchaser** with the net **NSP** quantity. The non-dedicated quantities for each **retailer** and **direct purchaser** at each over-allocated **NSP** must be adjusted in order to achieve balance as follows:

\[
Q_{NBAL NSPI Rj} = \frac{Q_{ILUN NSPI Rj} \times TOT_{ND NSPI}}{\text{sum}(Q_{ILUN NSPI R1}, \ldots, Q_{ILUN NSPI Rn})}
\]

where

- \(Q_{NBAL NSPI Rj}\) is the quantity of fully adjusted, non dedicated electricity per **NSP** allocated to each **retailer and direct purchaser** after balancing to match the **NSP** total
- \(Q_{ILUN NSPI Rj}\) is the quantity of non-dedicated electricity per **NSP** attributed to each **retailer and direct purchaser**, which has been adjusted for losses and ICP days, and is UFE inclusive
- \(TOT_{ND NSPI}\) is the quantity of non-dedicated electricity conveyed at the **NSP** (after allowing for relevant **balancing area** injection and extraction quantities):

(c) the **reconciliation manager** must identify the quantities of electricity by which the over-allocated **NSPs** have been reduced, by **retailer** and by **direct purchaser**, and re-allocate to the corresponding under-allocated **NSPs** within the **balancing area** using the following formulae:

(i) calculate the previously over-allocated quantity per **retailer and direct purchaser** per **balancing area** as follows:
where

\[ Q_{\text{OVER} \ Ri} = \sum (Q_{\text{ILUN NSP1 Ri}} - Q_{\text{BAL NSP1 Ri}}, \ldots, Q_{\text{ILUN NSPn Ri}} - Q_{\text{BAL NSPn Ri}}) \]

is the sum, over all NSPs in the balancing area that are over-allocated per retailer and direct purchaser, of the differences between the pre- and post-adjusted quantities in paragraph (b); and

\[ Q_{\text{ILUN NSP1 Ri}} \] and \[ Q_{\text{BAL NSP1 Ri}} \] have the meaning given to them in paragraph (b):

(ii) determine the proportions by which the over-allocated quantity must be allocated to the under-allocated NSPs, per retailer and direct purchaser, in order to ensure that the sum of all reconciliation participants’ totals balance, after re-allocation, to the NSP totals as follows:

\[ PR_{\text{NSP X}} = \frac{(\text{TOTND NSP X} - \sum (Q_{\text{ILUN NSPx R1}} \ldots Q_{\text{ILUN NSPx Rn}}))}{Q_{\text{OVER BA}}} \]

where

\[ PR_{\text{NSP X}} \] is the proportion by which the over-allocated quantity must be allocated to the under-allocated NSPs, per retailer and direct purchaser.

\[ Q_{\text{OVER BA}} \] is the sum of all over-allocated quantities for all retailers and direct purchasers for all over-allocated NSPs in the relevant balancing area.

\[ \text{TOTND NSP X} \] and \[ Q_{\text{ILUN NSPx R1}} \] have the meaning given to them in paragraph (b):

(iii) allocate the over-allocated quantities to each retailer and direct purchaser at each under-allocated NSP as follows:

\[ Q_{\text{BAL NSPx Ri}} = Q_{\text{OVER Ri}} x PR_{\text{NSP Rx}} + Q_{\text{ILUN NSPx Ri}} \]

where

\[ Q_{\text{BAL NSPx Ri}} \] is the over-allocated quantities of electricity attributed to each retailer and direct purchaser at each under-allocated NSP;

\[ Q_{\text{OVER Ri}} \] has the meaning given to it in subparagraph (i);

\[ Q_{\text{ILUN NSPx Ri}} \] has the meaning given to it in paragraph (b); and

\[ PR_{\text{NSP Rx}} \] has the meaning given to it in subparagraph (ii).
23  **Final quantities**

The **reconciliation manager** must determine the final quantities of **electricity** to be purchased by each **reconciliation participant** by adding the dedicated and non-dedicated, balanced quantities using the following formula:

\[ Q_{TOT Ri} = Q_{BAL NSPx Ri} + Q_{DED Ri} \]

where

- \( Q_{TOT Ri} \) is the final quantity of **electricity** to be purchased by each **reconciliation participant** determined by adding the dedicated and non-dedicated balanced quantities.
- \( Q_{BAL NSPx Ri} \) has the meaning given to it in clause 22(c)(iii).
- \( Q_{DED Ri} \) are the quantities of **electricity** to be purchased by each **reconciliation participant** for dedicated quantities.

24  **Reconciliation manager reporting requirements**

The **reconciliation manager** must provide the information specified in clauses 25 to 27 to those **reconciliation participants, participants** and the **Authority** listed in those clauses, in respect of the prior **consumption period**, by 1600 hours on the 7th **business day** of each **reconciliation period**, and in respect of revisions in accordance with clauses 15.27 and 15.28 by 1200 hours on the last **business day** of each **reconciliation period**.

25  **Retailer and direct purchaser reports**

The **reconciliation manager** must make the following reports available to each relevant **retailer** and **direct purchaser** trading on the **network**:

(a)  the **reconciliation manager** must produce 3 reports of the **UFE** factors for each **NSP** per **retailer** and **direct purchaser**, being—

   (i)  1 report by **trading period**; and
   (ii) 1 report by **consumption period**; and
   (iii) 1 report issued monthly in respect of the immediately preceding 12 **consumption periods**:

(b)  the **reconciliation manager** must report to each **retailer** and **direct purchaser** the **retailer’s** and **direct purchaser’s** own scorecard and market share proportions for each **NSP**:

(c)  the **reconciliation manager** must report the non **half hour** and **half hour ICP days** scaling factor for each **NSP** and each **retailer** and **direct purchaser**: 

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Compare: Electricity Governance Rules 2003 clause 12 schedule J4

Compare: Electricity Governance Rules 2003 clause 13 schedule J4
Compare: Electricity Governance Rules 2003 clause 14 schedule J4
(d) the reconciliation manager must report to each retailer and direct purchaser the retailer’s and direct purchaser’s monthly totals for half hour metered ICPs as supplied by that retailer and direct purchaser in accordance with clause 15.8, for which submission information has not been received within the time required by this Code:

(e) the reconciliation manager must report to each retailer and direct purchaser the retailer’s and direct purchaser’s number of ICP days for which submission information has not been received within the time required by this Code, separately for non half hour and half hour meter types:

(f) the reconciliation manager must report all half hourly metered ICPs that have switched retailer and direct purchaser in the previous 2 months and for which consumption has changed by a percentage determined by the Authority.

Compare: Electricity Governance Rules 2003 clause 14.1 schedule J4

26 Distributor reports
The reconciliation manager must forward a report to each distributor that includes the following information:

(a) electricity traded for each trader trading on the distributor’s network:

(b) electricity supplied information for each trader trading on the distributor’s network:

(c) submission information for each trader trading on the distributor’s network.

Compare: Electricity Governance Rules 2003 clause 14.2 schedule J4

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

(a) reports by retailers and direct purchasers for the total unaccounted for electricity for each NSP:

(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:

(c) summary reports of all half hour metered connections for which submission information has not been received within the time required by this Code:

(d) summary reports by retailers and direct purchasers separately for non half hour and half hour, of all ICP days for which reconciliation information has not been received within the time required by this Code:

(e) reports for each balancing area for the difference between the daily average non half hour kWh submitted by each retailer and direct purchaser per NSP, and the daily average non half hour kWh submitted by all retailers and direct purchasers per NSP:

(f) separate reports for non half hour and half hour submission information detailing the difference between the quantity of electricity in initial and the quantity of electricity in each subsequent submission information submission for each NSP and each retailer and direct purchaser.

Compare: Electricity Governance Rules 2003 clause 14.3 schedule J4
Clause 27(c): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

28 Provision of reconciliation information
The reconciliation manager must provide the following information to the clearing manager and those participants listed below, and in the case of paragraph (f), to the Authority, in respect of the prior consumption period, by 1600 hours on the 7th business day of each reconciliation period, and in respect of revisions in accordance with clauses 15.27 and 15.28 by 1200 hours on the last business day of each reconciliation period. These reports must be in the format, and contain the information determined by the Authority. The reports are—
(a) to each generator or purchaser, the reconciliation information applying to that generator or purchaser, to enable the generator or purchaser to verify its reconciliation information; and
(b) to each grid owner, such information as is required by that grid owner to calculate its charges; and
(c) to the clearing manager, the reconciliation information (including all amounts derived by the reconciliation manager in accordance with clause 20) applying to each participant to enable the clearing manager to calculate the amounts owing by the clearing manager to each participant and by each participant to the clearing manager; and
(d) to each retailer and direct purchaser, the calculated daily seasonal adjustment shape related to any point of connection for which the retailer and direct purchaser is trading; and
(e) to each retailer, generator, and direct purchaser, the reconciliation manager must publish half hour profile shape data for profiles; and
(f) to the Authority, the reconciliation manager must provide the report prepared by the reconciliation manager referred to in clause 10 of Schedule 15.3; and
(g) to the extended reserve manager, the reconciliation information applying to each participant to enable the extended reserve manager to carry out and manage its procurement process.

Clause 28(g): inserted, on 19 January 2017, by clause 17(3) of the Electricity Industry Participation Code Amendment (Extended Reserve) 2016.

29 Extended reserve manager use of reconciliation information
The extended reserve manager must not publish or otherwise make available any reconciliation information provided to it under clause 28 that identifies any retailer, purchaser, or generator.

Schedule 15.5

Profile administration

1 Contents of this Schedule
This Schedule (including the appendices) contains the requirements for the production of profiles that must be used for electricity trading if a metering installation or unmetered load meets the eligibility criteria described in this Schedule.
Compare: Electricity Governance Rules 2003 clause 1 schedule J5

2 Departure from requirements
The Authority may approve situations that depart from the requirements of this Schedule if it is satisfied that such departure would have minimal adverse effects on each participant.
Compare: Electricity Governance Rules 2003 clause 2 schedule J5

3 Load switching
If load switching information is required from the operation log of an external control system, such as a SCADA or ripple injection control system, the relevant reconciliation participant must ensure that the information, for the immediately preceding consumption period, is available by 1600 hours on the 4th business day of each month.
Compare: Electricity Governance Rules 2003 clause 3.1 schedule J5

4 Non metering information
A reconciliation participant using a profile must ensure that all non-metering information, such as external control equipment operation logs, used in the determination of profile data, is archived in accordance with clause 18 of Schedule 15.2.
Compare: Electricity Governance Rules 2003 clause 3.2 schedule J5

5 Profile population
Each reconciliation participant who uses a profile must keep a current profile population list for each month the profile is in use. This will form a part of the audit trail of how profiles are applied.
Compare: Electricity Governance Rules 2003 clause 3.3 schedule J5

6 Details of profile approved for use
(1) Each profile owner must keep a full copy of all of the details of each profile approved for use.
(2) The details must be kept in accordance with clause 18 of Schedule 15.2 for audit purposes.
Compare: Electricity Governance Rules 2003 clause 3.4 schedule J5

7  **Multiple meter registers**
If a metering installation has multiple meters or meters with multiple registers, a reconciliation participant may choose to have each meter or meter register treated as 1 of the profiles described in Appendix 1.
Compare: Electricity Governance Rules 2003 clause 3.5 schedule J5

8  **New profiles**
Each new profile must be developed in accordance with this Schedule.
Compare: Electricity Governance Rules 2003 clause 3.6 schedule J5

9  **Accuracy of clocks**
External or internal clocks used for switching of meter registers must have a time-keeping accuracy of better than 60 seconds per month. The current time indicated by each clock must be checked for accuracy at least once per year, and corrected as necessary.
Compare: Electricity Governance Rules 2003 clause 3.7 schedule J5

10  **Subtractive metering**
If a metering installation includes subtractive metering, each participant must derive the appropriate net consumptions.
Compare: Electricity Governance Rules 2003 clause 3.8 schedule J5

11  **Change of profile**
(1) A profile owner may apply to the Authority to change a profile.
(2) An application must contain—
   (a) the profile code for the profile to which the proposed change relates; and
   (b) details of the proposed change.
(3) The Authority must not approve an application unless the Authority is satisfied that the requirements in clause 20 (for NSP derived profiles), and clauses 25 and 27 (for statistically sampled engineered profiles), with all necessary modifications, have been met.
(4) The Authority must advise the profile applicant if the application has been approved or rejected, or of additional steps that must be completed before the application can be considered, no later than 15 business days after receipt of the application.
Compare: Electricity Governance Rules 2003 clause 3A schedule J5

12  **Approved profile classes**
(1) Approved profile classes are described in Appendix 1.
(2) Each reconciliation participant must, with the exception of profile classes 1.4 and 1.5, apply to use specific profiles within those profile classes in accordance with clauses 19 to 34.
Compare: Electricity Governance Rules 2003 clause 4 schedule J5
13 Allocation and storage of profile codes

(1) The Authority must determine the profile code for an approved profile in accordance with this clause.

(2) Profile class 1.4 and 1.5 each have a single approved profile code, being—
   (a) the profile code for the single approved profile in profile class 1.4 is RPS; and
   (b) the profile code for the single approved profile in profile class 1.5 is UML.

(3) Profile class 2.5 has 2 approved profile codes, being—
   (a) the profile code for the approved profile in profile class 2.5.1 non half hour photovoltaic embedded generation, is PV1; and
   (b) the profile code for the approved profile in profile class 2.5.2 other non half hour embedded generation, is EG1.

(4) Profile class 1.7 has a single approved profile being, for differenced load, DFP.

(5) The Authority must publish the following information for all approved profiles in the following format:

   profile reference: the unique reference under which the profile is allocated and stored
   profile class: refer to Appendix 1
   characteristics: type(s) of meter(s): A – None
   type(s) of load(s) D – Controlled
   E – Uncontrolled
   description: a brief description of the type of consumer or embedded generator to whom the profile applies.

Compare: Electricity Governance Rules 2003 clause 5 schedule J5

14 Calculate residual non half hour profile shapes

The reconciliation manager must calculate, half hour by half hour, a residual profile shape for each balancing area that must be used to allocate non half hour submission information (after adjustment for losses and ICP days) to trading periods in accordance with clauses 15 to 18.

Compare: Electricity Governance Rules 2003 clause 6 schedule J5

15 Determine total balancing area load

(1) This calculation determines the total electricity consumption inside a balancing area by summing all of the injection into a balancing area and subtracting the extraction out of the balancing area. In this case, injection is defined as electricity entering \((E_i)\) the balancing area and includes flows from embedded generators, or any other network (including embedded networks or the grid). Similarly, extraction is defined as the flows of electricity leaving \((L_i)\) the balancing area, to other networks.

(2) The process in subclause (1) must be carried out for each trading period and for each balancing area within which there is non half hour metered electricity to be reconciled by following the procedure below:
TOTBA = \( (E_{GD} + E_{LN} + E_{EN}) - (L_{GD} + L_{LN} + L_{EN}) + (E_{EG}) \)

where

TOTBA is the total quantity of electricity consumed within the balancing area, measured as being the sum of flows injected into the balancing area less flows out to any embedded network or to another electrically connected network.

\( E_{GD} \) is the quantity of electricity entering the balancing area, as measured by the grid NSP metering installation for the balancing area.

\( E_{LN} \) is the quantity of electricity, entering the balancing area through an interconnection point from another network, as measured by the NSP metering installation (which has been adjusted for losses).

\( L_{GD} \) is the quantity of electricity leaving the balancing area, as measured by the grid NSP metering installation for the balancing area.

\( E_{EN} \) is the quantity of electricity entering the balancing area from an embedded network, as measured by the NSP gateway metering installation for the embedded network.

\( E_{EG} \) is the quantity of electricity entering the balancing area from an embedded generator electrically connected to the network, (which may either be half hour or non half hour metered), as measured by the NSP metering installation.

\( L_{LN} \) is the quantity of electricity, leaving the balancing area through an interconnection point to another network, as measured by the NSP metering installation (which has been adjusted for losses).

\( L_{EN} \) is the quantity of electricity, leaving the balancing area to an embedded network, as measured by the NSP gateway metering installation for the embedded network.

Compare: Electricity Governance Rules 2003 clause 6.1 schedule J5

16 Calculate total non half hour shape
(1) Using the total balancing area quantities determined in accordance with clause 15 and the reconciliation participants’ half hour submission information (that has been
adjusted for losses and ICP days), the reconciliation manager must calculate, for each trading period, a total profile shape representing the aggregated consumption of all non half hour metered electricity for each balancing area by following the procedure below:

\[ \text{NHH}_{\text{Tot}} = \text{TOT}_{\text{BA}} - \text{HHR}_M \]

where

- \( \text{NHH}_{\text{Tot}} \) is the total quantity of non half hour metered electricity consumed in a balancing area provided that if the calculated quantity is less than 0, the quantity must, for the purposes of this clause, be deemed to be 0
- \( \text{TOT}_{\text{BA}} \) is the total quantity of electricity consumed within the balancing area, determined in accordance with clause 15
- \( \text{HHR}_M \) is the total quantity of consumed electricity which is calculated from all reconciliation participants’ half hour submission information (which has been adjusted for losses and ICP days).

(2) The volumes described in subclause (1) must not be published and are a process step only.

Compare: Electricity Governance Rules 2003 clause 6.2 schedule J5

17 Calculate initial residual profile shape and seasonal adjustment shape

(1) Using the resultant NHH\textsubscript{Tot} quantities from the calculation in clause 16, the reconciliation manager must calculate, for each trading period, half hour by half hour, the initial residual profile shape for each balancing area by following the procedure below:
Electricity Industry Participation Code 2010
Schedule 15.5

GXP\textsubscript{Init} = NHH\textsubscript{Tot} - (Pr\textsubscript{ENG} + Pr\textsubscript{STAT})

Sum of independently shaped, non half hour profiled consumption internal to the network area

where

GXP\textsubscript{Init} is the Initial Residual Profile. This is the remaining total quantity of electricity for each half hour that represents the shape-dependent balance of the non half hour consumption within a balancing area. This set of values, calculated for each trading period, is the initial residual profile for each NSP within the balancing area.

NHH\textsubscript{Tot} is as determined in clause 16

Pr\textsubscript{ENG} is the quantity of consumed electricity for each trading period that is in accordance with the approved engineered profile, calculated from the reconciliation participant submission information adjusted for ICP days and after application of loss factors.

Pr\textsubscript{STAT} is the quantity of consumed electricity for each trading period that is in accordance with the approved statistically sampled profile, calculated from the reconciliation participant submission information adjusted for ICP days and after the application of loss factors.

(2) The GXP\textsubscript{Init} values must be used by the reconciliation manager to allocate non half hour submission information to trading periods for each reconciliation participant that uses a profile that specifies the use of the initial residual profile shape at the NSP.

(3) The reconciliation manager must aggregate those trading period volumes into daily totals for each profile at the NSP, and those daily totals must be published by the reconciliation manager as the seasonal adjustment shape.

Compare: Electricity Governance Rules 2003 clause 6.3 schedule J5

18 Calculate final residual profile shape

(1) Using the resultant GXP\textsubscript{Init} quantity from the calculation in clause 17, the reconciliation manager must calculate, for each trading period, the final residual profile shape for each balancing area by following the procedure below:
GXP\textsubscript{Res} = GXP\textsubscript{Init} - (PrSh\textsubscript{1} + \ldots + PrSh\textsubscript{n})

where

GXP\textsubscript{Res} is the Final Residual Profile (which is given the code “RPS”). This is the remaining quantity of electricity for each trading period that represents the shape dependent balance of the non half hour load within a balancing area. The monthly file of this consumption, calculated for each trading period, is the final residual profile for each NSP within the balancing area.

GXP\textsubscript{Init} is as determined in clause 17

PrSh\textsubscript{X} is the quantity of consumed electricity for each trading period which is in accordance with the approved shape dependent profile calculated from the reconciliation participant loss and ICP days adjusted submission information.

(2) The GXP\textsubscript{Res} values in subclause (1) must be used by the reconciliation manager to allocate non half hour submission information to trading periods for each reconciliation participant who uses a profile that specifies the use of the residual half hour shape at the NSP, for each trading period of the reconciliation period.

Compare: Electricity Governance Rules 2003 clause 6.4 schedule J5

New NSP derived profiles

19 Applications
(1) An application to introduce a new NSP derived profile must be submitted to the Authority, who must either advise the profile applicant of further actions, or must approve or reject the application no later than 15 business days after its receipt.

(2) Each application must contain the following—

(a) a profile description:
(b) a suggested profile code:
(c) a profile class in accordance with Appendix 1:
(d) the criteria applied by the profile applicant to allocate ICP identifiers in the profile:
(e) a description of the methodology for compiling submission information and profile shapes:
(f) details of dynamics derived from sources external to the metering installation (including without limitation SCADA and ripple control) if appropriate.

Compare: Electricity Governance Rules 2003 clause 7.1 schedule J5

20 Assessment
Before approving a profile, the Authority must be satisfied that—
(a) there are clear criteria applied by the reconciliation participant to allocate ICP identifiers in the profile; and
(b) there are no obvious flaws in the methodology for compiling submission information and profile shapes; and
(c) the reconciliation manager is able to incorporate the profile into the reconciliation process; and
(d) the proposed profile is not at variance with existing profiles for like populations.

Compare: Electricity Governance Rules 2003 clause 7.2 schedule J5

21 Ownership
For the purposes of this Schedule, a profile applicant must become the profile owner once the application is approved. If the profile applicant is not a legal entity, a legal entity must be nominated by the profile applicant to be the profile owner.

Compare: Electricity Governance Rules 2003 clause 7.3 schedule J5

22 Withdrawal of applications
If an application is withdrawn by a profile applicant at any time following the declaration date, but before approval, the Authority must advise all participants.

Compare: Electricity Governance Rules 2003 clause 7.4 schedule J5

23 Rejected applications
If an application is rejected, the Authority must provide to the profile applicant a detailed explanation of why the application was rejected, together with actions required for a reconsideration of the application.

Compare: Electricity Governance Rules 2003 clause 7.5 schedule J5

24 Use of approved profiles
(1) A profile must not be used for reconciliation until it is approved by the Authority in accordance with clauses 19 and 20. The use of a profile must be effective from a date decided by the Authority, but not earlier than the 1st day of the month following the declaration date.

(2) A reconciliation participant who wishes to reconcile its ICP identifiers using an existing profile must first gain the approval of the profile owner.

Compare: Electricity Governance Rules 2003 clause 7.6 schedule J5
New statistically sampled/engineered profiles

25 Technical requirements
A new profile must be based on a process of statistical sampling carried out in accordance with the guidelines contained in the appendices to this Schedule, or derived using recognised engineering principles, or derived from NSP profiles.

Compare: Electricity Governance Rules 2003 clause 8.1 schedule J5

26 Applications
(1) An application to introduce a new profile must be submitted to the Authority, who must either advise the profile applicant of further actions, or approve or reject the application in writing no later than 15 business days after its receipt. Each application must contain the following:
   (a) a profile description:
   (b) a suggested profile code:
   (c) a profile class in accordance with Appendix 1:
   (d) the size of the profile population and a list that uniquely identifies each member of the profile population:
   (e) the criteria applied by the reconciliation participant to allocate ICP identifiers to the profile:
   (f) a description of the methodology for compiling submission information and profile shapes:
   (g) details of dynamics derived from sources external to the metering installation (including without limitation SCADA and ripple control) if appropriate:
   (h) details of any half-hour metering as a control or source of input data to the profile:
   (i) statistical or engineering data that supports the proposed profile shape.

(2) The profile applicant must supply any analytical information relating to the application in the format required by the Authority.

Compare: Electricity Governance Rules 2003 clauses 8.2 and 8.2A schedule J5

27 Assessment
The Authority must be satisfied that—
   (a) there are clear criteria applied by the reconciliation participant to allocate profiles to ICP identifiers; and
   (b) there is an audit trail for the allocation of profiles to ICP identifiers; and
   (c) there are no obvious flaws in the methodology for allocating profiles to ICP identifiers; and
   (d) the reconciliation manager is able to incorporate the profile into the reconciliation process; and
   (e) the proposed profile is not at variance with existing profiles for like populations.
28 Sampling requirements

(1) Statistical samples must be drawn using the methodology described in Appendix 2. Sampling information must be taken from fully certified metering installations. An interim certified metering installation must not be used for this purpose.

(2) For profiles that require statistical sampling, the Authority must specify the preliminary sample size and draw a preliminary sample of ICP identifiers from the profile population list, or must accept appropriate sampling performed by the profile applicant. Half hour research meters must be, or must have been, installed and operated by the profile applicant for this preliminary sample. The Authority must require a minimum sampling period of 60 days, and not more than 12 months. The Authority may withdraw ICP identifiers from the profile population list if it can be shown by the profile applicant that those ICP identifiers are in sites that are difficult to meter.

(3) The average unit cost and standard deviation of the unit cost must be calculated using the 60 days or more of data obtained as described above. If the sample co-efficient of variation is less than or equal to the profile acceptance limit specified in Appendix 2, the size of the profile sample must be the profile sample size. The Authority must provide a standard set of synthetic price scenarios to determine the variability of unit costs.

(4) If the sample co-efficient of variation is more than the profile acceptance limit, the Authority can reject the application, or can require the profile applicant to supply additional information until the Authority is satisfied that there is no clear evidence to suggest the population co-efficient of variation exceeds the profile acceptance limit.

(5) If the preliminary sample size is less than the profile sample size, the Authority must draw an additional random sample. The size of the additional random sample must equal the shortfall.

(6) If the profile sample size is less than the preliminary sample size, the preliminary sample must become the profile sample.

29 Ownership

For the purposes of this Schedule, a profile applicant must become the profile owner once the application is approved. If the profile applicant is not a legal entity, a legal entity must be nominated to be the profile owner.

30 Withdrawal of applications

If an application is withdrawn by a profile applicant at any time following the declaration date, but before approval, the Authority must advise all participants.
31 Rejected applications
(1) If an application is rejected, the Authority must provide the profile applicant with a detailed explanation of why the application was rejected, together with actions required for a reconsideration of the application.
(2) If an application is rejected because the coefficient of variation is found to be too large, the profile applicant may resubmit the application with a refined profile population.
(3) The refined profile population must be a subset of the original population and must be made up of ICP identifiers that are more homogenous in their unit costs than those in the original profile population.
(4) Data collected from half-hour metering in the original preliminary sample may be reused to constitute the refined preliminary sample as long as the data was collected from ICP identifiers that belong to the refined profile population.
(5) The Authority must determine if additional ICP identifiers are required to make up the refined preliminary sample.

Compare: Electricity Governance Rules 2003 clause 8.6 schedule J5

32 Use of approved profiles
(1) A profile must not be used for reconciliation until the Authority approves it. The use of a profile must be effective from a date decided by the Authority, but not earlier than the 1st day of the month following the declaration date. If an approved profile is used for reconciliation, every ICP identifier on the profile population list must be reconciled under that profile.
(2) A reconciliation participant who wishes to reconcile its eligible ICP identifiers using an existing profile must first gain the approval of the profile owner. ICP identifiers not already on the profile population list must be added to the list before the profile can be applied.

Compare: Electricity Governance Rules 2003 clause 8.7 schedule J5

33 Profile maintenance and changes
(1) The profile sample must be representative of the profile population. The profile owner must be responsible for maintaining a valid statistical sample which takes into account changes in the profile population.
(2) The profile owner must maintain a current profile population list. The profile owner must inform the Authority when an update is necessary (refer subclause (3)). The profile population list is subject to random audit by the Authority or its appointed audit agent.
(3) The profile sample must be updated when membership of the profile population has changed by more than 20% since the sample date. The profile owner must, no later than 10 business days after the profile owner becomes aware of such change in
membership, give written notice to the Authority of the changes in the profile population list. The Authority must determine, and give written notice to the profile owner of, any required modifications to the profile sample. The profile owner has 1 month from the date on which the profile owner receives the notice from the Authority to ensure that certified half hour meters are installed in the metering installations of these ICP identifiers, and that the metering installations are fully certified.

(4) If more than 5% of the profile sample has been lost or removed, the profile owner must submit to the Authority a list of ICP identifiers in the current profile sample who have been lost or removed from the profile population list. The Authority must draw ICP identifiers from the profile population list to replace those who are lost or removed from the profile sample. The profile owner must ensure that certified half hour meters are installed in the metering installations of these ICP identifiers, and that the metering installations are fully certified, no later than 1 month after the Authority issues its determination of the appropriate replacement ICP identifiers.

(5) The addition or removal of ICP identifiers to or from the profile sample must follow the procedures in Appendix 2.

(6) There must be at least 3 months between updates.

34 Exceptions to sampling methodology

The Authority may allow different sampling methodologies that are not described in this Schedule, only if—

(a) the methodology can, in the Authority’s assessment, produce sample data that meets the precision standards specified under Appendix 2; and

(b) the Authority or its audit agent is satisfied that the methodology can be audited to the same degree of rigour as the sampling methodology outlined in Appendix 2; and

(c) following the declaration date but before approval, details of the shape of the proposed profile must be provided by the profile owner on a monthly basis to all participants trading on the affected NSP(s). Use of such profile information is subject to clause 32. Following approval, such details must be provided to all participants by the reconciliation manager.

35 Audits

(1) A participant may request the selective audit of any participant’s compliance with this Schedule or the participant’s application and use of any profile.

(2) The Authority or its agent must audit the application of all profiles in a random order at least once every 2 years by applying a selection process that the Authority determines.

(3) As a minimum, a profile audit must cover the following:

(a) the documents detailing the methodology of the profile:
Electricity Industry Participation Code 2010
Schedule 15.5

(b) the application of dynamic and estimated elements of the profile;
(c) the profile population list.

Compare: Electricity Governance Rules 2003 clause 9 schedule J5

36 Reviews
(1) The Authority must review the structure of every approved profile at least every 3 years.
(2) Each review must determine whether—
   (a) the criteria for profile definition are still appropriate; and
   (b) if applicable, the existing sample needs to be redrawn.

Compare: Electricity Governance Rules 2003 clause 10 schedule J5

37 Removal of profiles
(1) The Authority must immediately remove a profile that fails an audit from the list of approved profiles held by the Authority.
(2) A participant who includes in a profile an ICP identifier that is not of the classification contained in the profile documentation breaches this Code. All alleged breaches must be reported to the Authority and resolved in accordance with the Act.
(3) The Authority may remove a profile—
   (a) at the request of the profile owner that introduced the profile; or
   (b) for such other reasons that the Authority decides.
(4) A profile owner that makes a request to the Authority under subclause (3)(a) must—
   (a) make the request in writing; and
   (b) request the profile's removal be effective from the start of the reconciliation period immediately following the date on which the Authority receives the request.
(5) If the Authority removes a profile, the Authority must decide on the actions to be taken with respect to the ICP identifiers to which the profile applied.

Compare: Electricity Governance Rules 2003 clause 11 schedule J5
Clause 37(3) to (5): replaced, on 5 October 2017, by clause 567(b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Appendix 1
Profile classes

1 Contents of this Appendix
This Appendix contains generic descriptions of metering installations to which particular profile classes may be assigned.
Compare: Electricity Governance Rules 2003 appendix 1 schedule J5

Participants NSP-derived profiles

2 Profile class 1.1 interval time of use meters
(1) Meters in the profile class 1.1 – interval time of use meter classification include the following:
(a) day-night two rate meters:
(b) night only meters:
(c) night only plus afternoon boost meters:
(d) 5 rate time of use meters.
(2) If register-switching is triggered by an external signal, such as a ripple relay, rather than by the meter's internal clock, data from the operation log of the equipment controlling the external signal must be used to provide the profile time period.
Compare: Electricity Governance Rules 2003 clause 1.1 appendix 1 schedule J5

3 Profile class 1.2 separately metered controlled load
(1) Meters in the profile class 1.2 separately metered controlled load classification include a separate meter for a ripple controlled water heater, which may be switched on and off at variable times of the day. The entire load recorded on this register must be available for control.
(2) Information from the operation logs of equipment controlling the connection of controllable loads must be used to determine the time period relating to them. If the controllable load component is not static, a calculation of the diversity of the load must be documented and applied.
(3) Other meters in the metering installation must be applied as per profile class 1.1 or 1.4, as appropriate.
Compare: Electricity Governance Rules 2003 clause 1.2 appendix 1 schedule J5

4 Profile class 1.3 non separately metered controlled load
(1) Installations in the profile class 1.3 classification non separately metered controlled load include a ripple controlled water heater but with only 1 meter measuring the whole installation including the water heater.
(2) The controlled load may be switched on and off at variable times of the day. In this case a proportion of the profile (kWh) must be applied as per profile class 1.2 with the remaining kWh applied as per profile class 1.1 or 1.4, as appropriate.

Compare: Electricity Governance Rules 2003 clause 1.3 appendix 1 schedule J5

5 Profile class 1.4 uncontrolled load 24 hour meters

(1) The profile from meters in the profile class 1.4 uncontrolled load 24 hour meters must follow the NSP residual profile.

(2) The NSP residual profile must be calculated in accordance with clauses 14 to 18 of Schedule 15.5.

Compare: Electricity Governance Rules 2003 clause 1.4 appendix 1 schedule J5

6 Profile class 1.5 unmetered loads

(1) Unmetered loads in the profile class 1.5 classification include, but are not limited to, under veranda lighting, electric fences, sewer pumps, advertising hoardings, public conveniences, supply to construction sites, electric parking meters, and public water fountains.

(2) For those types of unmetered load, a fixed annual kWh quantity must be assigned to each ICP and must be applied according to the 24 hour NSP final residual profile.

Compare: Electricity Governance Rules 2003 clause 1.5 appendix 1 schedule J5

7 Profile class 1.7 differenced load

Profile class 1.7 differenced load represents the result of subtractive processes performed by the reconciliation manager to form differenced load.

Compare: Electricity Governance Rules 2003 clause 1.7 appendix 1 schedule J5

Statistically sampled and engineering profile classes

8 Profile class 2.1 unmetered loads

(1) Profiles may be applied to intended loads with characteristics that are reasonably predictable using time and other observable values.

(2) The elements making up each load and time period must be documented by the profile owner.

(3) The documentation must include a description of the methodology, formula, and the results of any calculations for any estimated data.

Compare: Electricity Governance Rules 2003 clause 2.1 appendix 1 schedule J5

9 Profile class 2.2 half hour data, metering installations with interim certification

(1) Half hour data from interim certified metering installations may be—

(a) regarded as a 100% sampled profile until the expiry of the interim exemption validity period for those metering installations under Part 10. From that date, if the metering installation has not been recertified as a fully certified metering installation under Part 10, the metering installation must be assigned to profile class 1.4; or
(b) treated as if it was derived from fully certified metering installations until the expiry of the interim exemption validity period for those metering installations. To avoid doubt, the half hour data must be derived from an interrogation of the metering installation and must be submitted to the reconciliation manager in accordance with Schedule 15.4.

(2) For a 100% sampled profile, a method of calculating forward estimates must be adopted in accordance with clauses 2 to 7 of Schedule 15.3. A profile shape for the reconciliation period must be submitted to the reconciliation manager with the estimated data.

(3) If the gathering, validation and repair of volume information from an interim certified metering installation is carried out in a manner that is not in accordance with Schedule 15.2, these processes must be fully documented in the quality procedures of the participant.

Compare: Electricity Governance Rules 2003 clause 2.2 appendix 1 schedule J5
Clause 9(1)(a): amended, on 29 August 2013, by clause 38(b) and (c) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.
Clause 9(1)(b): amended, on 29 August 2013, by clause 38(d), (e) and (f) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.
Clause 9(3): amended, on 29 August 2013, by clause 38(g) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

10 Profile class 2.3 unmetered installations that require shape file to be submitted
(1) A profile may be applied to an intended load with characteristics that are reasonably predictable using time and other observable values.

(2) For those types of unmetered load, the profile must include a process for maintaining unmetered load quantities that are used in the reconciliation process. The shape file will be produced by the profile owner from a metering installation.

(3) The elements making up each load and time period must be documented by the profile owner. The documentation must include a description of the methodology, formula, and the results of any calculations for any estimated data.

Compare: Electricity Governance Rules 2003 clause 2.3 appendix 1 schedule J5

11 Profile class 2.4 metered installations that require shape file
(1) A profile may be applied to an intended load with characteristics that are reasonably predictable using time and other observable values.

(2) For those types of metered load, a metering installation must be used to determine the quantity of electricity for reconciliation purposes.

(3) The elements making up each load and time period must be documented by the profile owner. The documentation must include a description of the methodology, formula, and the results of any calculations for any estimated data.

Compare: Electricity Governance Rules 2003 clause 2.4 appendix 1 schedule J5

12 Profile class 2.5, non half hour embedded generation
(1) The Authority must—
(a) determine how each of the 2 types of non half hour embedded generator profiles under subclause (2) applies and operates; and
(b) having made its determination under paragraph (a), submit each non half hour embedded generator profile to the reconciliation manager.

(2) The 2 types of non half hour embedded generator profiles are:

(a) the photovoltaic is a time limited profile and may only be used for photovoltaic generation that injects electricity into the network during daylight hours; and

(b) the other profile is a non limited flat load profile and must be used for all other embedded generation that does not fit within the profile in paragraph (a) or if the reconciliation participant has not created an engineered profile for the embedded generator.

Compare: Electricity Governance Rules 2003 clause 2.5 appendix 1 schedule J5
Appendix 2
Determining statistically sampled profiles

1 Basic sampling scheme
The method of simple random sampling without replacement must be used in drawing statistical samples whenever such samples are required for profiles under this Code.
Compare: Electricity Governance Rules 2003 clause 1 appendix 3 schedule J5

2 Preliminary sample
(1) Unless the profile applicant has better information available that is acceptable to the Authority, the size of the preliminary sample must be determined by the following preliminary sample size formula:

\[ n_1 = \frac{(z_{\alpha}^2 \times C_A^2)}{r^2} \]

(2) If \( n_1/N \) is greater than 0.1, it must be modified to account for the finite population correction factor and is calculated as—

\[ n_1' = \frac{n_1}{1 + n_1/N} \]

(3) If either \( n_1 \) or \( n_1' \) is less than 20, the preliminary sample size must be 20.
(4) In the above formula—

- \( N \) is the size of the profile population
- \( \alpha \) is the confidence level
- \( z_{\alpha} \) is the value of the standard normal distribution which gives \( \alpha \) probability outside the tails
- \( C_A \) is the value of co-efficient of variation of the unit cost
- \( r \) is the relative standard error of the unit cost.

(5) The following parameter values are to be used:

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<tr>
<th>Parameter</th>
<th>Value</th>
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<tbody>
<tr>
<td>Value of co-efficient of variation</td>
<td>0.1</td>
</tr>
<tr>
<td>Relative standard error (r)</td>
<td>0.05</td>
</tr>
<tr>
<td>Confidence level (( \alpha ))</td>
<td>0.99</td>
</tr>
</tbody>
</table>

(6) The profile acceptance limit must be 0.2.
(7) These values must be subject to review in accordance with clause 5.
(8) The profile applicant must collect half hour data from the preliminary sample over a period of at least 60 days. The data, in its processed form, must be submitted to the
Authority for consideration. The data processing must include calculations of unit costs, and of mean and standard deviation of unit costs, over the sample period.

Compare: Electricity Governance Rules 2003 clause 2 appendix 3 schedule J5

3 Profile sample

(1) The size of the profile sample must be determined by the following profile sample size formula:

\[ n = \left( \frac{S_0^2}{Y_0^2} \right) \times \left( \frac{z_\alpha^2}{r^2} \right) \times \left[ 1 + 8 \times \left( \frac{r^2}{z_\alpha^2} \right) \times \left( \frac{S_0^2}{n_1 \times Y_0^2} \right) \right] + \frac{2}{n_1} \]

(2) If \( n/N \) is greater than 0.1, it must be modified to account for the finite profile population correction factor and is calculated as—

\[ n' = \frac{n}{1 + n/N} \]

(3) If either \( n \) or \( n' \) is less than \( n_1 \), the preliminary sample must become the profile sample.

(4) In the above formula—

- \( S_0 \) is the estimated standard deviation of unit costs from the preliminary sample, or from the existing profile sample in the case of updates.
- \( Y_0 \) is the estimated mean of unit costs from the preliminary sample, or from the existing profile sample in the case of updates.
- \( \alpha \) is the confidence level.
- \( z_\alpha \) is the value of the standard normal distribution which gives \( \alpha \) probability outside the tails.
- \( n_1 \) is the size of the preliminary sample, or the existing profile sample in the case of updates.
- \( r \) is the relative standard error of the unit cost.

(5) The relative standard error (\( r \)) and the confidence level (\( \alpha \)) must be the same as those specified in clause 2.

(6) If the size of the profile sample is larger than the size of the preliminary sample, additional ICP identifiers from the profile population must be drawn to increase the sample size to the required level.

(7) Data from the profile sample must be used to form the basis for future updates.

Compare: Electricity Governance Rules 2003 clause 3 appendix 3 schedule J5
4 Sample updates

(1) If an update is required because of a change in the profile population, the following procedures must be followed:
   (a) if the size of the updated profile sample is larger than the size of the existing profile sample, additional ICP identifiers must be drawn from new participants of the profile population to increase the sample size to the required level:
   (b) if the size of the updated profile sample is smaller than the size of the existing profile sample, ICP identifiers from the existing profile sample must be removed to decrease the sample size to the required level, unless the profile applicant decides to nominate the existing profile sample as the profile sample.

(2) For the purposes of updates, data from the existing profile sample must be used (instead of data from the preliminary sample) in all profile sample size calculations.

Compare: Electricity Governance Rules 2003 clause 4 appendix 3 schedule J5

5 Reviews

(1) The statistical parameters must be monitored by the Authority and reviewed when the Authority considers it appropriate. Modifications of those parameters are expected as the industry gains experience in the use of statistical profiles. Industry participants will be consulted as part of the review process.

(2) Each year the Authority must review data gathered during the year for each profile sample, and must re-examine the co-efficient of variation and the sample size. A relative standard error of 5% and a confidence level of 99% must be applied initially. A figure of 2% for the relative standard error is expected to be adopted by the Authority following the first 12-monthly review and may thereafter be reviewed from time to time.

(3) Reviews of existing standards must take place in the 6th month and the 12th month during the 1st year of profile introduction.

Compare: Electricity Governance Rules 2003 clause 5 appendix 3 schedule J5
Electricity Industry Participation Code 2010

Part 16
Special provisions relating to Rio Tinto agreements

[Revoked]

Part 16: revoked, on 16 December 2013, by clause 10 of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013
Electricity Industry Participation Code 2010

Part 16A
Audits

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16A.1 Contents of this Part
This Part specifies obligations on participants that perform functions under Parts 10, 11, and 15 in respect of audits required under the following clauses:
(a) 10.17A (Metering equipment providers and ATHs to arrange for regular audits):
(b) 10.17B (Authority and participant requested audits):
(c) 11.8B (Metering equipment providers to arrange for regular audits):
(d) 11.10 (Distributors to arrange for regular audits):
(e) 11.11 (Authority and participant requested audits):
(f) 15.37A (Reconciliation participants and dispatchable load purchasers to arrange for regular audits):
(g) 15.37B (Retailers to arrange for audits in respect of distributed unmetered load):
(h) 15.37C (Authority and participant requested audits).

16A.2 Purpose of this Part
The purpose of this Part is to require the performance of audits to support the accurate settlement and operation of the wholesale electricity market.

Subpart 1—Conduct of audits generally

16A.3 Auditors
(1) An audit must be undertaken by—
(a) the Authority; or
(b) an auditor appointed by the participant that is the subject of the proposed audit, from the list of auditors the Authority publishes under clause 16A.5(6).

(2) Despite subclause (1)(b), if an audit is carried out under clause 10.17B, 11.11, or 15.37C,—
(a) the Authority must carry out the audit or appoint an auditor to carry out the audit; and
(b) an auditor appointed by the Authority need not be an auditor from the list of auditors the Authority publishes under clause 16A.5(6).


16A.4 Participants to give access
(1) A participant must give the Authority or an auditor full access to all information that may be required for the purposes of carrying out an audit.

(2) The participant must provide the information—
(a) at no charge; and
(b) no later than 15 business days after receiving a request for the information from the Authority or an auditor, as the case may be.

16A.5 Approval of auditors by the Authority
(1) The Authority—
(a) may approve a person to be an auditor; and
(b) must specify the types of audits for which each such person is approved.

(2) An applicant for approval as an auditor, or renewal of an existing approval, must apply to the Authority using the prescribed form.

(3) The Authority may require an applicant to do any or all of the following:
(a) provide additional information or clarify any information provided:
(b) attend an interview;
(c) undertake an examination.

(4) The Authority must, no later than 2 months after receiving an application and, if applicable, the applicant has complied with subclause (3)—
(a) make a decision in relation to the application; and
(b) advise the applicant of the decision.
(5) If the Authority approves an application, the Authority must specify the date on which the approval expires in its advice to the applicant under subclause (4)(b), which must not be more than 36 months after the date of the approval.

(6) The Authority must publish, and keep updated, a list of the auditors that the Authority has approved, and the types of audits for which each auditor is approved.


16A.6 Expiry and cancellation of approval

(1) An auditor's approval expires on the date specified for its expiry under clause 16A.5(5).

(2) The Authority may cancel an auditor's approval at any time by advising the auditor in writing.

(3) The cancellation or expiry of an auditor's approval does not invalidate an audit previously completed by the auditor, but an audit completed after the date on which the Authority cancelled the auditor's approval, or after the date on which the auditor's approval expired, is not a valid audit for the purposes of this Code.

16A.7 Requirement to appoint new auditor

(1) Unless otherwise agreed with the Authority, a participant must appoint a new auditor to perform a type of audit at the later of—
   (a) 24 months after an auditor first performs an audit of that type in respect of the participant; or
   (b) after an auditor has performed 2 consecutive audits of that type in respect of the participant.

(2) A new auditor is an auditor that did not perform the last audit of the relevant type in respect of the participant.

(3) For the purposes of subclause (1),—
   (a) an audit completed under clause 16A.11 must be disregarded in determining the number of audits that an auditor has performed; and
   (b) a type of audit refers to an audit under any 1 of paragraphs (a), (c), (d), (f) or (g) of clause 16A.1.

16A.8 Combined audits

(1) A participant that is required to carry out an audit in accordance with this Part under more than 1 clause of this Code must arrange for a single audit report to be completed in respect of all of its obligations that relate to its role as a single type of industry participant or industry service provider.

(2) A participant that is required to carry out an audit in accordance with this Part in relation to more than 1 of its roles as an industry participant or industry service provider must arrange for a separate audit report to be completed in respect of its obligations for each of those roles.

(3) For example, a participant that is both a metering equipment provider and a reconciliation participant—
   (a) must arrange for a single audit report to be completed that relates to all of its obligations as a metering equipment provider; and
   (b) must arrange for a separate audit report to be completed that relates to its obligations as a reconciliation participant.
(4) Despite subclauses (1) and (2), a retailer that is responsible for distributed unmetered load must ensure that a separate audit report is completed in respect of the distributed unmetered load from any other audit report required under this Code.

16A.9 Authority may specify emphasis or scope of audit
(1) If the Authority advises a participant that it requires an audit to give emphasis to any aspect of the participant's systems or processes, the participant must instruct the auditor to give emphasis to that aspect in the audit report.
(2) If an audit is carried out under clause 10.17B, 11.11, or 15.37C, the Authority may specify the scope of the audit.
(3) If the Authority advises a participant under subclause (1), or specifies the scope of an audit under subclause (2), the Authority must give the participant concerned its reasons for doing so.

16A.10 Agent audits
If a participant appoints an agent to perform any of the participant's obligations under this Code in respect of which an audit is required under any of the clauses specified in clause 16A.1, the participant must ensure that—
(a) the agent has been audited to a standard that would have been required if the participant had performed the obligations itself; and
(b) the information produced as a result of the audit of the agent is included in the auditor's audit report produced under clause 16A.12.


16A.11 Audit required if participant makes material change
(1) If there is a material change to any of a participant's systems or processes that are the subject of regular audits under clause 10.17A, 11.8B, 11.10, 15.37A or 15.37B, the participant must arrange for an additional audit, which must be completed in accordance with this Part no later than 5 business days before the change is implemented.
(2) For the purposes of subclause (1), a material change to a system or process is a change that is likely to affect the ability of the participant to comply with any relevant provision of this Code.

16A.12 Process for completion of audits
(1) Subject to subclause (2), a participant that is the subject of an audit must ensure that the auditor carrying out the audit complies with the following requirements:
(a) the audit report must be in the prescribed form:
(b) the auditor must send a draft of the audit report, setting out the provisional findings of the audit, to the participant that is the subject of the audit:
(c) the auditor must consider any comments it receives from the participant about the draft audit report:
(d) the auditor must produce a final audit report and give the report to the participant after considering any comments under paragraph (c):
(e) the final audit report must—
(i) list each agent engaged by the participant to perform any of the participant's activities under the relevant provisions of this Code, and details of the obligations that the agent performs; and

(ii) identify, in relation to the relevant period, the extent to which the participant has failed to comply with the provisions of this Code to which the audit relates; and

(iii) identify any areas for improvement; and

(iv) specify any conditions that the auditor considers the participant must satisfy in order to comply with the provisions of this Code to which the audit relates, and any action that the participant has taken in respect of those conditions; and

(v) include a recommendation as to the date by which the auditor considers that the participant should complete its next audit; and

(vi) include any of the participant’s comments on the draft audit report that the auditor considers relevant.

(2) If the Authority carries out the audit, or appoints an auditor to carry out the audit, the Authority must ensure that the requirements specified in subclause (1) are complied with.

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 compliance plan and audit report must be in the prescribed form.

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

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

16A.14 Authority to make determination as to next audit date

1. The Authority must, after receiving a final audit report and compliance plan (if any) from a participant, advise the participant of the date by which the next audit of the participant must be completed, which must be—
   (a) no earlier than 3 months after the date on which the Authority advises the participant under this subclause; and
   (b) no later than 36 months after the date of the last audit.

2. For the purposes of subclause (1) and clauses 16A.17, 16A.19, 16A.22, 16A.24, 16A.25, and 16A.26, an audit is complete when the participant that is the subject of the audit gives the Authority the final audit report and a compliance plan (if any) under clause 16A.13.

3. This clause does not apply to audits carried out under clause 10.17B, 11.11, 15.37C, or 16A.11.

16A.15 Authority to publish information

1. The Authority must publish the following information:
   (a) each final audit report received under clause 16A.13:
   (b) the compliance plan (if any) that the relevant participant submitted in relation to each final audit report:
(c) the date by which the next audit of the participant must be completed, as determined under clause 16A.14.

(2) The Authority must publish the information no later than 20 business days after advising the relevant participant of the date by which the next audit of the participant must be completed under clause 16A.14.

(3) The Authority is not required to publish the information if doing so—
   (a) would disclose a trade secret; or
   (b) would be likely unreasonably to prejudice the commercial position of the person who supplied or is the subject of the information.


16A.16 Costs of audits
(1) The cost of an audit carried out under clause 10.17A, 11.8B, 11.10, 15.37A, 15.37B, or 16A.11 must be met by the participant that is the subject of the audit.

(2) The cost of an audit carried out under clause 10.17B, 11.11, or 15.37C must be met in accordance with subclauses (3) to (5).

(3) If an audit establishes that the participant that was the subject of the audit has breached the relevant provisions of this Code, the cost of the audit must be met by,—
   (a) in respect of an audit carried out as a result of the Authority initiating the audit, the participant that was the subject of the audit and the Authority, in proportions to be determined by the Authority;
   (b) in respect of an audit carried out in response to a request to the Authority under clause 10.17B(2), 11.11(2), or 15.37C(2), the participant that was the subject of the audit and the participant that requested the audit, in proportions to be determined by the Authority.

(4) If the audit establishes that the participant that was the subject of the audit has not breached the relevant provisions of this Code, or if there was a breach but the Authority considers it to be minor, the cost of the audit must be met by,—
   (a) in respect of an audit carried out as a result of the Authority initiating the audit, the Authority;
   (b) in respect of an audit carried out in response to a request to the Authority under clause 10.17B(2), 11.11(2), or 15.37C(2), the participant that was the subject of the audit and the participant that requested the audit, in proportions to be determined by the Authority.

(5) The costs under subclauses (3) and (4)(b) must be paid by the participants no later than 10 business days after being advised of the amount owing.

Subpart 2—Metering equipment provider audits

16A.17 Time frame for metering equipment provider audits
In relation to audits required under clauses 10.17A and 11.8B, a metering equipment provider must ensure that—
(a) an initial audit is completed no later than 3 months after the date on which the metering equipment provider's obligations under Part 10 commence in accordance with clause 10.19; and
(b) further audits are completed as specified by the Authority under clause 16A.14.

16A.18 Additional requirements for metering equipment provider audits

In addition to the requirements specified in clauses 16A.3 to 16A.16, a metering equipment provider must ensure that an auditor carrying out an audit required under clause 10.17A or 11.8B audits—

(a) the management and maintenance of each metering installation for which the metering equipment provider is responsible, including—
   (i) maintenance of metering records; and
   (ii) maintenance of metering components; and
   (iii) certification of metering components and metering installations; and
   (iv) metering installations that have been certified at a lower category under clause 6 of Schedule 10.7; and
   (v) inspections of metering installations in accordance with this Code; and
   (vi) investigations under clause 10.43(4); and

(b) the metering equipment provider’s—
   (i) provision of metering records to the registry manager and the maintenance of that information in the registry; and
   (ii) provision of metering records to the reconciliation manager; and

(c) the metering equipment provider’s provision of access under Part 10 to—
   (i) raw meter data:
   (ii) metering records:
   (iii) the metering installation; and

(d) the security of—
   (i) each metering installation for which the metering equipment provider is responsible; and
   (ii) if relevant, the metering equipment provider’s back office; and
   (iii) if relevant, the communication between the metering equipment provider’s back office and the metering installation.


Subpart 3—ATH audits

16A.19 Time frame for ATH audits

In relation to audits required under clause 10.17A, an ATH (or an applicant for approval as an ATH) must ensure that—

(a) an initial audit is completed no later than 2 months before the date on which the ATH (or the applicant for approval as an ATH) intends to be approved as an ATH under clause 1 of Schedule 10.3; and

(b) further audits are completed as specified by the Authority under clause 16A.14.

16A.20 Additional requirements for class B ATH audits

In addition to the requirements specified in clauses 16A.3 to 16A.16, a class B ATH (or an applicant for approval as a class B ATH) must ensure that the auditor carrying out an audit audits the class B ATH (or the applicant) in respect of the requirements of NZ/AS ISO 17025
for calibration that apply to the performance of the functions for which the class B ATH (or the applicant) is being audited.

16A.21 Incorporation of NZ/AS ISO 17025 by reference
(2) Subclause (1) is subject to Schedule 1 of the Act, which includes a requirement that the Authority must give notice in the Gazette before an amended or substituted NZ/AS ISO 17025 becomes incorporated by reference in this Code.

Subpart 4—Distributor audits

16A.22 Time frame for distributor audits
In relation to audits required under clause 11.10, a distributor must ensure that—
(a) an initial audit is completed no later than 3 months after the date on which the distributor has the first NSP identifier or ICP identifier recorded in the registry as being part of the distributor's network; and
(b) further audits are completed as specified by the Authority under clause 16A.14.

16A.23 Additional requirements for distributor audits
In addition to the requirements specified in clauses 16A.3 to 16A.16, a distributor must ensure that the auditor carrying out an audit audits the distributor's processes and procedures in relation to—
(a) the creation of ICP identifiers for ICPs; and
(b) the provision of ICP information to the registry manager and the maintenance of that information in the registry; and
(c) the creation and maintenance of loss factors.
Clause 16A.23(b): amended, on 5 October 2017, by clause 5778(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

Subpart 5—Reconciliation participant audits

16A.24 Time frame for reconciliation participant audits
In relation to audits required under clause 15.37A, a reconciliation participant (or an applicant for certification as a reconciliation participant) must ensure that—
(a) an initial audit is completed no later than 2 months before the date on which the reconciliation participant (or the applicant for certification as a reconciliation participant) is required to be certified as a reconciliation participant under clause 2A of Schedule 15.1; and
(b) further audits are completed as specified by the Authority under clause 16A.14.
Subpart 6—Dispatchable load purchaser audits

16A.25 Time frame for dispatchable load purchaser audits
In relation to audits required under clause 15.37A, a dispatchable load purchaser must ensure that—
(a) an initial audit is completed no later than 4 months after the date on which the system operator approves the first device or group of devices in respect of the purchaser to be a dispatch-capable load station under clause 13.3A; and
(b) further audits are completed as specified by the Authority under clause 16A.14.

Subpart 7—Distributed unmetered load audits

16A.26 Time frame for distributed unmetered load audits
(1) In relation to audits required under clause 15.37B, a retailer that is responsible for distributed unmetered load must ensure that—
(a) an initial audit is carried out in respect of the distributed unmetered load no later than 3 months after the date on which information about an ICP associated with the distributed unmetered load is first provided by the retailer to the reconciliation manager as submission information under clause 15.4; and
(b) further audits are completed as specified by the Authority under clause 16A.14.
(2) If responsibility for distributed unmetered load switches from one retailer to another, the retailer to which the responsibility switches must ensure that audits are completed in respect of the distributed unmetered load on the dates that would apply if the switch had not occurred.

Part 16A: inserted, on 1 June 2017 by clause 36 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
Electricity Industry Participation Code 2010

Part 17
Transitional provisions

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Transitional provisions relating to Part 1

17.1 Transitional provisions for definitions
(1) Administrative costs agreed by the Board and the system operator in accordance with the definition of administrative costs in rule 1 of part A of the rules that were in force immediately before this Code came into force, are deemed to be administrative costs that have been agreed to by the Authority and the system operator in accordance with the definition of administrative costs in clause 1.1(1).

(2) A declaration date nominated by a profile applicant in accordance with the definition of declaration date in rule 1 of part A of the rules that was in force immediately before this Code came into force, is deemed to be a declaration date nominated by a profile applicant in accordance with the definition of declaration date in clause 1.1(1).

(3) A distributor kvar reference node approved by the system operator in accordance with the definition of distributor kvar reference node in rule 1 of part A of the rules that was in force immediately before this Code came into force, is deemed to be a distributor.
17.2 Special definition of purchaser and payer

(1) A notice given under rule 5.2 of part A of the rules and in force immediately before this Code came into force, is deemed to be a notice given under clause 1.5(2), and may be—
   (a) approved by the Authority (if it has not been approved by the Board); and
   (b) revoked by the participant named in the notice as participant A or the participant in the notice named as participant B.

(2) A notice published by the Board under rule 5.8 of part A of the rules before this Code came into force, is deemed to be a notice published by the Authority under clause 1.5(8).

Transitional provisions relating to Part 2

17.3 Requests for rulebook information

(1) A request for rulebook information received by the Commission under regulation 15 of the Electricity Governance Regulations 2003 that had not been responded to immediately before this Code came into force, is deemed to be a request for Code information received by the Authority under clause 2.1.

(2) A request for rulebook information received by the Commission under regulation 17 of the Electricity Governance Regulations 2003 that had not been responded to immediately before this Code came into force, is deemed to be a request for Code information received by the Authority under clause 2.3.

(3) A request for rulebook information received by a participant under regulation 19 of the Electricity Governance Regulations 2003 that had not been responded to immediately before this Code came into force, is deemed to be a request for Code information received by a participant under clause 2.5.

(4) A notice transferring a request for rulebook information under regulation 22 of the Electricity Governance Regulations 2003 that had not been responded to immediately
before this Code came into force, is deemed to be a notice transferring a request for **Code information** under clause 2.8.

(5) A charge payable by a participant under regulation 26 of the Electricity Governance Regulations 2003 immediately before this Code came into force, is deemed to be a charge payable by a **requesting participant** under clause 2.12.

**Transitional provisions relating to Part 3**

17.4 **Appointment of market operation service providers**

(1) A person or persons appointed as a registry by the Commission under regulation 30 of the Electricity Governance Regulations 2003, and whose appointment was in force immediately before this Code came into force, is deemed to have been appointed by the **Authority** as a **registry manager** under clause 3.1.

(2) A person or persons appointed as a reconciliation manager by the Commission under regulation 30 of the Electricity Governance Regulations 2003, and whose appointment was in force immediately before this Code came into force, is deemed to have been appointed by the **Authority** as a **reconciliation manager** under clause 3.1.

(3) A person or persons appointed as a pricing manager by the Commission under regulation 30 of the Electricity Governance Regulations 2003, and whose appointment was in force immediately before this Code came into force, is deemed to have been appointed by the **Authority** as a **pricing manager** under clause 3.1.

(4) A person or persons appointed as a clearing manager by the Commission under regulation 30 of the Electricity Governance Regulations 2003, and whose appointment was in force immediately before this Code came into force, is deemed to have been appointed by the **Authority** as a **clearing manager** under clause 3.1.

(5) A person or persons appointed as a market administrator by the Commission under regulation 30 of the Electricity Governance Regulations 2003, whose appointment was in force immediately before this Code came into force, is deemed to have been appointed by the **Authority** as a **market administrator** under clause 3.1.

(6) A service provider's term of appointment and the date on which that term begins agreed under regulation 32 of the Electricity Governance Regulations 2003, and in force immediately before this Code came into force, is deemed to be the relevant **market operation service provider's** term of appointment for the purposes of clause 3.3 and the date on which the term begins, as the case may be.

(7) The remuneration and other terms and conditions of appointment of a service provider agreed under regulation 33 of the Electricity Governance Regulations 2003, and in force immediately before this Code came into force, are deemed to be the remuneration and terms and conditions of appointment of the relevant **market operation service provider**, as the case may be, for the purposes of clause 3.4.

(8) A service provider agreement published by the Commission under regulation 34 of the Electricity Governance Regulations 2003 and in force immediately before this Code came into force, is deemed to be a **market operation service provider agreement** published by the **Authority** under clause 3.5.
17.5 Insurance cover
(1) A requirement by the Commission that a service provider maintain insurance cover under regulation 36 of the Electricity Governance Regulations 2003 that was in force immediately before this Code came into force, is deemed to be a requirement by the Authority under clause 3.6.
(2) An insurer approved by the Commission under regulation 36 of the Electricity Governance Regulations 2003 immediately before this Code came into force, is deemed to be approved by the Authority under clause 3.6 on the same terms and in respect of the same risks.

17.6 Notification of a force majeure event by a service provider
A notification to the Commission of a force majeure event under regulation 38 of the Electricity Governance Regulations 2003 that was in force immediately before this Code came into force, is deemed to be a notification to the Authority of a force majeure event under clause 3.7.

17.7 Disclosure to the Authority
Information received by a service provider to which regulation 42 of the Electricity Governance Regulations 2003 applied immediately before this Code came into force, is deemed to be information received by the relevant market operation service provider on the day on which this Code came into force for the purposes of clause 3.11.

17.8 Performance standards
Performance standards agreed between the Commission and a service provider for the 2010/2011 financial year under regulation 43 of the Electricity Governance Regulations 2003 that were in force immediately before this Code came into force, are deemed to be the performance standards agreed between the Authority and the relevant market operation service provider under clause 3.12 for that financial year.

17.9 Market operation service providers must report to Authority
(1) Despite the revocation of the rules, a person who was a service provider immediately before this Code came into force must conduct a self-review of its performance as if regulations 44 and 45 of the Electricity Governance Regulations 2003 had not been revoked, and must provide the report required under regulation 45 of the Electricity Governance Regulations 2003 to the Authority.
(2) A report provided to the Authority under subclause (1) is deemed to be a report given under clause 3.14.

17.10 Review of market operation service providers
(1) If the Authority reviews a market operation service provider for the 2010/2011 financial year under clause 3.15, the Authority must report on the matters specified in regulation 46 of the Electricity Governance Regulations 2003 for the period up to the date on which this Code came into force, as well as matters specified in clause 3.15 for
the remainder of the period.

(2) Each report to which subclause (1) applies must consolidate all of the information required to be included so as to report on the period to which it relates as a whole.

17.11 Software specifications

(1) An agreement between the Commission and a service provider under regulation 51 of the Electricity Governance Regulations 2003 in force immediately before this Code came into force, is deemed to be an agreement between the Authority and the market operation service provider in force under clause 3.16.

(2) An agreement between the Commission and a service provider under regulation 52 of the Electricity Governance Regulations 2003 in force immediately before this Code came into force, is deemed to be an agreement between the Authority and the market operation service provider in force under clause 3.17.

(3) An audit report provided to the Commission under regulation 52 of the Electricity Governance Regulations 2003 before this Code came into force, is deemed to be an audit report provided to the Authority under clause 3.17.

Transitional provisions relating to Part 4

17.12 Notification of a force majeure event by an ancillary service agent

A notification to the system operator and the Commission of a force majeure event under regulation 53B of the Electricity Governance Regulations 2003 immediately before this Code came into force, is deemed to be a notification to the Authority of a force majeure event under clause 4.1.

Transitional provisions relating to Part 5

17.13 Undesirable trading situations

(1) An investigation of an undesirable trading situation initiated by the Commission under regulation 54 of the Electricity Governance Regulations 2003, and not completed immediately before this Code came into force, is deemed to be an investigation of an undesirable trading situation initiated by the Authority under clause 5.1.

(2) An action taken by the Commission to correct an undesirable trading situation under regulation 56 of the Electricity Governance Regulations 2003 before this Code came into force, is deemed to be an action taken by the Authority under clause 5.2.

(3) Consultation undertaken by the Commission with the system operator to correct an undesirable trading situation under regulation 58 of the Electricity Governance Regulations 2003 before this Code came into force, is deemed to be consultation undertaken by the Authority in respect of action taken under clause 5.2 to correct an undesirable trading situation under clause 5.3.

(4) Consultation undertaken by the Commission with participants under regulation 59 of the Electricity Governance Regulations 2003 before this Code came into force, is deemed to be consultation undertaken by the Authority with participants under clause 5.4.
17.14 Approval to connect
An approval granted by a distributor to a generator to connect distributed generation under regulation 7 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 that was in force immediately before this Code came into force, is deemed to be an approval granted to connect distributed generation under clause 6.4.

17.15 Connection of distributed generation outside regulated terms
A connection contract entered into by a distributor and a generator outside the regulated terms under regulation 8 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 that was in force immediately before this Code came into force, is deemed to be a connection contract outside the regulated terms under clause 6.5.
Clause 17.15: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

17.16 Connection of distributed generation on regulated terms
(1) If distributed electricity was connected on regulated terms under regulation 9 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 immediately before this Code came into force, it is deemed to be connected on regulated terms under clause 6.6.
(2) If a period for negotiating a connection contract under clause 9 or clause 24 of Schedule 1 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 had commenced but had not expired immediately before this Code came into force, the period expires for the purposes of clause 6.6 on the date on which it would have expired if the Electricity Governance (Connection of Distributed Generation) Regulations 2007 were not revoked.

17.17 Obtaining approval to connect distributed generation under 10kW
(1) An application by a generator to a distributor to connect distributed generation only capable of generating electricity at a rate of 10kW under clause 2 of Schedule 1 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007, and on which a distributor had not made a decision immediately before this Code came into force, is deemed to be an application under clause 2 of Schedule 6.1.
(2) A generator approved to connect distributed generation under clause 3 of Schedule 1 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 immediately before this Code came into force, is deemed to have been approved to connect distributed generation under clause 3 of Schedule 6.1.
(3) A notice of intention to proceed given by a generator under clause 5 of Schedule 1 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 that was in force immediately before this Code came into force, is deemed to be a notice
17.18 Obtaining approval to connect distributed generation over 10kW

(1) An initial application made by a generator to a distributor to connect distributed generation capable of generating electricity above 10kW under clause 11 of Schedule 1 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007, for which the generator had not made a final application in respect of the generation immediately before this Code came into force, is deemed to be an initial application under clause 11 of Schedule 6.1.

(2) Information provided under clauses 12 and 13 of Schedule 1 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 before this Code came into force, is deemed to be information provided under clauses 12 and 13 of Schedule 6.1.

(3) A final application made under clause 15 of Schedule 1 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007, on which a distributor had not made a decision immediately before this Code came into force, is deemed to be a final application made under clause 15 of Schedule 6.1.

(4) A generator approved to connect distributed generation under clause 18 of Schedule 1 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 immediately before this Code came into force, is deemed to have been approved to connect distributed generation under clause 18 of Schedule 6.1.

(5) Any conditions specified by a distributor in its decision on an application under clause 18 of Schedule 1 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 immediately before this Code came into force, are deemed to be conditions specified by the distributor under clause 18 of Schedule 6.1.

(6) A notice of an intention to proceed made by a generator under clause 20 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 that was in force immediately before this Code came into force, is deemed to be a notice under clause 20 of Schedule 6.1.

17.19 Confidentiality of information provided before connection

Information provided with an application made under Schedule 1 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 before this Code came into force, is subject to the confidentiality provisions in clause 25 of Schedule 6.1.

17.20 Annual reporting and record keeping

(1) An annual report given by a distributor under clause 26 of Schedule 6.1 for the year 1 January 2010 to 1 January 2011 must report on the matters contained in clause 26 of Schedule 1 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 for the period 1 January 2010 to the date on which this Code came into force, as well as matters contained in clause 26 of Schedule 6.1, for the remainder of the period.

(2) Each report to which subclause (1) applies must consolidate all of the information
required to be included so as to report on the period to which it relates as a whole.

(3) Records to which clause 28 of Schedule 1 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 applied immediately before this Code came into force, are deemed to be records to which clause 28 of Schedule 6.1 applies, and must be maintained accordingly.

17.21 Confidential information for regulated terms for connection of distributed generation

(1) Conditions specified under clause 18 of Schedule 2 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 apply as if they were specified under clause 17 of Schedule 6.2.

(2) Information that came within the definition of confidential information under clause 16 of Schedule 2 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007, is deemed to be confidential information as defined in clause 1.1(1).

17.22 Breach of regulated terms

A regulated terms breach under clause 21 of Schedule 2 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 that was not resolved immediately before this Code came into force, is deemed to be a regulated terms breach under clause 20 of Schedule 6.2.

17.23 Default dispute resolution process

(1) A dispute to which clause 1 of Schedule 3 of the Electricity Governance (Connection of Distributed Generation) Regulations 2007 applies that was not resolved immediately before this Code came into force, is deemed to be a dispute to which clause 1 of Schedule 6.3 applies.

(2) A notice of dispute given under clause 2 of Schedule 3 of Electricity Governance (Connection of Distributed Generation) Regulations 2007, for a dispute that was not resolved immediately before this Code came into force, is deemed to be a notice given under clause 2 of Schedule 6.3.

17.23A [Revoked]


Transitional provisions relating to Part 7

17.24 Security of supply forecasting and information policy

A security of supply forecasting and information policy issued by the Commission and in force immediately before this Code came into force, is deemed to be the security of supply forecasting and information policy prepared and published under clause 7.3, and may be substituted by the system operator accordingly.
17.25 Emergency management policy
An emergency management policy issued by the Commission and in force immediately
before this Code came into force, is deemed to be the emergency management policy
prepared and published under clause 7.3, and may be substituted by the system
operator accordingly.

17.26 Review of system operator
(1) The review of the performance of the system operator by the Authority for the
2010/2011 financial year required under clause 7.8 must report on the matters specified
in regulations 47 and 48 of the Electricity Governance Regulations 2003 for the period
up to the date on which this Code came into force, as well as the matters specified in
clauses 7.8 and 7.9 for the remainder of the period.
(2) Each report to which subclause (1) applies must consolidate the information required to
be included so as to report on the period to which it relates as a whole.

17.27 Review of the system operator
An assessment of the system operator’s performance submitted to the Commission
under rule 14 of section II of part C of the rules for the period ending 31 August 2010,
is deemed to have been submitted to the Authority under clause 7.11.

Transitional provisions relating to Part 8

17.28 Policy statements
(1) The policy statement set out in schedule C4 of part C of the rules immediately before
this Code came into force, continues in force and is deemed to be the policy statement
that applies under clause 8.9, with the following amendments:
(a) every reference to the Board must be read as a reference to the Authority:
(b) every reference to the rules must be read as a reference to the Code:
(c) every reference to the regulations must be read as a reference to the Code:
(d) every reference to a provision of the rules or the regulations must be read as a
reference to the corresponding provision of the Code.
(2) The Authority must, as soon as practicable after this Code came into force, publish a
version of the policy statement in which the provisions of this Code that correspond to
the provisions of the rules or regulations referred to in the policy statement are shown.

17.29 Existing contracts for higher levels of common quality
(1) This clause applies if—
(a) Transpower and any person have a contract or an arrangement to maintain
voltage at a point of connection that—
(i) was in force immediately before the rules came into force; and
(ii) remained in force after this Code came into force; and
(b) the effect of the contract or arrangement may cause the system operator to
operate the grid voltage within a lesser range than the range set out in the
AOPOs; and
(c) Transpower and the system operator have a matching contract or arrangement in that respect under clause 8.6.

(2) When this clause applies, any incremental cost arising from the system operator operating within a lesser range under a contract or arrangement to which subclause (1)(c) applies—
(a) must not be allocated according to clause 8.6; but instead
(b) is an allocable cost and must be paid as set out in clauses 8.55 and 8.67.

(3) Subclause (2) applies to the costs arising from a contract or arrangement to which subclause (1)(c) applies until the earlier of the following:
(a) the expiry date of the contract or arrangement:
(b) termination of the contract or arrangement:
(c) the end of the life of the assets employed in providing the voltage service provided for in the contract or arrangement.

17.30 System security forecast

(1) A review of the system security forecast prepared in accordance with rule 15.1 of section II of part C of the rules for the 6 month period immediately before this Code came into force, is deemed to be a review of the system security forecast under clause 8.15.

(2) The system security forecast last provided to the Commission under rule 15 of section II of part C of the rules immediately before this Code came into force, is deemed to have been prepared, published and provided to the Authority under clause 8.15.

17.31 Load shedding obligations to support voltage

A requirement expressed by the system operator under rule 3.3 of section III of part C of the rules that was in force immediately before this Code came into force, is deemed to be a requirement expressed by the system operator under clause 8.24.

17.32 Information provisions

(1) A notice given by the system operator to an embedded generator under rule 4.5 of section III of part C of the rules that was in force immediately before this Code came into force, is deemed to be a notice issued by the system operator to an embedded generator under clause 8.25(5)(b).

(2) An application to the Commission under rule 4.6 of section III of part C of the rules on which the Commission had not made a decision immediately before this Code came into force, is deemed to be an application to the Authority under clause 8.25(6).

(3) An approval given by the Commission under rule 4.6 of section III of part C of the rules immediately before this Code came into force, is deemed to be an approval given by the Authority under clause 8.25(6).

17.33 Commissioning plan or testing plan

A commissioning plan or testing plan agreed between the asset owner and the system
operator under rule 6 of section III of part C of the rules and in force immediately before this Code came into force, is deemed to be a commissioning plan or testing plan agreed between the asset owner and the system operator under clause 8.28(3)(b).

17.34 Equivalence arrangement or dispensation

(1) An approval of an equivalence arrangement under rule 7.2 of section III of part C of the rules, unless cancelled under rule 8.2 of section III of part C or revoked under rule 8.3 of section III of part C, that was in force immediately before this Code came into force, is deemed to be an approval of an equivalence arrangement under clause 8.30 and clause 8 of Schedule 8.1, as modified in accordance with rule 8.1 of section III of part C of the rules.

(2) A grant of a dispensation under rule 7.3 of section III of part C of the rules, unless cancelled under rule 8.2 of section III of part C, or revoked or varied under rule 8.3 of section III of part C, that was in force immediately before this Code came into force, is deemed to be a grant of a dispensation under clause 8.31 and clause 8 of Schedule 8.1 as modified in accordance with rule 8.1 of section III of part C of the rules.

(3) An application for an equivalence arrangement made under clause 2 of schedule C1 of part C of the rules, on which the system operator had not yet advised its decision immediately before this Code came into force, is deemed to be an application for an equivalence arrangement under clause 2 of Schedule 8.1.

(4) An application for a dispensation made under clause 2 of schedule C1 of part C of the rules, on which the system operator had not yet advised its decision immediately before this Code came into force, is deemed to be an application for a dispensation under clause 2 of Schedule 8.1.

(5) An agreement relating to the processing costs for the approval of an equivalence arrangement or the grant of a dispensation under clause 5 of schedule C1 of part C of the rules that was in force immediately before this Code came into force, is deemed to be an agreement under clause 5 of Schedule 8.1.

(6) A draft decision issued and published by the system operator on the grant of a dispensation under clause 6 of schedule C1 of part C of the rules, on which the system operator had not advised its decision immediately before this Code came into force, is deemed to be a draft decision issued and published by the system operator on the grant of a dispensation under clause 6 of Schedule 8.1.

17.35 Excluded generating stations

A directive issued by the Commission under rule 10 of section III of part C of the rules that was in force immediately before this Code came into force, is deemed to be a directive issued by the Authority under clause 8.38(2).

17.36 Procurement plan

(1) [Expired]

(2) [Expired]

(3) Subclauses (1) and (2) expire at the close of 30 November 2010.
(4) The **procurement plan** notified in the *Gazette* dated 15 July 2010 is deemed to be the **procurement plan** made under clause 8.41.

(5) Subclause (4) came into force on 1 December 2010.

(6) A draft procurement plan submitted to the Commission under rule 4 of section IV of part C of the **rules** on which the review process in rule 5 of section IV of part C had not been completed immediately before this Code came into force, is deemed to be a **draft procurement plan** submitted to the **Authority** under clause 8.43.

(7) A draft procurement plan published by the Commission under rule 5 of section IV of part C of the **rules** on which the review process in that rule had not been completed immediately before this Code came into force, is deemed to be a **draft procurement plan** published by the **Authority** under clause 8.44.

(8) A submission received on a draft procurement plan under rule 5 of section IV of part C of the **rules** on which the review process in that rule had not been completed immediately before this Code came into force, is deemed to be submission received on a **draft procurement plan** under clause 8.44.

(9) A request for variation to a current procurement plan by a participant that the Commission had determined to hold over until the next draft procurement plan process under rule 7.2.2 of section IV of part C of the **rules** immediately before this Code came into force, is deemed to be a request for variation to a current **procurement plan** that has been held over by the **Authority** until the next **draft procurement plan** process under clause 8.46(3).

(10) A report provided to the Board by the system operator under rule 8.2 of section IV of part C of the **rules** before this Code came into force, is deemed to be a report provided to the **Authority** under clause 8.47(2).

Clauses 17.36(1) and (2): expired, on 30 November 2012 by clause 17.36(3).

### 17.37 Alternative ancillary service arrangement

(1) An alternative ancillary service arrangement authorised under rules 9.1 to 9.3 of section IV of part C of the **rules**, unless cancelled under rule 9.6 of section IV of part C or revoked under rule 9.7 of section IV of part C, immediately before this Code came into force, is deemed to be an authorised **alternative ancillary service arrangement** under clause 8.48, with any modifications to the arrangement made by rules 9.4 and 9.5 of section IV of part C of the **rules**.

(2) An application for an authorisation of an alternative ancillary service arrangement made under rules 9.1 to 9.3 of section IV of part C of the **rules**, not determined immediately before this Code came into force, is deemed to be an application for authorisation of an alternative **ancillary service arrangement** made under clause 8.48 and clause 1 of Schedule 8.2.

(3) A notification given under rule 10 of section IV of part C of the **rules** that was in force immediately before this Code came into force, is deemed to be a notification under clause 8.54.
17.38 Allocating ancillary services costs

(1) Amounts payable pursuant to contracts under rule 11.1.1 of section IV of part C of the rules, not paid immediately before this Code came into force, are deemed to be amounts payable under clause 8.55(a).

(2) Actual administrative costs approved by the Commission under rule 11.1.2 of section IV of part C of the rules and in force immediately before this Code came into force, are deemed to be actual administrative costs under clause 8.55(b).

(3) Costs or charges payable under rule 11.5.1 of section IV of part C of the rules, not paid immediately before this Code came into force, are deemed to be costs or charges payable under clause 8.59.

(4) A notice given by the system operator to a participant under rule 11.5.1A of section IV of part C of the rules, for which the required information had not been provided immediately before this Code came into force, is deemed to be a notice given under clause 8.60.

(5) A draft determination published by the system operator under rule 11.5.1B of section IV of part C of the rules before this Code came into force, is deemed to be a draft determination published under clause 8.61.

(6) A submission received on a draft determination published by the system operator under rule 11.5.1B of section IV of part C of the rules before this Code came into force, is deemed to be a submission received under clause 8.61.

(7) A notice given to the Rulings Panel under rule 11.5.1C of section IV of part C of the rules that was in force immediately before this Code came into force, is deemed to be a notice given under clause 8.62.

(8) A decision made by the Rulings Panel under rule 11.5.1D of section IV of part C of the rules before this Code came into force, is deemed to be a decision made by the Rulings Panel under clause 8.63.

(9) A determination referred back to the system operator under rule 11.5.1D of section IV of part C of the rules that had not been resolved immediately before this Code came into force, is deemed to have been referred back to the system operator under clause 8.63.

(10) Costs or charges payable under rule 11.5.2 of section IV of part C of the rules, not paid immediately before this Code came into force, are deemed to be costs or charges payable under clause 8.64.

(11) An event charge that had been paid but not rebated under rule 11.5.3 of part IV of part C of the rules immediately before this Code came into force, must be rebated under clause 8.65.

(12) Costs or charges payable under rule 11.6 of section IV of part C of the rules, not paid immediately before this Code came into force, are deemed to be costs or charges payable under clause 8.67.

(13) Amounts payable under rule 11.7 of section IV of part C of the rules, not paid immediately before this Code came into force, are deemed to be amounts payable under clause 8.68.

(14) Amounts payable under rule 11.8 of section IV of part C of the rules, not paid
immediately before this Code came into force, are deemed to be amounts payable under clause 8.69.

17.39 Requirements for asset capability statement

An asset capability statement provided to the system operator by an asset owner under clause 2.5 of technical code A of schedule C3 of part C of the rules before this Code came into force, is deemed to be an asset capability statement provided under clause 2(5) of Technical Code A of Schedule 8.3.

17.40 Connection of local networks in parallel with the grid

An agreement under clause 6 of technical code A of schedule C3 of part C of the rules that was in force immediately before this Code came into force, is deemed to be an agreement under clause 6 of Technical Code A of Schedule 8.3.

17.41 Modification and changes to assets

A notification given by an asset owner to the system operator under clause 7.2 of schedule C3 of part C of the rules that was in force immediately before this Code came into force, is deemed to be a notification given under clause 7(2) of Schedule 8.3.

17.42 Records, tests and inspections

A written request made by the system operator to an asset owner under clause 8.3 of schedule C3 of part C of the rules that the asset owner had not responded to immediately before this Code came into force, is deemed to be a written request made under clause 8(3) of Technical Code A of Schedule 8.3.

17.43 Information provided

(1) Information provided by a North Island distributor under clause 6 of appendix B of technical code A of schedule C3 of part C of the rules before this Code came into force, is deemed to be information provided by a North Island distributor under clause 6 of Appendix B of Technical Code A of Schedule 8.3.

(2) Information provided by a South Island distributor under clause 7 of appendix B of technical code A of schedule C3 of part C of the rules before this Code came into force, is deemed to be information provided by a South Island distributor under clause 7 of Appendix B of Technical Code A of Schedule 8.3.

17.44 Retention of records

The system operator and each participant must retain records of formal notices issued under clause 4 of technical code B of schedule C3 of part C of the rules.

17.45 Redistribution of automatic under-frequency load shedding [Revoked]

Clause 17.45: revoked, on 7 August 2014, by clause 34 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.
17.46 Notice
A notice in relation to a participant under clause 6.5A.2 of technical code B of schedule C3 of part C of the rules that was in force immediately before this Code came into force, is deemed to be a notice in relation to a participant under clause 7(11) of Technical Code B of Schedule 8.3.

17.47 Specific requirements for document transmission communication
(1) A request made by an asset owner to the system operator under clause 4.1.2 of technical code C of schedule C3 of part C of the rules that had not been dealt with by the system operator immediately before this Code came into force, is deemed to be a request made under clause 5(2) of Technical Code C of Schedule 8.3.

(2) An approval of primary or backup means of document transmission communication under clauses 4.1 or 4.2 of technical code C of schedule C3 of part C of the rules that was in force immediately before this Code came into force, is deemed to be an approval under clause 5(2) or (3), as the case may be, of Technical Code C of Schedule 8.3.

17.48 Outage
(1) A notification of a planned outage under clause 2 of technical code D of schedule C3 of part C of the rules that was in force immediately before this Code came into force, is deemed to be a notification under clause 2 of Technical Code D of Schedule 8.3.

(2) Any asset outage programme published under clause 6 of technical code D of schedule C3 of part C of the rules that was in force immediately before this Code came into force, is deemed to be a asset outage programme published under clause 6 of Technical Code D of Schedule 8.3.

17.48A [Revoked]

17.48B [Revoked]
Clause 17.48B: inserted, on 7 August 2014, by clause 35 of the Electricity Industry Participation Code Amendment (Extended Reserve) 2014.

Transitional provisions relating to Part 9

17.49 System operator rolling outage plan
A system operator rolling outage plan issued by the Commission immediately before this Code came into force, is deemed to be the system operator rolling outage plan prepared and published under clause 9.2, and may be substituted by the system operator accordingly.
17.50 Participant rolling outage plans

(1) A notice given by the Commission to a specified participant under regulation 8A(2) of the Electricity Governance (Security of Supply) Regulations 2008 that was in force immediately before this Code came into force, is deemed to be a notice given by the system operator under clause 9.6(2).

(2) A participant outage plan submitted to the Commission for approval under regulation 8B(2) of the Electricity Governance (Security of Supply) Regulations 2008, that had not been approved by the Commission immediately before this Code came into force, is deemed to be a participant rolling outage plan submitted to the system operator for approval under clause 9.7(2).

(3) A participant outage plan approved by the Commission under regulation 8D of the Electricity Governance (Security of Supply) Regulations 2008 that was in force immediately before this Code came into force, is deemed to be a participant rolling outage plan approved by the system operator under clause 9.9.

(4) A revised participant outage plan submitted to the Commission for approval under regulation 8E(b) of the Electricity Governance (Security of Supply) Regulations 2008 that had not been approved by the Commission immediately before this Code came into force, is deemed to be a participant rolling outage plan submitted to the system operator for approval under clause 9.10(b).

(5) A participant outage plan approved by the Commission under regulation 8F of the Electricity Governance (Security of Supply) Regulations 2008 immediately before this Code came into force, is deemed to be a participant rolling outage plan approved by the system operator under clause 9.11.

(6) A participant outage plan published under regulation 8G of the Electricity Governance (Security of Supply) Regulations 2008 that was in force immediately before this Code came into force, is deemed to be a participant rolling outage plan published under clause 9.12.

(7) Every reference to the Commission in a participant outage plan published under regulation 8G of the Electricity Governance (Security of Supply) Regulations 2008 that was in force immediately before this Code came into force, is deemed to be a reference to the system operator.

(8) Every reference to the Security of Supply Outage Plan in a participant outage plan published under regulation 8G of the Electricity Governance (Security of Supply) Regulations 2008 that was in force immediately before this Code came into force, is deemed to be a reference to the System Operator Rolling Outage Plan.

(9) Every reference to a provision of the Electricity Governance (Security of Supply) Regulations 2008 in a participant outage plan published under regulation 8G of the Electricity Governance (Security of Supply) Regulations 2008 that was in force immediately before this Code came into force, is deemed to be a reference to the corresponding provision of the Code.

(10) A participant outage plan submitted to the Commission for approval under regulation 8H of the Electricity Governance (Security of Supply) Regulations 2008 that had not
been approved by the Commission immediately before this Code came into force, is deemed to be a participant rolling outage plan submitted to the system operator for approval under clause 9.13.

(11) A participant outage plan submitted to the Commission under regulations 8B(2), 8E(b), or 8H of the Electricity Governance (Security of Supply) Regulations 2008 and held by the Commission immediately before this Code came into force, must be made available by the Authority to the system operator on request by the system operator.

17.51 Supply shortage declaration
A supply shortage declaration in force under regulation 9 of the Electricity Governance (Security of Supply) Regulations 2008 immediately before this Code came into force, is deemed to be a supply shortage declaration in force under clause 9.14.

17.52 Security of supply direction
A direction in force under regulation 10 of the Electricity Governance (Security of Supply) Regulations 2008 immediately before this Code came into force, is deemed to be a direction in force under clause 9.15.

17.53 Provision of information
(1) A written notice for information received by a participant under regulation 14 of the Electricity Governance (Security of Supply) Regulations 2008 that had not been responded to immediately before this Code came into force, is deemed to be a written notice for information given by the system operator under clause 9.18.

(2) Any information provided to the Commission under regulation 14 of the Electricity Governance (Security of Supply) Regulations 2008 and held by the Commission immediately before this Code came into force, must be made available by the Authority to the system operator on request by the system operator.

Transitional provisions relating to Part 10

17.54 Meter installations
(1) Consultation undertaken by the Commission in respect of a new point of connection under rule 2 of part D of the rules, for which the responsibility had not been determined immediately before this Code came into force, is deemed to be consultation by the Authority under clause 10.2.

(2) Advice of an assignment of responsibility for provision of a metering installation made under rule 2 of part D of the rules immediately before this Code came into force, is deemed to be advice of an assignment of responsibility for provision of a metering installation to the Authority made under clause 10.2(2).

(3) The Authority is not required to advise registered participants of an assignment under clause 10.2(3) if the Commission advised registered participants of the assignment under rule 2 of part D of the rules.
17.55 Quantification at points of connection
A method of calculation approved by the Board under rule 3.1.2 of part D of the rules in force immediately before this Code came into force, is deemed to be a method of calculation approved by the Authority under clause 10.3(a)(ii).

17.56 Electricity recorded
(1) Electricity recorded in accordance with rule 3 of part D of the rules immediately before this Code came into force, is deemed to be electricity recorded under clause 10.3.
(2) Electricity recorded in accordance with rule 3.1 of part D of the rules immediately before this Code came into force, is deemed to be electricity recorded under clause 10.3(a).
(3) Electricity recorded in accordance with rule 3.3 of part D of the rules immediately before this Code came into force, is deemed to be electricity recorded under clause 10.3(c).
(4) Electricity recorded in accordance with rule 3.4 of part D of the rules immediately before this Code came into force, is deemed to be electricity recorded under clause 10.3(d).

17.57 Metering installation tests
(1) A notice requesting a test of a metering installation given under rule 9 of part D of the rules, for which a test had not been carried out immediately before this Code came into force, is deemed to be a notice under clause 10.9(1).
(2) Any cost of a test payable under rule 9 of part D of the rules, if not paid immediately before this Code came into force, is deemed to be a cost payable under clause 10.9(2).
(3) A direction by the reconciliation manager as to the adjustment, repair or replacement of a metering installation given under rule 11 of part D of the rules that had not been complied with immediately before this Code came into force, is deemed to be a direction of the reconciliation manager under clause 10.11.

17.58 Approved test house
(1) A person approved as an approved test house by the market administrator under clauses 7.1 to 7.4 of code of practice D2 of part D of the rules, whose approval had not been cancelled under rule 7.7 of code of practice D2 of part D of the rules, immediately before this Code came into force, is deemed to be an approved test house under clause 7(2) of Code of Practice 10.2 for the purposes of Code of Practice 10.2.
(2) An application for the renewal of an approval as an approved test house under clauses 7.1 to 7.4 of code of practice D2 of part D of the rules that was not determined immediately before this Code came into force, is deemed to be an application for renewal under clause 7(9) of Code of Practice 10.2.
(3) An audit carried out under clause 7.5 of code of practice D2 of part D of the rules before this Code came into force, is deemed to be an audit carried out under clause 8 of Code of Practice 10.2.
(4) A data logger certified under clause 3.4 of code of practice D3 of part D of the rules
immediately before this Code came into force, is deemed to be a **data logger** certified under clause 3.4 of Code of Practice 10.3.

(5) A report of defects, tampering and incidents under clause 10 of code of practice D3 of part D of the **rules** made before this Code came into force, is deemed to be a report under clause 12 of Code of Practice 10.3.

### 17.59 Certification of metering installations

1. A metering installation certified, or deemed by rule 6 of section III of part I of the **rules** to be certified, under clause 4 of code of practice D3 of part D of the **rules** immediately before this Code came into force, is deemed to be a **metering installation certified** under clause 4 of Code of Practice 10.3.

2. A metering installation that had, or was deemed by rule 5 of section III of part I of the **rules** to have, interim certification under clause 4 of code of practice D3 of part D of the **rules** immediately before this Code came into force, is deemed to be a **metering installation** that has interim **certification** under clause 4 of Code of Practice 10.3.

3. A metering installation recertified under clause 5.4.2 of code of practice D3 of part D of the **rules** immediately before this Code came into force, is deemed to be a **metering installation recertified** under clause 7 of Code of Practice 10.3.

### 17.60 Inspection requirements

A variation approved by the market administrator under clause 3 of code of practice D5 of part D of the **rules** that had not expired immediately before this Code came into force, is deemed to be a variation approved by the **market administrator** under clause 3 of Code of Practice 10.5.

### 17.61 Variation of requirements

A variation granted under code of practice D5 of part D of the **rules** that had not expired immediately before this Code came into force, is deemed to be a variation granted under Code of Practice 10.5.

*Transitional provisions relating to Part 11*

### 17.62 Requirement to provide complete and accurate information

For the purposes of clause 11.2(2), information provided by a participant under part E of the **rules** before this Code came into force, is deemed to be information provided under Part 11.

### 17.63 ICP identifiers for ICPs

An ICP identifier that applied to an ICP immediately before this Code came into force, is deemed to be an **ICP identifier** for that ICP created under this Code.

### 17.64 Participants may request that distributors create ICP identifiers for ICPs

A request by a participant that a distributor create an ICP identifier for an ICP made under rule 4 of part E of the **rules**, on which the distributor had not made a decision
immediately before this Code came into force, is deemed to be a request made under clause 11.5(1).

17.65 Provision of ICP information
Information provided by a distributor or a trader under rule 6 of part E of the rules before this Code came into force, is deemed to be information provided by a distributor or a trader, as the case may be, under clause 11.7.

17.66 Provision of and changes to ICP and NSP information
A notification given by a participant under rule 8.2 of part E of the rules that had not been processed immediately before this Code came into force, is deemed to be a notification given under clause 11.8(2).

17.67 Network owner notifications
A notification given by a network owner under rule 8.5 of part E of the rules that had not been processed immediately before this Code came into force, is deemed to be a notification given under clause 11.8(5).

17.68 Audits
(1) An initial audit completed in accordance with rule 10.1.1 of part E of the rules before this Code came into force, is deemed to be an initial audit completed in accordance with clause 11.10(1)(a).
(2) A further audit completed under rules 10.1.2 and 10.1.3 of part E of the rules before this Code came into force, is deemed to be a audit completed under clauses 11.10(1)(b) or (c), as the case may be.
(3) An audit carried out by the Board in accordance with rule 10A of part E of the rules before this Code came into force, is deemed to be an audit carried out by the Authority in accordance with clause 11.11.
(4) An audit report prepared in accordance with rule 10B of part E of the rules before this Code came into force, is deemed to be an audit report prepared in accordance with clause 11.12.
(5) Comments on a draft audit report provided by a distributor to an auditor under rules 10B.3 and 10B.4 of part E of the rules, in respect of an audit report that had not been finalised immediately before this Code came into force, are deemed to be comments provided by that distributor in accordance with clauses 11.12(c) and (d).
(6) A final audit report provided to a distributor by an auditor under clause 10B.6 of part E of the rules before this Code came into force, is deemed to be a final audit report provided under clause 11.12(f).
(7) Any conditions specified in a final audit report provided under clause 10B.6 of part E of the rules that were in force immediately before this Code came into force, are deemed to be conditions specified under clause 11.12(f).
(8) A summary published by the Board under rule 10C.2 of part E of the rules before this Code came into force, is deemed to be a summary published by the Authority under
clause 11.13(2).

17.69 Process for maintaining shared unmetered load
(1) A notification provided by a distributor to the registry under rule 14.2 of part E of the rules that had not been processed immediately before this Code came into force, is deemed to be a notification provided under clause 11.14(2).
(2) A notification provided by a trader to a distributor under rule 14.2A of part E of the rules that had not been processed immediately before this Code came into force, is deemed to be a notification provided under clause 11.14(3).
(3) A notification provided by a distributor to the registry and each trader under rule 14.2B of part E of the rules that had not been processed immediately before this Code came into force, is deemed to be a notification provided under clause 11.14(4).
(4) A notification provided by a distributor to all traders under rule 14.3 of part E of the rules that was in force immediately before this Code came into force, is deemed to be a notification provided under clause 11.14(5).

17.70 Timeframes and formats of information
Any requirements as to timeframes and formats of information specified by the Board in accordance with rule 20 of part E of the rules that were in force immediately before this Code came into force, are deemed to be requirements specified by the Authority under clause 11.19(2).

17.71 Confirmation of receipt of data
Confirmation provided by the registry to a participant under rule 22.2 of part E of the rules before this Code came into force, is deemed to be confirmation provided under clause 11.21(4).

17.72 Registry must maintain a database of information
A register of information and audit trail maintained by the registry under rule 22.3 of part E of the rules immediately before this Code came into force, is deemed to be a register of information and complete audit trail maintained in accordance with clause 11.22.

17.73 Reports from the registry
(1) A report published by the registry under rule 23 of part E of the rules immediately before this Code came into force, is deemed to be a report published by the registry under clause 11.23.
(2) An agreement between the Board and the registry as to other information that must be included in a report published under rule 23.3 of part E of the rules that was in force immediately before this Code came into force, is deemed to be an agreement made under clause 11.23(c).
17.74 Registry reports to specific participants
(1) A report delivered by the registry under rule 24.1A of part E of the rules before this Code came into force, is deemed to be a report delivered by the registry under clause 11.24.
(2) A request made by the system operator in accordance with rule 24.1.2 of part E of the rules that had not been processed immediately before this Code came into force, is deemed to be a request made by the system operator under clause 11.25(2).
(3) A variation requested under rule 24.1.5 of part E of the rules that had not been processed immediately before this Code came into force, is deemed to be a variation requested under clause 11.25(5).

17.75 Access to the registry
(1) An application made by a participant under rule 25.1 of part E of the rules that had not been processed immediately before this Code came into force, is deemed to be an application made under clause 11.28(1).
(2) Terms and conditions specified by the Board under rule 25.2 of part E of the rules that were in force immediately before this Code came into force, are deemed to be terms and conditions specified under clause 11.28(2).
(3) A report requested by a participant under rule 25.4 of part E of the rules that had not been provided immediately before this Code came into force, is deemed to be a report requested by a participant under clause 11.28(4).

17.76 Registry notifications
A notification provided by the registry to affected participants under rule 26 of part E of the rules that was in force immediately before this Code came into force, is deemed to be a notification provided under clause 11.29.

17.77 Customer and embedded generator queries
A request received by a trader or a distributor under rule 28 of part E of the rules that the trader or distributor had not responded to immediately before this Code came into force, is deemed to be a request received in accordance with clause 11.31.

17.78 Dispensations
A dispensation granted by the Board under clause 1.4 of schedule E1 of part E of the rules that was in force immediately before this Code came into force, is deemed to be a dispensation granted by the Authority under clause 4 of Schedule 11.1.

17.79 Distributors to provide ICP information to registry
Information provided by a distributor to the registry under clause 2 of schedule E1 of part E of the rules that had not been changed by the distributor under clause 2A of schedule E1 of part E of the rules immediately before this Code came into force, is deemed to be information provided to the registry under clause 7 of Schedule 11.1.
17.80 Traders to provide ICP information to registry
Information provided by a trader to the registry under clause 2 of schedule E1 of part E of the rules that had not been changed by the trader under clause 2A of schedule E1 of part E of the rules immediately before this Code came into force, is deemed to be information provided to the registry under clause 7 of Schedule 11.1.

17.81 Correction of errors in the registry
A list of ICPs and other information provided by the registry to each participant under clause 3B of schedule E1 of part E of the rules that was in force immediately before this Code came into force, is deemed to be a list of ICPs and other information provided by the registry to participants under clause 11 of Schedule 11.1.

17.82 Management of ICP status by distributors and traders
(1) The status of an ICP recorded on the registry and managed in accordance with clause 4 of schedule E1 of part E of the rules immediately before this Code came into force, is deemed to be the status of the ICP recorded on the registry and managed by distributors or traders, as the case may be, in accordance with clauses 12 to 20 of Schedule 11.1, as the case may be.
(2) A request made by a distributor to a trader under clause 4.3A.1 of schedule E1 of part E of the rules that had not responded to immediately before this Code came into force, is deemed to be a request made under clause 15(a) of Schedule 11.1.
(3) A method of calculation approved by the Board under clause 4.6.2 of schedule E1 of part E of the rules that was in force immediately before this Code came into force, is deemed to be a method of calculation approved by the Authority under clause 17(2)(b) of Schedule 11.1.
(4) Advice given by a distributor under clause 4.6A of part E of the rules before this Code came into force, is deemed to be advice given by a distributor under clause 18 of Schedule 11.1.

17.83 Updating table of loss category codes
A loss category code entered in the table in the registry under clause 5 of schedule E1 of part E of the rules and in force immediately before this Code came into force, is deemed to be a loss category code entered in accordance with clause 21 of Schedule 11.1.

17.84 Updating loss factors for loss category codes
A loss factor entered in the table in the registry under clause 5A of schedule E1 of part E of the rules that is in force immediately before this Code came into force, is deemed to be a loss factor entered in accordance with clause 22 of Schedule 11.1.

17.85 Updating table of price category codes
A price category code entered in the table in the registry under clause 6 of schedule E1 of part E of the rules that is in force immediately before this Code came into force, is
deemed to be a **price category** code entered in accordance with clause 23 of Schedule 11.1.

### 17.86 Balancing area information

1. A notification given to the reconciliation manager under clause 7.1 of schedule E1 of part E of the **rules** that was in force immediately before this Code came into force, is deemed to be a notification given under clause 24(1) of Schedule 11.1.

2. A notification of a change of information given to the reconciliation manager under clause 7.1A of schedule E1 of part E of the **rules** that was in force immediately before this Code came into force, is deemed to be a notification given under clause 24(2) of Schedule 11.1.

3. A notification given by the reconciliation manager to the registry of changes to balancing areas under clause 7.2 of schedule E1 of part E of the **rules** that was in force immediately before this Code came into force, is deemed to be a notification given under clause 24(4) of Schedule 11.1.

4. A schedule published by the registry under clause 7.3 of schedule E1 of part E of the **rules** that was in force immediately before this Code came into force, is deemed to be a schedule published under clause 24(5) of Schedule 11.1.

### 17.87 Creation and decommissioning of NSPs and transfer of ICPs

1. A notification given by a participant to the reconciliation manager under clause 8.1.1 of schedule E1 of part E of the **rules** that was in force immediately before this Code came into force, is deemed to be a notification given under clause 25(1)(a) of Schedule 11.1.

2. A notification given by the reconciliation manager to the market administrator and affected reconciliation participants under clause 8.1.2 of Schedule E1 of part E of the **rules** that was in force immediately before this Code came into force, is deemed to be a notification given under clause 25(1)(b) of Schedule 11.1.

3. A notification given by a distributor under clause 8.1A of schedule E1 of part E of the **rules** that was in force immediately before this Code came into force, is deemed to be a notification given under clause 25(2) of Schedule 11.1.

### 17.88 Information to be provided if NSPs are created or ICPs are transferred

1. A request made by a participant to the reconciliation manager under clause 9.1 of schedule E1 of part E of the **rules** that had not been responded to and resolved immediately before this Code came into force, is deemed to be a request made under clause 26(1) of Schedule 11.1.

2. Information provided by a distributor to the reconciliation manager under clause 9.3 of schedule E1 of part E of the **rules** before this Code came into force, is deemed to be information provided under clause 26(3) of Schedule 11.1.

3. A notification given by a distributor to the reconciliation manager under clause 9.4 of schedule E1 of part E of the **rules** that was in force immediately before this Code came into force, is deemed to be a notification given under clause 26(4) of Schedule 11.1.
17.89 Information to be provided if ICPs become NSPs
A notification given by a distributor to traders under clause 10 of schedule E1 of part E of the rules that was in force immediately before this Code came into force, is deemed to be a notification given under clause 27 of Schedule 11.1.

17.90 Reconciliation manager to allocate new identifiers
An NSP identifier allocated by the reconciliation manager under clause 11 of schedule E1 of part E of the rules and in force immediately before this Code came into force, is deemed to be an NSP identifier allocated under clause 28 of Schedule 11.1.

17.91 Obligations concerning change in network owner
A notification given by a network owner under clause 12 of schedule E1 of part E of the rules that was in force immediately before this Code came into force, is deemed to be a notification given under clause 29 of Schedule 11.1.

17.92 Reconciliation manager to advise registry
(1) Advice given by the reconciliation manager to the registry under clause 13.1 of schedule E1 of part E of the rules before this Code came into force, is deemed to be advice given under clause 30(1) of Schedule 11.1.
(2) A schedule published by the registry under clause 13.2 of schedule E1 of part E of the rules that was in force immediately before this Code came into force, is deemed to be a schedule published by the registry under clause 30(2) of Schedule 11.1.

17.93 Transfer of ICPs between distributors' networks
(1) A notification given by a distributor to the market administrator under clause 2 of schedule E1A of part E of the rules that was in force immediately before this Code came into force, is deemed to be a notification given under clause 2 of Schedule 11.2.
(2) Confirmation given by a distributor to the market administrator under clause 5 of schedule E1A of part E of the rules before this Code came into force, is deemed to be confirmation given under clause 5 of Schedule 11.2.
(3) A validated meter reading or permanent estimate taken by a reconciliation participant under clause 11 of schedule E1A of part E of the rules before this Code came into force, is deemed to be a validated meter reading or permanent estimate taken under clause 11 of Schedule 11.2.
(4) An authorisation given by the Board to the reconciliation manager under clause 12 of schedule E1A of part E of the rules and in force immediately before this Code came into force, is deemed to be an authorisation given by the Authority under clause 12 of Schedule 11.2.
17.94 Standard switching process for ICPs with non half-hour metering and unmetered ICPs

(1) A period identified by a gaining trader under clause 1.1B.1 of schedule E2 of part E of the rules before this Code came into force, is deemed to be a period identified under clause 1(2)(a) of Schedule 11.3.

(2) An arrangement deemed to come into effect under clause 1.1B.2 of schedule E2 of part E of the rules before this Code came into force, is deemed to be an arrangement deemed to come into effect under clause 1(2)(b) of Schedule 11.3.

(3) Advice given to the registry under clause 1.1 of schedule E2 of part E of the rules before this Code came into force, is deemed to be advice given under clause 2 of Schedule 11.3.

(4) An event date established by a losing trader under clause 1.2 of schedule E2 of part E of the rules before this Code came into force, is deemed to be an event date established under clause 3 of Schedule 11.3.

(5) Acknowledgment of a switch request, final information, or a request for withdrawal of a switch provided by a losing trader under clause 1.2 of schedule E2 of part E of the rules before this Code came into force, is deemed to be an acknowledgement, final information, or request for withdrawal of a switch, as the case may be, provided under clause 3 of Schedule 11.3.

(6) Information provided by a losing trader under clause 1.3 of schedule E2 of part E of the rules before this Code came into force, is deemed to be information provided by a losing trader under clause 5 of Schedule 11.3.

(7) A dispute of a validated meter reading or permanent estimate raised under clause 1.4.2 of schedule E2 of part E of the rules that had not been resolved immediately before this Code came into force, is deemed to be a dispute under clause 6(b) of Schedule 11.3.

(8) A changed validated meter reading or permanent estimate provided under clause 1.4.2 of schedule E2 of part E of the rules before this Code came into force, is deemed to be a changed validated meter reading or permanent estimate provided under clause 6(b) of Schedule 11.3.

(9) A notice given by a losing trader under clause 1.4.2.1 or 1.4.2.2 of schedule E2 of part E of the rules that was in force immediately before this Code came into force, is deemed to be a notice given under clause 6(b)(i) or (ii) of Schedule 11.3.

(10) A dispute notified under clause 1.5 of schedule E2 of part E of the rules that had not been resolved immediately before this Code came into force, is deemed to be a dispute under clause 7 of Schedule 11.3.

17.95 Switch move process for ICPs with non half-hour metering and unmetered ICPs

(1) A period identified by a gaining trader under clause 2.1B.1 of schedule E2 of part E of the rules before this Code came into force, is deemed to be a period identified under clause 8(2)(a) of Schedule 11.3.

(2) An arrangement deemed to come into effect under clause 2.1B.2 of schedule E2 of part E of the rules before this Code came into force, is deemed to be an arrangement deemed to come into effect under clause 8(2)(b) of Schedule 11.3.
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(3) Advice given to the registry under clause 2.1 of schedule E2 of part E of the rules before this Code came into force, is deemed to be advice given under clause 9 of Schedule 11.3.

(4) A proposed event date confirmed or set by a losing trader under clause 2.2 of schedule E2 of part E of the rules before this Code came into force, is deemed to be an event date confirmed or set under clause 10 of Schedule 11.3.

(5) Acknowledgment of a switch move, final information, or a request for withdrawal of a switch provided by a losing trader under clause 2.2 of schedule E2 of part E of the rules before this Code came into force, is deemed to be an acknowledgement, final information, or request for a switch move, as the case may be, provided under clause 10 of Schedule 11.3.

(6) Information provided by a losing trading trader under clause 2.3 of schedule E2 of part E of the rules before this Code came into force, is deemed to be information provided by a losing trader under clause 11 of Schedule 11.3.

(7) A dispute of a validated meter reading or permanent estimate raised under clause 2.4.2 of schedule E2 of part E of the rules that had not been resolved immediately before this Code came into force, is deemed to be a dispute under clause 12(2)(b) of Schedule 11.3.

(8) A changed validated meter reading or permanent estimate provided under clause 2.4.2 of schedule E2 of part E of the rules before this Code came into force, is deemed to be a changed validated meter reading or permanent estimate provided under clause 12(3) of Schedule 11.3.

(9) A notice given by a losing trader under clause 2.4.2 of schedule E2 of part E of the rules that was in force immediately before this Code came into force, is deemed to be a notice given under clause 12(3) of Schedule 11.3.

(10) A dispute notified under clause 2.4.2.1 of schedule E2 of part E of the rules that had not been resolved immediately before this Code came into force, is deemed to be a dispute under clause 12(3)(i) of Schedule 11.3.

17.96 Half-hour switching process

(1) A period identified by a gaining trader under clause 3.1A.1 of schedule E2 of part E of the rules before this Code came into force, is deemed to be a period identified under clause 13(2)(a) of Schedule 11.3.

(2) An arrangement deemed to come into effect under clause 3.1A.2 of schedule E2 of part E of the rules before this Code came into force, is deemed to be an arrangement deemed to come into effect under clause 13(2)(b) of Schedule 11.3.

(3) Advice given to the registry under clause 3.2 of schedule E2 of part E of the rules before this Code came into force, is deemed to be advice given under clause 14 of Schedule 11.3.

(4) Information provided by a losing trader under clause 3.3 of schedule E2 of part E of the rules before this Code came into force, is deemed to be information provided by a losing trader under clause 15 of Schedule 11.3.
(5) A notice given to the registry under clause 3.4 of schedule E2 of part E of the rules that was in force immediately before this Code came into force, is deemed to be a notice given under clause 16 of Schedule 11.3.

17.97 Withdrawal of switch requests
(1) Codes for withdrawing a switch request determined and published by the Board under clause 4.1 of schedule E2 of part E of the rules before this Code came into force, are deemed to be codes determined and published by the Authority under clause 18(b) of Schedule 11.3.
(2) Information provided to the registry under clause 4.2 of schedule E2 of part E of the rules immediately before this Code came into force, is deemed to be information provided under clause 18(e) of Schedule 11.3.
(3) A notification given by a trader under clause 4.3 of schedule E2 of part E of the rules that was in force immediately before this Code came into force, is deemed to be a notification given under clause 18(d) of Schedule 11.3.
(4) A rejection notification given by the registry under clause 4.3 of schedule E2 of part E of the rules for a switch withdrawal request that had not been resolved immediately before this Code came into force, is deemed to be a rejection notification given under clause 18(d) of Schedule 11.3.
(5) A switch withdrawal request resubmitted by a trader under clause 4.4 of schedule E2 of part E of the rules that had not been resolved immediately before this Code came into force, is deemed to be a switch withdrawal request resubmitted under clause 18(e) of Schedule 11.3.
(6) A request that a switch request be withdrawn made under clause 4.5 of schedule E2 of part E of the rules that had not been resolved immediately before this Code came into force, is deemed to be a request made under clause 18(f) of Schedule 11.3.

17.98 Participants to use file formats
(1) File formats determined and published by the Board under clause 5.1 of schedule E2 of part E of the rules that were in force immediately before this Code came into force, are deemed to be file formats determined and published by the Authority under clause 19 of Schedule 11.3.

17.99 Method of exchanging files
(1) Consultation carried out under clause 5.2 of schedule E2 of part E of the rules before this Code came into force, is deemed to be consultation carried out under clause 20(1) of Schedule 11.3.
(2) A method by which participants must exchange information in file formats determined and published by the Board under clause 5.2 of schedule E2 of part E of the rules that were in force immediately before this Code came into force, are deemed to be methods and file formats determined and published by the Authority under clause 20 of Schedule 11.3.
17.100 Costs of interrogation or estimation

The costs of an interrogation or validated meter reading or permanent estimate carried out in accordance with clause 1.3.2 or clause 2.2.2 of schedule E2 of part E of the rules before this Code came into force, are deemed to be costs for the purposes of clause 21 of Schedule 11.3.

17.101 Registry notifications

A notification provided by the registry to participants under clause 5.4 of schedule E2 of part E of the rules that was in force immediately before this Code came into force, is deemed to be a notice provided by the registry to participants under clause 22 of Schedule 11.3.

17.101A Switching under Schedule 11.3

(1) This clause applies to an arrangement between a trader and a customer or embedded generator to carry out a switch in relation to an ICP under Schedule 11.3.

(2) If the arrangement came into effect before 9 October 2015 and the relevant switch had not been completed by that date, the switch must be completed in accordance with Schedule 11.3 as amended by the Electricity Industry Participation Code Amendment (ICP Switching) 2014 and the Electricity Industry Participation Code Amendment (ICP Switching) 2015.


Transitional provisions relating to Part 12

17.102 Discretion to waive requirements

An agreement by the Board to waive rule requirements under rule 2.1 of section I of part F of the rules that was in force immediately before this Code came into force, is deemed to be an agreement by the Authority to waive Code requirements under clause 12.2.

17.103 Benchmark agreements to be default transmission agreements

A process commenced but not completed under rule 3.1.3 of section II of part F of the rules immediately before this Code came into force, must be continued and completed under clause 12.10 and any action taken, information provided, or advice given under that rule is deemed to be an action taken, information provided, or advice given, as the case may be, under clause 12.10.

17.104 Changes to the connection assets under default transmission agreements

A process commenced but not completed under rule 3.1.5 of section II of part F of the rules immediately before this Code came into force, must be continued and completed under clause 12.12, and any action taken, information provided, or advice given under
that rule is deemed to be an action taken, information provided, or advice given, as the case may be, under clause 12.12.

17.105 Expiry or termination of transmission agreements
A process commenced but not completed under rule 3.1.6 of section II of part F of the rules immediately before this Code came into force, must be continued and completed under clause 12.13, and any action taken, information provided, or advice given under that rule is deemed to be an action taken, information provided, or advice given, as the case may be, under clause 12.13.

17.106 Transmission agreement to be provided and published
(1) A transmission agreement provided by Transpower to the Board under rule 3.2.2.1 of section II of part F of the rules immediately before this Code came into force, is deemed to be a transmission agreement provided by Transpower to the Authority under clause 12.15(1).
(2) A transmission agreement published under rule 3.2.2.3 of section II of part F of the rules immediately before this Code came into force, is deemed to be a transmission agreement published under clause 12.15(3).

17.107 Review of Connection Code
A review initiated by the Board under rule 3.3.10 of section II of part F of the rules but not completed immediately before this Code came into force, is deemed to be a review initiated by the Authority under clause 12.18.

17.108 Increased services and reliability
A certification given under rule 5.1 of section II of part F of the rules immediately before this Code came into force, is deemed to be a certification given under clause 12.35.

17.109 Approval of decreased services and reliability
An approval given under rule 5.2 of section II of part F of the rules that was in force immediately before this Code came into force, is deemed to be an approval given under clause 12.36.

17.110 Approval of other variations to terms of benchmark agreement
An approval given under rule 5.4 of section II of part F of the rules that was in force immediately before this Code came into force, is deemed to be an approval given under clause 12.38.

17.111 Customer specific value of unserved energy
(1) An application made but not approved or declined under rule 5.5.1 of section II of part F of the rules immediately before this Code came into force, is deemed to be an application made under clause 12.39(2).
(2) A provisional approval of a value of unserved energy given under rule 5.5.3 of section II of part F of the rules that was in force immediately before this Code came into force, is deemed to be a provisional approval given under clause 12.39(4).

(3) An approval given under rule 5.5.4.1 of section II of part F of the rules that was in force immediately before this Code came into force, is deemed to be an approval given under clause 12.39(5)(a).

17.112 Replacement and enhancement of shared connection assets
A process commenced but not completed under rule 5.6 of section II of part F of the rules immediately before this Code came into force, must be continued and completed under clause 12.37, and any notification, proposal, or attempt to reach agreement made under that rule is deemed to be a notification, proposal, or attempt to reach an agreement, as the case may be, under clause 12.40.

17.113 Resolution of disputes relating to transmission agreements
(1) A dispute process commenced but not determined under rule 6 of section II of part F of the rules immediately before this Code came into force, is deemed to be a dispute process commenced under clause 12.45.

(2) A determination made by the Rulings Panel under rule 6.3 of section II of part F of the rules before this Code came into force, is deemed to be a determination made by the Rulings Panel under clause 12.47.

17.114 Review of benchmark agreement
A review initiated by the Board under rule 7 of section II of part F of the rules but not completed immediately before this Code came into force, is deemed to be a review initiated by the Authority under clause 12.28.

17.115 Existing agreements
A request made by the Board under rule 8.2.1 of section II of part F of the rules that had not been complied with immediately before this Code came into force, is deemed to be a request made by the Authority under clause 12.50.

17.116 Transpower to publish grid reliability report
The grid reliability report last published by Transpower under rule 12A.1 of section III of part F of the rules immediately before this Code came into force, is deemed to be the grid reliability report published by Transpower under clause 12.76(1).

17.117 Issues paper
(1) An issues paper prepared under rule 4 of section IV of part F of the rules and in force immediately before this Code came into force, is deemed to be an issues paper prepared under clause 12.81.

(2) A date notified under rule 5.1 of section IV of part F of the rules before this Code came into force, is deemed to be a date notified under clause 12.82(1).
(3) A submission received on an issues paper under rule 5.2 of section IV of part F of the rules that had not been considered immediately before this Code came into force, is deemed to be a submission received under clause 12.82(2).

17.118 Development of transmission pricing methodology
The process and guidelines for the development of the transmission pricing methodology last published by the Board under rule 6 of section IV of part F of the rules immediately before this Code came into force, are deemed to be the process and guidelines for the development of transmission pricing methodology published by the Authority under clause 12.83.

17.119 Development of transmission prices
The transmission prices last developed and published by Transpower under rule 9.2 of section IV of part F immediately before this Code came into force, are deemed to be the transmission prices developed and published under clause 12.96.

17.120 Audit of transmission prices
(1) An auditor appointed under rule 9.3.1 of section IV of part F of the rules who had not yet completed their review immediately before this Code came into force, is deemed to have been appointed under clause 12.97(1).

(2) If Transpower had received an auditor’s report but had not yet responded to the report under rule 9.4 of section IV of part F of the rules immediately before this Code came into force, Transpower must be provided with the opportunity to respond to the auditor’s report in accordance with clause 12.98.

(3) If an auditor had received a response from Transpower but had not yet provided certification under rule 9.5 of section IV of part F of the rules immediately before this Code came into force, the auditor must provide certification to the Authority in accordance with clause 12.99(1).

17.121 Review of approved transmission pricing methodology
A proposed variation to a transmission pricing methodology submitted under rule 11.1 of section IV of part F of the rules but not reviewed immediately before this Code came into force, is deemed to be a proposed variation submitted under clause 12.85.

17.122 Transpower to identify interconnection branches, and propose service measures and levels
(1) Information provided under rule 2 of section VI of part F of the rules immediately before this Code came into force, is deemed to be information provided under clause 12.107.

(2) A request made under rule 2.6 of section IV of part F of the rules that had not been complied with immediately before this Code came into force, is deemed to be a request made under clause 12.107(6).
(3) Information and diagrams that had been published under rule 2.7 of section VI of part F of the rules and that had not been consulted on immediately before this Code came into force, is deemed to be the interconnection asset capacity and grid configuration published for consultation under clause 12.108.

17.123 Transpower to propose reliability investments
A process commenced but not completed under rule 6.1 of section VI of part F of the rules immediately before this Code came into force, is deemed to be a process commenced under clause 12.114.

17.124 Transpower to propose economic investments
The grid economic investment report last published under rule 6.2 of section VI of part F of the rules immediately before this Code came into force, is deemed to be the previous grid economic investment report for the purposes of clause 12.115(2).

17.125 Information on capacities of individual interconnection assets
The information last published under rule 7 of section VI of part F of the rules immediately before this Code came into force, is deemed to be the information published under clause 12.116.

17.126 Transpower to provide and publish annual report on interconnection asset capacity and grid configuration
The annual report last provided to the Board and published under rule 9 of section VI of part F of the rules immediately before this Code came into force, is deemed to have been provided to the Authority and published under clause 12.118.

17.127 Transpower to report on availability and reliability
The information most recently published and provided to the Board under rule 10.8 of section VI of part F of the rules immediately before this Code came into force, is deemed to be information published and provided to the Authority under clause 12.127.

Transitional provisions relating to Part 13

17.128 Requests for rulebook information
A participant who discovers, that any information disclosed by it to any person under part G of the rules before this Code came into force was misleading, deceptive, or incorrect, must immediately disclose the corrected information to the person who originally received the misleading, deceptive, or incorrect information.

17.129 Approval process for industrial co-generating stations
(1) An application to the Board to be an industrial co-generating station in accordance with rule 3 of section I of part G of the rules that was not approved, declined, or rescinded immediately before this Code came into force, is deemed to be an application to the
Authority to be an industrial co-generating station under clause 13.3 and must be continued and completed.

(2) A generator approved as an industrial co-generating station by the Board under rule 3 of section I or schedule G9 of part G of the rules, whose approval had not been rescinded immediately before this Code came into force, is deemed to be a generator approved by the Authority as an industrial co-generating station under clause 13.3 and Schedule 13.4.

(3) A notice issued by the Board of an amendment or rescission of an approval under rule 3 of section I or clause 14 of schedule G9 of part G of the rules immediately before this Code came into force, where the amendment or rescission is to take effect after this Code came into force, is deemed to be a notice issued by the Authority under clause 13.3 and clause 14 of Schedule 13.4.

17.129A Transitional provisions for co-generators
An approval granted by the Authority or deemed to have been granted under Schedule 13.4 and in effect immediately before 27 May 2015 is deemed to be an approval granted by the Authority under clause 8(1)(a)(i) of Schedule 13.4 of 1 or more generating units as a type A industrial co-generating station.


17.130 Offer preparation by generators
(1) An offer submitted by a generator under rule 3.1 of section II of part G of the rules on the day immediately before the day on which this Code came into force for the trading day on which this Code came into force, made in accordance with section II of part G of the rules, is deemed to be an offer by a generator under clause 13.6, subject to any revision of that offer made in accordance with part G of the rules or Part 13 of this Code, as applicable.

(2) An offer submitted by an embedded generator under rule 3.2 of section II of part G of the rules on the day immediately before the day on which this Code came into force for the trading day on which this Code came into force, made in accordance with section II of part G of the rules, is deemed to be an offer by an embedded generator under clause 13.6, subject to any revision of that offer made in accordance with part G of the rules or Part 13 of this Code, as applicable.

(3) An offer submitted by an intermittent generator under rule 3.13 of section II of part G of the rules on the day immediately before the day on which this Code came into force for the trading day on which this Code came into force, made in accordance with section II of part G of the rules, is deemed to be an offer by an intermittent generator under clause 13.6, subject to any revision of that offer made in accordance with section II of part G of the rules or Part 13 of this Code as the case may be.

17.131 Generators' notice of initial offer
Notice of an initial offer in respect of a generating plant given under rule 3.2 of the section II of part G of the rules and in force immediately before this Code came into
17.132 Bids by purchasers
A bid submitted by a purchaser under rule 3.3 of section II of part G of the rules on the day immediately before the day on which this Code came into force for the trading day on which this Code came into force, made in accordance with section II of part G of the rules, is deemed to be a bid by a purchaser under clause 13.7, subject to any revision of that bid made in accordance with part G of the rules or Part 13 of this Code, as applicable.

17.133 Purchasers' notice of initial bids
Notice of an initial bid in respect of a generating plant given under rule 3.4.1 of the section II of part G of the rules and in force immediately before this Code came into force, is deemed to be notice of an initial bid under clause 13.7.

17.134 Bids and offers are valid until cancelled
A purchaser or generator who failed to make a bid or offer under rules 3.1 to 3.4 of section II of part G of the rules by 1300 hours on the day immediately before the day on which this Code came into force for the trading day on which this Code came into force, is deemed to have made the same bid or offer for the trading day on which this Code came into force as that made in respect of the same trading period of the trading day immediately before the day on which this Code came into force, until that bid or offer is cancelled or revised by the purchaser or generator in accordance with rules 3.14 to 3.20 of section II of part G of the rules or clauses 13.17 to 13.21 of this Code as the case may be.

17.135 Offers made by unit of plant
Notice given under rule 3.8 of section II of part G of the rules, that was in force immediately before this Code came into force, is deemed to be notice given under clause 13.11.

17.136 New, revised or cancelled bid or offer inside the 2 hour period
(1) A report of a new, revised, or cancelled bid made to the Board under rule 3.19 of section II of part G of the rules before this Code came into force, for any trading period on the trading days immediately before and on which this Code came into force, is deemed to be a report made to the Authority under clause 13.21.
(2) A report of a revised or cancelled bid made to the Board under rule 3.19 of section II of part G of the rules that had not been determined by the Board under rule 3.20 of section II of part G of the rules immediately before this Code came into force, is deemed to be a report to the Authority under clause 13.21.

17.137 Backup procedures if the information system is unavailable
Backup procedures specified by the market administrator under rules 3.25, 5.14, 6.23,
or 7.3 to 7.5 of section II, 3.10 to 3.12 of section III, or 3.36 of section V of part G of the rules immediately before this Code came into force, are deemed to be backup procedures specified by the market administrator for the purposes of clauses 13.23, 13.36, 13.52, 13.55 and 13.67 and 13.191.

17.138 Backup procedures
Backup procedures specified by the market administrator under rule 5.11 of section V of part G of the rules immediately before this Code came into force, are deemed to be backup procedures specified by the market administrator under clause 13.211.

17.139 Plant with special circumstance
An offer submitted in respect of an automatic control plant under rule 3.26 of section II of part G of the rules immediately before this Code came into force, is deemed to be an offer submitted under clause 13.24.

17.140 Retention of bids and offers
The system operator must retain records of all bids and offers for electricity submitted by participants and all reserve offers submitted by ancillary service agents under section II of part G of the rules, including all revised bids and offers and revised reserve offers, all cancelled bids and offers and all cancelled reserve offers.

17.141 Special treatment of some grid exit points
(1) An application to the Board under rule 4 of section II of part G of the rules that was not determined by the Board immediately before this Code came into force, is deemed to be an application to the Authority under clause 13.28.
(2) 2 or more grid exit points approved to be, or deemed to be approved to be, treated as 1 grid exit point under rule 4 of section II of part G of the rules immediately before this Code came into force, are deemed to be approved to be treated as 1 grid exit point under clause 13.28.

17.142 Standing data to be provided to the system operator
Standing data provided to the system operator under rules 5.1 to 5.3 of section II of part G of the rules before this Code came into force, is deemed to be standing data provided under clauses 13.29 to 13.31, as the case may be.

17.143 Transmission grid capability information to be updated
The period of time agreed between the system operator and each grid owner for updates to information described in rules 5.1 to 5.3 and rule 5.5 of section II of part G of the rules immediately before this Code came into force for the purposes of rule 5.4 of section II of part G of the rules, is deemed to be the period of time agreed between the system operator and each grid owner for updates to information described in clauses 13.29 to 13.31 and 13.33 as the case may be, for the purpose of clause 13.32.
17.144 Grid owners must submit revised information to the system operator
Any revised information submitted to the system operator in accordance with rule 5.5 of section II of part G of the rules immediately before this Code came into force for any trading period immediately after this Code came into force, is deemed to be revised information submitted under clause 13.33, and may be varied in accordance with rules 5.6 to 5.9 of section II of the part G of the rules or clause 13.34, as the case may be.

17.145 Changes may be made within 2 hours prior to the trading period
A report made to the Board under rule 5.8 of section II of part G of the rules immediately before this Code came into force for any trading period on the trading day immediately before or on which this Code came into force, is deemed to be a report to the Authority under clause 13.34(3).

17.146 System operator to approve ancillary service agents wishing to make reserve offers
A contract between an ancillary service agent and the system operator to provide reserve offers entered into in accordance with rule 6.1 of section II of part G of the rules that was in force immediately before this Code came into force, is deemed to be a contract entered into in accordance with clause 13.37.

17.147 Ancillary service agents to submit reserve offers to the system operator
(1) A reserve offer submitted by an ancillary service agent under rules 6.2 to 6.4 of section II of part G of the rules immediately before this Code came into force, for the trading day on which this Code came into force, made in accordance with part G of the rules, is deemed to be a reserve offer by an ancillary service agent under clause 13.38, subject to any revision or cancellation of that reserve offer made in accordance with part G of the rules or Part 13 of this Code, as applicable.
(2) A report made to the Board under rule 5.8 of section II of part G of the rules, not determined by the Board immediately before this Code came into force, is deemed to be a report to the Authority under clause 13.34(3).

17.148 Revised reserve offer inside the 2 hour period
(1) A report of a new, revised, or cancelled reserve offer to the Board under rule 6.16 of section II of part G of the rules before this Code came into force, for any trading period on the trading days immediately before or on which this Code came into force, is deemed to be a report to the Authority under clause 13.49.
(2) A report of a new, revised or cancelled bid under rule 6.18 of section II of part G not determined by the Board immediately before this Code came into force, is deemed to be a report under clause 13.50.

17.149 Availability of final bids and final offers
All information made available under rule 7 of section II of part G of the rules immediately before this Code came into force, is deemed to be information made
available under clause 13.55.

17.150 Process for preparing a pre-dispatch schedule

(1) A pre-dispatch schedule for any schedule period for the trading day on which this Code came into force prepared in accordance with rules 3.1 to 3.5 of section III of part G of the rules immediately before this Code came into force, is a pre-dispatch schedule under clause 13.58.

(2) In preparing pre-dispatch schedules for the trading day on which this Code came into force, the system operator may use the most recent information received under section II and schedule G6 of part G of the rules before this Code came into force, and any information received under Part 13 or Schedule 13.3 of this Code, as applicable.

17.151 Block dispatch may occur

(1) A notification provided to the system operator under rules 3.6 to 3.62 of section III of part G of the rules immediately before this Code came into force, in respect of trading periods that occur after this Code came into force, is deemed to be a notification under clause 13.60 in respect of those trading periods.

(2) An agreement or deemed agreement to treat a group of generating stations as a block dispatch group under rule 3.6 of section III of part G of the rules that was in force immediately before this Code came into force, is deemed to be an agreement under clause 13.60.

17.152 System operator to notify block security constraints

A notification of block security constraints under rule 3.6.5 of section III of part G of the rules immediately before this Code came into force, which applies to trading periods after this Code came into force, is deemed to be a notification of block security constraints under clause 13.61(1).

17.153 Station dispatch may occur

(1) A notification given, or deemed by rule 4.2 of section IV of part I of the rules to be given, by a generator to the system operator in accordance with rule 3.9 of section III of part G of the rules before this Code came into force, which applies to a period after this Code came into force, is deemed to be a notification given under clause 13.64.

(2) An election notified, or deemed by rule 4.2 of section IV of part I of the rules to be notified, by the system operator to a generator and the clearing manager in accordance with rule 3.9 of section III of part G of the rules before this Code came into force, which applies to a period after this Code came into force, is deemed to be an election notified under clause 13.64.

17.154 System operator to notify security constraints

A notification of a dispatch made in accordance with rules 3.91 and 3.92 of section III of part G of the rules that was in force immediately before this Code came into force, which applies to a period after this Code came into force, is deemed to be a notice under
clause 13.65.

17.155 Generator notifies change from station to unit dispatch
A notification of a change from a station dispatch group to a generating unit under rule 3.9.3 of section III of part G of the rules that was in force immediately before this Code came into force, which applies to a period after this Code came into force, is deemed to be a notification under clause 13.66.

17.156 Dispatch instructions
(1) Dispatch instructions issued to a generator under rule 4.6 of section III of part G of the rules immediately before this Code came into force, which apply to a period after this Code came into force, are deemed to be dispatch instructions issued under clause 13.73.
(2) Dispatch instructions issued to an ancillary service agent under rule 4.7 of section III of part G of the rules immediately before this Code came into force, which apply to a period after this Code came into force, are deemed to be dispatch instructions issued under clause 13.74.

17.157 Market administrator to appointment person to monitor and assess demands side participation
A person appointed by a market administrator to monitor and access real time prices under rules 7.8 and 7.9 of section III of part G of the rules immediately before this Code came into force, is deemed to be a person appointed to monitor and assess real time prices under clause 13.93.

17.158 Grid emergency
A grid emergency declared under rules 8.1 and 8.2 of section III of part G of the rules immediately before this Code came into force, which applies to a period after this Code came into force, is deemed to be a grid emergency declared under clause 13.97.

17.159 The effect of a grid emergency in total quantities bid
A revision made under rule 8.4 of section III of part G of the rules that was in force immediately before this Code came into force, is deemed to be a revision made under clause 13.99.

17.160 Reporting requirements in respect of grid emergencies
A report made to the Board under rules 8.6 and 8.7 of section III of part G of the rules and not resolved by the Board immediately before this Code came into force, is deemed to be a report a made to the Authority under clause 13.101.

17.161 Reporting obligation of the system operator
A report by the system operator under rule 9 of section II of part G of the rules that was in force immediately before this Code came into force, is deemed to be a report under
clause 13.102.

17.162 System operator to publish information
Information that a system operator is responsible for publishing under rules 10.1 to 10.7 of section III of part G of the rules that had not been published immediately before this Code came into force, is deemed to be information the system operator is responsible for publishing under clauses 13.103 to 13.106.

17.163 Run dispatch options
(1) An authorisation by the clearing manager of a generator's bid under rule 2.1 and 2.2 of section IV of part G of the rules before this Code came into force, for a period after this Code came into force, is deemed to be an authorisation under clause 3.109.
(2) A calculation of auction revenue payable by a generator under rules 2.3 and 2.4 of section IV of part G of the rules but not paid immediately before this Code came into force, is deemed to be an amount payable by a generator under clause 13.110.
(3) Auction revenue payable to a purchaser under rules 2.6 and 2.7 of section IV of part G of the rules but not paid immediately before this Code came into force, is deemed to be auction revenue payable under clause 13.112.
(4) Auction rights acquired under rule 2.8 of section IV of part G of the rules immediately before this Code came into force, which relate to a time block after this Code came into force, are deemed to be auction rights acquired under clause 13.115 and those rights may be exercised in accordance with clause 13.113.

17.164 Clearing manager must conduct auctions
The format specified by the clearing manager for bidding under rule 3.3 of section IV of part G of the rules that was in force immediately before this Code came into force, is deemed to be the format for bidding under clause 13.117(3), until further amended.

17.165 Deadline for auction bids
An auction bid submitted under rule 3.7 of section IV of part G of the rules immediately before this Code came into force for any period after this Code came into force, is deemed to be an auction bid submitted under clause 13.121, unless revised or cancelled in accordance with rule 3.8 of section IV of part G of the rules or clause 13.122 of this Code, as the case may be.

17.166 Authorisation to successful bidders
An authorisation issued by the clearing manager under rule 3.15 of section IV of part G of the rules immediately before this Code came into force, is deemed to be an authorisation issued by the clearing manager under clause 13.129.

17.167 High spring washer price situation
(1) Notice of a high spring washer price situation given in accordance with rules 3.6, 3.18, or 3.21 of section V of part G of the rules and in force, immediately before this Code
come into force, is deemed to be a notice in accordance with clause 13.144(1),
13.156(1)(e), or 13.159(a)(iii) respectively, and is subject to clause 13.134, unless
resolved.

(2) Provisional prices published under rule 3.11 of section V of part G of the rules
immediately before this Code came into force, are deemed to be published in
accordance with clause 13.149 for the purposes of clause 13.134, unless resolved.

(3) Provisional reserve prices in accordance with rule 3.12 of section V of part G of the
rules immediately before this Code came into force, are deemed to be published in
accordance with clause 13.150, for the purpose of clause 13.134, unless resolved.

(4) If revised data had not been provided as required by rule 3.8 of section V of part G of
the rules immediately before this Code came into force, it is deemed that the revised
data has not been provided as required by clause 13.146, for the purpose of clause
13.134.

(5) If notice required by rule 3.9 of section V of part G of the rules had not been given
immediately before this Code came into force, it is deemed that no notice has been
provided as required by clause 13.147, for the purposes of clause 13.134.

17.168 Preparation of provisional and final prices

(1) To calculate provisional prices, provisional reserve prices, interim prices, interim
reserve prices, final prices and final reserve prices under clause 13.135, the pricing
manager may use input information provided under rule 3.3 of section V of part G of
the rules immediately before this Code came into force, as well as the input
information in clause 13.141, as appropriate.

(2) To calculate provisional prices, provisional reserve prices, final prices and final
reserve prices under clause 13.135, the pricing manager may use the methodology in
schedule G6 of part G of the rules as well as methodology in Schedule 13.3, as
appropriate.

17.169 Half-hour metering information

(1) The manner and form of half-hour metering information stipulated by the pricing
manager under rule 3.2.3 of section V of part G of the rules immediately before this
Code came into force, is deemed to be the manner and form for half-hour metering
information stipulated by the pricing manager under clause 13.138.

(2) Half-hour metering information provided under rule 3.2.3 of section V of part G of the
rules that was in force before this Code came into force, is deemed to be half-hour
metering information provided under clause 13.138.

17.170 Input information

Input information estimated in accordance with rule 3.3 of section V of part G of the
rules before this Code came into force, for any period after this Code came into force, is
deemed to be estimated input information in accordance with clause 13.141.
17.171 Pricing manager to publish interim prices
A notice published under rule 3.4.1 of section V of part G of the rules and in force immediately before this Code came into force, is deemed to be a notice published under clause 13.142(1).

17.172 SCADA situation
Notice by a grid owner of a SCADA situation under rule 3.5 of section V of part G of the rules that was in force immediately before this Code came into force, relating to a period 2 days before this Code came into force or a period after this Code came into force, is deemed to be a notice of a SCADA situation in accordance with clause 13.143.

17.173 Metering situation
Notice by a pricing manager of a metering situation under rules 3.6 and 3.6A of section V of part G of the rules that was in force immediately before this Code came into force, relating to a period 2 days before this Code came into force or a period after this Code came into force, is deemed to be notice of a metering situation in accordance with clause 13.144(1).

17.174 High spring washer price situation
Notice by the pricing manager of a high spring washer price situation in accordance with rules 3.6 and 3.6A of section V of part G of the rules that was in force immediately before this Code came into force, relating to a period 2 days before this Code came into force or a period after this Code came into force, is deemed to be notice of a high spring washer price situation in accordance with clause 13.144(1).

17.175 Requirements if provisional price situation exists
Revised data given to the pricing manager in accordance with rule 3.8 of section V of part G of the rules immediately before this Code came into force, relating to a period 2 days before this Code came into force or any period after this Code came into force, is deemed to be revised data given under clause 13.146.

17.176 Provisional prices and provisional reserve prices
If notice of a provisional price situation is given immediately before this Code came into force under rules 3.6 to 36.A of section V of part G of the rules, and no revised data is provided in accordance with rule 3.8 of section V of part G and no notice is provided in accordance with rule 3.9 of section V of part G of the rules immediately before this Code came into force, no notice is deemed to be given under clauses 13.146 and 13.147 and accordingly clauses 13.149 and 13.150 apply as appropriate.

17.177 Interim prices and provisional prices and provisional reserve prices
(1) Interim prices and interim reserve prices in relation to a provisional price situation (other than a high spring washer price situation) published under rule 3.18 of section V
of part G of the rules immediately before this Code came into force, are deemed to be interim prices and interim reserve prices published under clause 13.156(1)(a).

(2) Interim prices and interim reserve prices in relation to a high spring washer price situation published under rule 3.18 of section V of part G of the rules immediately before this Code came into force, are deemed to be interim prices and interim reserve prices published under clause 13.156(1)(a).

(3) Interim prices and interim reserve prices that do not give rise to a provisional price situation published under rule 3.18 of section V of part G of the rules immediately before this Code came into force, are deemed to be interim prices and interim reserve prices published under clause 13.156(1)(b).

(4) If an infeasibility situation arises after interim prices and interim reserve prices are published under rule 3.18 of section V of part G of the rules before this Code came into force, an infeasibility situation is deemed to have arisen under clause 13.156(1)(a).

(5) Notice of a high spring washer price situation issued under rule 3.18 of section V of part G of the rules and in force immediately before this Code came into force, is deemed to be notice of a high spring washer price situation issued under clause 13.159.


17.178 Publish final prices or notice that a high spring washer price situation exists

(1) Notice that a high spring washer price situation exists under rule 3.21 of section V of part G of the rules, relating to the 2 day period before this Code came into force or any period after this Code came into force, is deemed to be notice that a high spring washer price situation exists under clause 13.159.

(2) Interim prices and interim reserve prices published in accordance with rule 3.21 of section V of part G of the rules immediately before this Code came into force, which relate to a 2 day period before this Code came into force or a period after this Code came into force, are deemed to be interim prices and interim reserve prices published under clause 13.159.

17.179 System operator to apply high spring washer price relaxation factor and give notice

Notice published under rule 3.21B of section V of part G of the rules immediately before this Code came into force, which relates to a period 2 days before this Code came into force or a period after this Code came into force, is deemed to be a notice published under clause 13.161.

17.180 Revised data

Notice given under rule 3.22 of section V of part G of the rules and in force immediately before this Code came into force, is deemed to be notice given under clause 13.163.
17.181 If a provisional price situation (other than a high spring washer price situation) continues
(1) Notice given under rule 3.23 of section V of part G of the rules and in force immediately before this Code came into force, is deemed to be notice given under clause 13.164.
(2) Notice given to the Board under rules 3.24 and 3.25 of section V of part G of the rules that was unresolved immediately before this Code came into force, is deemed to be notice to the Authority under clause 13.165.

17.182 Interim pricing period
(1) A form received by the pricing manager under rule 3.26D.3 of section V of part G of the rules before this Code came into force, is deemed to be a form received by the pricing manager under clause 13.170(c).
(2) Prices published by the pricing manager under rule 3.26E.2 of section V of part G of the rules immediately before this Code came into force, are deemed to be prices published under clause 13.171(2).
(3) A process commenced under rule 3.26G of section V of part G of the rules but not completed immediately before this Code came into force, is deemed to be a process commenced under clause 13.173.
(4) A determination made by the pricing manager that had not been recommended to the Board under rule 3.26H of section V of part G of the rules immediately before this Code came into force, is deemed to be a determination to which clause 13.174 applies.
(5) A recommendation received by the Board under rule 3.26I of section V of part G of the rules that had not been accepted or rejected immediately before this Code came into force, is deemed to be a recommendation received by the Authority under clause 13.175.
(6) A notice published under rule 3.26J of section V of part G of the rules immediately before this Code came into force, is deemed to be a notice published under clause 13.176.
(7) An action taken by the Board under rule 3.26N of section V of part G of the rules immediately before this Code came into force, is deemed to be an action taken by the Authority under clause 13.180.
(8) A request under rule 3.26O of section V of part G of the rules that had not been complied with immediately before this Code came into force, is deemed to be a request under clause 13.181.

17.183 Authority may order delay of publication of final prices
An order by the Board to delay publication under rule 3.28 of section V of part G of the rules that was in force immediately before this Code came into force, is deemed to be an order to delay publication under clause 13.184.

17.184 System operator to give pricing manager a list of model variable failures
A list of values provided that was in force under rule 3.33 of section V of part G of the rules
rules immediately before this Code came into force, is deemed to be a list of values provided under clause 13.189, effective as at the date set under the rules.

**17.185 Calculate constrained off amounts**
Calculation of constrained off amounts under rule 4.3.1 of section V of part G of the rules for the billing period immediately before this Code came into force, is deemed to be calculation of constrained off amounts under clause 13.194.

**17.186 Rights to constrained off information**
A request for information under rule 4.7 of section V of part G of the rules not resolved immediately before this Code came into force, is deemed to be a request for information under clause 13.200.

**17.187 Constrained on amounts**
Calculation of constrained on amounts under rule 5.4 of section V of part G of the rules for the billing period immediately before this Code came into force, is deemed to be calculation of constrained on amounts under clause 13.205.

**17.188 Payment of constrained on compensation**
(1) For the purposes of clause 13.212(1) compensation for constrained on amounts determined under rules 5.3 and 5.4 of section V of part G of the rules before this Code came into force, is deemed to be compensation payable.

(2) For the purposes of clause 13.212(2), a constrained on amount compensation calculated under rule 5.4 of section V of part G of the rules immediately before this Code came into force, is deemed to be a constrained on compensation amount payable.

(3) The above entitlements are subject to clauses 13.212(3) to (8), as if the compensation were payable under clause 13.212, with any necessary modifications.

**17.189 Market administrator to publish pricing manager reports**
Daily reports provided under rule 7.1 of section V of part G of the rules that were in force immediately before this Code came into force relating to the calendar month immediately before this Code came into force, are deemed to be daily reports for the purposes of clause 13.213.

**17.190 Right to information concerning pricing manager's action**
(1) A request for further information under rule 7.3 of section V of part G of the rules that had not been resolved immediately before this Code came into force, is deemed to be a request for information under clause 13.215.

(2) Information specified in rules 3 to 7 of section VI of part G of the rules and not submitted immediately before this Code came into force, is deemed to be information specified in clauses 13.219 and 13.221 to 13.223, for the purposes of clause 13.218.
17.191 Information that must be submitted
The form specified by the Board for submission of information under rule 3 of section VI of part G of the rules immediately before this Code came into force, is deemed to be the form specified by the Authority under clause 13.219.

17.192 Calculation of contract price
Guidelines issued by the Board under rule 4 of section VI of part G of the rules and in force immediately before this Code came into force, are deemed to be guidelines issued by the Authority under clause 13.220.

17.193 Information submitted
Information submitted under rules 3, 7 and 8 of section VI of part G of the rules immediately before this Code came into force, is deemed to be information submitted under clauses 13.219, 13.223, and 13.224 respectively.

17.194 Timeframes for submitting that information
Information submitted in accordance with rule 9 of section VI of part G of the rules immediately before this Code came into force, is deemed to be information submitted under clause 13.225.

Transitional provisions relating to Part 14

17.195 Acceptable forms of security
(1) A cash deposit paid under rule 2.4.1 of part H of the rules before this Code came into force, is deemed to be a cash deposit paid under clause 14.5(a).
(2) A security agreement provided and maintained under rule 2.4.1 of part H of the rules immediately before this Code came into force, is deemed to be a security agreement provided and maintained under clause 14.5(a).
(3) An unconditional guarantee or letter of credit provided and maintained under rule 2.4.2 of part H of the rules immediately before this Code came into force, is deemed to be an unconditional guarantee or letter of credit provided and maintained under clause 14.5(b).
(4) An unconditional third party guarantee provided and maintained under rule 2.4.3 of part H of the rules immediately before this Code came into force, is deemed to be an unconditional third party guarantee provided and maintained under clause 14.5(c).
(5) A security bond provided and maintained under rule 2.4.4 of part H of the rules immediately before this Code came into force, is deemed to be a security bond provided and maintained under clause 14.5(d).
(6) A hedge settlement agreement lodged under rule 2.4.5 of part H of the rules immediately before this Code came into force, is deemed to be a hedge settlement agreement lodged under clause 14.5(e).
(7) If the terms of a security were approved by the Commission under rule 2.4 of part H of the rules immediately before this Code came into force, those terms are deemed to be approved by the Authority under clause 14.5.
17.196 Cash deposits
(1) A cash deposit account established under rule 2.6.1 of part H of the rules immediately before this Code came into force, is deemed to be a cash deposit account established under clause 14.7(1).
(2) An acknowledgment obtained under rule 2.6.3 of part H of the rules immediately before this Code came into force, is deemed to be an acknowledgment obtained under clause 14.7(3).
(3) A cash deposit received under rule 2.6.4 of part H of the rules immediately before this Code came into force, is deemed to be a cash deposit received under clause 14.8, and must be paid accordingly.
(4) Bank fees that were owed in relation to a cash deposit under rule 2.6.8 of part H of the rules immediately before this Code came into force, are deemed to be bank fees owed under clause 14.11.
(5) A statement issued under rule 2.6.9 of part H of the rules immediately before this Code came into force, is deemed to be a statement issued under clause 14.12.

17.197 Change in form of security
A notice given under rule 2.7 of part H of the rules that was in force immediately before this Code came into force, is deemed to be a notice given under clause 14.13.

17.198 Reductions and releases
A notice given under rule 2.8 of part H of the rules that was in force immediately before this Code came into force, is deemed to be a notice given under clause 14.14.

17.199 Hedge settlement agreements
A notice given under rule 2.9 of part H of the rules that was in force immediately before this Code came into force, is deemed to be a notice given under clause 14.15.

17.200 Release of security
A notice given under rule 2.10 of part H of the rules that was in force immediately before this Code came into force, is deemed to be a notice given under clause 14.16.

17.201 Level of security
(1) A determination made under rules 3.1.1 or 3.1.2 of part H of the rules that was in force immediately before this Code came into force, is deemed to be a determination made under clause 14.18(1) or (2), as the case may be.
(2) A notice of a call given under rule 3.1.3 of part H of the rules that was in force immediately before this Code came into force, is deemed to be a notice of a call given under clause 14.18(3).
(3) A determination made under rule 3.2 of part H of the rules that was in force immediately before this Code came into force, is deemed to be a determination made under clause 14.19.
17.202 Information, monitoring and reporting
(1) Historical records or a business plan submitted under rule 4.1 of part H of the rules that were in force immediately before this Code came into force, are deemed to be historical records or a business plan, as the case may be, submitted under clause 14.23.
(2) Information provided under rule 4.2 of part H of the rules before this Code came into force, is deemed to be information provided under clause 14.24.
(3) Information provided under rule 4.3 of part H of the rules before this Code came into force, is deemed to be information provided under clause 14.25.
(4) Information provided under rule 4.4 of part H of the rules before this Code came into force, is deemed to be information provided under clause 14.26.
(5) If a person had consented to the disclosure of information provided by them under rule 4.5 of part H of the rules before this Code came into force, they are deemed to have consented to the disclosure of that information under clause 14.27.
(6) A report provided under rule 4.6 of part H of the rules that was in force immediately before this Code came into force, is deemed to be a report provided under clause 14.28.

17.203 Disputes
A matter that was referred to the Rulings Panel under rule 5.1 of part H of the rules but which remain unresolved immediately before this Code came into force, is deemed to be a matter referred to the Rulings Panel under clause 14.29(1).

17.204 Invoices to and payments by payers
(1) Reconciliation information received under rule 7.1 of part H of the rules for which no invoice had been issued immediately before this Code came into force, is deemed to be reconciliation information received under clause 14.36, and is deemed to have been received on the date on which the reconciliation information was received under that rule.
(2) An invoice issued under rule 7.1 of part H of the rules that remained unpaid immediately before this Code came into force, is deemed to be an invoice issued under clause 14.36.
(3) An invoice sent using one of the methods in rule 7.7 of part H of the rules before this Code came into force, is deemed to have been sent using that method under clause 14.41.

17.205 Operating account
(1) An operating account established under rule 7.11 of part H of the rules immediately before this Code came into force, is deemed to be an operating account established under clause 14.43(1).
(2) An acknowledgment obtained under rule 7.12 of part H of the rules immediately before this Code came into force, is deemed to be an acknowledgment obtained under clause 14.43(2).
17.206 Payments to and from payees
(1) A pro forma invoice issued under rule 8.1 of part H of the rules immediately before this Code came into force, is deemed to be a pro forma invoice issued under clause 14.44.
(2) Any interest that was owed under rules 8.7 or 8.8 of part H of the rules before this Code came into force, is deemed to be interest owed under clause 14.50 and continues to accrue accordingly.

17.207 Defaults
(1) An event of default under rule 9.1 of part H of the rules that occurred before this Code came into force, is deemed to be an event of default under clause 14.55.
(2) A matter referred to the Commission under rule 9.2 of part H of the rules and not resolved immediately before this Code came into force, that remains unresolved is deemed to be a matter referred to the Authority under clause 14.56.

17.208 Disputed invoices
A dispute notified under rule 10 of part H of the rules that was not resolved immediately before this Code came into force, is deemed to be a dispute notified under clause 14.64.

17.209 Washups
(1) Corrected information received under rule 11.1 of part H of the rules before this Code came into force, is deemed to be corrected information received under clause 14.65.
(2) An invoice issued under rule 11.7 of part H of the rules before this Code came into force, is deemed to be an invoice issued under clause 14.72.

17.210 Reporting obligations
(1) A report made under rule 13.1 of part H of the rules that was not resolved immediately before this Code came into force, is deemed to be a report made under clause 14.74 and may be published accordingly.
(2) A request made under rule 13.3 of part H of the rules immediately before this Code came into force, is deemed to be a request made under clause 14.76.

17.210A [Revoked]

17.210B [Revoked]

17.210C [Revoked]

17.210D [Revoked]

17.210E [Revoked]

17.210F [Revoked]

17.210G [Revoked]

17.210H [Revoked]

17.210I [Revoked]

17.210J [Revoked]

17.210K [Revoked]
17.210L [Revoked]
Clause 17.210L(2) and (3): inserted, on 24 March 2015, by clause 27 of the Electricity Industry Participation Code Amendment (Settlement and Prudential Security) 2014.

17.210M [Revoked]

17.210N [Revoked]

17.210O [Revoked]

Transitional provisions relating to Part 15

17.211 Requirement to provide complete and accurate information
For the purposes of clause 15.2, information provided by a participant under part J of the rules before this Code came into force, is deemed to be information provided by that participant under Part 15.

17.212 Provision of trading information at point of connection to network
(1) A notification given by a trader under rule 3.1 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a notification given under clause 15.3(1).
(2) Procedures or requirements specified by the reconciliation manager under rule 3.2 of part J of the rules that were in force immediately before this Code came into force, are deemed to be procedures or other requirements, as the case may be, specified by the reconciliation manager under clause 15.3(2).

17.213 Submission information to be delivered for reconciliation
Submission information delivered or revised by a reconciliation participant under rule 4.1 of part J of the rules before this Code came into force, is deemed to be submission information delivered or revised, as the case may be, by that reconciliation participant under clause 15.4.
17.214 Retailer and direct purchaser ICP days information
A report delivered to the reconciliation manager under rule 4.2.1 of part J of the rules before this Code came into force, is deemed to be a report delivered under clause 15.6(1).

17.215 Retailer electricity supplied information
Information delivered by a retailer to the reconciliation manager under rule 4.2.2 of part J of the rules before this Code came into force, is deemed to be information delivered to the reconciliation manager under clause 15.7.

17.216 Retailer and direct purchaser half-hourly metered ICPs monthly kWh information
Information delivered by a retailer or direct purchaser to the reconciliation manager under rule 4.2.3 of part J of the rules before this Code came into force, is deemed to be information delivered to the reconciliation manager under clause 15.8.

17.217 Grid owner volume information
Information delivered by a grid owner to the reconciliation manager under rule 4.3.1 of part J of the rules before this Code came into force, is deemed to be information delivered to the reconciliation manager under clause 15.9.

17.218 Local network and embedded network submission information
Information provided by a participant to the reconciliation manager under rule 4.3.2 of part J of the rules before this Code came into force, is deemed to be information provided to the reconciliation manager under clause 15.10.

17.219 Grid connected generator
Information delivered by a generator to the reconciliation manager under rule 4.3.3 of part J of the rules before this Code came into force, is deemed to be information delivered to the reconciliation manager under clause 15.11.

17.220 Accuracy of submitted information
For the purposes of clause 15.12, information submitted by a participant under the rules before this Code came into force, is deemed to be information submitted by that participant in accordance with this Code.

17.221 Notification by embedded generators
A notification given by an embedded generator to the reconciliation manager under rule 4A of part J of the rules that was in force immediately before this Code came into force, is deemed to be a notification given under clause 15.13.

17.222 Notification of changes to the grid
(1) A notification given by a grid owner to the reconciliation manager under rule 5 of part J
of the rules that was in force immediately before this Code came into force, is deemed to be a notification given under clause 15.14(1).

(2) Procedures or other requirements specified by the reconciliation manager under rule 5 of part J of the rules that were in force immediately before this Code came into force, are deemed to be procedures or other requirements, as the case may be, specified under clause 15.14(1).

(3) A copy of a notice given by the reconciliation manager to the clearing manager and the Board under rule 5 of part J of the rules before this Code came into force, is deemed to be given under clause 15.14(3).

(4) A notice given by a grid owner of an intended change to an existing point of connection to the grid or a new point of connection to the grid to be commissioned under rule 5 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a notice given under clause 15.14(4).

17.223 System operator notifies reconciliation manager of points of connection to the grid subject to outages or alternative supply
A notification given by the system operator to the reconciliation manager under rule 6.1 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a notification given under clause 15.15.

17.224 Balancing area NSP grouping changes
(1) A determination made by the reconciliation manager under rule 6.2 of part J of the rules before this Code came into force, is deemed to be a determination made under clause 15.16.

(2) A change effected by the reconciliation manager under rule 6.2 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a change effected under clause 15.16.

17.225 Submission information to be reviewed in the case of an outage constraint
(1) A review of submission information undertaken by the reconciliation manager in accordance with rule 6.3.1 of part J of the rules before this Code came into force, is deemed to be a review undertaken under clause 15.17(a).

(2) Submission information reconciled under rule 6.3.2 of part J of the rules immediately before this Code came into force, is deemed to be submission information reconciled under clause 15.17(b).

(3) A notification given by the reconciliation manager under rule 6.3.3 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a notification given under clause 15.17(c).

(4) A consultation or assessment carried out by the reconciliation manager in accordance with rule 6.3.4 of part J of the rules before this Code came into force, is deemed to be a consultation or assessment, as the case may be, carried out in accordance with clause 15.17(d).

(5) A change to an alternative balancing area NSP grouping or update to information
carried out in accordance with rule 6.3.4 of part J of the rules before this Code came into force, is deemed to be a change or update, as the case may be, carried out in accordance with clause 15.17(d).

17.226 Reconciliation manager may request additional information
   (1) Notice given by the reconciliation manager under rule 7 of part J of the rules before this Code came into force, is deemed to be a notice given under clause 15.18.
   (2) Information provided by a reconciliation participant under rule 7 of part J of the rules before this Code came into force, is deemed to be information provided under clause 15.18.

17.227 Providing information specific to reconciliation participants
   Information provided by the reconciliation manager under rule 10.1 of part J of the rules before this Code came into force, is deemed to be information provided under clause 15.21.

17.228 Providing information to reconciliation participants
   (1) Information provided by the reconciliation manager to a reconciliation participant under rule 10.2 of part J of the rules before this Code came into force, is deemed to be information provided under clause 15.22.
   (2) A time agreed between a reconciliation participant and the reconciliation manager or determined by the Board under rule 10.2 of part J of the rules before this Code came into force, is deemed to be a time agreed between the reconciliation participant and the reconciliation manager or determined by the Authority, as the case may be, under clause 15.22.
   (3) A request made by a reconciliation participant under rule 10.2.1 of part J of the rules that had not been responded to immediately before this Code came into force, is deemed to be a request made under clause 15.22(a).
   (4) For the purposes of clause 15.23, information provided by a participant under rule 10 of part J of the rules before this Code came into force, is deemed to be information provided by that participant in accordance with clauses 15.21 to 15.26.

17.229 Reconciliation information checked
   (1) Reconciliation information provided by the reconciliation manager under rule 10 of part J of the rules that had not been checked by the relevant reconciliation participant immediately before this Code came into force, is deemed to be reconciliation information provided under clauses 15.21 to 15.26.
   (2) A dispute commenced under rule 10.4A of part J of the rules that had not been resolved immediately before this Code came into force, is deemed to be a dispute commenced under clause 15.24(2).

17.230 Reconciliation manager must assess information not supplied
   (1) For the purposes of clause 15.25(1), information that is required to be provided under
part E of the rules before this Code came into force, is deemed to be information required to be provided under Part 11.

(2) Information acquired or estimated by the reconciliation manager under rule 10.5 of part J of the rules before this Code came into force, is deemed to be information acquired or estimated, as the case may be, under clause 15.25(1).

(3) A direction by the Board under rule 10.5A of part J of the rules given before this Code came into force, is deemed to be a direction given under clause 15.25(2).

17.231 Reconciliation manager to correct information
(1) An issue referred to the Board under clause 10.7 of part J of the rules that had not been resolved immediately before this Code came into force, is deemed to be an issue referred to the Authority under clause 15.26(2).

(2) A direction given by the Board to the reconciliation manager under rule 10.7 of part J of the rules immediately before this Code came into force, is deemed to be a direction given by the Authority under clause 15.26(2).

(3) For the purposes of clause 15.26, information corrected by the reconciliation manager under rule 10.7 of part J of the rules immediately before this Code came into force, is deemed to be information corrected under clause 15.26.

(4) Corrected information provided to the clearing manager and reconciliation participants under rule 10.9 of part J of the rules immediately before this Code came into force, is deemed to be information provided under clause 15.26(4).

17.232 Transitional provisions concerning revision
A list of incumbent retailers published by the reconciliation manager under rule 11.4.3.4 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a list published under clause 15.28(3).

17.233 Volume information disputes
(1) A dispute commenced by a reconciliation participant under rule 12.1 of part J of the rules that had not been resolved immediately before this Code came into force, is deemed to be a dispute commenced under clause 15.29(1).

(2) A notification given by the reconciliation manager under rule 12.3 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a notification given under clause 15.29(3).

(3) A direction given by the Board under rule 12.4 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a direction given by the Authority under clause 15.29(4).

(4) A dispute referred to the Rulings Panel under rule 12.9 of part J of the rules that had not been resolved immediately before this Code came into force, is deemed to be a dispute referred to the Rulings Panel under clause 15.29(9).

(5) A determination made by the Rulings Panel under rule 12.10 of part J of the rules before this Code came into force, is deemed to be a determination made by the Rulings Panel under clause 15.29(10).
(6) Notice given by the Rulings Panel under rule 12.11 of part J of the rules before this Code came into force, is deemed to be notice given under clause 15.29(11).

(7) A revised seasonal adjustment shape issued under rule 12.12 of part J of the rules before this Code came into force, is deemed to be a revised seasonal adjustment shape issued under clause 15.29(12).

(8) An agreement by parties to a dispute to resolve the dispute made under rule 12 of part J of the rules that was in force immediately before this Code came into force, is deemed to be an agreement made under clause 15.29(12).

(9) Corrected submission information provided by a reconciliation participant under rule 12.12 of part J of the rules before this Code came into force, is deemed to be corrected submission information provided under clause 15.29(12).

(10) Corrected volume information provided to the clearing manager under rule 12.13 of part J of the rules before this Code came into force, is deemed to be corrected volume information provided under clause 15.29(13).

17.234 Alleged breaches reported by the reconciliation manager
A report provided by the reconciliation manager to the Board under rule 13.1 of part J of the rules before this Code came into force, is deemed to be a report provided to the Authority under clause 15.30.

17.235 Right to information concerning reconciliation manager's actions
Notice given by a reconciliation participant under rule 13.2 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a notice given under clause 15.31(1).

17.236 Reconciliation reports
A report given by the reconciliation manager to the Board under rule 13.3 of part J of the rules before this Code came into force, is deemed to be a report given to the Authority under clause 15.32.

17.237 The publication of reports
Sections of a report published by the Board under rule 14 of part J of the rules that were in force immediately before this Code came into force, are deemed to be published under clause 15.33.

17.238 Provision of information
Timeframes notified by the Board or formats determined by the Board under rule 16 of part J of the rules that were in force immediately before this Code came into force, are deemed to be timeframes notified by or formats determined by the Authority, as the case may be, under clause 15.35.

17.239 New Zealand daylight time adjustment techniques
Techniques specified by the Board under rule 17 of part J of the rules that were in force
immediately before this Code came into force, are deemed to be techniques specified by the Authority under clause 15.36.

17.240 Audit
A requirement issued by the Board that a participant have an audit undertaken under rule 18 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a requirement issued by the Authority under clause 15.37.

17.241 Functions requiring certification
Certification to carry out functions under the Code obtained and maintained by a reconciliation participant under rule 19 of part J of the rules that by that reconciliation participant was in force immediately before this Code came into force, is deemed to be certification obtained and maintained under clause 15.38.

17.242 Participant must use participant identifiers
(1) For the purpose of clause 15.39, a participant identifier obtained by a participant under the rules before this Code came into force, is deemed to be the participant identifier for that participant under this Code.
(2) An application made by a participant under rule 20.2 of part J of the rules before this Code came into force, is deemed to be an application made under clause 15.39(2).
(3) A notification given by the Board under rule 20.3 of part J of the rules before this Code came into force, is deemed to be a notification given by the Authority under clause 15.39(3).

17.243 Requirement for certification
A reconciliation participant required to obtain certification in accordance with clause 1A of schedule J1 of the rules immediately before this Code came into force, is required to obtain certification in accordance with clause 2 of Schedule 15.1 of this Code, but must do so no later than the expiry of the remainder of the 3 calendar month period specified in clause 1A of schedule J1 of part J of the rules as at the date on which this Code came into force.

17.244 Obtaining certification
(1) An application made by a reconciliation participant under clause 3.1 of schedule J1 of the rules before this Code came into force, is deemed to be an application made under clause 4(1) of Schedule 15.1.
(2) A request by the Board for information under clause 3.1A of schedule J1 of part J of the rules made before this Code came into force, is deemed to be a request made by the Authority under clause 4(2) of schedule 15.1.
(3) Information provided by a reconciliation participant under clause 3.1A of schedule J1 of part J of the rules before this Code came into force, is deemed to be information provided under clause 4(2) of Schedule 15.1.
17.245 Granting certification
A quality certification deemed by the Board to be equivalent to AS/NZS ISO 9001:2000 or AS/NZS ISO 9001:2008 before this Code came into force, is deemed to be a quality certification deemed by the Authority to be equivalent to AS/NZS ISO 9001:2000 or AS/NZS ISO 9001:2008, as the case may be, under clause 5(1)(b)(iii) of Schedule 15.1.

17.246 Lists of certified reconciliation participants and agents
A list of certified reconciliation participants and agents used by certified reconciliation participants published and updated by the Board in accordance with clause 3A of schedule J1 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a list of certified reconciliation participants or agents used by certified reconciliation participants, as the case may be, under clause 6 of Schedule 15.1.

17.247 Renewed certification
A certification renewed by the Board under clause 3B of schedule J1 of part J of the rules before this Code came into force, is deemed to be a certification renewed by the Authority under clause 7(2) of Schedule 15.1.

17.248 Changes that affect certification
(1) A notification and an audit report provided by a reconciliation participant to the Board under clause 3C.1 of schedule J1 of part J of the rules before this Code came into force, is deemed to be a notification or an audit report, as the case may be, provided to the Authority under clause 8(1) of Schedule 15.1.
(2) Notice given by the Board under clause 3C.2 of schedule J1 of part J of the rules before this Code came into force, is deemed to be notice given by the Authority under clause 8(2) of Schedule 15.1.
(3) A notice given by the Board to a reconciliation participant under rule 3C.3.2 of schedule J1 of part J of the rules before this Code came into force, is deemed to be a notice given by the Authority under clause 8(3)(b) of Schedule 15.1.

17.249 Auditors
(1) An auditor approved by the Board under clause 5.1A of schedule J1 of part J of the rules who had not had its approval withdrawn by the Board immediately before this Code came into force, is deemed to be an auditor approved by the Authority under clause 9(1) of Schedule 15.1.
(2) An application by a person to be an auditor or for the renewal of an existing approval made under clause 5.1A of schedule J1 of part J of the rules that had not been processed by the Board immediately before this Code came into force, is deemed to be an application made under clause 9(4) of Schedule 15.1.
(3) A request for clarification, further data, or information made by the Board under clause 5.1A.3 of schedule J1 of part J of the rules before this Code came into force, is deemed to be a request for clarification, further data, or information, as the case may be,
requested by the Authority under clause 9(4) of Schedule 15.1.

(4) A list of auditors published by the Board under clause 5.1B of schedule J1 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a list published by the Authority under clause 9(7) of Schedule 15.1.

17.250 Audits

(1) The prescribed form for an audit report prescribed by the Board under clause 6.1 of schedule J1 of part J of the rules before this Code came into force, is deemed to be the prescribed form for an audit report prescribed by the Authority under clause 10 of Schedule 15.1.

(2) An audit report provided by an auditor to a reconciliation participant under clause 6 of schedule J1 of part J of the rules before this Code came into force, is deemed to be an audit report provided under clause 10(a) of Schedule 15.1.

(3) Comments received by an auditor from a reconciliation participant under clause 6.3 of schedule J1 of part J of the rules in respect of an audit report that had not been finalised immediately before this Code came into force, are deemed to be comments received under clause 10(d) of Schedule 15.1.

(4) Any conditions specified in a final audit report provided under clause 6.5 of Schedule J1 of part J of the rules that were in force immediately before this Code came into force, are deemed to be conditions specified under clause 10(f) of Schedule 15.1.

17.251 Audit reports

(1) A final audit report provided to the Board under clause 6A of schedule J1 of part J of the rules before this Code came into force, is deemed to be a final audit report provided to the Authority under clause 11(1) of Schedule 15.1.

(2) A summary published by the Board under clause 6A.2 of schedule J1 of part J of the rules before this Code came into force, is deemed to be a summary published by the Authority under clause 11(2) of Schedule 15.1.

(3) An agreement between a reconciliation participant and the Board made under clause 6A.3 of schedule J1 of part J of the rules that was in force immediately before this Code came into force, is deemed to be an agreement made under clause 11(3) of Schedule 15.1.

17.252 Participant requested audits

A request made by a participant under clause 8.1A of schedule J1 of part J of the rules before this Code came into force, is deemed to be a request made under clause 12(2) of Schedule 15.1.

17.253 Scope of audits

A requirement of the Board issued for the purposes of clause 8.2 of schedule J1 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a requirement of the Authority issued under clause 13 of Schedule 15.1.
17.254 Information requests
A request by the Board or its auditor under clause 8.2A of schedule J1 of part J of the rules made before this Code came into force, is deemed to be a request made by the Authority or its auditor, as the case may be, under clause 14 of Schedule 15.1.

17.255 Participants provide access and information
Additional information that the Board or its auditor reasonably considers is necessary under clause 8.3 of schedule J1 of the rules and requested before this Code came into force, is deemed to be additional information that the Authority or its auditor, as the case may be, reasonably considers is necessary under clause 15 of Schedule 15.1.

17.256 Production of audit report
An audit report produced under clause 8.4 of schedule J1 of part J of the rules before this Code came into force, is deemed to be an audit report produced under clause 16 of Schedule 15.1.

17.257 Determination
(1) A determination by the Board of an instance of non-compliance made under clause 8.5 of schedule J1 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a determination made by the Authority under clause 17(1) of Schedule 15.1.
(2) Details submitted by a participant under clause 8.5 of schedule J1 of part J of the rules before this Code came into force, are deemed to be details submitted under clause 17(2) of Schedule 15.1.

17.258 Summary of audit report
A summary of an audit report published by the Board under clause 8.6 of schedule J1 of part J of the rules before this Code came into force, is deemed to be a summary published by the Authority under clause 18 of Schedule 15.1.

17.259 Meter interrogation for non half-hour metering
(1) A report given by a reconciliation participant under clause 5.4.1 of schedule J2 of part J of the rules before this Code came into force, is deemed to be a report given under clause 8(1) of Schedule 15.2.
(2) A requirement that a reconciliation participant explain why a level was not achieved and describe steps taken issued under clause 5.4.2 of schedule J2 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a requirement issued under clause 8(1) of Schedule 15.2.

17.260 Non half-hour meter reading every 4 months
(1) A report given by a reconciliation participant to the market administrator under clause 5.5.1 of schedule J2 of part J of the rules before this Code came into force, is deemed to be a report given under clause 9(1) of Schedule 15.2.
(2) A requirement issued by the market administrator that a reconciliation participant explain why a level was not achieved and describe the steps that are being taken to achieve a level issued under clause 5.5.2 of schedule J2 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a requirement issued under clause 9(1)(b) of Schedule 15.2.

17.261 Interrogation logs
An interrogation log produced under clause 5.6 of schedule J2 of part J of the rules before this Code came into force, is deemed to be an interrogation log produced under clause 10 of Schedule 15.2.

17.262 Meter interrogation for half-hour metering
(1) An estimate submitted to the reconciliation manager by a reconciliation participant under clause 6.5 of schedule J2 of part J of the rules before this Code came into force, is deemed to be an estimate submitted under clause 15(1) of Schedule 15.2.
(2) A percentage specified by the Board under clause 6.5 of schedule J2 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a percentage specified by the Authority under clause 15(2) of Schedule 15.2.

17.263 Audit trails
Information provided to and received from the registry, provided to and received from the reconciliation manager, or provided to and received from other reconciliation participants and their agents under clause 11.1 of schedule J2 of part J of the rules immediately before this Code came into force, is deemed to be information provided to and received from the registry, provided to and received from the reconciliation manager, or provided and received from other reconciliation participants and their agents, as the case may be, under clause 21(2).

17.264 Correction of meter readings
A journal generated and archived by a reconciliation participant under clause 11.4.2 of schedule J2 of part J of the rules before this Code came into force, is deemed to be a journal generated and archived under clause 22(2) of Schedule 15.2.

17.265 Creation of submission information
(1) The time period covered by kWhp published by the reconciliation manager under clause 2.2.1.1 of schedule J3 of part J of the rules before this Code came into force, is deemed to be published by the reconciliation manager under clause 4(a) of Schedule 15.3.
(2) A percentage specified and published by the Board under clause 2.2.3 of schedule J3 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a percentage specified and published, as the case may be, by the Authority under clause 6(3) of Schedule 15.3.
17.266 Provision of submission information to reconciliation manager
Submission information provided by a reconciliation participant to the reconciliation manager under clause 3 of schedule J3 of part J of the rules before this Code came into force, is deemed to be submission information provided under clause 8 of Schedule 15.3.

17.267 Reporting requirements
(1) A report provided by a reconciliation participant to the reconciliation manager under clause 4 of schedule J3 of part J of the rules before this Code came into force, is deemed to be a report provided under clause 10(1) of Schedule 15.3.

(2) A report provided by the reconciliation manager to the Board under clause 4 of schedule J3 of part J of the rules before this Code came into force, is deemed to be a report provided to the Authority under clause 10(2) of Schedule 15.3.

(3) Information published by the Board under clause 4 of schedule J3 of part J of the rules immediately before this Code came into force, is deemed to be information published by the Authority under clause 10(2) of Schedule 15.3.

17.268 Distributed unmetered load database
A database maintained by a retailer in accordance with clause 5 of schedule J3 of part J of the rules before this Code came into force, is deemed to be a database maintained by that retailer under clause 11 of Schedule 15.3.

17.269 Calculation by difference for embedded networks
A notice given by a trader to the reconciliation manager designating an ICP under clause 3 of schedule J4 of part J of the rules that had not been revoked immediately before this Code came into force, is deemed to be a notice given under clause 3 of Schedule 15.4.

17.270 Calculation by difference for local networks
(1) An application made by a trader to the Board under clause 3A of schedule J4 of part J of the rules before this Code came into force, is deemed to be an application made under clause 4(1) of Schedule 15.4.

(2) A designation granted by the Board under clause 3A of schedule J4 of part J of the rules that had not been revoked by the Board immediately before this Code came into force, is deemed to be a designation granted by the Authority under clause 4 of Schedule 15.4.

17.271 ICP days information
The default values for profiles and loss category codes determined by the Board under clause 4.2.2 of schedule J4 of part J of the rules that were in force immediately before this Code came into force, are deemed to be default values for profiles and loss category codes, as the case may be, determined by the Authority under clause 7(5) of Schedule 15.4.
17.272 Calculation of residual non half-hour profile shape
A residual profile shape for a balancing area calculated by the reconciliation manager under clause 5 of schedule J4 of part J of the rules before this Code came into force, is deemed to be a residual profile shape for a balancing area calculated by the reconciliation manager under clause 9 of Schedule 15.4.

17.273 Convert non half-hour quantities using profiles
(1) A notification given by a profile owner to the reconciliation manager under clause 6.1.2 of schedule J4 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a notification given under clause 10(b) of Schedule 15.4.
(2) A authorisation given by a profile owner to a reconciliation participant under clause 6.1.3 of part J of the rules that was in force immediately before this Code came into force, is deemed to be an authorisation given under clause 10(c) of Schedule 15.4.

17.274 Invalid submission information
Default values specified by the Board under clause 6.5.2 of schedule J4 of part J of the rules that were in force immediately before this Code came into force, are deemed to be default values specified by the Authority under clause 14(b) of Schedule 15.4.

17.275 Loss factors
A direction given by the Board under clause 7 of schedule J4 of part J of the rules that was current immediately before this Code came into force, is deemed to be a direction given by the Authority under clause 15(1) of Schedule 15.4.

17.276 Scorecard rating
(1) A scorecard rating given to a retailer by the reconciliation manager under clause 9 of schedule J4 of part J of the rules that was in force immediately before this Code came into force, is deemed to be the scorecard rating of the retailer under clause 17 of Schedule 15.4.
(2) Information about the quantity of electricity supplied to the reconciliation manager under clause 9 of schedule J4 of part J of the rules before this Code came into force, is deemed to be information provided under clause 17(2) of Schedule 15.4.
(3) An unusual circumstance approved by the Board under clause 9.1 of schedule J4 of part J of the rules that was in force immediately before this Code came into force, is deemed to be an unusual circumstance approved by the Authority under clause 17(3) of Schedule 15.4.

17.277 Calculation of scorecard rating
(1) A scorecard rating for a retailer that was calculated, published, or applied under clause 9.2 of schedule J4 of part J of the rules before this Code came into force, is deemed to be a scorecard rating calculated, published, or applied, as the case may be,
(2) A value specified by the Board under clause 9.2.2 of schedule J4 of part J of the **rules** that was in force immediately before this Code came into force, is deemed to be a value specified by the **Authority** under clause 18(1)(b) of Schedule 15.4.

17.278 Application of scorecard rating

A scorecard rating notified by the Board under clause 9.3 of schedule J4 of part J of the **rules** that was in force immediately before this Code came into force, is deemed to be a **scorecard rating** notified by the **Authority** under clause 18(4) of Schedule 15.4.

17.279 Reconciliation manager reporting requirements

(1) Information provided by the reconciliation manager under clause 14 of schedule J4 of part J of the **rules** before this Code came into force, is deemed to be information provided by the **reconciliation manager** under clauses 24 to 27, as the case may be, of Schedule 15.4.

(2) A percentage determined by the Board under clause 14.1.6 of schedule J4 of part J of the **rules** that was in force immediately before this Code came into force, is deemed to be a percentage determined by the **Authority** under clause 25(f) of Schedule 15.4.

17.280 Provision of reconciliation information

(1) Information provided by the reconciliation manager under clause 15 of schedule J4 of part J of the **rules** before this Code came into force, is deemed to be information provided under clause 28 of Schedule 15.4.

(2) A format or information requirement determined by the Board under clause 15 of schedule J4 of part J of the **rules** that was in force immediately before this Code came into force, is deemed to be a format or information requirement, as the case may be, determined by the **Authority** under clause 28 of Schedule 15.4.

17.281 Departure from requirements for profile administration

An approval given by the market administrator under clause 2 of schedule J5 of part J of the **rules** that was in force immediately before this Code came into force, is deemed to be an approval given under clause 2 of Schedule 15.5.

17.282 Profile population list

A profile population list kept by a reconciliation participant under clause 3.3 of schedule J5 of part J of the **rules** immediately before this Code came into force, is deemed to be a **profile population** list kept under clause 5 under Schedule 15.5.

17.283 Profiles approved for use

Details kept by a profile owner under clause 3.4 of schedule J5 of part J of the **rules** immediately before this Code came into force, are deemed to be details kept under clause 6 of Schedule 15.5.
17.284 Change of profile
(1) An application made under clause 3A of schedule J5 of part J of the rules that had not been approved or rejected immediately before this Code came into force, is deemed to be an application made under clause 11 of Schedule 15.5.
(2) Advice given by the market administrator under clause 3A.4 of schedule J5 of part J of the rules that was in force immediately before this Code came into force, is deemed to be advice given under clause 11(4) of Schedule 15.5.

17.285 Profile codes
(1) A profile code determined by the market administrator under clause 5 of schedule J5 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a profile code determined under clause 13 of Schedule 15.5.
(2) Information published by the market administrator under clause 5.2 of schedule J5 of part J of the rules that was in force immediately before this Code came into force, is deemed to be information published under clause 13(5) of Schedule 15.5.

17.286 New NSP derived profiles
(1) An application made under clause 7.1 of schedule J5 of part J of the rules that had not been approved, withdrawn, or rejected immediately before this Code came into force, is deemed to be an application made under clause 19 of Schedule 15.5.
(2) Advice given by the market administrator to a profile applicant under clause 7.1 of schedule J5 of part J of the rules that was in force immediately before this Code came into force, is deemed to be advice given under clause 19(1) of Schedule 15.5.
(3) A legal entity nominated by a profile applicant under clause 7.3 of schedule J5 of part J of the rules immediately before this Code came into force, is deemed to be a legal entity nominated under clause 21 of Schedule 15.5.
(4) An explanation provided by the market administrator under clause 7.5 of schedule J5 of part J of the rules that was in force immediately before this Code came into force, is deemed to be an explanation provided under clause 23 of Schedule 15.5.
(5) A profile approved by the market administrator under clause 7 of schedule J5 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a profile approved by the market administrator under clauses 19 to 24, as the case may be, of Schedule 15.5.
(6) An approval given by a profile owner to a reconciliation participant under clause 7.6 of schedule J5 of part J of the rules that was in force immediately before this Code came into force, is deemed to be an approval given under clause 24(2) of Schedule 15.5.

17.287 New statistically sampled/engineered profiles
(1) An application to introduce a new profile submitted under clause 8.2 of schedule J5 of part J of the rules on which a decision had not been made immediately before this Code came into force, is deemed to be an application submitted under clause 26 of Schedule 15.5.
(2) Advice given by the market administrator under clause 8.2 of schedule J5 of part J of
the rules that was in force immediately before this Code came into force, is deemed to be advice given under clause 26(1) of Schedule 15.5.

(3) A format for the supply of analytical information required by the market administrator under clause 8.2A of schedule J5 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a format required under clause 26(2) of Schedule 15.5.

(4) A legal entity nominated to be the profile owner under clause 8.5 of schedule J5 of part J of the rules immediately before this Code came into force, is deemed to be a legal entity nominated under clause 29 of Schedule 15.5.

(5) Advice given by the market administrator to participants under clause 8.6 of schedule J5 of part J of the rules immediately before this Code came into force, is deemed to be advice given under clause 30 of Schedule 15.5.

(6) An explanation provided by the market administrator under clause 8.7 of schedule J5 of part J of the rules immediately before this Code came into force, is deemed to be an explanation provided under clause 31 of Schedule 15.5.

(7) A date decided by the market administrator under clause 8.8 of schedule J5 of part J of the rules immediately before this Code came into force, is deemed to be a date decided under clause 32(1) of Schedule 15.5.

(8) An approval given by a profile owner to a reconciliation participant under clause 8.8 of schedule J5 of part J of the rules that was in force immediately before this Code came into force, is deemed to be an approval given under clause 32(2) of Schedule 15.5.

(9) A profile population list maintained by a profile owner under clause 8.9 of schedule J5 of part J of the rules immediately before this Code came into force, is deemed to be a profile population list maintained under clause 33 of Schedule 15.5.

(10) A notification given by the market administrator to a profile owner under clause 8.9.2 of schedule J5 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a notification given under clause 33(3) of Schedule 15.5.

(11) A list of ICP identifiers submitted under clause 8.9.2 of schedule J5 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a list of ICP identifiers submitted under clause 33(4) of Schedule 15.5.

(12) A determination of appropriate replacement ICP identifiers issued by the market administrator under clause 8.9.2 of schedule J5 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a determination under clause 33(4).

17.288 MARIA profiles
A profile deemed, in accordance with rule 4 of section III of part I of the rules to be a profile determined under rules 6.1 and 7.2 of code of practice G2 of schedule G8 of part G of the rules, is deemed to be a profile approved in accordance with clauses 19 to 34, as the case may be, of Schedule 15.5.

17.289 Audits
(1) A request for an audit made under clause 9 of schedule J5 of part J of the rules before
this Code came into force, is deemed to be a request made under clause 35 of Schedule 15.5.

(2) An audit conducted under clause 9.2 of schedule J5 of part J of the rules before this Code came into force, is deemed to be an audit conducted under clause 35(2) of Schedule 15.5.

(3) A selection process maintained by the market administrator and monitored by the Board under clause 9.2 of schedule J5 of part J of the rules that was in force immediately before this Code came into force, is deemed to be a selection process maintained by the market administrator and monitored by the Authority under clause 35(2) of Schedule 15.5.

17.290 Removal of profiles
(1) A breach reported to the Board under clause 11.1 of schedule J5 of part J of the rules that was not resolved immediately before this Code came into force, is deemed to be a breach reported to the Authority under clause 37(2) of Schedule 15.1.
(2) A request that a profile be removed made under clause 11.2 of schedule J5 of part J of the rules immediately before this Code came into force, is deemed to be a request made under clause 37(3) and (4) of Schedule 15.5.

17.291 Reviews
A review undertaken under clause 5 of Appendix 3 of schedule J5 of part J of the rules before this Code came into force, is deemed to be a review undertaken under clause 5 of Appendix 2 of Schedule 15.5.


17.292 [Revoked]

17.293 [Revoked]

17.294 [Revoked]

17.295 [Revoked]

Transitional provisions relating to Part 16A
Cross Heading: inserted on 1 June 2017, by clause 37 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.
17.295A Metering equipment provider audits
(1) If, on the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, the Authority has specified a date under clause 1(1)(b) of Schedule 10.5 by which a metering equipment provider must ensure that an audit is carried out, the metering equipment provider must ensure that an audit is completed in accordance with Part 16A by the later of—
(a) the date that the Authority has specified; or
(b) the date that is 1 month after the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force.

(2) If, on the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, the Authority has not specified a date under clause 1(1)(b) of Schedule 10.5 by which a metering equipment provider must ensure that an audit is carried out,—
(a) the Authority must, no later than 1 month after the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, specify a date by which the metering equipment provider must ensure that an audit is carried out in accordance with Part 16A; and
(b) the metering equipment provider must comply with that requirement.

(3) Clause 16A.17 applies to a metering equipment provider to which subclauses (1) or (2) apply as if the audit completed under those subclauses were the initial audit required under clause 16A.17(a).


17.295B ATH audits
(1) If, on the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, the Authority has specified a date under clause 1(4)(c) of Schedule 10.3 by which an ATH must ensure that an audit is carried out, the ATH must ensure that an audit is completed in accordance with Part 16A by the later of—
(a) the date that the Authority has specified; or
(b) the date that is 1 month after the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force.

(2) If, on the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, the Authority has not specified a date under clause 1(4)(c) of Schedule 10.3 by which an ATH must ensure that an audit is carried out,—
(a) the Authority must, no later than 1 month after the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, specify a date by which the ATH must ensure that an audit is carried out in accordance with Part 16A; and
(b) the ATH must comply with that requirement.

(3) Clause 16A.19 applies to an ATH to which subclauses (1) or (2) apply as if the audit completed under those subclauses were the initial audit required under clause 16A.19(a).
Clause 17.295B: inserted on 1 June 2017, by clause 37 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

17.295C Distributor audits

(1) If, immediately before the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, a distributor was required to arrange for an audit to be completed by a date determined in accordance with clause 11.10(1)(b), the distributor must ensure that an audit is completed in accordance with Part 16A by the later of—
   (a) the date determined in accordance with clause 11.10(1)(b); or
   (b) the date that is 1 month after the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force.

(2) Clause 16A.22 applies to a distributor to which subclause (1) applies as if the audit completed under that subclause were the initial audit required under clause 16A.22(a).

Clause 17.295C: inserted on 1 June 2017, by clause 37 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

17.295D Reconciliation participant audits

(1) If, immediately before the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, a reconciliation participant was required to provide a final audit report to the Authority by a date determined in accordance with clause 11(1) of Schedule 15.1, the reconciliation participant must ensure that an audit is completed in accordance with Part 16A by the later of—
   (a) the date determined in accordance with clause 11(1) of Schedule 15.1; or
   (b) the date that is 1 month after the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force.

(2) Clause 16A.24 applies to a reconciliation participant to which subclause (1) applies as if the audit completed under that subclause were the initial audit required under clause 16A.24(a).

Clause 17.295D: inserted on 1 June 2017, by clause 37 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

17.295E Dispatchable load purchaser audits

(1) If, immediately before the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force, a dispatchable load purchaser was required to provide a final audit report to the Authority by a date determined in accordance with clause 11(1) of Schedule 15.1, the dispatchable load purchaser must ensure that an audit is completed in accordance with Part 16A by the later of—
   (a) the date determined in accordance with clause 11(1) of Schedule 15.1; or
   (b) the date that is 1 month after the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force.

(2) Clause 16A.25 applies to a dispatchable load purchaser to which subclause (1) applies as if the audit completed under that subclause were the initial audit required under clause 16A.25(a).
Clause 17.295E: inserted on 1 June 2017, by clause 37 of the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016.

17.295F Distributed unmetered load audits

(1) A retailer that is responsible for distributed unmetered load on the date that the Electricity Industry Participation Code Amendment (Requirements and Processes for Audits) 2016 comes into force must ensure that an audit is completed in accordance with Part 16A no later than 12 months after that date.

(2) Clause 16A.26(1) applies to a retailer to which subclause (1) applies as if the audit completed under that subclause were the initial audit required under clause 16A.26(1)(a).


Transitional provisions relating to exemptions

17.296 Exemptions

(1) An exemption in force under regulations 194 to 197 of the Electricity Governance Regulations 2003 immediately before this Code came into force, in relation to a rule, continues in force and is deemed to be an exemption from the obligation to comply with the corresponding provision of this Code and may be amended and revoked accordingly.

(2) A proposed exemption being considered by the Commission under regulation 194 of the Electricity Governance Regulations 2003 immediately before this Code came into force must be treated by the Authority as a proposed exemption under section 11 of the Act.

(3) An application for a variation or revocation of an exemption under regulation 196 of the Electricity Governance Regulations 2003 that was in force immediately before this Code came into force must be dealt with by the Authority under section 11 of the Act.