

Electricity Industry Participation Code 2010

Part 1 Preliminary provisions

Contents

- 1.1 Interpretation
- 1.2 General principles of construction
- 1.3 Special definition of “related”
- 1.4 Special definition of “independent”
- 1.5 Special definition of “purchaser” and “payer”
- 1.6 Contents tables
- 1.7 Defined terms appear in bold

Schedule 1.1

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

Schedule 1.2

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

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**

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

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

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

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 **market administrator** in accordance with clause 13.188

applications layer means a part of a **metering installation** used for a function that is not performed by the **metrology layer**

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

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 test house means a **meter** testing and **calibration** facility that has been approved by the **market administrator** in accordance with Part 10

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

approved test laboratory means a test laboratory that has been accredited under the Testing Laboratory Registration Act 1972 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**

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 **AOP** 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 connection with any works or **electrical 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 means the value of **co-efficient of variation** that is set by the **market administrator** for the purpose of calculating the **preliminary sample size**

at risk HVDC transfer means the quantity of **MWh** for each **trading period** calculated in accordance with Tables 1 and 2, where—

$INJ_{HVDCHAYt}$ 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

$INJ_{HVD CBENT}$ 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

$INJ_{Pole2HAYt}$ 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**

HVDC configuration at the beginning of trading period t	At risk HVDC transfer north in trading period t (expressed in MWh)
Pole 1 one half pole only	$INJ_{HVDCHAYt}$
Pole 2 only	$INJ_{HVDCHAYt}$
Pole 3 only	$INJ_{HVDCHAYt}$
Pole 2 and Pole 1 one half pole	$INJ_{Pole2HAYt}$
Pole 3 and Pole 2 bipole round power	$INJ_{HVDCHAYt}$
Pole 3 and Pole 2 bipole not round power	$\max(0, INJ_{HVDCHAYt} - 263)$

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

HVDC configuration at the beginning of trading period t	At risk HVDC transfer south in trading period t (expressed in MWh)
Pole 2 only	$INJ_{HVDCBEN_t}$
Pole 3 only	$INJ_{HVDCBEN_t}$
Pole 3 and Pole 2 bipole round power	$INJ_{HVDCBEN_t}$
Pole 3 and Pole 2 bipole not round power	$\max(0, INJ_{HVDCBEN_t} - 263)$

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 payable in accordance with clause 13.112(2) and, for a **purchaser**, the amount receivable 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, and 15, a person approved by the **Authority** to carry out an **audit**; and
- (b) for all other Parts of this Code, a person carrying out an **audit**

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 automatic shedding of electrical load when frequency falls below the relevant preset frequency specified in clause 7(6) of **Technical Code B** of Schedule 8.3

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

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 connected from time to time under normal circumstances

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 **publicised** 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

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; but

(c) excludes a **bid** cancelled in accordance with clause 13.19A

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.

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 livened and connected to the **grid**

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 **market administrator** not to be a **business day** by notice to each **registered participant**

Clause 1.1(1) **business day**: amended, on 21 September 2012, by clause 4(1) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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**

Clause 1.1(1) **calibration report**: substituted, on 29 August 2013, by clause 4(2)(b) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

call has the meaning given to it in clause 14.18(3)

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

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 **payer** in accordance with clause 14.5, and includes any interest under clause 14.10(1) that has not been paid out

cash deposit accounts means the trust accounts established by the **clearing manager** in accordance with clause 14.7(1)

cash interest rate means the interest rate calculated by taking a weighted average of interest rates applying to each **purchaser's cash deposit**

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.

Clause 1.1(1) **category 2 metering installation**: substituted, on 29 August 2013, by clause 4(2)(d) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

causer, 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 means information kept by the **Authority** relating to transmission and **transmission alternatives** under clauses 12.72 to 12.75

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 that **reconciliation participant** has met the requirements of Schedule 15.1

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

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

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

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 disconnect a faulted **asset** from the **grid** in the allocated time; and
- (b) may disconnect non-faulted **assets** from the **grid** as well as a faulted **asset**

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.

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 1 **participant** to another **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)

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

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

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

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 means the owner of an **industrial co-generating station**. To avoid doubt, clauses specifying **co-generators** apply only to the **industrial co-generating stations** owned by the **co-generator**

commissioning means, for the purposes of Part 10, to verify the correct operation of metering equipment installed in a **metering installation**

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

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

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

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*]

Clause 1.1(1) **complete**: revoked, on 16 December 2013, by clause 4(2)(a) of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.

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**

Clause 1.1 **configuration**: substituted, on 1 July 2012, by clause 4(2) of the Electricity Industry Participation (HVDC Pole 3 Minor Amendments) Code Amendment 2012.

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

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

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

connect, in relation to **distributed generation**, means to be connected to a **distribution network** or to a **consumer installation** that is connected to a **distribution 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 the connection of **distributed generation** and the operation of the **distribution network**, including requirements relating to the planning, design, construction, testing, inspection, and operation of **assets** that are, or are proposed to be, connected to the **distribution network**; 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

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 the 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**

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** payable to a **dispatched purchaser** under clause 13.201A; or
- (b) **constrained off amounts** payable to the **clearing manager** under clause 13.201A by **purchasers**

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

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** payable 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** payable 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

Clause 1.1(1) **constraint price**: amended, on 15 May 2014, by clause 4(1) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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

Clause 1.1(1) **construct**: amended, on 21 September 2012, by clause 4(2) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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 definitions of **connect**, **distributed generation**, **electrical installation**, **fittings**, and Part 6, includes—

- (a) an **electrical installation**; and
- (b) any **fittings** that are used, or designed or intended for use, by any person in or in connection with the generation of **electricity** so that **electricity** can be injected into a **distribution network**

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) in which the quantity of **electricity** that the contract relates to equals or exceeds 0.25 MW of **electricity**

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**

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

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

control system means equipment that adjusts the output voltage, frequency, **MW** or **reactive power** (as the case may be) of an **asset** in response to certain aspects of **common quality** such as voltage, frequency, **MW** or **reactive power**, including speed governors and exciters

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 means a person who purchases, or has agreed to purchase, **electricity** from a **retailer** at a specific **ICP**

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

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

data logger [*Revoked*]

Clause 1.1(1) **data logger**: revoked, on 15 May 2014, by clause 4(2) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 **market administrator** must, for a particular **profile**, notify every **registered participant** of the information set out in clause 13 of Schedule 15.5 for that **profile**
decommissioning means—

- (a) for the purposes of Part 10, the permanent physical removal of a **metering installation** for 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 means the operation of any isolator, **circuit breaker**, or switch or the removal of any fuse or link so that no **electricity** can flow through a **point of connection** on a **network**, and **de-energise** and **de-energised** have corresponding meanings

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.

de-energise has the meaning given to it in the definition of **energisation**

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.

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 a **bid** that a **purchaser** submits to the **system operator** 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*]

Clause 1.1(1) **disclosed**: revoked, on 16 December 2013, by clause 4(2)(b) of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.

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 publicly available, 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 means, in relation to a **grid injection point**, **grid exit point** or **point of connection**, that there is no load or generation at, or connected to, the **grid injection point**, **grid exit point** or **point of connection** in the modelling system

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.

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.

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

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.

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 equipment used, or proposed to be used, for generating **electricity** that—

- (a) is connected, or proposed to be connected, to a **distribution network**, or to a **consumer installation** that is connected to a **distribution network**; and
- (b) is capable of injecting **electricity** into that **distribution network**

distributed generator, for the purposes of Part 6, means a person who owns or operates **distributed generation**

distributed unmetered load means **unmetered load** with a single **profile** supplied to a single **customer** across more than 1 **point of connection**

distribution network means the **electricity lines**, and **associated equipment**, owned or operated by a **distributor**, but does not include—

- (a) the **national grid**; or
- (b) an **embedded network** that is used to convey less than 5 GWh per annum

distributor means as follows:

- (a) except in Part 12A, and as provided in paragraph (b), a **participant** who supplies **line function services** to another person;
- (b) in Parts 1 (except for the definitions of **connection and operation standards**, **distribution network**, and **specified participant**), 8, 10, 11, 12, 13, 14 and 15, a **participant** who owns or operates a **local network**; and—
 - (i) in Part 8, includes a **direct consumer**; and
 - (ii) in Parts 10, 11, 13 and 15 includes an **embedded network** owner

Clause 1.1(1) **distributor**: amended, on 21 September 2012, by clause 4(3) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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)

Clause 1.1(1) **draft policy statement**: amended, on 10 January 2013, by clause 4(1) of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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

Clause 1.1(1) **draft procurement plan**: amended, on 10 January 2013, by clause 4(2) of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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 of information between **distributors** and **traders**

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) for the purposes of the definitions of **associated equipment** and **consumer installation**—

- (i) all **fittings** that form part of a system for conveying **electricity** at any point from the **point of supply** to a **consumer** to any point from which **electricity** conveyed through that system may be consumed; and
- (ii) includes any **fittings** that are used, or designed or intended for use, by any person, in or in connection with the generation of **electricity** for that person's use and not for supply to any other person; but

- (iii) 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:
- (b) for the purposes of the rest of this Code, 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 connection with, the generation of **electricity** for that person's use and not for supply to any other person), but does not include any electrical appliance

electrically connecting means connecting, or permitting the connection of, a new **point of connection** to a **network**, for the purposes of an activity regulated under Parts 11 or 15, and **electrically connect** and **electrically connected** have corresponding meanings

Clause 1.1(1) **electrically connecting**: inserted, on 29 August 2013, by clause 4(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).

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**

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** between two points (point A and point B), where—

- (a) point A is a **point of connection** between a **local network** or another **embedded network**; and
- (b) point B is a **point of connection** between a **consumer**, an **embedded generating station**, or both; and
- (c) the **electricity** flow at point A is quantified by a **metering installation** in accordance with Part 10

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**

Clause 1.1(1) **EMP departure situation**: inserted, on 21 September 2012, by clause 4(4) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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

energisation means the operation of an isolator, circuit breaker, or switch, or the placing of a fuse or link, so that **electricity** can flow through a **point of connection** on a **network**, and—

- (a) energise and energised have corresponding meanings; and
- (b) **de-energise** means to reverse the process of **energisation** and **de-energised** and **de-energisation** have corresponding meanings

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

Clause 1.1(1) **energisation**: substituted, on 29 August 2013, by clause 4(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).

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
- 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**

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

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 date on which an arrangement between a **customer** and a **trader** for the supply of **electricity** at the **ICP** comes into effect

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 14.55

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 means the cost per kW, estimated by the **Authority** from time to time, which exceeds the cost per kW that any persons are expected to incur as a direct consequence of block 2 **automatic under-frequency load shedding** facilities operating in accordance with clause 7(6) of **Technical Code B** of Schedule 8.3

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.

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**

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.

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:

$$\frac{Eday_4 + Eday_3 + Eday_2 + Eday_1}{4} \times \left\{ \frac{(IslandLoad_0)}{\left(\frac{IslandLoad_4 + IslandLoad_3 + IslandLoad_2 + IslandLoad_1}{4} \right)} \right\}$$

where

Eday₁ 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

Eday₂ 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

Eday₃ 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

Eday₄ 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 Load₀ 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 Load₁ 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 Load₂ 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 Load₃ 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 Load₄ 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 means the 12 month period beginning on the date determined by the **Authority**

fittings, for the purpose of the definition of **consumer installation** and paragraph (a) of the definition of **electrical installation**, means everything used, or designed or intended for use, in or connection with the generation, conversion, transformation, conveyance, or use of **electricity**

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 **market operation service provider** or **ancillary service agent** 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

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

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

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

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

Clause 1.1(1) **formal notice**: amended, on 1 June 2013, by clause 4(b) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

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 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

Clause 1.1(1) **frequency keeping unit**: inserted, on 3 October 2013, by clause 4 of the Electricity Industry Participation (Technology Neutral Language in Frequency Keeping) Code Amendment 2013.

frequency time error means a deviation from **New Zealand standard time** caused by variations in system frequency

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

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

FTR account means the trust account established by the **clearing manager** in accordance with clause 14.43A

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

FTR acquisition cost means—

- (a) the amount a **participant** must pay or be paid 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 payable under clause 13.249(3)

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 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 payable 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 payable 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 for the purposes of 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 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** advises the **registry** may become 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.

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**

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.

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**

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

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** and **co-generators**

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 means information recorded directly by a **metering installation** measuring the quantity of **electricity** conveyed in each **trading period**. For

a **generator** who is selling **electricity** to the **clearing manager** and other persons at the same **grid injection point** in the same **trading period**, **half-hour metering information** also 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
half-hour metering installation means a **metering installation** used for **half-hour metering**

Clause 1.1(1) **half-hour metering installation**: amended, on 29 August 2013, by clause 4(2)(l) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

hedge settlement agreement means an agreement in the form set out in Schedule 14.5 between a **generator** and a **purchaser** 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

Clause 1.1(1) **high spring washer price relaxation factor**: amended, on 21 September 2012, by clause 4(1) of the Electricity Industry Participation (High Spring Washer Price Situation) Code Amendment 2012.

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 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**: amended, on 21 September 2012, by clause 4(2) of the Electricity Industry Participation (High Spring Washer Price Situation) Code Amendment 2012.

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 situation methodology**: amended, on 21 September 2012, by clause 4(3) of the Electricity Industry Participation (High Spring Washer Price Situation) Code Amendment 2012.

high spring washer price trigger ratio means the ratio in clause 13.133

high voltage terminal means the connection point where the higher voltage side of a **grid owner's** transformer connects to the **grid**

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**

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**

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**

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

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 a **customer** installation 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**

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**

industrial co-generating station means 1 or more **generating unit**—

- (a) that is connected to the **grid** or to a **local network**; and
- (b) that 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) that is tightly coupled to an **industrial process**; and
- (d) that has been approved by the **Authority** under 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 means the system or systems required for the conveyance of information between persons in accordance with this Code as may be approved from time to time by the **Authority**

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

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

interruptible load means a form of **instantaneous reserve** comprised of energy being consumed that is able to be 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 **de-energise** a **point of connection** by the **Authority** or the **Rulings Panel** under the **Act** or this Code or by the **clearing manager** or 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

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)

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

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, for the purposes of the definition of **distributor** and in Part 12A, means the following:

- (a) the provision and maintenance of works for the conveyance of **electricity**;
- (b) the operation of such works, including the control of voltage and assumption of responsibility for losses of **electricity**

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**

Clause 1.1(1) **line owner**: amended, on 21 September 2012, by clause 4(5) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

lines, for the purpose of the definition of **distribution network** and Part 6, means works that are used or intended to be used for the conveyance of **electricity**

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 14.73(2)

loss category means the relevant code in the schedule published by the **registry** 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)

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

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

Clause 1.1(1) **loss factor**: amended, on 15 May 2014, by clause 5(4) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

loss of communication means a sustained disruption of communications between the **system operator** and 1 or more **dispatch customers** 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 disconnects a faulted **asset** from the **grid** with the minimum of 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 means the **market operation service provider** who is for the time being appointed as market administrator under this Code

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 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)

Clause 1.1(1) **metering installation**: substituted, on 29 August 2013, by clause 4(2)(q) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

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
- (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.

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

Clause 1.1(1) **metering standards**: substituted, on 29 August 2013, by clause 4(2)(r) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

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 means an occurrence where the frequency of **electricity** deviates outside the **normal band** but is restored as soon as reasonably practicable. With respect to the frequency targets in clause 7(2)(b)(ii), the maximum and minimum frequency during a **momentary fluctuation** determine the frequency band in which the **momentary fluctuation** is recorded

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**

national grid, for the purposes of the definition of **distribution network**, has the meaning given to it in section 5 of the **Act**

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

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**

network supply point and **NSP** mean 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**

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 means a **bid** submitted by a **purchaser**—

- (a) *[Revoked]*

- (b) *[Revoked]*
- (c) *[Revoked]*
- (d) means a **bid** that a **purchaser** submits to the **system operator** to indicate a reasonable estimate of the quantity of—
 - (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.

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

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**

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

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

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

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**.

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

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 outages means planned outages of **assets** forming part of or connected to the **grid** or **local network** that have been planned by the **asset owners** concerned and have been notified to the **system operator** in accordance with **Technical Code D** of Schedule 8.3

notify means to notify the persons referred to in the relevant clause by way of letter, e-mail or facsimile, to a contact person and address provided by that person, that the information referred to in that clause has been **published**

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**

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

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

Clause 1.1(1) **obligation FTR**: amended, on 1 November 2012, by clause 4(3) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

offer means the information submitted to the **system operator** by a **generator** in accordance with clause 13.6(1) to (3) and includes any revised **offer** made in accordance with clauses 13.17 to 13.19, but excludes any **offer** cancelled in accordance with clause 13.17

Clause 1.1(1) **offer**: amended, on 15 May 2014, by clause 4(3) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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)

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

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

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 14.43(1)

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

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

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

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 is **disconnected**, as notified by the **system operator** in accordance with clauses 15.15 to 15.17

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

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**

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

Clause 1.1(1) **participant identifier**: amended, on 15 May 2014, by clause 4(4) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 means—

- (a) a **participant** who is a **generator** or an **ancillary service agent**; or
- (b) when receiving payment for **ancillary service administrative costs**, the **system operator**; or
- (c) a person to whom any amount is payable under an **FTR**; or
- (d) a **dispatched purchaser**

Clause 1.1(1) **payee**: substituted, on 1 October 2011, by clause 4(2) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011

Clause 1.1(1) **payee**: amended, on 15 May 2014, by clause 5(6) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

payer—

- (a) means any of the following:
 - (i) a **participant** who is a **purchaser**:
 - (ii) a **generator** who is deemed to be a **purchaser** under clause 14.21:
 - (iii) a **purchaser**, a **generator**, a **distributor**, a **grid owner** or a **direct consumer** who purchases **ancillary services**:
 - (iv) a person by whom any amount is payable under an **FTR**:
- (b) for the purposes of Parts 8, 13, and 14 of this Code, has the additional meaning set out in clause 1.5

Clause 1.1(1) **payer** paragraph (iv): inserted, on 1 October 2011, by clause 4(3) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

permanent estimate means 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**

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**.

Clause 1.1(1) **pivotal**: inserted, on 17 July 2014, by clause 4(1) of the Electricity Industry Participation Code Amendment (Pivotal Supply) 2014.

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**

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, for the purposes of Part 12, means the period from 1 July in a year to 30 June in the following year, preceding the date by which **Transpower** is required to **publish** information under either clauses 12.118 or 12.127, as the case may be

preceding year day means the day preceding the relevant **trading day** by 364 days, but—

- (a) if the relevant **trading day** is a **national holiday**, the **preceding year day** will be deemed to be the Sunday before the 364th day;
- (b) if the relevant **trading day** is a **business day**, but the 364th day before it is a **national holiday**, the **preceding year day** is deemed to be the next **business day** after the **national holiday**

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 obligations and **PPOs** mean the **system operator** obligations set out in clause 7.2

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 **market administrator** 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

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

publicise means to make available to the public, at no cost to the public,—

- (a) on the **Authority's** website at all reasonable times; and
(b) in any other manner that the **Authority** may decide

publish means—

- (a) in respect of information to be published by the **Authority** or a **market operation service provider**, to make such information available to the intended recipient through the **information system**; and
(b) in respect of a **document** to be published under Part 9,—
(i) to make the **document** available to the public, at no cost, on an internet site maintained by or on behalf of the **system operator**, at all reasonable times, and
(ii) to give notice in the *Gazette* of the **document**, of the fact that it is available on the Internet at no cost, and of the Internet site address; and
(c) in respect of all other information, to make available to the intended recipient in such manner as may be prescribed from time to time by the **Authority**,—

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

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

qualifying customer has the meaning set out in clause 9.21

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

qualifying date means the day after the last day of a **public conservation period**

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**

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

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 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

Clause 1.1(1) **real time price**: amended, on 21 September 2012, by clause 4(6) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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 **capacity** of the **distribution network** at the point of injection; or
 - (ii) results in excessive power flow at feeder points or a significant adverse effect on voltage levels; or
 - (iii) results in a significant adverse effect on the quality and reliability of supply 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**

reasonable and prudent system operator means exercising that degree of skill, diligence, prudence, foresight and economic management, as determined by good

international practice and that would reasonably and ordinarily be expected from a skilled and experienced **system operator** engaged in the co-ordination of an integrated transmission network under the same or similar circumstances as applied in New Zealand at the time

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**

Clause 1.1(1) **reconciliation period**: amended, on 1 June 2011, by clause 4(2) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2011.

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

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 connected; or
 - (ii) if there is no Pole 2 or Pole 3 **injection** or **offtake** connected to a Haywards 220kV bus, the first indexed 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 connected; or
 - (ii) if there is no Pole 2 or Pole 3 **injection** or **offtake** connected to a Benmore 220kV bus, the first indexed Benmore 220 kV **node**

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

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 and **registry manager** means the person or persons for the time being appointed as the 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 means the contracts established under clauses 14.30 and 14.31

Clause 1.1(1) **relevant information**: amended, on 21 September 2012, by clause 4(7) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 1.1(1) **relevant information**: revoked, on 1 October 2013, by clause 4(3) of the Electricity Industry Participation (Disclosure Obligations) Code Amendment 2013.

relevant local reconciliation contracts means the contracts for the sale and/or the purchase of **electricity** within a **local network**

relevant participant means, for the purposes of Part 10, a **metering equipment provider** or an **ATH**

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.

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 means to **publish** again following a recalculation using revised data, and **republished** and **publication** have corresponding meanings

reserve offer means the information an **ancillary service agent** submits to the **system operator** under clauses 13.37 to 13.54 specifying the quantity of **instantaneous reserve** the **ancillary service agent** is willing and able to provide—

- (a) including a **reserve offer** that is revised in accordance with clauses 13.46 and 13.47; but
- (b) excluding a **reserve offer** that is cancelled in accordance with clauses 13.46 and 13.47

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.

residual loss and constraint excess means, in respect of a **billing period**, an amount remaining in the **FTR account** 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 clauses 13.249(6)

Clause 1.1(1) **residual loss and constraint excess**: inserted, on 1 October 2011, by clause 4(1) of the Electricity

Industry Participation (Financial Transmission Rights) Code Amendment 2011.

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, and 10 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 by the **registry manager** 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.

Rio Tinto agreement *[Revoked]*

Clause 1.1(1) **Rio Tinto agreement**: revoked, on 16 December 2013, by clause 4(2)(c) of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013

Rio Tinto party *[Revoked]*

Clause 1.1(1) **Rio Tinto party**: revoked, on 16 December 2013, by clause 4(2)(d) of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013

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**

Clause 1.1(1) **risk management contract**: amended, on 15 May 2014, by clause 4(5) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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

Clause 1.1(1) **round power**: inserted, on 1 July 2012, by clause 4(4) of the Electricity Industry Participation (HVDC Pole 3 Minor Amendments) Code Amendment 2012.

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)

Clause 1.1(1) **SCADA situation**: amended, on 15 May 2014, by clause 5(7) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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

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

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**

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.

Clause 1.1(1) **serious financial breach**: inserted, on 16 December 2013, by clause 4 of the Electricity Industry Participation (Managing Retailer Default Situations) Code Amendment 2013.

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.

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

shortage situation: inserted, on 1 June 2013, by clause 4(a) of the Electricity Industry Participation (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**

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

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**, reduction of **demand**, or reduction 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.

Clause 1.1(1) **special protection scheme**: amended, on 15 May 2014, by clause 4(6) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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

Clause 1.1(1) **spot price risk disclosure statement**: inserted, on 1 December 2011, by clause 4 of the Electricity Industry Participation Code (Spot Price Risk Disclosure) Amendment 2011.

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**

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

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 **publicised** by the **Authority** under clause 13.236D

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

sub-block dispatch groups means that grouping of **generating stations** or **generating units** within a **block dispatch group** into subgroups to take account of any **block**

security constraints notified by the **system operator** in accordance with clauses 13.61(1) and 13.73(1)(j)

Clause 1.1(1) **sub-block dispatch groups**: amended, on 21 September 2012, by clause 4(8) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 1.1(1) **sub-block dispatch groups**: amended, on 15 May 2014, by clause 5(8) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

sub-station dispatch groups means that grouping of individual **generating units** or **generating stations** within a **station dispatch group** into subgroups to take account of any **station security constraints** notified by the **system operator** in accordance with clauses 13.61(1) and 13.73(1)(k)

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 notified by the Authority in accordance with clause 8.12(2); and
- (b) in the case of a submission on a draft procurement plan, the date notified by the Authority in accordance with clause 8.44(2); and
- (c) in the case of a submission on the **transmission agreement** structure, the date notified by the Authority in accordance with clause 12.6(3); and
- (d) in the case of a submission on the draft **benchmark agreement**, the date notified by the Authority in accordance with clause 12.32(2); and
- (e) in the case of a submission on the draft **grid reliability standards**, the date notified by the Authority in accordance with clause 12.61(3); and
- (f) in the case of a submission on the issues paper, the date notified 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 notified by the Authority in accordance with clause 12.92(2)

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**

synchronised means the condition whereby a synchronous machine is 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

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 make it available to **registered participants** at no cost on the **system operator's** website at all reasonable times

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** connected to the **grid**, to assess the interaction of the **asset** with the **grid**

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 means the temporary **energisation** of a **point of connection** for the purposes of carrying out, at that **point of connection**,—

- (a) the activities or processes necessary for, or as part of, the **certification** of a **metering installation**; or

(b) the maintenance, repair, testing, or **commissioning** of a **metering installation**

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 payable 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

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

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]*

Clause 1.1(1) **transmission alternative**: amended, on 21 September 2012, by clause 4(9) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 1.1(1) **transmission alternative**: revoked, on 15 May 2014, by clause 4(7)(a) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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**)

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

Clause 1.1(1) **transmission alternative**: inserted, on 15 May 2014, by clause 4(7)(b) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 set in relation to the **HVDC link**

Transpower means Transpower New Zealand Limited

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)

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

Clause 1.1(1) **undesirable trading situation**: amended, on 17 July 2014, by clause 4(2) of the Electricity Industry Participation Code Amendment (Pivotal Supply) 2014.

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**

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 expected unserved energy that applies under clause 4 of Schedule 12.2

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 clauses 14.65 to 14.72 if incorrect information, including **volume information**, has been used in preparing any **payer's** or **payee's** invoice

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

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

working day means any day of the week other than—

- (a) Saturdays, Sundays, and **national holidays**; and
- (b) a day in the period commencing on 25 December in any year and ending on 15 January in the following year

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**

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

works has the meaning given to it in section 5 of the **Act**

year means a year commencing on the 1st day of April of each calendar year and expiring on the 31st day of March of the following calendar year

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**.

Compare: Electricity Governance Rules 2003 rule 1 part A

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**.

Compare: Electricity Governance Rules 2003 rule 2 part A

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 3 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 “payer”

- (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, or 14 of this Code to a **purchaser** or a **payer**, 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, and 14 of this Code of another **participant** named in the notice (participant B) in participant B’s capacity as a **purchaser** and a **payer**.
- (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, or 14 of this Code would confer a right or impose an obligation on participant B in participant B’s capacity as a **purchaser** or a **payer**, 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

1.6 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

cl 1.5(2)

Notice of assumption of rights and obligations under Parts 8, 13, and 14 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, and 14 of the Electricity Industry Participation Code 2010 in participant B's capacity as a purchaser and as a payer.
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

cl 1.5(5)

Revocation of notice of assumption of rights and obligations under Parts 8, 13, and 14 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, and 14 of the Electricity Industry Participation Code 2010 of _____ (participant B) in participant B's capacity as a purchaser and as a payer 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

Electricity Industry Participation Code 2010

Part 2 Availability of Code information

Contents

	<i>Power to request Code information</i>
2.1	Requests for Code information
	<i>Information held by Authority</i>
2.2	Information held by Authority
	<i>Information held by other participants</i>
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

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) notify the **participant** with which the information originated of the request for the supply of that information, before supplying it.

Compare: SR 2003/374 r 16

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.

Compare: SR 2003/374 r 17

2.4 Authority must contact participant believed to hold requested information

The **Authority** must, as soon as practicable after receiving a request for the supply of **Code information** that it does not hold, send a written notice to the **participant** who the **Authority** believes holds the relevant **Code information**—

- (a) notifying the **participant** 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.

Compare: SR 2003/374 r 18

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.

Compare: SR 2003/374 r 19

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, publicly available; 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 connected with the activities of another **participant**.

(2) The **participant** to which the notice was sent must promptly, and in any case not later than 10 **working 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, notify 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 that notification, 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 is notified 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

Contents

3.1	Appointment of market operation service providers
3.2	Functions, rights, powers, and obligations of market operation service providers
3.3	Term of appointment of market operation service provider
3.4	Terms of market operation service provider agreements
3.5	Publication of market operation service provider agreements
3.6	Insurance cover
	<i>Force majeure provisions relating to market operation service providers</i>
3.7	Relief of obligation because of force majeure
3.8	Effect of relief
3.9	Authority may contract elsewhere during force majeure event
3.10	Authority may terminate market operation service provider agreements
	<i>Disclosure to Authority</i>
3.11	Disclosure to Authority
	<i>Performance standards</i>
3.12	Performance standards to be agreed
	<i>Accountability of market operation service providers via self-review</i>
3.13	Self-review must be carried out by market operation service providers
3.14	Market operation service providers must report to Authority
	<i>Review of market operation service providers by Authority</i>
3.15	Review of market operation service providers
	<i>Market operation service provider software</i>
3.16	Software specifications for market operation service providers
3.17	Market operation service provider must arrange audit of software
3.18	Requirements for using software

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) the **registry manager**;
 - (b) a **reconciliation manager**;
 - (c) a **pricing manager**;
 - (d) a **clearing manager**;
 - (e) a **market administrator**;
 - (f) any other role identified in regulations as a **market operation service provider** role.
- (2) The **Authority** may appoint a person or persons to perform the **market operation service provider** role of wholesale information trading system provider.

- (3) The **system operator** is also a **market operation service provider**, but clauses 3.3, 3.10, 3.11, 3.12, 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 (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the **Act**.

Compare: SR 2003/374 r 31

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 (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 the **Act**.

Compare: SR 2003/374 r 33

3.5 Publication of market operation service provider agreements

The **Authority** must **publicise** 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
 - (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 **publicise** 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 **publicise** or otherwise make publicly available 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.

Compare: SR 2003/374 r 38

Clause 3.7: substituted, on 1 November 2012, by clause 5 of the Electricity Industry Participation (Force Majeure) Code Amendment 2012.

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**.

Compare: SR 2003/374 r 39

Clause 3.8(a): amended, on 1 November 2012, by clause 6 of the Electricity Industry Participation (Force Majeure) Code Amendment 2012.

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**.

Compare: SR 2003/374 r 40

Clause 3.9: amended, on 1 November 2012, by clause 7 of the Electricity Industry Participation (Force Majeure) Code Amendment 2012.

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 (except Parts 6 and 9) 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 **financial year**, 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 (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the **Act**; and

- (b) the operation of this Code (except Parts 6 and 9) 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, within 10 **working days** after the end of each calendar month, provide a written report to the **Authority** on the results of the review carried out under clause 3.13.
- (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 (except Parts 6 and 9) 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

Review of market operation service providers by Authority

3.15 Review of market operation service providers

- (1) At the end of each **financial year**, the **Authority** may review the manner in which each **market operation service provider** has performed its duties and obligations under this Code (except Parts 6 and 9) 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 (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the **Act**; and
 - (b) the operation of this Code (except Parts 6 and 9) 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 46

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.

Compare: SR 2003/374 r 51(1AA) to (2)

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 connection with this Code (except Parts 6 and 9) 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) The **auditor** must 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.

Compare: SR 2003/374 r 52

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).

Compare: SR 2003/374 r 53

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 **publicise** 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 **publicise** or otherwise make publicly available 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

Clause 4.2(a): amended, on 21 September 2012, by clause 5 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 4.2(a): amended, on 1 November 2012, by clause 9 of the Electricity Industry Participation (Force Majeure) Code Amendment 2012.

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.

Compare: SR 2003/374 r 54

Clause 5.1(2) and (3): inserted, on 18 July 2013, by clause 5 of the Electricity Industry Participation (Undesirable Trading Situation) Code Amendment 2013.

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.

Clause 5.1A: inserted, on 18 July 2013, by clause 6 of the Electricity Industry Participation (Undesirable Trading Situation) Code Amendment 2013.

Clause 5.1A: amended, on 15 May 2014, by clause 5 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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

Clause 5.2(1): substituted, on 18 July 2013, by clause 7(1) of the Electricity Industry Participation (Undesirable Trading Situation) Code Amendment 2013.

Clause 5.2(2): substituted, on 18 July 2013, by clause 7(2) of the Electricity Industry Participation (Undesirable Trading Situation) Code Amendment 2013.

Clause 5.2(2A): inserted, on 18 July 2013, by clause 7(2) of the Electricity Industry Participation (Undesirable Trading Situation) Code Amendment 2013.

Clause 5.2(4): amended, on 18 July 2013, by clause 7(3) of the Electricity Industry Participation (Undesirable Trading Situation) Code Amendment 2013.

Clause 5.2(5): inserted, on 18 July 2013, by clause 7(4) of the Electricity Industry Participation (Undesirable Trading Situation) Code Amendment 2013.

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**

Contents

- 6.1 Contents of this Part
- 6.2 Purpose
- 6.3 Distributors must make information publicly available
- 6.4 Process for obtaining approval to connect
- 6.5 Connection contract outside regulated terms
- 6.6 Connection on regulated terms
- 6.7 Extra terms
- 6.8 Dispute resolution
- 6.9 Pricing principles
- 6.10 Application of this Part to persons other than distributors and distributed generators
- 6.11 Distributors must act at arms length
- 6.12 This Part does not affect rights and obligations under Code

Transitional provisions

- 6.13 Regulations do not apply to earlier connections

Schedule 6.1

Process for obtaining approval to connect

Part 1

Applications for connection and operation of distributed generation 10 kW or less in total

Application process

Connection process

Part 2

Applications for connection and operation of distributed generation above 10 kW in total

Initial application process

Final application process

Connection process

Part 3

General provisions

Confidentiality

Annual reporting and record keeping

Schedule 6.2

Regulated terms for connection of distributed generation

General

Meters

Access

Interruptions and disconnections

Confidentiality

Pricing

Liability

Schedule 6.3
Default dispute resolution process

Schedule 6.4
Pricing principles
Share of generation-driven costs
Repayment of previously funded investment
Non-firm connection service

Schedule 6.5
Prescribed maximum fees

6.1 Contents of this Part

This Part specifies—

- (a) a framework to enable connection of **distributed generation** where connection is consistent with **connection and operation standards**; and
- (b) in Schedule 6.1, processes (including time frames) under which **distributed generators** may apply to **distributors** for approval to **connect distributed generation** (including the information to be exchanged and the criteria for approval); 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.

Compare: SR 2007/219 r 4

6.2 Purpose

The purpose of this Part is to enable connection of **distributed generation** if connection is consistent with **connection and operation standards**.

Compare: SR 2007/219 r 3

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 connection of **distributed generation** where consistent with **connection and operation standards**.
- (2) Each **distributor** must make publicly available, free of charge, from its office and Internet site,—
 - (a) application forms for connection of **distributed generation**; 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 to **connect distributed generation** is granted; and
 - (ii) the **distributor** and the **distributed generator** do not enter into a connection contract outside the **regulated terms**; and
 - (d) a statement of the policies, rules, or conditions under which **distributed generation** is, 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
 - (e) the application fees specified by the **distributor** in respect of applications for connection of **distributed generation**.
- (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.

Compare: SR 2007/219 r 6

6.4 Process for obtaining approval to connect

- (1) Schedule 6.1 applies if a **distributed generator** wishes to apply for approval to **connect distributed generation** (whether on the **regulated terms** or outside the **regulated terms**).
- (2) A **distributor** must grant approval to **connect distributed generation** if and as required to do so by Schedule 6.1.
- (3) A **distributor** cannot contract out of the provisions of Schedule 6.1.

Compare: SR 2007/219 r 7

6.5 Connection contract outside regulated terms

If a **distributor** and a **distributed generator** who wishes to apply for approval to **connect distributed generation** enter into a connection contract outside the **regulated terms** 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.

Compare: SR 2007/219 r 8

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 if a **distributor** and a **distributed generator** who wishes to apply for approval to **connect distributed generation** do not enter into a connection contract outside the **regulated terms** by the expiry of the period for negotiating a connection contract under clauses 9 or 24 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, the **distributor** and the **distributed generator** who wishes to apply for approval to **connect distributed generation** may at any time, by mutual agreement, enter into a connection contract outside the **regulated terms** that will apply instead of the **regulated terms**.

Compare: SR 2007/219 r 9

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 (**extra terms**) 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 outside the **regulated terms** or are terms that would be implied by law if the connection was under a contract outside the **regulated terms**; 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 contract outside the **regulated terms** for the purposes of this Part.

Compare: SR 2007/219 r 10

6.8 Dispute resolution

- (1) Schedule 6.3 applies—
- (a) to disputes between a **distributed generator** and a **distributor** arising from an allegation that a party has breached any of the **regulated terms** that apply under clause 6.6(2); and
 - (b) if there is any other dispute between a **distributor** and a **distributed generator** about an alleged breach of 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 outside the **regulated terms**; 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

6.9 Pricing principles

Schedule 6.4 applies in accordance with—

- (a) clause 20 of Schedule 6.2; and
- (b) clause 4 of Schedule 6.3.

Compare: SR 2007/219 r 12

6.10 Application of this Part to persons other than distributors and distributed generators

- (1) This Part applies, in so far as it is applicable, to—
 - (a) a **retailer** with whom a **distributor** or a **distributed generator** has entered into a contract (for example, a use of systems agreement) that provides for the **retailer** to have any of the applicable rights, or carry out any of the obligations, that are regulated by this Part; and
 - (b) a person to whom any of the **distributor's** or the **distributed generator's** obligations under the **regulated terms** are transferred, or a person who assumes any of those obligations.
- (2) This Part applies to the other persons referred to in subclause (1)(a) and (b) in the same way in which it applies to the **distributor** or the **distributed generator**, as the case may be.
- (3) This clause does not limit the rights and obligations of the **distributor** and the **distributed generator** under this Part.

Compare: SR 2007/219 r 13

6.11 Distributors must act at arms length

A **distributor** must use, in respect of all **distributed generators**, the same reasonable efforts in processing and considering applications for the connection of **distributed generation**, and in connecting **distributed generation**, regardless of whether—

- (a) the **distributor** owns or has a beneficial interest in the **distributed generator**; or
- (b) the proposed generation is owned by the **distributor's** associate or by another **distributed generator**.

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

Transitional provisions

6.13 Regulations do not apply to earlier connections

- (1) 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 to the extent that the contract has expired.
- (2) For the purpose of subclause (1), expired does not include cancelled by the **distributor** before the date on which the contract would otherwise have expired.

Compare: SR 2007/219 r 17

Schedule 6.1

Process for obtaining approval to connect

cl 6.4

Contents

Part 1

Applications for connection and operation of distributed generation 10 kW or less in total

1 Contents of this Part

Application process

2 Distributed generator wishing to connect must apply

3 Distributor's decision on application

4 Extension of time by mutual agreement for distributor to process application

5 Distributed generator must give notice of intention to proceed

Connection process

6 30 business days to negotiate connection contract if distributed generator notifies intention to proceed

7 Testing and inspection

8 Connection of distributed generation outside regulated terms if contract negotiated

9 Connection of distributed generation on regulated terms if contract not negotiated

Part 2

Applications for connection and operation of distributed generation above 10 kW in total

10 Contents of this Part

Initial application process

11 Distributed generator wishing to connect must make initial application and provide information

12 Distributor must provide information to distributed generator

13 Other matters to assist with decision making

14 Distributor and distributed generator must make reasonable endeavours regarding new information

Final application process

15 Distributed generator must make final application

16 Application for connection

17 Priority of final applications

18 Distributor's decision on application

19 Time within which distributor must decide final applications

20 Distributed generator must give notice of intention to proceed

Connection process

21 30 business days to negotiate connection contract if distributed generator notifies intention to proceed

22 Testing and inspection

23 Connection of distributed generation outside regulated terms if contract negotiated

24 Connection of distributed generation on regulated terms if contract not negotiated

Part 3

General provisions

Confidentiality

- 25 Confidentiality of information provided before connection
 - Annual reporting and record keeping*
 - 26 *[Revoked]*
 - 27 *[Revoked]*
 - 28 Distributors must keep records
-

Part 1

Applications for connection and operation of distributed generation 10 kW or less in total

1 Contents of this Part

- (1) This Part of this Schedule applies only to **distributed generation** that is only capable of generating **electricity** at a rate of 10 kW or less in total.
- (2) This Part of this Schedule provides for a 1-stage application process.

Compare: SR 2007/219 clause 1 Schedule 1

Application process

2 Distributed generator wishing to connect must apply

- (1) A **distributed generator** who wishes to **connect distributed generation** that is only capable of generating **electricity** at a rate of 10 kW or less in total must apply to the **distributor**.
- (2) The **distributed generator** must apply 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** proposed to be connected 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.
- (3) The information may include the following:
 - (a) the full name and address of the owner or operator of the **distributed generation** and the contact details of a person that the **distributor** may contact regarding the **distributed generation**;
 - (b) whether the proposed connection is a new connection or an increase in **capacity** for an existing connection and evidence of the size (nominal **capacity**) of the **generating unit**, including the name plate rating (if known) or other suitable evidence that the **generating unit** is or will be only capable of generating **electricity** at a rate of 10 kW or less, including,—

- (i) if the proposed connection is a new connection, the size (nominal **capacity**) of the total generation:
- (ii) if the application is for an increase in **capacity** for an existing connection, both the size (nominal **capacity**) of the additional generation and the aggregate size (nominal **capacity**) of all devices at the **point of connection**:
- (c) type of **distributed generation** (for example, solar photovoltaic):
- (d) proposed location of the **distributed generation** and when the **distributed generation** is likely to be connected:
- (e) technical specifications of the **distributed generation** and **associated equipment**, including—
 - (i) technical specifications of equipment that allows the **distributed generation** to be **disconnected** from the **network** on loss of mains voltage:
 - (ii) manufacturer's rating of equipment:
 - (iii) number of phases:
 - (iv) proposed **point of connection** to the **distribution network** (for example, the **ICP** number and street address):
 - (v) details of either or both of any inverter and battery storage:
 - (vi) details of any load at the proposed **point of connection**:
 - (vii) details of the connected voltage (for example, 415 V or 11 kV):
- (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.
- (4) The application must be accompanied by the application fee specified by the **distributor**, which must not exceed the maximum fee prescribed in Schedule 6.5.
- (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

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 to **connect distributed generation** 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 in Employment Act 1992; and
 - (ii) the **distributed generation** will comply at all times with the **Act**, and this Code; and
 - (iii) the connection of the **distributed generation** would be consistent with 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, if the **distributed generator** makes a new application, the steps that the applicant can take to ensure connection; and
 - (b) the default process under Schedule 6.3 for the resolution of disputes about an alleged breach of the **regulated terms** or any other provision of Part 6 of this Code.

Compare: SR 2007/219 clause 3 Schedule 1

4 Extension of time by mutual agreement for distributor to process application

- (1) The **distributor** may seek an extension of the time specified in clause 3(1) by which the **distributor** must give notice in writing stating whether the 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** who made the application may grant an extension of up to 20 **business days** and must not unreasonably withhold consent to an extension.

Compare: SR 2007/219 clause 4 Schedule 1

5 Distributed generator must give notice of intention to proceed

- (1) If the **distributor** advises that the **distributed generator's** application to **connect distributed generation** is approved, the **distributed generator** must provide written notice to the **distributor** confirming whether or not the **distributed generator** intends to proceed with the connection and, if so, confirming the details of the generation to be connected.
- (2) The **distributed generator** must give the notice within 10 **business days** after the **distributor** gives notice of approval to **connect distributed generation**, or within a longer period of time mutually agreed between the **distributor** and the **distributed generator**.
- (3) The **distributor's** duties under Part 6 of this Code arising from the application for connection of **distributed generation** 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 for connection of **distributed generation** under Part 6 of this Code.

Compare: SR 2007/219 clause 5 Schedule 1

Connection process

6 30 business days to negotiate connection contract if distributed generator notifies intention to proceed

- (1) If a **distributed generator** whose application to **connect distributed generation** is approved gives notice 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 mutual 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) A **distributed generator** whose application to **connect distributed generation** is approved must test and inspect its **distributed generation**.
- (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 provide the **distributor** with a written test report when testing and inspection is complete, including suitable evidence that the **metering installation** complies with the **metering standards** in this Code.
- (5) The **distributed generator** must pay any fee specified by the **distributor** for observing the testing and inspection, up to the maximum fee prescribed in Schedule 6.5.

Compare: SR 2007/219 clause 7 Schedule 1

8 Connection of distributed generation outside regulated terms if contract negotiated

If the **distributor** and the **distributed generator** whose application to **connect distributed generation** is approved enter into a connection contract before the period for negotiating a connection contract under this Part of this Schedule expires,—

- (a) the **distributor** must **connect the distributed generation** in accordance with that contract as soon as practicable; and
- (b) the **distributed generator** must complete the testing and inspection under clause 7.

Compare: SR 2007/219 clause 8 Schedule 1

9 Connection of distributed generation on regulated terms if contract not negotiated

If the **distributor** and the **distributed generator** whose application to **connect distributed generation** is approved do not enter into a connection contract before the period for negotiating a connection contract under this Part of this Schedule expires,—

- (a) the **distributor** must **connect the distributed generation** on the **regulated terms** as soon as practicable after the expiry of that period; and
- (b) the **distributed generator** must complete the testing and inspection under clause 7.

Compare: SR 2007/219 clause 9 Schedule 1

Part 2

Applications for connection and operation of distributed generation above 10 kW in total

10 Contents of this Part

- (1) This Part of this Schedule applies only to **distributed generation** that is capable of generating **electricity** at a rate above 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 wishing to connect must make initial application and provide information

- (1) A **distributed generator** who wishes to **connect distributed generation** that is capable of generating **electricity** at a rate above 10 kW in total must first make an **initial application** to the **distributor**.
- (2) The **distributed generator** must make the **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** proposed to be connected 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.
- (3) The information may include the following:
 - (a) the full name and address of the owner or operator of the **distributed generation** and the contact details of a person whom the **distributor** may contact regarding the **distributed generation**;
 - (b) whether the proposed connection is a new connection or an increase in **capacity** for an existing connection and evidence of the size (nominal **capacity**) of the **generating unit**, including the name plate rating (if known), including,—
 - (i) if the proposed connection is a new connection, the size (nominal **capacity**) of the total generation;
 - (ii) if the application is for an increase in **capacity** for an existing connection, both the size (nominal **capacity**) of the additional generation and the aggregate size (nominal **capacity**) of all devices at the **point of connection**;
 - (c) type of **distributed generation** (for example, solar photovoltaic);
 - (d) proposed location of the **distributed generation** and when the **distributed generation** is likely to be connected;
 - (e) technical specifications of the **distributed generation** and **associated equipment**, including—
 - (i) technical specifications of equipment that allows the **distributed generation** to be **disconnected** from the **network** on loss of mains voltage;

- (ii) manufacturer's rating of equipment:
- (iii) number of phases:
- (iv) proposed **point of connection** to the **distribution network** (for example, the **ICP** number and street address):
- (v) details of either or both of any inverter and battery storage:
- (vi) details of any load at the proposed **point of connection**:
- (vii) details of the connected voltage (for example, 415 V or 11 kV):
- (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 (**MVAr**s) (if any):
- (i) resistance and reactance details of the **generating unit**:
- (j) fault level contribution (**kA**):
- (k) method of voltage control:
- (l) single line diagram of proposed connection:
- (m) means of **synchronisation** and connection and disconnection to the **network**, including the type and ratings of **circuit breaker** proposed:
- (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.
- (4) The application must be accompanied by the application fee specified by the **distributor**, which must not exceed the maximum fee prescribed in Schedule 6.5.
- (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

12 Distributor must provide information to distributed generator

The **distributor** must provide the **distributed generator** who wishes to **connect distributed generation** with a copy of the following within 30 **business days** of receiving a 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 supply to other connected parties:
- (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 network-related measures or conditions identified under paragraph (c) and an estimate of time constraints or restrictions that may delay the connecting of the **distributed generation**:
- (e) information about any further detailed investigative studies that the **distributor** reasonably considers are necessary to identify any potential adverse effects on the system resulting from the proposed connection, 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

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 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 who 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** who wishes to **connect distributed generation** must make a **final application**, within 12 months after receiving the information under clauses 12 and 13, if the **distributed generator** intends to proceed to **connect** to the **distribution network**.
- (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.

Compare: SR 2007/219 clause 15 Schedule 1

16 Application for connection

A **distributor** who receives a **final application** must use reasonable endeavours to notify in writing—

- (a) all persons who have made an **initial application** for connection of **distributed generation** to the particular part of the **distribution network** that the **distributor** considers would be affected by the connection of the **distributed generation** that is the subject of the **final application**; and
- (b) all **distributed generators** who have **distributed generation** above 10 kW in total connected on the **regulated terms** to the particular part of the **distribution network** that the **distributor** considers would be affected by the connection of the **distributed generation**.

Compare: SR 2007/219 clause 16 Schedule 1

17 Priority of final applications

- (1) This clause applies if—
 - (a) a **distributor** receives a **final application** for connection to a **distribution network** (the **first application**); and
 - (b) the **distributor** receives another **final application**, within 10 **business days** after receiving the first application, for connection to a particular part of the **distribution network** that the **distributor** considers would be affected by the connection of the **distributed generation** that is the subject of the **first application**.
- (2) The **distributor**—
 - (a) may consider the 2 or more **final applications** together as if they were competitive bids to use the same part of the **network**; and
 - (b) must consider the **final applications** in light of the purpose of Part 6 of this Code; and

- (c) in giving reasons under clause 18 in the case of a **final application** that is declined, must set out the criteria used in making a decision that relates to paragraph (a) or (b).
- (3) In any other case in which a **distributor** receives more than 1 **final application** for connection 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

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** to **connect distributed generation**, 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 in Employment Act 1992; and
 - (ii) the **distributed generation** will comply at all times with the **Act** and this Code; and
 - (iii) the connection of the **distributed generation** would be consistent with the **distributor's connection and operation standards** (assuming that the **distributed generator** performs the conditions (if any) referred to in subclause (3)).
- (3) A notice stating that an application is approved subject to conditions must be accompanied by the following information:
 - (a) a detailed description of the conditions (or other measures) that are conditions of connection, and what the **distributed generator** who wishes to **connect distributed generation** must do to comply with them;
 - (b) detailed reasons for those conditions (or other measures);
 - (c) a detailed description of the charges payable by the **distributed generator** who wishes to **connect distributed generation**;
 - (d) the default process for resolution of disputes under Schedule 6.3, if the **distributed generator** who wishes to **connect distributed generation** 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, if the **distributed generator** who wishes to **connect distributed generation** makes a new application, the steps that the applicant can take to ensure connection;
 - (b) the default process for resolution of disputes under Schedule 6.3.

Compare: SR 2007/219 clause 18 Schedule 1

19 Time within which distributor must decide final applications

- (1) The written notice required by clause 18 must be provided within—
 - (a) 45 **business days** after the date of receipt of the **final application**, in the case of an application for **distributed generation** that is not capable of generating **electricity** at a rate of at least 1 **MW**; or
 - (b) 60 **business days** after the date of receipt of the **final application**, in the case of an application for **distributed generation** that is capable of generating **electricity** at a rate of at least 1 **MW** but is not capable of generating **electricity** at a rate of at least 5 **MW**; or
 - (c) 80 **business days** after the date of receipt of the **final application**, in the case of an application for **distributed generation** that is capable of generating **electricity** at a rate of at least 5 **MW** or above.
- (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) The **distributed generator** who wishes to **connect distributed generation** may grant an extension of up to 40 **business days** and 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 the **distributor** advises that the **distributed generator's final application to connect distributed generation** is approved, the **distributed generator** must provide written notice to the **distributor** confirming whether or not the **distributed generator** intends to proceed with the connection and, if so, confirming—
 - (a) the details of the **distributed generation** to be connected; and
 - (b) that the **distributed generator** accepts all of the conditions (or other measures) that have been specified by the **distributor** under clause 18 as conditions of the connection.
- (2) The **distributed generator** must give that notice within 30 **business days** after the day on which the **distributor** gives notice of approval to **connect distributed generation**, or within a longer period of time mutually agreed between the **distributor** and the **distributed generator**.
- (3) If the **distributed generator** does not accept all of those conditions, but does intend to **connect distributed generation**, the **distributed generator** must—
 - (a) give notice of the dispute within 30 **business days** after the day on which the **distributor** gives notice of approval to **connect distributed generation**; 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 for connection of **distributed generation** no longer apply if the **distributed generator** fails to give notice to the **distributor** of an intention to proceed with the connection within the time limits specified in this clause.

- (5) Subclause (4) does not prevent the **distributed generator** from making a new application for connection of **distributed generation** under Part 6 of this Code.
Compare: SR 2007/219 clause 20 Schedule 1

Connection process

21 30 business days to negotiate connection contract if distributed generator notifies intention to proceed

- (1) If a **distributed generator** whose application to **connect distributed generation** is approved gives notice under clause 20, 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 mutual 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) The **distributed generator** whose application to **connect distributed generation** is approved must test and inspect its **distributed generation**.
- (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 provide the **distributor** with a written test report when testing and inspection is complete, including suitable evidence that the **metering installation** complies with the appropriate **metering standards** in this Code.
- (5) The **distributed generator** must pay any fee specified by the **distributor** for observing the testing and inspection, up to the maximum fee prescribed in Schedule 6.5.

Compare: SR 2007/219 clause 22 Schedule 1

23 Connection of distributed generation outside regulated terms if contract negotiated

- If the **distributor** and the **distributed generator** whose application to **connect distributed generation** is approved enter into a connection contract before the period for negotiating a connection contract under this Part of this Schedule expires,—
- (a) the **distributor** must **connect the distributed generation** in accordance with that contract as soon as practicable; and
- (b) the **distributed generator** must complete the testing and inspection under clause 22.

Compare: SR 2007/219 clause 23 Schedule 1

24 Connection of distributed generation on regulated terms if contract not negotiated

- (1) If the **distributor** and the **distributed generator** whose application to **connect distributed generation** is approved do not enter into a connection contract before the period for negotiating a connection contract under this Part of this Schedule expires,—

- (a) the **distributor** must **connect** the **distributed generation** on the **regulated terms** as soon as practicable after the later of—
 - (i) the expiry of that period; and
 - (ii) 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; and
 - (b) the **distributed generator** must complete the testing and inspection under clause 22.
- (2) However, to the extent that those conditions (or other measures) were the subject of a dispute under clause 20(3), or of negotiation during the period for negotiation of the connection contract, the **distributor** must **connect** the **distributed generation** on the **regulated terms**, as soon as practicable after the later of—
- (a) the dates referred to in subclause (1); and
 - (b) the date on which the dispute about the conditions or other measures is finally resolved or negotiated and the **distributed generator** has performed those conditions (or other matters).

Compare: SR 2007/219 clause 24 Schedule 1

Part 3 General provisions

Confidentiality

25 Confidentiality of information provided before connection

- (1) All information provided with an application made under this Schedule, or otherwise provided by a **distributed generator** who wishes to **connect distributed generation** under this Schedule, must be kept confidential by the **distributor** except as agreed otherwise by the person who provides the information.
- (2) Despite subclause (1), the **distributor**—
 - (a) may, in response to an application for connection of **distributed generation**, disclose to the applicant that another **distributed generator** has made an application to **connect distributed generation** to the **distribution network** (without identifying who that other **distributed generator** is); and
 - (b) may, in the case of an application for connection of **distributed generation** that is only capable of generating **electricity** at a rate of 10 kW or less in total, generally indicate the location of the possible connection; and
 - (c) may, in the case of an application for connection of **distributed generation** that is capable of generating **electricity** at a rate above 10 kW, disclose the size and location of the proposed **distributed generation**.
- (3) The obligation to keep information confidential includes—
 - (a) an obligation not to use the information for any purpose other than enabling the connection of the **distributed generation**; and
 - (b) an obligation to destroy the information as soon as is reasonably practicable after the later of—

- (i) when the information is no longer required for the purpose of the connection of the **distributed generation**; and
- (ii) **5 years** after receiving the information.

Compare: SR 2007/219 clause 25 Schedule 1

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: amended, on 21 September 2012, by clause 6 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012

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, for **5 years**, records of all applications received under this Schedule and the resulting outcomes (including records of how long it took to **connect** or decline an application, and justification for these outcomes).

Compare: SR 2007/219 clause 28 Schedule 1

Schedule 6.2

Regulated terms for connection of distributed generation

cl 6.6

Contents

General

- 1 Contents of this Schedule
- 2 Interpretation
- 3 General obligations

Meters

- 4 Installation of meters and access to metering information

Access

- 5 Right of distributor to access distributed generator's premises
- 6 Process if distributor wants to access distributed generator's premises
- 7 Distributor must not interfere with distributed generator's equipment
- 8 Distributed generator must not interfere with, and must protect, distributor's equipment
- 9 Obligation to notify if interference with distributor's equipment or theft of electricity is discovered

Interruptions and disconnections

- 10 General obligations relating to interruptions
- 11 Circumstances allowing distributor to temporarily disconnect distributed generation
- 12 Obligations if distributed generation temporarily disconnected by distributor
- 13 Adverse operating effects
- 14 Interruptions by distributed generator
- 15 Permanent disconnections

Confidentiality

- 16 General obligations relating to confidentiality
- 17 When confidential information can be disclosed
- 18 Disclosures by employees, agents, etc

Pricing

- 19 Pricing principles

Liability

- 20 General obligations relating to liability
 - 21 Exceptions to general obligations relating to liability
 - 22 Limits on liability
 - 23 Liability clauses do not apply to fraud, wilful breach, and breach of confidentiality
 - 24 Indemnity
 - 25 Force majeure
-

General

1 Contents of this Schedule

This Schedule sets out the **regulated terms** for connection of **distributed generation** that apply to the connection of **distributed generation** that is connected in accordance with clause 6.6 and Schedule 6.1.

Compare: SR 2007/219 clause 1 Schedule 2

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.

Compare: SR 2007/219 clause 2 Schedule 2

3 General obligations

- (1) A **distributor** and a **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**, interconnect, 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**, interconnect, 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 as conditions of the connection (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 3 Schedule 2

Meters

4 Installation of meters and access to metering information

- (1) The **distributed generator** must ensure that 1 or more **metering installations** are installed that—

- (a) separately record any inflows of **electricity** from the **distribution network** and any **electricity** injected into the **distribution network**; and
- (b) fully comply with this Code.
- (2) The **distributed generator** must provide to the **distributor**, at the **distributor's** request, the interval data and cumulative data recorded by those **metering installations**.
- (3) If the **meter** is part of a **category 2 metering installation**, or a category 3 **metering installation**, or a category 4 **metering installation**, or a category 5 **metering installation**, or a category 6 **metering installation**, the **distributor** may require that **reactive** metering be installed.
- (4) The **distributor's** requirements in respect of metering measurement and accuracy must be consistent with this Code.

Compare: SR 2007/219 clause 4 Schedule 2

Clause 4(3): substituted, on 1 December 2011, by clause 5 of the Electricity Industry Participation Code (Distributor Use-of-System Agreements and Distributor Tariffs) Amendment 2011.

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 reconnecting or 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) A **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 notify if interference with distributor's equipment or theft of electricity is discovered

- (1) If the **distributor** or the **distributed generator** discover evidence of interference with the **distributor's** equipment, or evidence of theft of **electricity**, the party discovering the interference or evidence must notify 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

Interruptions and disconnections

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 disconnect distributed generation

Despite clause 10, a **distributor** may interrupt the connection service, or curtail either the operation or output of the generation, or both, and may temporarily 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) if the **distributed generator** modifies its **distributed generation**, without prior authorisation from the **distributor**, in such a way that it has a material effect on the **distributed generator's injection of electricity into the network**;
- (f) in accordance with clause 13 (adverse operating effects).

Compare: SR 2007/219 clause 11 Schedule 2

12 Obligations if distributed generation temporarily disconnected by distributor

- (1) The **distributor** must make reasonable endeavours to—
 - (a) notify 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 temporary disconnection.
- (3) In the case of a forced outage, the **distributor** must, subject to the need to restore the **distribution network**, make reasonable endeavours to restore service to the **distributed generator** and to advise the **distributed generator** of the expected duration of the outage.

Compare: SR 2007/219 clause 12 Schedule 2

13 Adverse operating effects

- (1) A **distributor** must notify a **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 notice, the **distributed generator** fails to remedy the adverse operating effect within a reasonable time, the **distributor** may disconnect the 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

14 Interruptions by distributed generator

- (1) This clause applies to any connected **distributed generation** above 10 kW in total.
- (2) The **distributed generator** must notify the **distributor** of any **planned outages** and must make reasonable endeavours to advise the **distributor** of an event that affects **network** operations.
- (3) The **distributed generator** must make reasonable endeavours to notify 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 Permanent disconnections

- (1) Despite clause 10, the **distributor** may permanently 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 failed to comply with either the connection or safety requirements of the **distributor** and there is an ongoing risk to persons or property:
 - (c) without notice, on receipt of the **registry** inactive status with reason “De-energised—ready for decommissioning” if the trader has de-energised a site, attempted to recover the **meters**, and updated the **registry** to that status:
 - (d) on at least 10 **business days**’ notice of intention to disconnect, if—
 - (i) the **distributed generator** has not injected **electricity** into the **network** at any time in the preceding 12 months; and
 - (ii) the **distributor** has not been notified by the **distributed generator** of 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) If the **point of connection** is to remain as a consumption point, the **distributed generator** must (if applicable) cancel any seller contracts and ensure the trader decommissions the embedded generation network service point with the **reconciliation manager**. The site must revert to a standard **ICP**.
- (3) If the **point of connection** is to be disestablished in its entirety, a permanent disconnection must be performed by means of isolation of generation by removal of all electrical connections to **distributor's lines**. The **distributor** must notify the **distributed generator** within 2 **business days** of the work having been completed. If

- applicable, the **distributed generator** must cancel any seller contracts, ensure that the **retailer** decommissions the embedded generation network service point with the **reconciliation manager**, and that the **retailer** arranges decommissioning of the **ICP**.
- (4) Once having the status of decommissioned on the **registry**, the **ICP** must not be used again. The process for new connections in Part 1 or 2, as the case may be, of Schedule 6.1 must be followed if generation is to be connected again at this **point of connection**.
- (5) Both the **distributor** and the **distributed generator** (through notification to a **retailer** where selling to a **retailer**) must ensure that the **registry** is correctly updated throughout this process in accordance with this Code.

Compare: SR 2007/219 clause 15 Schedule 2

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

Connection charges that are payable by a **distributed generator** 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 a **distributor** or **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 does 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

21 Exceptions to obligations relating to liability

- (1) Neither the **distributor** nor a **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) a failure to convey or a reduction of **injection** or supply of **electricity** into the **distribution network**; or
 - (B) an interruption in the conveyance of **electricity** in the **network**, 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 installed **capacity** up to a maximum of \$5 million.

Compare: SR 2007/219 clause 23 Schedule 2

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 a **distributor** or **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

24 Indemnity

- (1) Each party (the **indemnifying party**) must indemnify the other for damages claimed by third parties to the extent that the loss is caused by a breach of these **regulated terms** by the **indemnifying party**, where the loss is materially caused by an action or omission of the **indemnifying party**.
- (2) The indemnity in this clause is subject to the limits on liability specified in clauses 20 to 23.

Compare: SR 2007/219 clause 25 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 **supply** or availability of **electricity** to 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 notify 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 notify 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

Schedule 6.3

Default dispute resolution process

cl 6.8

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

- (1) This Schedule applies in accordance with clause 6.8.
- (2) To avoid doubt, this Schedule applies to disputes about either of the following:
 - (a) the conditions specified by the **distributor** under clause 18 of Schedule 6.1:
 - (b) whether a party is attempting to negotiate in good faith under clauses 6 or 21 of Schedule 6.1.

Compare: SR 2007/219 clause 1 Schedule 3

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

cl 6.9

- 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 20 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 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 transmission and distribution costs that an efficient **market operation service provider** would be able to avoid as a result of the 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 connected to the **distribution network** were, and deducting the costs that would have been incurred had the generation not been connected. In this case, if the costs differ from the costs charged to the **distributed generator**, the **distributor** must notify 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 endeavours 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 expressed in dollars per annum:
- (g) before the connection of **distributed generation**, the **distributor** must notify the **distributed generator** in writing of the connection charges that will be payable, and explain how the connection charges have been calculated:
- (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 notify 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 **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 **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 5 **years**, 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 **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 **network**;
- (m) no refund of previous payments from the **distributed generator** referred to in paragraph (k) is required after a period of 3 **years** 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 **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

- 3 In this Schedule, incremental costs means the reasonable costs that an efficient **market operation service provider** would incur in providing **electricity** distribution services with connection services to the **distributed generation**, less the costs that the efficient **market operation service provider** would incur if it did not provide those connection services.

Compare: SR 2007/219 clause 3 Schedule 4

cls 2(4), 7(5), 11(4), and 22(5) of Sch 6.1

Schedule 6.5
Prescribed maximum fees

- 1 In this Schedule, reference to a kW or MW rate, in relation to **distributed generation**, is a reference to the kW or MW rate at which **distributed generation** is capable of generating **electricity**.
- 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:

Fee for application for distributed generation 10 kW or less in total	\$
Distributed generation of 10 kW or less in total	200
Fee for initial application for distributed generation above 10 kW	
Distributed generation of above 10 kW in total but less than 100 kW in total	500
Distributed generation of 100 kW or above in total but less than 1 MW	1,000
Distributed generation of 1 MW and above	5,000
Fee for observation of testing and inspection under clauses 7 and 22 of Schedule 6.1	
Distributed generation of 10 kW or less in total	60
Distributed generation of above 10 kW in total but less than 100 kW in total	120
Distributed generation of 100 kW and above	1,200

Compare: SR 2007/219 Schedule 5

Electricity Industry Participation Code 2010

Part 7 System operator

Contents

7.1	Contents of this Part
7.2	Principal performance obligations of the system operator in relation to common quality and dispatch
7.3	Functions of the system operator in relation to security of supply and emergency management
7.4	Incorporation of security of supply forecasting and information policy and emergency management policy by reference
7.5	Approval of draft security of supply forecasting and information policy and emergency management policy
7.6	Variations to security of supply forecasting and information policy and emergency management policy
7.7	System operator and Authority joint development programme
7.8	Review of system operator
7.9	Additional matters to be taken into account in system operator review
7.10	Separation of Transpower roles
7.11	Review of performance of the system operator
7.12	Authority must publicise system operator reports

7.1 Contents of this Part

This Part provides for—

- (a) high level, output focussed performance obligations of the **system operator** in relation to the real time delivery of **common quality** and **dispatch**; and
- (b) the functions of the **system operator** in relation to security of supply and supply emergencies; and
- (c) **system operator** performance review.

7.2 Principal performance obligations of the system operator in relation to common quality and dispatch

(1) The **principal performance obligations** of the **system operator** are—

- (a) to act as a **reasonable and prudent system operator** with the objective of **dispatching assets** made available in a manner that avoids the cascade failure of **assets** resulting in the loss of **demand** and arising from—
 - (i) frequency or voltage excursions; or
 - (ii) **supply** and **demand** imbalances; and
- (b) with regard to the frequency of **electricity**—
 - (i) subject to subparagraphs (ii) to (iv) and subclause (2), to act as a **reasonable and prudent system operator** with the objective of maintaining frequency in the **normal band** in accordance with Schedule 8.4, and

- (ii) subject to subclause (2), to act as a **reasonable and prudent system operator** with the objective of ensuring that during **momentary fluctuations** frequency stays between 47 Hertz and 52 Hertz (both inclusive); and
- (iii) subject to subclause (2), to act as a **reasonable and prudent system operator** with the objective of ensuring that the aggregated rate of occurrence of **momentary fluctuations** experienced in the North and South Islands of New Zealand does not exceed the statistical equivalent of the following levels:

Frequency band (Hertz) (where “x” is the frequency during a momentary fluctuation)	Maximum number of occurrences by period (commencing on and from 1 March 2004)
52.00 > x ≥ 51.25	7 in any 12 month period
51.25 > x ≥ 50.50	50 in any 12 month period
49.50 ≥ x > 48.75	60 in any 12 month period
48.75 ≥ x > 48.00	6 in any 12 month period
48.00 ≥ x > 47.00	1 in any 60 month period

- (iv) to act as a **reasonable and prudent system operator** with the objective of ensuring that when a fluctuation in frequency occurs, the frequency is restored to the **normal band** as soon as reasonably practicable having regard to all the circumstances surrounding the fluctuation; and
 - (v) to act as a **reasonable and prudent system operator** with the objective of ensuring **frequency time error** is not greater than 5 seconds of **New Zealand standard time**; and
 - (vi) to act as a **reasonable and prudent system operator** with the objective of ensuring that at least once every day the **frequency time error** is eliminated; and
- (c) if reasonably requested by a **participant**, to identify the cause of the problem if the following standards are not being met at any **point of connection** to the **grid**, and take any action available to it under this Code, as reasonably requested of the **system operator** by a **participant**, and practicable given the **assets** made available to it to resolve the problem:
- (i) New Zealand Electrical Code of Practice (NZECP 36.1993) for harmonic levels, as amended from time to time;
 - (ii) Australian Standard (AS2279.4 1991) for voltage flicker levels, as amended from time to time;
 - (iii) the requirement to use reasonable endeavours to maintain **negative sequence voltage** at less than 1% and to ensure that **negative sequence**

voltage will be no more than 2% in any part of the **grid**.

- (2) The **principal performance obligations** in this clause are qualified as follows:
- (a) the frequency in the South Island may fall below 47 Hertz only if—
 - (i) the statistical equivalent of 1 **momentary fluctuation** below 47 Hertz in any 60 month period is not exceeded; and
 - (ii) the frequency does not fall below 45 Hertz:
 - (b) the frequency in the South Island may exceed 52 Hertz only if—
 - (i) the frequency does not exceed 55 Hertz; and
 - (ii) the rate of **momentary fluctuations** experienced does not exceed the statistical equivalent of the following levels:

Frequency band (Hertz) (where “x” is the frequency during a momentary fluctuation)	Maximum number of occurrences by period (commencing on and from 1 March 2004)
$55.00 > x \geq 53.75$	1 in any 60 month period
$53.75 > x \geq 52.00$	2 in any 12 month period

Compare: Electricity Governance Rules 2003 rules 2 and 3 section II part C

7.3 Functions of the system operator in relation to security of supply and emergency management

- (1) The functions of the **system operator** in relation to the provision of information and short- to medium-term forecasting on all aspects of security of supply are—
- (a) to 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 connection with the information **published** under subparagraphs (i) and (iii), sufficient details of the modelling data, assumptions, and methodologies that the **system operator** has used to prepare that information as to allow interested parties to recreate that information (but without **publishing** information that is confidential to any **participant**); and

- (b) to 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 **publicise** a security standards assumptions document.
- (2B) Subject to subclause (2C) and (2D), if the **Authority** has **publicised** 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 **publicised** 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 functions of the **system operator** in relation to managing supply emergencies are—
 - (a) to prepare and **publish** an **emergency management policy** that sets out the steps that the **system operator** must take, as a **reasonable and prudent system operator**, and 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) within 2 years of this Code coming into force, to 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 a **reasonable and prudent 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) to implement and comply with the **emergency management policy** prepared and **published** in accordance with paragraph (a).

- (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 act as a **reasonable and prudent system operator**.
- (6) If the **system operator** makes a departure under subclause (5) because of an **EMP departure situation**, 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(2)(a): amended, on 3 January 2013, by clause 4(1) of the Electricity Industry Participation (Supply Standards) Code Amendment 2012.

Clause 7.3(2)(b): amended, on 3 January 2013, by clause 4(2) of the Electricity Industry Participation (Supply Standards) Code Amendment 2012.

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(4)(b): amended, on 10 January 2013, by clause 5 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

Clause 7.3(5): amended, on 21 September 2012, by clause 7(1) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 7.3(6): amended, on 21 September 2012, by clause 7(2) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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** for the time being in effect 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) The **system operator** must, within 1 year of this Code coming into effect, submit a draft **emergency management policy** to the **Authority** for approval.
- (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 notify 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 specified by the **Authority** 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 each **financial year**.
- (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**.

Compare: SR 2003/374 r 47

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) the reports from the **system operator** to the **Authority**;
- (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;
- (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.

Compare: SR 2003/374 r 48

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 30 September 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 31 August.
- (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 carrying out its functions with respect to—
 - (a) the **policy statement**; and
 - (b) the **security of supply forecasting and information policy**; and
 - (c) the **emergency management policy**; and
 - (d) the joint development programme prepared under clause 7.7(1).
- (3) The **Authority** must review and assess the performance of the **system operator** in the period to which the self-review relates having regard to the self-review and such other matters as the **Authority** considers relevant.
- (4) The **Authority** must **publish** its review and assessment of the **system operator** no later than 10 **business days** after the **Authority** completes the review and assessment.

Compare: Electricity Governance Rules rule 14 section II part C

Clause 7.11(4): amended, on 15 May 2014, by clause 6 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

7.12 Authority must publicise system operator reports

- (1) The **Authority** must **publicise** 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 **publicise** each report within 5 **working days** after receiving the report.

Compare: SR 2003/374 r 49

Electricity Industry Participation Code 2010

Part 8 Common quality

Contents

- 8.1 Contents of this Part
 - Subpart 1—Performance obligations of the system operator
- 8.2 Contents of this subpart
- 8.3 Recovery of costs from causes of voltage non-compliance
- 8.4 System operator may rely on information provided
- 8.5 Restoration
- 8.6 System operator may contract for higher levels of common quality
- 8.7 System operator must not contract contrary to this arrangement
- Policy statement*
- 8.8 Purpose of policy statement
- 8.9 *[Revoked]*
- 8.10 Incorporation of policy statement by reference
- 8.10A Review of policy statement
- 8.10B System operator decides not to propose change to the policy statement
- 8.10C Authority may require system operator to reconsider
- 8.11 Content of draft policy statement
- 8.11A Changes and variations
- 8.12 Consultation on draft policy statement
- 8.12A Technical and non-controversial changes
- 8.12B Authority adopts new policy statement
- 8.13 *[Revoked]*
- 8.14 Departure from policy statement
- System security forecast*
- 8.15 System operator to prepare and review system security forecast
 - Subpart 2—Asset owner performance obligations and technical standards
- 8.16 Contents of this subpart
 - Asset owner performance obligations and technical standards concerning frequency*
 - 8.17 Contribution by injections to overall frequency management
 - 8.18 Contributions by purchasers to overall frequency management
 - 8.19 Contributions to frequency support in under-frequency events
 - 8.20 Contributions by grid owners to frequency support
 - 8.21 Excluded generating stations
 - Asset owner performance obligations and technical standards concerning voltage*
 - 8.22 Voltage range AOPOs
 - 8.23 Voltage support AOPOs
 - 8.24 Load shedding obligations to support voltage
 - 8.25 Other asset owner performance obligations and technical standards
 - 8.26 Asset owners must co-operate
 - Compliance*
 - 8.27 System operator to monitor compliance

- 8.28 Responsibility for compliance
Equivalence arrangements and dispensations
- 8.29 Right to apply for approval of equivalence arrangement or grant of dispensation
- 8.30 Approval of equivalence arrangements
- 8.31 Grant of dispensations
- 8.32 Liability of asset owner pending decision
- 8.33 Modification of equivalence arrangement or dispensation
- 8.34 Cancellation of equivalence arrangement or dispensation
- 8.35 Revocation of equivalence arrangement and revocation or variation of dispensation
- 8.36 Appeal against decisions
- 8.37 Other provisions relating to equivalence arrangements and dispensations
- 8.38 Authority may require excluded generating stations to comply with certain clauses
Subpart 3—Arrangements concerning ancillary services
- 8.39 Contents of this subpart
Procurement plan
- 8.40 System operator to use reasonable endeavours to implement and comply with procurement plan
- 8.41 *[Revoked]*
- 8.42 Incorporation of procurement plan by reference
- 8.42A Review of procurement plan
- 8.42B System operator decides not to amend the procurement plan
- 8.42C Authority may require system operator to reconsider
- 8.43 Content of draft procurement plan
- 8.43A Changes and variations
- 8.44 Consultation on draft procurement plan
- 8.44A Technical and non-controversial amendments
- 8.44B Authority adopts new procurement plan
- 8.45 Contracts with ancillary service agents
- 8.45A Methodology to assess net purchase quantity
- 8.46 *[Revoked]*
- 8.47 Departure from procurement plan
Alternative ancillary service arrangements
- 8.48 Alternative ancillary service arrangements
- 8.49 Suspension of alternative ancillary service arrangement
- 8.50 Modification of alternative ancillary service arrangement
- 8.51 Cancellation of alternative ancillary service arrangement
- 8.52 Revocation of alternative ancillary service arrangements
- 8.53 Appeal of system operator decisions
- 8.54 Other provisions relating to alternative ancillary service arrangements
Allocating ancillary services costs
- 8.55 Identifying costs associated with each ancillary service
- 8.56 Black start costs allocated the grid owner
- 8.57 Over frequency reserve costs allocated to HVDC owner
- 8.58 Frequency keeping costs are allocated to purchasers
- 8.59 Availability costs allocated to generators and HVDC owner
- 8.60 Process for determining causer of under-frequency event

- 8.61 System operator must determine causer of under-frequency event
- 8.62 Disputes regarding system operator determinations
- 8.63 Decision of the Rulings Panel
- 8.64 Event costs allocated to event causers
- 8.65 Rebates paid for under-frequency events
- 8.66 Payments and rebates
- 8.67 Voltage support costs allocated in 3 parts – nominated peak, monthly peak and residual charges
- 8.68 Clearing manager to determine amounts payable and receivable
- 8.69 Clearing manager to determine wash up amounts payable and receivable
- 8.70 System operator pays ancillary service agents

Schedule 8.1

Approval of equivalence arrangement or grant of dispensation

Schedule 8.2

Approval of alternative ancillary service arrangement

Schedule 8.3

Technical codes

Technical Code A – Assets

Appendix A: Main protection system requirements

Appendix B: Routine testing of assets and automatic under-frequency load shedding systems

Technical Code B – Emergencies

Technical Code C – Operational communications

Appendix A: Indications and Measurements

Technical Code D – Co-ordination of outages affecting common quality

Schedule 8.4

Reserve management objective

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**, and **technical codes**.

Compare: Electricity Governance Rules 2003 rule 1 section I part C

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 causes 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(1)(c), 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

8.4 System operator may rely on information provided

For the purposes of this Code, the **system operator** may rely on the **assets** and information about the **assets** made available to the **system operator** by **asset owners**, and may 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**.

Compare: Electricity Governance Rules 2003 rule 4 section II part C

8.5 Restoration

- (1) If an event disrupts the **system operator's** ability to comply with the **principal performance obligations**, the **system operator** must act as a **reasonable and prudent system operator** to re-establish normal operation of the power system as soon as possible, given—
 - (a) the capability of **generation** and **ancillary services**; 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 Purpose of policy statement

- (1) The **policy statement** sets out policies and means that are considered appropriate during the term of the **policy statement** for the **system operator** to observe in complying with the **principal performance obligations**.
- (2) Subclause (1) is subject to the obligation of the **system operator** to act as a **reasonable and prudent system operator** and to therefore depart from the **policy statement** if required.
- (3) The **policy statement** allows the **system operator** to use its discretion in operational matters in accordance with clause 8.14.

Compare: Electricity Governance Rules 2003 rule 8 section II part C

8.9 *[Revoked]*

Clause 8.9: revoked, on 10 January 2013, by clause 6 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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

Clause 8.10(1): amended, on 10 January 2013, by clause 7 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

8.10A Review of policy statement

- (1) At least once every two 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**.

Clause 8.10A: inserted, on 10 January 2013, by clause 8 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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.

Clause 8.10B: inserted, on 10 January 2013, by clause 8 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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 **publicise** 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).

Clause 8.10C: inserted, on 10 January 2013, by clause 8 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

8.11 Content of draft policy statement

- (1) *[Revoked]*
- (2) *[Revoked]*
- (3) The **draft policy statement** must address the matters in, and must be prepared on the basis of, clause 8.8 and 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) the policies and means by which the **system operator** intends to address 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

Clause 8.11 Heading: substituted, on 10 January 2013, by clause 9(a) of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

Clause 8.11(1): revoked, on 10 January 2013, by clause 9(b) of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

Clause 8.11(2): revoked, on 10 January 2013, by clause 9(c) of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

Clause 8.11(3): amended, on 10 January 2013, by clause 9(d) of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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 on its website.
- (4) If the **system operator** declines a request under subclause (3), the **Authority** may require the **system operator** to reconsider its decision, giving reasons.

Clause 8.11A: inserted, on 10 January 2013, by clause 10 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

8.12 Consultation on draft policy statement

- (1) The **Authority** must **publicise** 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** publicises 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** publicises 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 **publicise** 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 **publicise** 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: substituted, on 10 January 2013, by clause 11 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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) **publicise** 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 **publicise** its decision and reasons as soon as practicable.

Clause 8.12A: inserted, on 10 January 2013, by clause 12 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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) **publicise** the new **policy statement** and the date on which it takes legal effect.

Clause 8.12B: inserted, on 10 January 2013, by clause 12 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

8.13 *[Revoked]*

Compare: Electricity Governance Rules 2003 rule 12 section II part C

Clause 8.13: revoked, on 10 January 2013, by clause 13 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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 in terms of the **system operator** acting as a **reasonable and prudent system operator**.
- (2) If the **system operator** departs from a **policy statement** under subclause (1) because of a **system security situation**, 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 **publicise** the report within a reasonable time after receiving it.

Compare: Electricity Governance Rules 2003 rule 13 section II part C

Clause 8.14(3): substituted, on 10 January 2013, by clause 14 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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

Clause 8.15(1): substituted, on 21 September 2012, by clause 8 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 8.15(1A): inserted, on 21 September 2012, by clause 8 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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 7.2(1)(b)) 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 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 connected, its **assets** contribute to supporting frequency during an **under-frequency event** in either **island** by—
 - (a) remaining 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 connected to those **assets** making up the **grid** in the North Island and South Island while the frequency in both **islands** remains below 48 Hertz and above 47 Hertz for 90 seconds; and
 - (c) remaining 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 North Island **distributor** and each South Island **grid owner** must ensure that it has established and maintained **automatic under-frequency load shedding** in block sizes and with relay settings in accordance with the **technical codes**.

Compare: Electricity Governance Rules 2003 rule 2.3 section III part C

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 7.2(1)(b)(ii) and, for South Island **assets**, clause 7.2(2)(b).

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 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, 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

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:

Nominal grid voltage (kV)	Voltage limits			
	Minimum (kV)		Maximum (kV)	
220	198	-10.0%	242	10.0%
110	99	-10.0%	121	10.0%
66	62.7	-5.0%	69.3	5.0%
50	47.5	-5.0%	52.5	5.0%

- (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 **distributor** 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).

Compare: Electricity Governance Rules 2003 rule 3.1 section III part C

8.23 Voltage support AOPs

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:

Nominal grid voltage (kV)	Voltage range for which reactive power is required			
	Minimum (kV)		Maximum (kV)	
220	198	-10.0%	242	10.0%
110	99	-10.0%	121	10.0%
66	62.7	-5.0%	69.3	5.0%
50	47.5	-5.0%	52.5	5.0%
33	31.35	-5.0%	34.65	5.0%
22	21.45	-2.5%	22.55	2.5%
11	10.725	-2.5%	11.275	2.5%

- (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:

Nominal grid voltage (kV)	Voltage range for which reactive power is required			
	Minimum (kV)		Maximum (kV)	
220	209	-5.0%	242	10.0%
110	104.5	-5.0%	121	10.0%
66	62.7	-5.0%	69.3	5.0%
50	47.5	-5.0%	52.5	5.0%
33	31.35	-5.0%	34.65	5.0%
22	21.45	-2.5%	22.55	2.5%
11	10.725	-2.5%	11.275	2.5%

- (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

Clause 8.23: amended, on 21 September 2012, by clause 9 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

8.24 Load shedding obligations to support voltage

- (1) If it is not possible for a **distributor** 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 **distributor** 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 **distributor** 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) the **system operator** must notify 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

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 the discretion, acting as a **reasonable and prudent system operator**, 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 an **asset owner** receives notification under clause 8.27(3), it 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

Equivalence arrangements and dispensations

8.29 Right to apply for approval of equivalence arrangement or grant of dispensation

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.

Compare: Electricity Governance Rules 2003 rule 7.1 section III part C

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) 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

DispCost_{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** established in accordance with clause 7.2(2)

Q_{GENxt} 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**.

- (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(1): amended, on 15 May 2014, by clause 7 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 **APOOs** 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

Clause 8.32: amended, on 15 May 2014, by clause 8 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 **APOOs** 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** or an **asset owner** 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

Clause 8.37(1A): inserted, on 15 May 2014, by clause 9 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

8.38 Authority may require excluded generating stations to comply with certain clauses

- (1) Despite clauses 8.17 and 8.19, 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 and 8.19 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

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]

Clause 8.41: revoked, on 10 January 2013, by clause 15 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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

Clause 8.42(1): amended, on 10 January 2013, by clause 16 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

8.42A Review of procurement plan

- (1) At least once every two 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**.

Clause 8.42A: inserted, on 10 January 2013, by clause 17 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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.

Clause 8.42B: inserted, on 10 January 2013, by clause 17 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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 **publicise** 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).

Clause 8.42C: inserted, on 10 January 2013, by clause 17 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

8.43 Content of draft procurement plan

- (1) 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

Clause 8.43: substituted, on 10 January 2013, by clause 18 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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 on its website.
- (4) If the **system operator** declines a request under subclause (3) the **Authority** may require the **system operator** to reconsider its decision, giving reasons.

Clause 8.43A: inserted, on 10 January 2013, by clause 19 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

8.44 Consultation on draft procurement plan

- (1) The **Authority** must **publicise** 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** publicises 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** publicises 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 **publicise** 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 **publicise** 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.

Compare: Electricity Governance Rules 2003 rule 5 section IV part C

Clause 8.44: substituted, on 10 January 2013, by clause 20 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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) **publicise** 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 **publicise** its decision and reasons as soon as practicable.

Clause 8.44A: inserted, on 10 January 2013, by clause 21 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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) **publicise** the new **procurement plan** and the date on which it takes legal effect.

Clause 8.44B: inserted, on 10 January 2013, by clause 21 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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 on its website as soon as practicable.

Clause 8.45A: inserted, on 10 January 2013, by clause 22 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

8.46 [Revoked]

Compare: Electricity Governance Rules 2003 rule 7 section IV part C

Clause 8.46: revoked, on 10 January 2013, by clause 23 of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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 **publicise** the report within a reasonable time after receiving it.

Compare: Electricity Governance Rules 2003 rule 8 section IV part C

Clause 8.47(2): amended, on 10 January 2013, by clause 24(a) of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

Clause 8.47(3): inserted, on 10 January 2013, by clause 24(b) of the Electricity Industry Participation (Policy Statement and Procurement Plan Review Process) Code Amendment 2012.

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 an **asset owner** receives notification under subclause (1), it 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

Allocating ancillary services costs

8.55 Identifying costs associated with each ancillary service

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.

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:

$$\text{Share}_{\text{PURx}} = \text{Fc} * \frac{\max(0, \sum_t (\text{Offtake}_{\text{PURxt}} - E_{\text{PURxt}}^{\text{FK}}))}{\sum_x \max(0, \sum_t (\text{Offtake}_{\text{PURxt}} - E_{\text{PURxt}}^{\text{FK}}))}$$

where

$\text{Share}_{\text{PURx}}$ is **purchaser x's share of allocable cost** in relation to **frequency keeping**

Fc is the **allocable cost** of **frequency keeping** services in the **billing period**

$\text{Offtake}_{\text{PURxt}}$ is the total **reconciled quantity** in **kWh** for **purchaser x** across all **grid exit points** in **trading period t** in the **billing period**

$E_{\text{PURxt}}^{\text{FK}}$ 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:

$$\text{Share}_t = \frac{A_{c_t} * m_t}{M_t}$$

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_t}	is the availability cost for the North Island or South Island as appropriate incurred in respect of trading period t
m_t	$\left\{ \begin{array}{l} \text{is } \max(0, \text{INJ}_{\text{GENxt}} - (h * \text{INJ}_D) - E^{\text{IR}}_{\text{GENxt}}) = m_{xt} \text{ for any } \mathbf{generating\ unit} \\ \text{is } \max(0, \text{HVDC}_{\text{Riskt}} - (h * \text{INJ}_D) - E^{\text{IR}}_{\text{HVDCt}}) = m_{ht} \text{ for the } \mathbf{HVDC\ link} \end{array} \right.$
M_t	is $\sum_x m_{xt} + m_{ht}$
h	is 0.5 MWh/MW
$\text{INJ}_{\text{GENxt}}$	is the electricity injected (expressed in MWh) by generating unit x in trading period t into the North Island or South Island as appropriate
$E^{\text{IR}}_{\text{GENxt}}$	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
$\text{HVDC}_{\text{Riskt}}$	is the at risk HVDC transfer (expressed in MWh) in trading period t into the North Island or South Island as appropriate
$E^{\text{IR}}_{\text{HVDCt}}$	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
INJ_D	is 60 MW.

Compare: Electricity Governance Rules 2003 rule 11.5.1 section IV part C

8.60 Process for determining causer of under-frequency event

- (1) The **system operator** must promptly notify 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 rule.
- (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.

Compare: Electricity Governance Rules 2003 rule 11.5.1A section IV part C

8.61 System operator must determine causer of under-frequency event

- (1) The **system operator** must determine whether an **under-frequency event** has been caused by a **generator** or **grid owner**.
- (2) The **system operator** 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 **system operator** must give reasons for its findings in the draft determination.
- (4) The **system operator** must consult every **generator**, **grid owner** and other **participant** substantially affected by an **under-frequency event** in relation to the draft determination.
- (5) At the time the **system operator** publishes the draft determination under subclause (2), the **system operator** must give notice to **generators**, **grid owners**, and other **participants** substantially affected by an **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 **system operator** 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 **system operator** must **publish** a final determination.

Compare: Electricity Governance Rules 2003 rule 11.5.1B section IV part C

8.62 Disputes regarding system operator determinations

- (1) The **Authority** or 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 **system operator'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 **system operator** must provide the **Rulings Panel** with all information considered by the **system operator** 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 **system operator** with directions as to the particular matters that require reconsideration or amendment.
- (2) The **system operator'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 system operator as soon as reasonably practicable.
- (4) The **system operator** must **publish** the **Rulings Panel's** decision as soon as reasonably practicable.
- (5) If the **Rulings Panel** refers the matter back to the **system operator**, the **system operator** 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:

$$EC = ECR * (\sum_y (INT_{ye} \text{ for all } y) - INJ_D)$$

where

EC is the **event charge** payable by the **causer**

ECR is \$1,250 per **MW**

INJ_D is 60 **MW**

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

Clause 8.64: amended, on 21 September 2012, by clause 10 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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:

$$\text{Rebate}_{xe} = EC_e * Z_{xe}/Z_{tote}$$

where

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

EC_e is the **event charge** paid for Event e

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**

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.

Compare: Electricity Governance Rules 2003 rule 11.5.4 section IV part C

8.67 Voltage support costs allocated in 3 parts – nominated peak, monthly peak and residual charges

- (1) Each **distributor** 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 **distributor** must pay a nominated peak kvar charge calculated in accordance with the following formula:

$$\text{NomCharge}_{xz} = \text{PeakRate}_z * \sum_j Q_{xjz}$$

where

NomCharge_{xz} is the total nominated peak charges for **distributor** x in **zone** z

Peak Rate_z is the fixed \$/kvar set annually in advance by **system operator** for **zone** z

Q_{xjz} is $\text{Nom Peak}_{\text{LINES}_{xjz}}$, 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 **distributor x** at its **distributor kvar reference node j**

Σ_j is the sum across all **distributor kvar reference nodes j** of **distributor x** in **zone z**

- (3) Each **distributor** must pay a monthly peak penalty charge calculated in accordance with the following formula:

$$\text{PeakPenaltyCharge}_{\text{LINE}x,z} = \text{PenaltyRate}_z * \Sigma_j \text{PenaltyQuantity}_{\text{LINE}x,j,z}$$

where

$\text{PeakPenaltyCharge}_{\text{LINE}x,z}$ is the total peak penalty charges for **distributor x** across all **distributor kvar reference nodes j** for **distributor x** in **zone z**

PenaltyRate_z is the fixed \$/kvar penalty charge for “kvar above nominated kvar” set annually in advance by the **system operator** in **zone z**

Σ_j is the sum across all **distributor kvar reference nodes j** of **distributor x** in **zone z**

$\text{PenaltyQuantity}_{\text{LINE}x,j,z}$ is the “kvar above nominated kvar” quantity for **distributor x** at its **distributor kvar reference node j** in **zone z**

- (4) For the purpose of calculating the “kvar above nominated kvar” quantity, the kvar taken by the **distributor**—
- (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 **distributor** in each month measured at the **distributor kvar reference node j** within the **zone z**,—
- and “kvar above nominated kvar” is the difference between the kvar taken by the **distributors** as determined in accordance with paragraphs (a) to (c) and the nominated kvar specified by the **distributor**.
- (5) Each **distributor** must pay a residual charge or receive a residual payment calculated in accordance with the following formulae:

$$\text{Residual}_{\text{ALL}z} = \text{Vcost}_z - \text{Nom Charge}_{\text{ALL}z} - \text{PeakPenaltyCharge}_{\text{ALL}z}$$

$$\text{Residual}_{\text{LINE}allz} = \text{Residual}_{\text{ALL}z} * (\Sigma_{xj} \text{NomPeak}_{\text{LINE}x,j,z} / \Sigma_{xj} Q_{xj,z})$$

$$\text{Residual}_{\text{LINE}x,z} = \text{Residual}_{\text{LINE}allz} * (\text{BillingPeriodOfftake}_{\text{LINE}x,z} / \text{BillingPeriodOfftake}_{\text{ALL}z})$$

where

V_{cost_z}	is the total allocable costs for voltage support in zone z in the billing period
$Nom\ Charge_{ALLz}$	is the sum of all $Nom\ Charge_{xz}$ for zone z
$PeakPenaltyCharge_{ALLz}$	is the sum of all distributors' $PeakPenaltyCharge_{LINExz}$ for zone z
$Residual_{ALLz}$	is the total residual to be recovered from or paid to distributors in zone z
$Residual_{LINEallz}$	is the portion of $Residual_{ALLz}$ to be recovered from or paid to distributors in zone z
$Residual_{LINExz}$	is the portion of $Residual_{LINEallz}$ to be recovered from or paid to distributor x in zone z
$BillingPeriodOfftake_{LINExz}$	is the sum of metering information for distributor x across all distributor kvar reference nodes in zone z for the billing period for all trading periods
$BillingPeriodOfftake_{ALLz}$	is the sum of metering information for all distributors across all distributor kvar reference nodes in zone z for the billing period for all trading periods
Σ_{xj}	is the sum across all distributor kvar reference nodes j for all distributors x in zone z
Σ_j	is the sum across all distributor kvar reference nodes j of distributor x in zone z
Q_{xjz}	is $Nom\ Peak_{LINEsxjz}$, 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 distributor x at its distributor kvar reference node j

- (6) For the purposes of this clause, a **distributor** 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

Clause 8.67(5): amended, on 15 May 2014, by clause 10 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

8.68 Clearing manager to determine amounts payable and receivable

- (1) The **clearing manager** must determine the amount payable to the **system operator** by each **grid owner**, **purchaser**, **generator** and **distributor** 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 payable to it under clauses 8.6 and 8.31(1)(a), by including the relevant amounts in the invoices issued by the **clearing manager** under Part 14. All amounts payable under this clause are subject to the priority order of payments set out in clause 14.47.

- (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.

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 amount payable to the **system operator** by each **grid owner, purchaser, generator and distributor**, and the amount payable to each **grid owner, purchaser, generator and distributor** by the **system operator** for **ancillary services** under clauses 8.55 to 8.67 as a result of any **washups** that might occur under clause 14.65. On behalf of the **system operator** the **clearing manager** must collect or pay those amounts, 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 in the invoices issued by the **clearing manager** under Part 14. All amounts payable under this clause are subject to the priority order of payments set out in clause 14.47.
- (2) To enable the **clearing manager** to determine those amounts, 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.

Compare: Electricity Governance Rules 2003 rule 11.8 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**.

Compare: Electricity Governance Rules 2003 clause 1 schedule C1 part C

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.

Compare: Electricity Governance Rules 2003 clause 2 schedule C1 part C

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) notify 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.

Compare: Electricity Governance Rules 2003 clause 3 schedule C1 part C

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** notifies 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) All submissions must be considered by the **system operator**, and the **system operator** must notify any **participant** who made a submission as to the **system operator's** decision on 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) notify 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** notifies 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

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

cl 1.1

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 **distributors**, 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 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 livening of the **assets**; 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 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 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**).

Compare: Electricity Governance Rules 2003 clause 2 technical code A schedule C3 part C

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 disconnected by the **main protection system** first and the other **assets** are not prematurely 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 disconnected totally 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) 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 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
 - (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) At a **point of connection**—
- (a) an **asset owner**, other than a **grid owner**, must provide a means of checking **synchronisation** before the switching of **assets** if it is possible that such switching may result in connection of parts of the New Zealand electric power system that are not **synchronised**; and
 - (b) a **grid owner** must provide a means of checking **synchronisation** before the switching of **assets** in locations agreed with the **system operator** so that it is not possible for such switching to result in connections of parts of the New Zealand electric power system that are not **synchronised**.
- (6) An auto-reclose facility at the **grid interface**, at which power flows into the **grid** can occur, must include an appropriate **synchronising** check facility.

Compare: Electricity Governance Rules 2003 clause 4 technical code A schedule C3 part C

Clause 4 Heading: amended, on 15 May 2014, by clause 11 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 **grid-connected generator** 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 7.2(1)(c)(iii) 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**.

Compare: Electricity Governance Rules 2003 clause 5 technical code A schedule C3 part C

6 Specific requirements for local networks

Each **distributor** must agree with the **system operator** any temporary or permanent connection of the **distributor's assets** if those **assets** become simultaneously connected to the **grid** at more than 1 **point of connection**.

Compare: Electricity Governance Rules 2003 clause 6 technical code A schedule C3 part C

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 notify 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**.

Compare: Electricity Governance Rules 2003 clause 7 technical code A schedule C3 part C

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 of its **assets** and **automatic under-frequency load shedding** systems in accordance with Appendix B.
- (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** disconnects a faulted **asset** before a **back up protection system** initiates the 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

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.

Compare: Electricity Governance Rules 2003 clause 4 appendix A technical code A schedule C3 part C

Appendix B: Routine testing of assets and automatic under-frequency load shedding systems

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**. Each **asset owner** and each owner of **automatic under-frequency load shedding** systems may be legally required, other than under this Code, to carry out additional tests to ensure that their **assets** and **automatic under-frequency load shedding** systems are safe and reliable.
- (2) 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

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 **North Island distributor automatic under-frequency load shedding systems profiles and trip settings**

Each North Island **distributor** must—

- (a) provide the profile information described in clause 7(9) of **Technical Code B** of

Schedule 8.3 to the **system operator** in an updated **asset capability statement** at least once every year; and

- (b) test the operation of its **automatic under-frequency load shedding** systems at least once every 4 years; and
- (c) based on the test carried out in accordance with paragraph (b), provide a verified set of 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 6 appendix B technical code A schedule C3 part C

7 South Island grid owner automatic under-frequency load shedding systems profiles and trip settings

Each South Island **grid owner** must—

- (a) provide the profile information described in clause 7(9) of **Technical Code B** of Schedule 8.3 to the **system operator** in an updated **asset capability statement** at least once every year; and
- (b) test the operation of its **automatic under-frequency load shedding** systems at least once every 4 years; and
- (c) based on the test carried out in accordance with paragraph (b), provide a verified set of 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 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.

Compare: Electricity Governance Rules 2003 clause 9 appendix B technical code A schedule C3 part C

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 10 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 once every 4 years; and
- (d) test the operation of each of its **HVDC link's** digital protection systems at least once every 10 years; and
- (e) test the modulation functions on its **HVDC link** at least once every 10 years; and
- (f) based on the tests carried out in accordance with paragraphs (a) or (b), provide a set of **control system** test results and verified modelling parameters to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test; and
- (g) based on the tests carried out in accordance with paragraphs (c) or (d), provide a set of protection system test results to the **system operator** in an updated **asset capability statement** within 3 months of the completion date of each such test; and
- (h) based on the tests carried out in accordance with paragraph (e), provide a set of modulation function test results 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 **HVDC link**; and
 - (ii) a parameter list showing gains, time constants, limiters and other settings applicable to the block diagram; and
 - (iii) a detailed functional description of all of the components of the **HVDC link** and how they interact in each mode of control.

Compare: Electricity Governance Rules 2003 clause 12 appendix B technical code A schedule C3 part C

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

Clause 15(1): amended, on 21 September 2012, by clause 11(1) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 15(2): amended, on 21 September 2012, by clause 11(2) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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 disconnect **demand** at each **point of connection** are specified.

Compare: Electricity Governance Rules 2003 clause 3 technical code B schedule C3 part C

Clause 4: amended, on 15 May 2014, by clause 12 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 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 **trading periods** 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.

Compare: Electricity Governance Rules 2003 clause 4 technical code B schedule C3 part C

Clause 5(1A): inserted, on 1 June 2013, by clause 5(a) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

Clause 5(1B): inserted, on 1 June 2013, by clause 5(a) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

Clause 5(1C): inserted, on 1 June 2013, by clause 5(a) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

Clause 5(2): amended, on 1 June 2013, by clause 5(b) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

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 **distributor** reduce **demand**:
 - (c) require a **grid owner** to reconfigure the **grid**:
 - (d) require the disconnection of **demand** in accordance with clause 7(19):
 - (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 **distributor** reduces its **demand**:

- (d) require the disconnection of **demand** in accordance with clause 7(19);
- (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 disconnection of **demand** in accordance with clause 7(20) 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 disconnection of **demand** in accordance with clause 7(19) 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 Load shedding systems

- (1) Each North Island **distributor** must ensure, at all times, that an **automatic under-frequency load shedding** system is installed in accordance with subclause (6) for each **grid exit point** to which its **local network** is connected.
- (2) Every South Island **grid owner** must ensure, at all times, that an **automatic under-frequency load shedding** system is installed in accordance with subclause (6) for each **grid exit point** in the South Island.
- (3) Subject to subclause (8), each **distributor** and **grid owner** must use reasonable endeavours to ensure that at all times its **automatic under-frequency load shedding** systems are maintained in accordance with subclause (6).
- (4) If, at any time, a **distributor** or **grid owner** believes that an **automatic under-frequency load shedding** system may not be capable of meeting the requirements of subclause (6), it must notify the **system operator** as soon as practicable and provide any information that the **system operator** reasonably requests.
- (5) Each South Island **distributor** must co-operate fully with any **grid owner** in relation to an **automatic under-frequency load shedding** system installed at any **GXPs** at which the **distributor's local network** is connected to the **grid**. Each South Island **distributor** must also provide the **grid owner** with any information relating to **automatic under-frequency load shedding** that the **grid owner** reasonably requests.
- (6) An **automatic under-frequency load shedding** system required to be provided in accordance with subclause (1), must enable, at all times, automatic disconnection of 2 blocks of **demand** (each block being a minimum of 16% of the total pre-event **demand**) at that **grid exit point** subject to subclause (8), with block one disconnecting **demand**—
 - (a) in the North Island, within 0.4 seconds after the frequency reduces to, and remains at or below, 47.8 Hertz; and
 - (b) in the South Island, within 0.4 seconds after the frequency reduces to, and remains at or below 47.5 Hertz;and block two disconnecting **demand**—
 - (c) in the North Island,—
 - (i) 15 seconds after the frequency reduces to, and remains at or below, 47.8

- Hertz; or
- (ii) within 0.4 seconds after the frequency reduces to, and remains at or below, 47.5 Hertz; and
- (d) in the South Island,—
 - (i) 15 seconds after the frequency reduces to, and remains at or below, 47.5 Hertz; or
 - (ii) within 0.4 seconds after the frequency reduces to, and remains at or below, 45.5 Hertz.
- (7) To avoid doubt, **automatic under-frequency load shedding** blocks must not include any **interruptible load** procured by the **system operator**.
- (8) Subject to the **system operator's** agreement, which must not be unreasonably withheld, a **distributor** or a **grid owner** may redistribute **automatic under-frequency load shedding** quantities between **grid exit points**, if the overall **automatic under-frequency load shedding** quantity obligations in subclause (6) are met.
- (9) Each **distributor** and each **grid owner** must provide **automatic under-frequency load shedding** block **demand** profile information to the **system operator** if reasonably requested by the **system operator**. That information must be in a form that enables the **system operator** to make a reasonable assessment of the total amount of **demand** available to be disconnected if **automatic under-frequency load shedding** blocks operate in accordance with subclauses (6) to (8).
- (9A) *[Revoked]*
- (9B) *[Revoked]*
- (10) Subclauses (12) to (16) apply if a direction under clause 9.15 is in force.
- (11) When subclauses (12) to (16) apply, the **system operator** may give notice to 1 or more of the **participants** specified in subclause (14), specifying modifications to the extent to which subclauses (1) to (4) and (6) apply to the **participant** during any 1 or more periods, or in any 1 or more circumstances, specified in the notice.
- (12) The **system operator** must keep a record of each notice given under subclause (11).
- (12A) *[Revoked]*
- (12B) *[Revoked]*
- (13) When a notice under subclause (11) is in force in relation to a **participant**, the requirements of subclauses (1) to (4) and (6) 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.
- (14) The **participants** to whom the **system operator** may issue a notice in accordance with subclause (11) are—
 - (a) **distributors** in the North Island; and
 - (b) **grid owners** in the South Island.
- (15) The **system operator** may amend or revoke a notice, or revoke and substitute a new notice.
- (16) A notice under subclause (11) 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 (10).
- (16A) *[Revoked]*

(16B) *[Revoked]*

- (17) The **system operator**, each **distributor**, each **grid owner** and relevant **retailers** must co-operate, if reasonably practicable, to ensure that any **interruptible load** contracted by the **system operator** that could affect the size of an **automatic under-frequency load shedding** block is identified to assist the **distributor** or the **grid owner** to meet its obligations in subclauses (5) to (9).
- (18) On the operation of an **automatic under-frequency load shedding** system, the **distributor** or **grid owner**—
- (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 disconnected; and
 - (b) may restore **demand** only when permitted to do so by the **system operator**; and
 - (c) must ensure **demand** restored in accordance with paragraph (b) complies with subclause (6); and
 - (d) must report to the **system operator** if **demand** is moved between **points of connection**; and
 - (e) may request permission to restore **demand** from the **system operator** if no instruction to restore **demand** is received from the **system operator** within 15 minutes of the frequency returning to the **normal band**; and
 - (f) may cautiously and gradually restore the **demand** disconnected through the **automatic under-frequency load shedding** system if there is a **loss of communication**, after 15 minutes of the **loss of communication** occurring. This restoration must be done only while the frequency is within the **normal band** and the voltage is within the required range. Each **distributor** must immediately cease the restoration of **demand** and, to the extent necessary, disconnect **demand**, if the frequency drops below the **normal band** or the voltage moves outside the required range. As soon as practicable after communications are restored, each **distributor** or each **grid owner** must report to the **system operator** on the status of load restoration and the status of re-arming the automatic under-frequency relays.
- (19) Each **distributor** must maintain an up to date process for the disconnection of **demand** for **points of connection**, including the specification of the **participant** who will effect the disconnection of **demand**. The **distributor** must obtain agreement for the process from the **system operator** and each **grid owner** (such agreement not to be unreasonably withheld). Each **distributor** must advise the **system operator** of the agreed process in addition to any changes to a process previously advised.
- (20) If the **system operator** requires the disconnection of **demand** in accordance with this **technical code**, the **system operator** must instruct **distributors** and **grid owners** (as the case may be) in accordance with the agreed process in subclause (19) to disconnect **demand** for the relevant **point of connection**. If the **system operator** and a **distributor** or **grid owner** (as the case may be) have not agreed on a process for disconnection of **demand** at a **point of connection**, the **system operator** must instruct **grid owners** to

disconnect **demand** directly at the relevant **point of connection**. To the extent practicable, the **system operator** must use reasonable endeavours when instructing the disconnection of **demand**, to ensure equity between **distributors**.

- (21) Each **distributor** or **grid owner** must act as instructed by the **system operator** operating in accordance with clauses 6 and 7.

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(10): revoked, from 3 January 2013 to 2 October 2013, by clause 4(b) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2012.

Clause 7(10): revoked, on 2 October 2013, by clause 4(b) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2013.

Clause 7(10): inserted, on 3 April 2014, by clause 5(b) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2013.

Clause 7(11): amended, from 3 January 2013 to 2 October 2013, by clause 4(c) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2012.

Clause 7(11): amended, on 2 October 2013, by clause 4(c) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2013.

Clause 7(11): amended, on 3 April 2014, by clause 5(c) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2013.

Clause 7(12A) and (12B): inserted, from 3 January 2013 to 2 October 2013, by clause 4(d) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2012.

Clause 7(12A) and (12B): inserted, on 2 October 2013, by clause 4(d) 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(13): amended, from 3 January 2013 to 2 October 2013, by clause 4(e) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2012.

Clause 7(13): amended, on 2 October 2013, by clause 4(e) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2013.

Clause 7(13): amended, on 3 April 2014, by clause 5(e) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2013.

Clause 7(15): amended, from 3 January 2013 to 2 October 2013, by clause 4(f) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2012.

Clause 7(15): amended, on 2 October 2013, by clause 4(f) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2013.

Clause 7(15): amended, on 3 April 2014, by clause 5(f) of the Electricity Industry Participation (Automatic Under-Frequency Load Shedding Systems) Code Amendment 2013.

Clause 7(16): 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(16): 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(16): substituted, 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.

8 Obligations of grid owners

- (1) A **grid owner** must use reasonable endeavours to ensure that appropriate **assets** are installed for the manual 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 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 disconnect **demand** at **points of connection** while the voltage remains below that minimum voltage limit, being guided by any arrangements with **distributors** as advised by the **system operator**.

Compare: Electricity Governance Rules 2003 clause 7 technical code B schedule C3 part C

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**, connecting to the **grid** and loading each **generating unit** that is not connected but is able to be connected and operated in this manner;
 - (iii) **re-synchronise**, re-connect to the **grid** and load each **generating unit** that has tripped and is able to be 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 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**, connect to the **grid** 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 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** and connect available **generating units** to the **grid** if the **generating units** currently 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) connect available **reactive capability** resources to the **grid** if the currently 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 notify **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 back up 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 document transmission communication

- (1) Subject to subclause (2) and the **information system**, each **asset owner** must use facsimile transmission as the primary means of transmitting a document between the **control room** of the **asset owner** and the **system operator**.
- (2) An **asset owner** may request the **system operator** to approve an alternative primary means of transmitting a document (such approval not to be unreasonably withheld).
- (3) Each **asset owner** must have in place a backup means of transmitting a document. The backup means of document 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, voice communication or email; and
 - (c) may only be used if the primary means of document transmission 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

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 Notification of planned outages of primary means of communication

Each **asset owner** must notify 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.

Indication or measurement	Values required	Accuracy ³
Station net MW	Import and export	±2%
Generating unit gross MW ¹	Import and export, for each generating unit	±2%
Station net Mvar	Import and export	±2%
Generating unit gross Mvar ¹	Import and export, for each generating unit	±2%
Generating unit circuit breaker status ¹	Open /closed /in transition/ indication error ²	N/A
Grid interface circuit breaker status	Open /closed /in transition/ indication error ²	N/A
Grid interface disconnecter status	Open /closed /in transition/ indication error	N/A
Special protection scheme status	Enabled/disabled/summer/winter	N/A
Maximum output capacity of generating station (for intermittent generators only)	Number of connected generating units × MW capability of each generating unit	N/A

Compare: Electricity Governance Rules 2003 table A1 appendix A technical code C schedule C3 part C

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**.

Indication or measurement	Values required	Accuracy ³
Grid interface circuit breaker status	Open /closed /in transition/ indication error ²	N/A
Grid interface disconnecter status	Open/ closed/ in transition/ closed to earth/ indication error	N/A
Grid interface auto reclose status	Enabled/disabled/ operated/locked out	N/A
Grid interface MW	Import and export	±2%
Grid interface Mvar	Import and export	±2%
Circuit Amps	Current at each termination point of a circuit	N/A

Indication or measurement	Values required	Accuracy ³
Circuit MW	MW at each termination point of a circuit	N/A
Circuit Mvar	Mvar at each termination point of a circuit	N/A
Special protection scheme status	Enabled/disabled/summer/winter	N/A
Tap positions for interconnecting transformers and supply transformers with on-load tap changers	Tap position for all windings including tapped tertiaries	N/A
Tap positions for interconnecting transformers and supply transformers with off-load tap changers ⁴	Tap position for all windings including tapped tertiaries	N/A
Reactive plant (eg RPC equipment, capacitor, reactor, condenser) Mvar	Import and export	±2%
Bus voltage	kV	±2%
Special protection scheme status	Enabled/disabled/summer/winter	N/A
HVDC modulation status	Frequency stabiliser/ spinning reserve sharing/ Haywards frequency control/ AC transient voltage support	N/A

Compare: Electricity Governance Rules 2003 table A2 appendix A technical code C schedule C3 part C

Table A3: Requirements of distributors

Each **distributor** must provide the indications and measurements shown in Table A3 in respect of **assets** connected to, or forming part of, the **grid**.

Indication or measurement	Values required	Accuracy ³
Grid interface circuit breaker status	Open/ closed/ in transition/ indication error ²	N/A
Grid interface disconnector status	Open/ closed/ in transition/ indication error	N/A
Grid interface auto reclose status	Enabled/disabled/operated/locked out	N/A
Special protection scheme status	Enabled/disabled/summer/winter	N/A
Reactive plant ⁵ (eg RPC equipment, capacitor, reactor, condenser) Mvar	Import and export	±2%

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 notify 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**.

Compare: Electricity Governance Rules 2003 clause 1 technical code D schedule C3 part C

2 Notification of planned outages

- (1) Each **asset owner** must, in relation to each of its **assets**, notify 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 notify 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.

Compare: Electricity Governance Rules 2003 clause 2 technical code D schedule C3 part C

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**.

Compare: Electricity Governance Rules 2003 clause 3 technical code D schedule C3 part C

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**.

Compare: Electricity Governance Rules 2003 clause 4 technical code D schedule C3 part C

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 to comply, with the **principal performance obligations**.
- (2) The **system operator** may advise an **asset owner** when an appropriate time would be.
- (3) If an **asset owner** is able to modify the **notified planned outage** period for an **asset** in the manner suggested by the **system operator** without material cost or disruption, the

asset owner must endeavour to do so.

Compare: Electricity Governance Rules 2003 clause 5 technical code D schedule C3 part C

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

Reserve management objective

cl 7.2

1 Reserve management objective

- (1) The objective of the reserves management process is to provide the scheduling, pricing and dispatching tool (SPD) with the information necessary to permit the SPD to schedule a minimum quantity of **instantaneous reserve**.
- (2) Simultaneously, but subject to the availability of sufficient **offers** or **reserve offers**, the process must satisfy the requirement that sufficient **instantaneous reserve** is scheduled to maintain the power system frequency of the North and the South Islands within the limits of the under-frequency standard specified below.

2 Under-frequency standard

- (1) For a contingent event in any **island**, the frequency of the **island** where the event took place must—
 - (a) stay at or above 48 Hz; and
 - (b) return to or above 49.25 Hz within 60 seconds after the event.
- (2) For an extended contingent event in the North Island the frequency must—
 - (a) stay at or above 47 Hz; and
 - (b) not drop to or below 47.1 Hz for longer than 5 seconds; and
 - (c) not drop to or below 47.3 Hz for longer than 20 seconds; and
 - (d) return to or above 49.25 Hz within 60 seconds after the event.
- (3) For an extended contingent event in the South Island the frequency must—
 - (a) stay at or above 45 Hz; and
 - (b) return to or above 49.25 Hz within 60 seconds after the event.

Compare: Electricity Governance Rules 2003 schedule C6 part C

Electricity Industry Participation Code 2010

Part 9 Security of supply

Contents

Subpart 1—Planning for shortage of supply situations

9.1 Purpose

System operator rolling outage plan

9.2 System operator must prepare and publish system operator rolling outage plan

9.3 Incorporation of system operator rolling outage plan by reference

9.4 Contents of system operator rolling outage plan

9.5 Amendments and substitutions of system operator rolling outage plans

Participant rolling outage plans

9.6 System operator must require specified participants to develop participant rolling outage plans

9.7 Specified participants must develop participant rolling outage plans

9.8 Contents of participant rolling outage plans

9.9 Approval of participant rolling outage plans

9.10 Revision of participant rolling outage plans

9.11 Approval of revised participant rolling outage plans

9.12 Publishing of participant rolling outage plans

9.13 Specified participants must keep participant rolling outage plans up to date

Subpart 1A—Urgent temporary grid reconfigurations

9.13A Purpose

9.13B Request for urgent temporary grid reconfiguration

Subpart 2—Outages in shortage of supply situation

9.14 Supply shortage declaration

9.15 Power to direct outages in security of supply situation

9.16 Specified participants must comply with direction

9.17 Revocation of supply shortage declaration

Subpart 3—Miscellaneous

9.18 Provision of information

Subpart 4—Customer compensation schemes

9.19 Contents of this subpart

Requirement for retailers to have customer compensation scheme

9.20 Retailer must have customer compensation scheme

9.21 Qualifying customers

9.22 Requirement to implement customer compensation schemes

Official conservation campaign

9.23 System operator commences official conservation campaign

Default customer compensation scheme

9.24 Requirements of default customer compensation schemes

Minimum weekly amount of compensation

- 9.25 Authority must determine minimum weekly amount

Additional customer compensation schemes

- 9.26 Retailer may have additional customer compensation schemes
9.27 Qualifying customer may elect to be covered by additional customer compensation scheme
9.28 Publishing description of additional customer compensation schemes

Statutory declaration

- 9.29 Each retailer must provide statutory declaration

Audit

- 9.30 Audit of compliance
9.31 Retailer must provide information to auditor
9.32 Auditor must provide audit report
9.33 Payment of auditor's costs
-

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** for the time being in effect 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**, and the notice in the *Gazette* that is part of the **publishing** of the 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 **working 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.

Compare: SR 2008/252 r 7 and 8

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**.

Compare: SR 2008/252 r 8A

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).

Compare: SR 2008/252 r 8B

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 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 **working 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 **working 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 **working 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).

Compare: SR 2008/252 r 8H

Subpart 1A—Urgent temporary grid reconfigurations

Heading: inserted, on 16 December 2013, by clause 4 of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.

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**.

Clause 9.13A: inserted, on 16 December 2013, by clause 4 of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.

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 **publicise** the report.

Clause 9.13B: inserted, on 16 December 2013, by clause 4 of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.

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.

Compare: SR 2008/252 r 9

Clause 9.14(2)(a): amended, on 18 July 2013, by clause 8(1) of the Electricity Industry Participation (Undesirable Trading Situation) Code Amendment 2013.

Clause 9.14(2A): inserted, on 18 July 2013, by clause 8(2) of the Electricity Industry Participation (Undesirable Trading Situation) Code Amendment 2013.

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, direct **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) A direction may be communicated through the **information system** operated by the **system operator**.
- (4) The **system operator** must **publish** a 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.

Compare: SR 2008/252 r 10

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

Subpart 4: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

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**.

Clause 9.19: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

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 scheme** (if any) in accordance with clause 9.27.
- (3) A **retailer's customer compensation scheme** may cover a **customer** who is not a **qualifying customer**.

Clause 9.20: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

9.21 Qualifying customers

- (1) A **retailer's qualifying customer** is a person who, as at the end of the **qualifying date**, —
 - (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 previous **year**, 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** previous **year's** consumption at the **ICP** is not available to the **retailer**, the **retailer** must make a reasonable estimate of the consumption.
- (4) To avoid doubt,—
 - (a) there is no **qualifying customer** at an **ICP** if, at the end of the **qualifying date**,—
 - (i) the premises to which the **ICP** is connected are vacant; or
 - (ii) the **ICP** is disconnected:
 - (b) a **retailer's qualifying customers** includes a **customer** who switched—

- (i) to the **retailer** from another **retailer** on or before the **qualifying date**, including during a **public conservation period**; or
- (ii) from the **retailer** to another **retailer** between the **qualifying date** and the date on which the **retailer** pays compensation under the **customer compensation scheme**.

Clause 9.21: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

Clause 9.21(1)(b)(i): amended, on 1 December 2011, by clause 6 of the Electricity Industry Participation Code (Distributor Use-of-System Agreements and Distributor Tariffs) Amendment 2011.

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.

Clause 9.22: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

Clause 9.22(2): amended, on 21 September 2012, by clause 12 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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 make publicly available on its website 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.

Clause 9.23: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

Clause 9.23(4)(b)(i): amended, on 21 September 2012, by clause 13 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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, for each week of the **official conservation campaign**; 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, for each week of the **public conservation period**; and
 - (c) to pay at least the minimum weekly amount—
 - (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 **qualifying date**.

- (2) Each **retailer's default customer compensation scheme** must provide that if a **public conservation period** runs for more than a whole number of weeks, the **retailer** must, in addition to making payments in accordance with subclause (1) for each whole week of the **public conservation period**, pay at least the minimum weekly amount of compensation at a pro rata daily rate for the number of days that exceed the whole number of weeks of the **public conservation period**.
- (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**.

Clause 9.24: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

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) **publicise** 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 calendar 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.

Clause 9.25: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

Additional customer compensation schemes

9.26 Retailer may have additional customer compensation schemes

A **retailer** may have 1 or more **additional customer compensation schemes**.

Clause 9.26: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

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—
- (a) be part of the contract between the **qualifying customer** and the **retailer** for the supply of **electricity**; or
 - (b) affect the tariff options that the **retailer** offers to the **qualifying customer**; or
 - (c) be affected by the tariff option in the **qualifying customer's** contract with the **retailer**.

Clause 9.27: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

9.28 Publishing description of additional customer compensation schemes

A **retailer** who has 1 or more **additional customer compensation schemes** must—

- (a) make a description of its **additional customer compensation schemes** publicly available, at no cost, on an Internet site maintained by or on behalf of the **retailer**, at all reasonable times; and
- (b) on request from a **customer**, provide a written description of the **additional customer compensation schemes**.

Clause 9.28: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

Statutory declaration

9.29 Each retailer must provide statutory declaration

- (1) Each **retailer** must provide the **Authority** with a declaration confirming that—
 - (a) its **customer compensation scheme** complies with this subpart; and
 - (b) it has provided compensation to its **qualifying customers**, to the extent required by this subpart.
- (2) The declaration provided under subclause (1) must be—
 - (a) a statutory declaration; and
 - (b) in the form specified by the **Authority**; and
 - (c) signed and dated by—
 - (i) 2 directors 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 declarations as follows:
 - (a) within 7 months of the end of a **public conservation period**;
 - (b) subject to subclause (4), within 1 month of receiving a request to do so by the **Authority**.
- (4) The **Authority** must not request a declaration under subclause (3)(b) before 1 October 2011.

Clause 9.29: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

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.

Clause 9.30: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

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**.

Clause 9.31: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

9.32 Auditor must provide audit report

- (1) The **auditor** must provide the **Authority** with an **audit** report on the **retailer's** compliance with this subpart.
- (2) Before the **auditor** provides the **audit** report to the **Authority**, the **auditor** must refer any non-compliance to the **retailer** for comment. The **retailer** must provide comments within a time specified by the **auditor**.
- (3) The **auditor** must include the **retailer's** comments, if any, in the **audit** report.
- (4) The **auditor** must not provide the **Authority** with a copy of any of the information provided by the **retailer** to the **auditor** under clause 9.31 unless requested by the **Authority**.

Clause 9.32: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

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.

Clause 9.33: inserted, on 1 April 2011, by clause 5 of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011.

Electricity Industry Participation Code 2010

Part 10 Metering

Contents

10.1 Contents of this Part

Subpart 1—Preliminary provisions

- 10.2 Authority's and market administrator's discretion and powers
- 10.3 Use of contractors
- 10.4 Participant obligations
- 10.5 References to timing
- 10.6 Participant to provide accurate information
- 10.7 Access to premises in which metering installation located
- 10.8 Requirements for information to be recorded, given, produced, or received
- 10.9 Demarcation of responsibility between metering equipment provider and reconciliation participant
- 10.10 Standards used

Metering installations

- 10.11 Categories of metering installation
- 10.12 Interference with metering installation
- 10.13 Electricity conveyed

Unmetered load

- 10.14 Unmetered load

Metering data

- 10.15 Security of metering data
- 10.16 Metering data exchange timing and formats

Audits

- 10.17 Audits

Subpart 2—Ongoing obligations

Metering equipment providers

- 10.18 Category 1 metering installations and higher categories of metering installations must have metering equipment provider
- 10.19 Metering equipment provider
- 10.20 Obligations of metering equipment provider
- 10.21 When metering equipment provider's obligations come into effect
- 10.22 Change of metering equipment provider
- 10.23 Termination of metering equipment provider responsibility

Responsibility for ensuring there are metering installations

- 10.24 Responsibility for ensuring there is metering installation for ICP that is not also NSP
- 10.25 Responsibility for ensuring there is metering installation for NSP that is not point of connection to grid
- 10.26 Responsibility for ensuring there is metering installation for point of connection to grid
- 10.27 Change in responsibility for ensuring metering installation for point of connection to

grid

Electrically connecting and energising points of connection

- 10.28 Electrically connecting of connection
- 10.29 Electrically connecting point of connection to grid
- 10.30 Electrically connecting NSP that is not point of connection to grid
- 10.31 Electrically connecting ICP that is not NSP
- 10.32 Reconciliation participant requesting electrical connection of point of connection
- 10.33 Energisation of point of connection

General metering installation requirements

- 10.34 Installation and modification of metering installations
- 10.35 Physical location of metering installations
- 10.36 Reconciliation participant to have arrangement with metering equipment provider

Active and reactive energy metering

- 10.37 Active and reactive measuring and recording requirements

Certification of metering installations

- 10.38 Certification of metering installations

Metering infrastructure

- 10.39 Responsibility for metering infrastructure integration

Approved test houses and ATHs

- 10.40 General requirements for approval as ATH
- 10.41 Requirements applying to ATHs
- 10.42 ATH's functions and ongoing obligations

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
- 10.44 Metering installations that are inaccurate, defective, or not fit for purpose to be tested
- 10.45 Investigation and testing costs
- 10.46 Statement of situation
- 10.47 Correction of defects and inaccuracies in metering installation
- 10.48 Correction of defects and inaccuracies in raw meter data

NSP table

- 10.49 NSP table

Dispute resolution

- 10.50 Dispute resolution

Transitional provisions

- 10.51 Transitional provisions

**Schedule 10.1
Tables**

**Schedule 10.2
Audits**

Schedule 10.3

ATHs – approval, expiry, cancellation, and renewal of approval

Schedule 10.4

ATH ongoing functions and obligations

Requirements for calibration of metering components

Schedule 10.5

Metering equipment provider audits

Schedule 10.6

Metering equipment provider ongoing obligations and functions

Schedule 10.7

Metering installation requirements

Metering installation general requirements

Metering installation design reports

Determination of metering installation categories

Certification of metering installation

Statistical sampling recertification

Certification validity periods

Accuracy and error calculation

Installation of metering components in metering installations

Certification of metering components

Inspection requirements

Sealing

Schedule 10.8

Metering component requirements

Meters

Measuring transformers

Control devices

Data storage devices

Wiring

Fuses and circuit breakers

Certification stickers

Onsite calibration and certification

10.1 Contents of this Part

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) the processes and procedures that apply to **auditing ATHs** and **metering**

- equipment providers; and**
- (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.

Subpart 1—Preliminary provisions

10.2 Authority's and market administrator's discretion and powers

- (1) A clause in this Part that gives the **Authority** or **market administrator** a discretion or power—
 - (a) confers an absolute discretion, subject to the **Authority** or the **market administrator**, as the case may be,—
 - (i) taking into account any specific requirements set out in the clause; and
 - (ii) observing the rules 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** or the **market administrator**, as the case may be, considers appropriate in the circumstances.
- (2) The **Authority** or the **market administrator**, when exercising a discretion or power under this Part, must act in a timely manner.
- (3) The **Authority** or the **market administrator** must give an applicant reasons for its decision if the **Authority** or the **market administrator**—
 - (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** or the **market administrator**, as the case may be, considers appropriate in the circumstances.
- (4) Nothing in this Part limits any of the **Authority's** rights and obligations under the **Act**.

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 **published** by 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;
 - (b) ending on a date, it ends at the close of the final **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**, having provided information under this Part, becomes aware that the

participant has not complied with subclause (1), 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 **participant** complies with subclause (1).

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 connection with 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) Part 3 of the Electronic Transactions Act 2002 does not, because of section 14(2)(a) of that Act, apply to this Part.
- (3) The **Authority** must act reasonably when determining the requirements referred to in subclause (1).

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**.

Clause 10.10(a): amended, on 29 August 2013, by clause 11 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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 the **reconciliation manager** a notification 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 the **reconciliation manager** a notification 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**.

Clause 10.14(5)(c)(ii): amended, on 29 August 2013, by clause 12 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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 **notified** by the **Authority**; and
- (b) in the format **notified** to **participants** from time to time by the **Authority**.
- (2) The **Authority** must provide reasonable notice of any changes to the format **notified** 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 **notified** by the **Authority** 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.

Audits

10.17 Audits

- (1) The **Authority** may require a **relevant participant** to have an **audit** undertaken.
- (2) An **audit** must be undertaken by an **auditor** included in the list of approved **auditors published** by the **Authority** under clause 1(7) of Schedule 10.2.
- (3) Schedule 10.2 applies to every such **audit**.

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 **market administrator**;
 - (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 who advises the **registry** that it accepts 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.

Clause 10.19(1): amended, on 29 August 2013, by clause 13(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Clause 10.19(1)(a): amended, on 29 August 2013, by clause 13(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Clause 10.19(1)(c): amended, on 29 August 2013, by clause 13(3) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

10.20 Obligations of metering equipment provider

A **metering equipment provider** must—

- (a) ensure that it is **audited** in accordance with all applicable requirements in this Part including Schedule 10.5; and
- (b) comply with all of its obligations in this Code including the obligations under Schedules 10.6, 10.7, and 10.8.

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**.

Clause 10.21(1)(a): substituted, on 29 August 2013, by clause 14 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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** advises the **registry** of the **gaining metering equipment provider** in accordance with Part 11; and
- (ii) the **gaining metering equipment provider** advises 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**.

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).

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 **energised 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 of Part 15.

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**; and
- (c) no later than 20 **business days** after the date of **certification** of each **metering installation**, advise the **reconciliation participant** for the **NSP** of the **certification** expiry date of the **metering installation**.

Clause 10.25(1): amended, on 29 August 2013, by clause 15(1) of the Electricity Industry Participation (Metering

Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Clause 10.25(2): amended, on 29 August 2013, by clause 15(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Clause 10.25(2)(b)(ii): amended, on 29 August 2013, by clause 15(3) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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 **market administrator**—
 - (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 **market administrator** must determine which **participant** must provide the **metering installation**; and
 - (c) the **market administrator** 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 **market administrator** 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 **market administrator** 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 **market administrator** 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 **market administrator**, 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 **market administrator** for additional details; and
 - (c) ensure that any reasonable changes to the **metering installation** or its configuration requested by the **market administrator** 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(1): amended, on 29 August 2013, by clause 16(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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)

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.

Electrically connecting and energising 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)

10.28 Electrically connecting point of connection

- (1) A **grid owner** may **electrically connect** a **point of connection** to the **grid**.
- (2) A **distributor** that initiates the creation of an **NSP** on its **network** under Part 11 may **electrically 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.
- (3) An **embedded network** owner that initiates the creation of an **NSP** on its network under Part 11 may **electrically connect** the **NSP** to another **embedded network** if the other **embedded network** owner has agreed to the connection.
- (4) A **distributor** may **electrically connect** an **ICP** that is not an **NSP**.
- (5) No other **participant** may effect an **electrical connection** to which subclauses (1) to (4) apply.

- (6) A **metering equipment provider** must not request the **temporary energisation** of a new **point of connection** unless—
 - (a) the **metering equipment provider** is authorised to do so by the **reconciliation participant** responsible for the **point of connection**; and
 - (b) the **metering equipment provider** has an arrangement with that **reconciliation participant** to provide **metering** services.
- (7) A **network** owner must not **electrically connect** a new **point of connection** to its **network** that is to be quantified with a **category 1 metering installation**, or higher category of **metering installation**, unless requested to do so by—
 - (a) the **metering equipment provider**, for a **temporary energisation** of the **point of connection**; or
 - (b) the **reconciliation participant** responsible for ensuring there is a **metering installation**, for the **point of connection**.

Clause 10.28: substituted, on 29 August 2013, by clause 17 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

10.29 Electrically connecting point of connection to grid

- (1) Despite clause 10.28(1), a **grid owner** must not **electrically 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 **market administrator**, to connect the **point of connection**; and
 - (c) obtained the authorisation referred to in paragraph (b) from the **market administrator**.
- (2) The **grid owner** must, within 5 **business days** of **electrically 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.

Clause 10.29: substituted, on 29 August 2013, by clause 18 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

10.30 Electrically connecting NSP that is not point of connection to grid

- (1) Despite clause 10.28(2), a **distributor**—
 - (a) must not **electrically connect** an **NSP** unless a **reconciliation participant** has requested the connection; but
 - (b) may **electrically connect** an **NSP** if a **metering equipment provider** has requested **temporary energisation** of the **NSP**.
- (2) A **distributor** must, within 5 **business days** of **electrically 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)

10.31 Electrically connecting ICP that is not NSP

Despite clause 10.28(4), a **distributor** must not **electrically connect** an **ICP** that is not an **NSP** unless—

- (a) the **trader** trading at the **ICP** has requested the connection; or
- (b) the **metering equipment provider** who has an arrangement with the **trader** trading at the **ICP** has requested **temporary energisation** of the **ICP**.

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)

10.32 Reconciliation participant requesting electrical connection of point of connection

A **reconciliation participant** must only request the **electrical 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 Energisation of point of connection

- (1) A **reconciliation participant** may **energise** a **point of connection**, or authorise a **point of connection** to be **energised**, if—
 - (a) the **reconciliation participant** is recorded in the **registry** as being responsible for the **ICP**; and
 - (b) 1 or more **certified metering installations** are in place in accordance with this Part; and
 - (c) the owner of the **network** to which the **point of connection** is connected has given written approval.
- (2) A **reconciliation participant** that meets the requirements of subclause (1)(a)—
 - (a) may authorise a **metering equipment provider**, with which it has an arrangement, to request the **temporary energisation** of a **point of connection**:
 - (b) may authorise **energisation** 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 **energisation** date:
 - (c) may **energise** an **ICP** if the **point of connection** is solely for **unmetered load**.
- (3) A **reconciliation participant** must not authorise the **energisation** of a **point of connection** in any of the following circumstances:

- (a) a **distributor** has **de-energised** the **point of connection** for safety reasons, and has not subsequently approved the **energisation**:
 - (b) the **energisation** of the **point of connection** would breach the Electricity (Safety) Regulations 2010.
- (4) No **participant** may **energise** a **point of connection**, or authorise the **energisation** of a **point of connection**, other than a **reconciliation participant** as described in subclauses (1) to (3).

Clause 10.33: substituted, on 29 August 2013, by clause 22 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

General metering installation requirements

10.34 Installation and modification of metering installations

- (1) This clause applies to each **metering installation**—
 - (a) proposed to be installed at a **point of connection** other than a **point of connection** to the **grid**; or
 - (b) at a **point of connection** other than a **point of connection** to the **grid**, which is proposed to be modified.
- (2) A **metering equipment provider** must, if this clause applies, consult with and use its best endeavours to agree with the **distributor** and the **trader** for the **point of connection**, before the design of the **metering installation** is finalised, on 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 (2)(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.

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.

Clause 10.35(3): amended, on 29 August 2013, by clause 23(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Clause 10.35(4): amended, on 29 August 2013, by clause 23(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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 **de-energisation** 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** which is a **category 2 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**.
- (2) Despite subclause (1)(a)—
 - (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: amended, on 29 August 2013, by clause 24 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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 a **de-energised 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 Schedule 10.3; 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 **category 2 metering installation**;
 - (c) 5 **business days** after becoming aware of the event or circumstance, for a category 3 or higher **metering installation**.

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 **market administrator**, including the reasons, if and to the extent known, why agreement was not reached.
- (5) The **market administrator** 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 **market administrator**.
- (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 **market administrator**—
 - (i) for all category 3 and above **metering installations**; and
 - (ii) if requested by the **market administrator**, for each **category 1 metering installation** and each **category 2 metering installation**.

Clause 10.46(2): substituted, on 15 May 2014, by clause 13 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 **market administrator** must **publish** and maintain an **NSP** table, or ensure that an **NSP** table is **published** and maintained, on the **Authority's** website.
- (2) The **reconciliation manager** must advise the **market administrator** of any change to the information contained in the **NSP** table within 1 **business day** of becoming aware of such change.
- (3) The **market administrator** must update the **NSP** table, or ensure that the **NSP** table is updated, within 2 **business days** of being advised by the **reconciliation manager** under subclause (2).

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 10.5** 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).

Clause 10.51: amended, on 29 August 2013, by clause 25 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Schedule 10.1 Tables

cls 10.37 and 10.43

Table 1: Metering installation characteristics and associated requirements

Defining Characteristics				Associated Requirements of active energy metering							
Metering installation category	Primary voltage (V)	Primary current (I)	Measuring transformers	Metering installation certification type	Accuracy tolerances		Selected component metering installation minimum IEC class (more accurate components may be used)		Metering installation certification and inspection		
					Maximum permitted error	Maximum site uncertainty	Meter	Current Transformer	Maximum metering installation certification validity period	Maximum sample inspection and recertification period	Inspection period
1	V < 1kV	I ≤ 160A	None	NHH or HHR	± 2.5%	0.6%	2	N/A	180 months	84 months	120 months ± 6 months
2	V < 1kV	I ≤ 500A	CT	NHH or HHR	± 2.5%	0.6%	2	1	120 months	N/A	120 months ± 6 months
3	V < 1kV	500A < I ≤ 1200A	CT	HHR only	± 1.25%	0.3%	1	0.5	120 months	N/A	60 months ± 3 months
	1kV ≤ V ≤ 11kV	I ≤ 100A	VT & CT				N/A	N/A			
	11kV < V ≤ 22kV	I ≤ 50A					N/A	N/A			
4	V < 1kV	I > 1200A	CT	HHR only	± 1.25%	0.3%	N/A	N/A	60 months	N/A	30 months ± 3 months
	1kV ≤ V ≤ 6.6kV	100A < I ≤ 400A	VT & CT								
	6.6kV < V ≤ 11kV	100A < I ≤ 200A									
	11kV < V ≤ 22kV	50A < I ≤ 100A									
5	1kV ≤ V ≤ 6.6kV	I > 400A	VT & CT	HHR only	± 0.75%	0.2%	N/A	N/A	36 months	N/A	18 months ± 1 month
	6.6kV < V ≤ 11kV	I>200A									
	V > 11kV	I > 100A									
	V > 22kV	Any current									

Table 2: Maximum certification validity periods for the purposes of clause 1(2) of Schedule 10.8

Metering installation category	Class 0.2 meter (months)	Class 0.5 meter (months)	Class 1.0 meter (months)	Class 2.0 meter (months)
1	180	180	180	180
2	120	120	120	120
3 where $V < 1\text{kV}$	120	120	120	N/A
3 where $V \geq 1\text{kV}$	120	120	N/A	N/A
4	60	60	N/A	N/A
5	36	N/A	N/A	N/A

Table 3: Selected component certification and comparative recertification minimum test requirements

Event		Design	Measuring transformer	Meter	Primary injection to meter	Prevailing load	Data storage device	Software security and communication equipment	Control device	Wiring check	Component certification check	Review of compensation factors	Raw meter data output	Supply polarity	Register advance	Installation or component configuration
Metering installation	Initial certification category 1	M						M		M	M	M	M	M	M	M
	Initial certification categories 2 and 3	M				M		M		M	M	M	M	M	M	M
	Recertification categories 1 to 3	M				M		M		M	M	M	M	M	M	M
	Recertification category 1 where meter is replaced with a certified meter	M						M		M	M	M	M	M	M	M
Component change or recertification	Meter change including internal data storage devices	M		M		M	M	M		M		M	M	M	M	M
	Metrology change either onsite or remote	M		M			M	M				M	M		M	M
	External data storage device change	M					M	M		M		M	M		M	M
	Measuring transformer change or ratio change	M	M			M				M		M	M	M	M	
	Control device change	M					MI		M	M			M			M
	Additional equipment (eg wiring)	M				M				M			M	M	M	

Key: M = mandatory, MI = mandatory if the control device is integral with the meter.

Table 3: rows 6 and 8 amended, on 15 May 2014, by clause 14 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

Electricity Industry Participation Code 2010
Schedule 10.1

Table 4: Fully calibrated certification minimum test requirements

Event		Design	Measuring transformer	Meter	Primary injection to meter	Prevailing load	Data storage device	Software security and communication equipment	Control device	Wiring check	Component certification check	Review of compensation factors	Raw meter data output	Supply polarity	Register advance	Installation or component configuration
Metering installation	Initial certification	M	M	M	T	M	M	M	M	M	M	M	M	M	M	M
	Recertification	M		M		M	M	M	M	M	M	M	M	M	M	M
	Meter change including internal data storage	M		M		M	M	M		M		M	M	M	M	M
	Metrology change either onsite or remote	M		M			M	M				M	M		M	M
Component change or recertification	External data storage device change	M					M	M		M		M	M		M	M
	Measuring transformer change or ratio change	M	M		T	M				M		M	M	M	M	
	Control device change	M					MI		M	M			M			M
	Additional equipment (eg wiring)	M			T	M				M			M	M	M	
	Initial certification	M	M	M	T	M	M	M	M	M	M	M	M	M	M	M
	Recertification	M		M		M	M	M	M	M	M	M	M	M	M	M

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

Meter and data storage device standards	Standards
Electricity metering equipment (AC) – Part 1: General requirements, tests and test conditions (classes 0.5, 1 and 2)	EN 50470-1
Electricity metering equipment (AC) – Part 2: Particular requirements – Electromechanical meters for active energy (classes 1 and 2)	EN 50470-2
Electricity metering equipment (AC) – Part 3: Particular requirements – Static meters for active energy (classes 0.5, 1 and 2)	EN 50470-3
Electricity metering equipment (AC) – Particular requirements – Part 11: Electromechanical meters for active energy (classes 0.5, 1 and 2)	IEC 62053-11
Electricity metering equipment (AC) – Particular requirements – Part 21: Static meters for active energy (classes 1 and 2)	IEC 62053-21
Electricity metering equipment (AC) – Particular requirements – Part 22: Static meters for active energy (classes 0.2 S and 0.5 S)	IEC 62053-22
Electricity metering equipment (AC) – Particular requirements – Part 23: Static meters for reactive energy (classes 2 and 3)	IEC 62053-23
Electricity metering equipment (AC) – Particular requirements – Part 61: Power consumption and voltage requirements	IEC 62053-61
Electricity metering equipment (AC) – General requirements, tests and test conditions – Part 11: Metering equipment	IEC 62052-11
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 5: row 1 amended, on 15 May 2014, by clause 15 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

Table 6: Standards of accuracy and overall uncertainty for active and reactive meter calibration and testing

Value of Current %	Power Factor	Maximum Overall Uncertainty %	Percentage Error Limits of Meter, Including Uncertainty
Class of meter 2.0 and 2.0S			
5 to 120	1	±0.4	±1.9
10 to 120	0.5 lagging	±0.6	±1.9
10 to 120	0.8 leading	±0.6	±1.9
Class of meter 1.0 and 1.0S			
5 to 120	1	±0.2	±0.9
10 to 120	0.5 lagging	±0.25	±0.9
10 to 120	0.8 leading	±0.25	±0.9
Class of meter 0.5 and 0.5S			
5 to 120	1	±0.1	±0.5
10 to 120	0.5 lagging	±0.12	±0.6
10 to 120	0.8 leading	±0.12	±0.6
Class of meter 0.2S			
5 to 120	1	±0.06	±0.2
10 to 120	0.5 lagging	±0.09	±0.3
10 to 120	0.8 leading	±0.09	±0.3
Class of meter 3.0 reactive			
20 to 120	Zero	±1.0	±3.0
20 to 120	0.8 leading	±1.5	±3.5
20 to 120	0.8 lagging	±1.5	±3.5
Class of meter 2.0 reactive			
20 to 120	Zero	±0.5	±2.0
20 to 120	0.8 leading	±1.0	±2.5
20 to 120	0.8 lagging	±1.0	±2.5

Table 7: Voltage, current, and phase displacement parameters for polyphase meters

Polyphase meters	Class of meter			
	0.2 and 0.5	1.0	2.0	3.0
Each of the voltages between line and neutral or between any 2 lines will not differ from the average corresponding voltage by more than:	±0.1%	±1.0%	±1.0%	±1.0%
Each of the currents in the conductors will not differ from the average current by more than:	±1.0%	±2.0%	±2.0%	±2.0%
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:	2°	2°	2°	2°

Table 8: Required minimum sample size for category 1 metering installation inspections required under clause 45(2)(c) of Schedule 10.7

Number of metering installations identified	Minimum sample size
1	1
2-8	2
9-15	3
16-25	5
26-50	8
51-90	13
91-150	20
151-280	32
281-500	50
501-1200	80
1201-3200	125
3201-10,000	200
10,001-35,000	315
35,001-150,000	500
150,001+	800

Schedule 10.2 Audits

cl 10.17

1 Auditors

- (1) The **Authority** may approve a person to act as, and to perform the functions of, an **auditor**, for a specified type of **audit**, in accordance with this Schedule.
- (2) Approval lasts for 24 months from the date of the approval unless it is cancelled under subclause (8).
- (3) An **auditor** must be approved, under this clause, when it carries out an **audit**, and must not have received notice from the **Authority** of the cancellation of its approval.
- (4) A person applying to the **Authority** for approval, or for renewal of an existing approval, as an **auditor** must—
 - (a) use the **prescribed form**; and
 - (b) respond to the **Authority**, as quickly as practicable, providing any clarification, further data, or information that the **Authority** may request.
- (5) The **Authority** has not more than 2 calendar months from the date on which it receives a completed application, to assess and, if in the **Authority's** view it is appropriate, to approve the application.
- (6) The **Authority** may require an applicant to attend an interview or undertake an examination, or both.
- (7) The **Authority** must **publish**, and keep updated, a list of **auditors** approved for specific types of **audits**.
- (8) The **Authority** may, at any time with immediate effect by giving written notice to the **auditor**, cancel an **auditor's** approval and if it does this, must remove the **auditor** from the list of approved **auditors**.
- (9) The cancellation of an **auditor's** approval does not invalidate an **audit** previously completed by the **auditor**. However, an **audit** in progress or completed after the date on which the **auditor's** approval is cancelled is not a valid **audit** for the purposes of this Code.

2 Audits

A **relevant participant** must ensure that an **auditor** undertaking an **audit** under this Part 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 **relevant participant** to whom the **audit** relates;
- (c) the **auditor** must give the **relevant participant** a reasonable opportunity to comment on the draft **audit** report;
- (d) the **auditor** must consider any comments it receives from the **relevant participant** about the draft **audit** report;
- (e) the **auditor** must produce a final **audit** report and provide that report to the **relevant participant** within 10 **business days** of receiving any comments under paragraph (d):

- (f) the final **audit** report must—
 - (i) specify conditions (if any) that the **auditor** considers the **relevant participant** must satisfy for the **relevant participant** to comply with this Part, and any action that the **relevant participant** has taken in respect of those conditions; and
 - (ii) include the **relevant participant's** comments, if any, on the draft **audit** report; and
 - (iii) include a summary that specifies—
 - (A) the date of the **audit** report; and
 - (B) the name of the **audited relevant participant**; and
 - (C) the scope of the **audit**; and
 - (D) whether or not the **audit** established that the **relevant participant's** processes and procedures have complied with this Part; and
 - (E) the name of the **auditor**.

3 Authority and participant requested audits

- (1) The **Authority** may, in its discretion, carry out an **audit**, or appoint an **auditor** to carry out an **audit**, to determine whether a **relevant participant** has complied with this Part.
- (2) If a **participant** reasonably considers that a **relevant participant** may not have complied with this Part, the **participant** may request in writing to the **Authority** that the **Authority** carry out an **audit** of the **relevant participant** or that the **Authority** appoints an **auditor** to carry out an **audit**.
- (3) Nothing in this Schedule affects the **Authority's** rights under the **Act** or the **regulations**.

4 Scope of audits

An **audit** must address such matters as the **Authority** reasonably requires, having regard to the reasons for which the **Authority** considers that the **audit** is required, and any matters that arise during the **audit**.

5 Authority or auditor may request information, carry out inspections and audit participant's facilities, processes, procedures, and other items

The **Authority** or the **auditor** may, in accordance with the **Act**, to enable it to carry out an **audit**,—

- (a) require the **relevant participant** being **audited** to provide additional information;
- (b) carry out inspections of the **relevant participant's** facilities, processes, and any other items used by the **relevant participant** being **audited**;
- (c) **audit** the **relevant participant's** facilities, processes, procedures, and any other items used by the **relevant participant**, that the **Authority** or the **auditor** considers necessary.

Clause 5: amended, on 15 May 2014, by clause 16 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

6 Participants to provide access

- (1) A **relevant participant** must provide, at no charge, to the **Authority** or an **auditor**

appointed by the **Authority** for this purpose, full access to all relevant facilities, processes, procedures, and other relevant items, personnel, records, and manuals at any time within normal working hours.

- (2) The **relevant participant** must provide information at no charge and within 20 **business days** after receiving a request from the **Authority** or the **auditor**, as the case may be.

7 Production of audit report

The **Authority**, or the **relevant participant**, must ensure that an **auditor** produces an **audit** report that—

- (a) addresses the matters required of it; and
- (b) identifies, if the **Authority** so requires, the extent to which the **relevant participant** failed to comply with this Part, both at the time of the **audit** and historically; and
- (c) identifies any areas for improvement.

8 Authority to make determination

- (1) This clause applies to an **audit** carried out under clause 3.
- (2) The **Authority** must, after considering the **audit** report and any other matters as appropriate,—
 - (a) determine any instances of non-compliance; and
 - (b) if it determines that there has been 1 or more instances of non-compliance, report those instances to the non-compliant **relevant participant**.
- (3) The **relevant participant** must, by no later than 10 **business days** after it receives a report referred to in subclause (2)(b), submit to the **Authority** details of action that the **relevant participant** has taken to correct each instance of non-compliance.

9 Authority to publish summary of audit report

The **Authority** must **publish** the summary of the **audit** report, required under clause 2(f)(iii).

Clause 9: amended, on 15 May 2014, by clause 17 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

10 Payment of auditor's costs

- (1) If an **audit** establishes, to the **Authority's** reasonable satisfaction, that the **relevant participant** alleged to be in breach has complied with this Part, or the non-compliance is minor—
 - (a) for an **audit** carried out under clause 3(1), the **Authority** must pay the **auditor's** costs; and
 - (b) for an **audit** carried out under clause 3(2), the **participant** who requested the **audit** must pay the **auditor's** costs within 10 **business days** of being advised of them.
- (2) If an **audit** establishes, to the **Authority's** reasonable satisfaction, that the **relevant participant** alleged to be in breach has not complied with this Part, and the non-compliance is not minor,—

- (a) for an **audit** carried out under clause 3(1), the **relevant participant** and the **Authority** must pay the **auditor's** costs, in proportions determined by the **Authority**; and
- (b) for an **audit** carried out under clause 3(2), the **relevant participant** and the **participant** who requested the **audit** must pay the **auditor's** costs, in proportions determined by the **Authority**, within 10 **business days** of being advised of them.

Schedule 10.3

cl 10.40

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 clause 2, 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 calendar months from the date of approval; and
 - (b) functions that the applicant has been approved to carry out; and
 - (c) date of the next scheduled **audit**, which must be at least 3 months, and no more than 36 months, from the date of approval; and
 - (d) date of approval.

2 Audits

- (1) An applicant under clause 1(1) must ensure that an **audit** is carried out in accordance with Schedule 10.2, with all necessary amendments.

- (2) An applicant applying for renewal of approval must ensure that the final **audit** report includes—
 - (a) a list of all contractors that the applicant has engaged for any purpose under this Part since the applicant's last **audit**; and
 - (b) details of the activities that each contractor has performed for the applicant since the applicant's last **audit**.
- (3) An applicant applying for approval, or renewal of approval, as a **class B ATH** to **calibrate metering components**, must ensure that the final **audit** report includes a list of all relevant requirements of NZ/AS ISO 17025 for **calibration**, and all relevant methodologies, for which the applicant has been **audited**.

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 9001:2000 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 9001:2000 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)(b): amended, on 29 August 2013, by clause 26 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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 9001:2000 certification for at least the requested term of the approval; and
 - (b) the scope of its AS/NZS ISO 9001:2000 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 9001:2000 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)(b): amended, on 29 August 2013, by clause 27 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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 Notification of cancellation, expiry, or revision of scope of ATH approval

- (1) The **Authority** must **notify** 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 **notification** 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 notified** 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 **notified** under subclause (2) and follow the procedures set out in clauses 10.43 to 10.48.
 - (4) Despite subclause (3), the **Authority** may **notify** a **metering equipment provider** 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

cl 10.42

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.

Clause 1(c)(iv): amended, on 29 August 2013, by clause 28 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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

Standard		Initial calibration interval (months beginning from the date of the first calibration)	Maximum calibration interval (months beginning from the date of the current calibration report)
Reference standard or working standard (other than a working standard used for on-site calibration)	Measuring transformers	36	60
	Comparator bridges	36	60
	Meters	12	24
	Power factor, voltage and current meters	12	24
Working standard used for on-site calibration	All	2	12

- (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 9001:2000 at all times while the person carries out the work.

Schedule 10.5

Metering equipment provider audits

cl 10.20

1 Metering equipment provider must ensure audits are carried out

- (1) A **metering equipment provider** must—
 - (a) ensure that an initial **audit** by an **auditor** under subclause (2) is completed—
 - (i) in the case of a **participant** who becomes a **metering equipment provider** on or after 29 August 2013, within 3 calendar months after the date on which the **metering equipment provider** first becomes a **metering equipment provider**; or
 - (ii) despite anything else in this Code, in the case of a **participant** who becomes the **metering equipment provider** under clause 10.19(1), by no later than 28 February 2014; and
 - (b) ensure that an **audit** of its compliance with this Part and Part 11 under subclause (2) is carried out within a period specified by the **Authority**, which period must be at least 3 months, but no more than 36 months, after the date of the **audit** report for the **metering equipment provider's** previous **audit**; and
 - (c) ensure that an **audit** under paragraph (a) or (b) is carried out in accordance with Schedule 10.2, with all necessary amendments; and
 - (d) ensure that the **auditor** includes in the **audit** report a recommendation on the date by which the **metering equipment provider** must have completed its next **audit** and **audit** report; and
 - (e) provide the finalised **audit** report to the **Authority** within 1 month of the **audit** being completed, or within such other timeframe determined and **published** by the **Authority**; and
 - (f) pay the costs of an **audit** required under this clause in accordance with the terms of the applicable arrangement with the **auditor**.
- (2) A **metering equipment provider** must ensure an **auditor** carrying out an **audit** under subclause (1) **audits** the following processes and procedures:
 - (a) the appropriate 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 in accordance with this Code; and
 - (vi) investigations under clause 10.43(4); and
 - (b) the **metering equipment provider's** provision of **metering records** to—
 - (i) the **registry**; and
 - (ii) the **reconciliation manager**; and
 - (c) the **metering equipment provider's** provision of access under this Part 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.**

Clause 1(1)(a)(i): amended, on 29 August 2013, by clause 29(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Clause 1(1)(a)(ii): amended, on 29 August 2013, by clause 29(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

2 Metering equipment provider audit reports

Despite anything in Schedule 10.2, a **metering equipment provider** must also ensure that the **auditor** includes in the final **audit** report under clause 1—

- (a) any conditions that the **auditor** considers the **metering equipment provider** would need to satisfy for the **metering equipment provider** to comply with this Code, and any action the **metering equipment provider** has taken in respect of satisfying those conditions; and
- (b) a list of all contractors engaged by the **metering equipment provider** to perform the **metering equipment provider's** activities under this Part, and details of the obligations that each of those contractors perform.

3 Changes to metering equipment provider's facilities, systems, and processes

If a **metering equipment provider** intends to materially change any of its facilities, processes, or procedures, the **metering equipment provider** must, at least 10 **business days** before the change is to take effect,—

- (a) advise the **Authority** of all relevant details of the change; and
- (b) ensure that an **audit** of its facilities, processes, and procedures has been undertaken; and
- (c) submit to the **Authority** an **audit** report confirming that the **metering equipment provider** will continue to meet its requirements under this Code after the change has been made.

Schedule 10.6

cl 10.20

Metering equipment provider ongoing obligations and functions

- 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 connection with 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

- (ii) a contractor to a **trader**, person, or party; and
- (b) the security of the **raw meter data** and the **metering installation** is maintained; and
- (c) access to **raw meter data** under subclauses (1) to (6) is limited to only the specific **raw meter data**—
 - (i) authorised by a contract described in subclause (3), in the case of a **trader** under subclause (1) or a person under subclause (2); or
 - (ii) required for the purposes of exercising the party's rights and performing the party's obligations under this Code, any relevant **regulations**, or the **Act** in connection with the party's **audit**, administration, and testing functions, in the case of a party referred to in subclause (4).
- (8) Nothing in this Part affects proprietary interests in **metering data**.

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**;
 - (e) a **gaining metering equipment provider**.

- (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 connection with 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 connection with 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**; 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 keep **metering records** relating to—
- (a) a **metering component** in a **metering installation** for which it is responsible, for at least 48 months after the **metering component** is removed from the **metering installation**; and
 - (b) a **metering installation** for which it is responsible, for at least 48 months after the date on which the **metering installation** is **decommissioned**.

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 connection with 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 connection with 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

Metering installation category	Half-hour metering installations (seconds)	Non half-hour metering installations (seconds)
1	±30	±60
2	±10	±60
3	±10	NA
4	±10	NA
5	±5	NA

- (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.

Schedule 10.7 cls 10.11, 10.20, 10.26, 10.38 and 10.42 **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.

Metering installation design reports

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(1)(b): amended, on 29 August 2013, by clause 30(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Clause 6(2)(b)(i): amended, on 29 August 2013, by clause 30(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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)

Clause 6(2)(c)(iii): amended, on 29 August 2013, by clause 30(5) 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**.

Clause 8(3): amended, on 29 August 2013, by clause 31 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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.

Clause 9(1): amended, on 29 August 2013, by clause 32(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Clause 9(1)(c)(i) and (ii): inserted, on 29 August 2013, by clause 32(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Clause 9(1A): inserted, on 29 August 2013, by clause 32(3) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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.

Clause 11(3)(b): substituted, on 29 August 2013, by clause 33(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Clause 11(3)(b): amended, on 15 May 2014, by clause 18 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

Clause 11(3)(c): inserted, on 29 August 2013, by clause 33(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Clause 11(5)(e): amended, on 29 August 2013, by clause 33(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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 calendar 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.

Clause 14(1): amended, on 29 August 2013, by clause 34 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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 a **de-energised 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)(a)(i): amended, on 29 August 2013, by clause 35(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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)

Clause 16(2)(c): amended, on 29 August 2013, by clause 35(5) 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.

Clause 18: amended, on 29 August 2013, by clause 36 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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) a **control device** that does not switch **meter** registers has malfunctioned and been replaced with another **certified control device** that complies with subclause (3A).
- (3A) A replacement **control device** complies with this subclause if—
- (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) A procedure under subclause (3A)(b)(ii) must ensure that, within 10 **business days** of the replacement occurring, the person carrying out the replacement provides the notification 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)(e), 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 1 of the following events takes place:
- (a) the **metering installation** is modified otherwise than under subclause 19(3) 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, advise the **registry** of the **compensation factor** 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, 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—
 - (a) a **meter**; and
 - (b) a **data storage device**.

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**.

Clause 27(3): amended, on 29 August 2013, by clause 38 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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
 - (ia) the **test facility** and the provision for isolation are installed as physically close to the **meter** as practicable in the circumstances; and
 - (ii) the **test facility** has a transparent cover that is not obscured; 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).

Clause 28(4)(a): substituted, on 29 August 2013, by clause 39 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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 **de-energisation** restrictions; 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]*

Clause 30(2)(vi): amended, on 29 August 2013, by clause 40(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Clause 30(2)(vii): inserted, on 29 August 2013, by clause 40(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Clause 30(3): revoked, on 29 August 2013, by clause 40(3) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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 a **class A ATH** or 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)

Clause 31(7)(b): amended, on 15 May 2014, by clause 19 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 advised the **registry** of the **certification** under this clause.
- (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 **market administrator** 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 **market administrator** 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 **market administrator** 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.

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.
- (a) the **control device** is contained in a **metering installation** for which the **metering equipment provider** is responsible; and
 - (b) the **metering installation** is dependent on control signals for its operation; and
 - (c) the **metering equipment provider** uses the **control device** to do either or both of the following:
 - (i) control a load;
 - (ii) switch **meter** registers.
- (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.

Clause 33(1A): inserted, on 29 August 2013, by clause 42(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Clause 33(1): substituted, on 29 August 2013, by clause 42(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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.

Clause 34(4)(a): substituted, on 29 August 2013, by clause 43 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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**, 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**.

Clause 36(3): amended, on 29 August 2013, by clause 44 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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 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 all of its outputs and inputs appropriately electrically isolated and 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, **notify** 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), an **ATH** may **certify a category 1 metering installation** that contains a **meter** which has been **certified** and subsequently installed in, and removed from, another **category 1 metering installation**, in which case, the **ATH** must—
 - (a) be satisfied that external factors have not affected the accuracy of the **meter**; and
 - (b) check and confirm in the **certification report** for the **metering installation** that the date on which the **meter** was previously installed in the other **metering installation** is less than 12 months before the **commissioning** date of the **metering installation** that the **ATH** is **certifying**.

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) advise the **registry** of 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 paragraph (a); and

- (d) randomly selecting a sample, of the size required under paragraph (c), from the list produced under 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).

Clause 45(10): amended, on 29 August 2013, by clause 45 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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 Metering component requirements

cl 10.20, 10.38 and 10.42

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**; 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 the 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) obtain confirmation of accuracies from the **measuring transformer's** manufacturer if the in-service burden is lower than a test point specified in a standard listed in Table 5 of Schedule 10.1; 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.

Clause 2(1)(c): amended, on 29 August 2013, by clause 46 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

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**; 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 the 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.

Control devices

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)

Clause 4(1)(b): amended, on 15 May 2014, by clause 20 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

Data storage devices

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.

Electricity Industry Participation Code 2010

Part 11 Registry information management

Contents

- 11.1 Contents of this Part
- 11.2 Requirement to provide complete and accurate information
- 11.2A Use of contractors
- 11.3 Certain points of connection must have ICP identifiers
- 11.4 Distributors must create ICP identifiers for ICPs
- 11.5 Participants may request that distributors create ICP identifiers for ICPs
- 11.6 ICP status
- 11.7 Provision of ICP information
- 11.8 Provision of and changes to ICP information and NSP information by participants
- 11.8A Metering equipment providers to provide registry metering records to registry
- 11.8B Metering equipment provider audits
- 11.9 *[Revoked]*
- 11.10 Distributors' processes to be audited
- 11.11 Audits requested by Authority or participant
- 11.12 Audits
- 11.13 Audit reports provided to Authority
- 11.14 Process for maintaining shared unmetered load
- 11.15 Process for customer or embedded generator switching
- 11.15A Application of Schedule 11.4
- 11.15B Retailer contracts with customers must permit assignment by Authority
- 11.15C Process for retailer events of default
- 11.16 Parties to ensure arrangements for line function services
- 11.17 Electrically connecting ICP that is not also NSP
- 11.18 Trader responsibility for ICP
- 11.18A Registry to advise metering equipment providers
- 11.18B Metering equipment provider responsibility for metering installation for ICP
- 11.19 Authority to specify timeframes and formats of information
- 11.20 Registry must be open between 0730 and 1930 each day
- 11.21 Confirmation of receipt of data
- 11.22 Registry must maintain a database of information
- 11.23 Reports from the registry
- 11.24 Registry reports to specific participants
- 11.25 Reports to the clearing manager, system operator or reconciliation manager
- 11.26 Reports to the reconciliation manager
- 11.27 Reports to the market administrator
- 11.28 Access to registry
- 11.29 Registry information change
- 11.30 Use of ICP identifier on invoices
- 11.31 Customer and embedded generator queries
- 11.32 Reliance on registry
- 11.33 *[Expired]*

- 11.34 *[Expired]*
11.35 *[Expired]*
11.36 *[Expired]*

Schedule 11.1

Creation and management of ICPs, ICP identifiers and NSPs

ICPs and ICP identifiers

Provision of ICP Information to the registry

Management of ICP status

Updating registry standing information

Schedule 11.2

Transfer of ICPs between distributors' networks

Schedule 11.3

Switching

Standard switching process

Switch move process

Half-hour switching process

Withdrawing a switch request

Exchange of information

Schedule 11.4

Metering equipment provider switching and registry metering records

Schedule 11.5

Process for retailer event of default

11.1 Contents of this Part

This Part—

- (a) provides for the management of information held by the **registry**; and
- (b) prescribes a process for switching **customers** and **embedded generators** 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 **retailer events of default**.

Compare: Electricity Governance Rules 2003 rule 1 part E

Clause 11.1(d): inserted, on 29 August 2013, by clause 6 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

Clause 11.1(e): inserted, on 16 December 2013, by clause 5 of the Electricity Industry Participation (Managing Retailer Default Situations) Code Amendment 2013

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, in providing information under this Part, the **participant** has not complied with subclause (1), the **participant** must, as soon as practicable, provide such further information as is necessary to ensure that the **participant** complies with subclause (1).

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—
- (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.

Clause 11.2A: inserted, on 29 August 2013, by clause 7 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

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** in accordance with Schedule 11.1.
- (2) A **trader** must provide information about each **ICP** at which the **trader** trades **electricity** to the **registry** 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 notification 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 notification required by clause 29 of Schedule 11.1.

Compare: Electricity Governance Rules 2003 rule 8 part E

11.8A Metering equipment providers to provide registry metering records to registry

- (1) A **metering equipment provider** must, for each **metering installation** described in subclause (2) for which it is responsible,—
 - (a) provide to the **registry** 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 provider audits

A **metering equipment provider** must—

- (a) arrange for an **audit** of its **registry** processes and procedures under this Part; and
- (b) ensure that an **audit** under paragraph (a) is carried out under Schedule 10.5 (with all necessary amendments).

Clause 11.8B: inserted, on 29 August 2013, by clause 8 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

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' processes to be audited

- (1) Each **distributor** must arrange for the conduct of **audits** by an **auditor**, and provide final **audit** reports to the **Authority** as follows:
 - (a) an initial **audit** completed within 3 calendar months after the date on which the **distributor** has the first **NSP identifier** or **ICP identifier** recorded on the **registry** as being part of the **distributor's network**;
 - (b) a further **audit** completed within 12 months after the date of the initial **audit**;
 - (c) at least 1 annual **audit** completed no later than each anniversary date of the initial **audit**.
- (1A) If a **distributor** appoints a contractor to perform the **distributor's registry** obligations under this Code—
 - (a) the **distributor** must provide the contractor's **audit** report to the **Authority**; and
 - (b) the contractor's **audit** report must be prepared in accordance with subclause (1), as if it were a **distributor's audit** report; and
 - (c) the **distributor** must provide the contractor's **audit** report to the **Authority** with the **distributor's** final **audit** report.
- (2) Each **audit** required by this clause must be conducted by an **auditor**.
- (3) The purpose of each **audit** conducted under this clause is to determine whether the processes and procedures used by the **distributor** to create and maintain information under this Part comply with this Code.
- (4) The **distributor's** processes and procedures that must be **audited** include—
 - (a) the creation of **ICP identifiers** for **ICPs**; and
 - (b) the provision of **ICP** information to the **registry** and the maintenance of that information; and
 - (c) the creation and maintenance of **loss factors**.
- (5) An **audit** required by this clause must be conducted in accordance with the procedure set out in clause 11.12.
- (6) The **distributor** is responsible for the costs of **audits** required by this clause.

Compare: Electricity Governance Rules 2003 rule 10 part E

Clause 11.10(1)(c): substituted, on 29 August 2013, by clause 5(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

Clause 11.10(1A): inserted, on 29 August 2013, by clause 5(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

11.11 Audits requested by Authority or participant

- (1) The **Authority** may carry out an **audit** in accordance with clause 12(1) of Schedule 15.1 (with all necessary amendments).
- (2) A **participant** may request that the **Authority** carry out an **audit** in accordance with clause 12(2) of Schedule 15.1 (with all necessary amendments).
- (3) An **audit** requested by the **Authority** or a **participant** must be carried out in accordance with clauses 13 to 19 of Schedule 15.1 (with all necessary amendments).

Compare: Electricity Governance Rules 2003 rule 10A part E

11.12 Audits

A **distributor** must ensure that an **auditor** undertaking an **audit** in accordance with clause 11.10 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 **distributor** to whom the **audit** relates;
- (c) the **auditor** must give the **distributor** a reasonable opportunity to comment on the draft of the **audit** report;
- (d) the **auditor** must consider any comments it receives from the **distributor** about the draft of the **audit** report;
- (e) the **auditor** must produce a final **audit** report and provide the report to the **distributor**;
- (f) the final **audit** report must—
 - (i) specify conditions (if any) that the **auditor** considers the **distributor** must satisfy for the **distributor** to comply with this Code, and any action that the **distributor** has taken in respect of those conditions; and
 - (ii) include a list of all agents engaged by the **distributor** to perform the **distributor's** information gathering, processing, and managing obligations with respect to the **registry** process, and details of the obligations that each of those agents perform; and
 - (iii) include a summary that specifies—
 - (A) the date of the **audit** report; and
 - (B) the name of the **audited participant** or agent; and
 - (C) the scope of the **audit**; and
 - (D) whether or not the **audit** established that the **distributor's** processes and procedures comply with this Code in respect of the matters set out in clause 11.10(4); and
 - (E) the name of the **auditor**.

Compare: Electricity Governance Rules 2003 rule 10B part E

11.13 Audit reports provided to Authority

- (1) A **distributor** must, no later than 1 month after receiving a final **audit** report, provide a copy of the final **audit** report to the **Authority**.
- (2) The **Authority** must publish the summary required under clause 11.12(f)(iii).
- (3) Except for the summary referred to in subclause (2), an **audit** report is confidential to the **distributor**, the **auditor**, and the **Authority**, unless otherwise agreed between the **distributor** and the **Authority**.

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 notify the **registry**, 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 notification under subclause (2) must notify 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 notification under subclause (3) must notify the **registry** 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 notify all **traders** who receive notification under subclause (2) of the change or decommissioning as soon as practicable after the change or decommissioning.
- (6) A **trader** who receives notification under subclause (5) must, as soon as practicable after receiving the notification, 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 notify the **distributor** of the change under subclause (3). The amount of **electricity** attributable to that **ICP** becomes **UFE**.

Compare: Electricity Governance Rules 2003 rule 14 part E

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.

Compare: Electricity Governance Rules 2003 rule 15 part E

11.15A Application of Schedule 11.4

The following parties must comply with Schedule 11.4:

- (a) a **trader** who **notifies** the **registry** of the **gaining metering equipment provider** responsible for each **metering installation** for an **ICP**;
- (b) the **registry**;

- (c) the **gaining metering equipment provider**.

Clause 11.15A: inserted, on 29 August 2013, by clause 10 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

11.15B Retailer contracts with customers must permit assignment by Authority

- (1) Each **retailer** must at all times ensure that the terms of each contract under which a **customer** of the **retailer** purchases **electricity** from the **retailer** permit—
- (a) the **Authority** to assign the rights and obligations of the **retailer** under the contract to another **retailer** if the **retailer** commits an **event of default**; and
 - (b) the terms of the assigned contract to be amended on such an assignment to—
 - (i) the standard terms that the recipient **retailer** 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 **retailer** 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 **retailer** to provide information about the **customer** to the **Authority** and for the **Authority** to provide the information to another **retailer** if required under Schedule 11.5; and
 - (e) the **retailer** to assign the rights and obligations of the **retailer** to another **retailer**.
- (2) The terms specified in subclause (1) must—
- (a) be expressed to be for the benefit of the **Authority** for the purposes of the Contracts (Privity) Act 1982; and
 - (b) not be able to be amended without the consent of the **Authority**.
- (3) This clause applies—
- (a) from 16 January 2014 to every **customer** contract entered into by a **retailer** after this clause comes into force; and
 - (b) from 16 June 2014 to every **customer** contract entered into by a **retailer** before this clause comes into force.

Clause 11.15B: inserted, on 16 December 2013, by clause 6 of the Electricity Industry Participation (Managing Retailer Default Situations) Code Amendment 2013

11.15C Process for retailer events of default

- (1) This clause applies if the **Authority** is satisfied that a **retailer** has committed an **event of default** under paragraph (a) or (b) or (f) or (h) of clause 14.55.
- (2) The **Authority** and each **participant** must comply with Schedule 11.5.

Clause 11.15C: inserted, on 16 December 2013, by clause 6 of the Electricity Industry Participation (Managing Retailer Default Situations) Code Amendment 2013

Clause 11.15C(2): amended, on 15 May 2014, by clause 21 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

11.16 Trader to ensure arrangements for line function services and metering

Before providing the **registry** 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**.

Compare: Electricity Governance Rules 2003 rule 15 part E

Clause 11.16: substituted, on 29 August 2013, by clause 11 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

11.17 Electrically connecting ICP that is not also NSP

- (1A) A **distributor** must, when **electrically connecting** an **ICP** that is not also an **NSP**, follow the connection process set out in clause 10.31.
- (1) A **distributor** must not electrically 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 electrically 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: heading amended, on 29 August 2013, by clause 12(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

Clause 11.17: heading amended, 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): 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).

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

Clause 11.18: substituted, on 29 August 2013, by clause 13 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

Clause 11.18(5): amended, on 15 May 2014, by clause 22 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

11.18A Registry to advise metering equipment providers

The **registry** 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** 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.

Clause 11.18A: inserted, on 29 August 2013, by clause 13 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

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) If an **ICP** is to be **decommissioned**, the **metering equipment provider** who is responsible for each **metering installation** for the **ICP** must, —
 - (a) if the **trader** is responsible for the **interrogation** of the **metering installation**, prior to the **decommissioning**, advise the **trader**, not less than 3 **business days** prior to the **decommissioning**, that the **trader** must, when the status of the **ICP** is changed to inactive in accordance with clause 19 of Schedule 11.1, as part of the **decommissioning** of the **ICP**, carry out a final **interrogation**; or
 - (b) if the **metering equipment provider** is responsible for the **interrogation** of the **metering installation**, when the status of the **ICP** is changed to inactive in accordance with clause 19 of Schedule 11.1, as part of the **decommissioning** of the **ICP**, arrange for a final **interrogation** to take place and provide the **raw**

meter data to the **trader** who is recorded in the **registry** as being responsible for the **ICP**.

Clause 11.18B: inserted, on 29 August 2013, by clause 13 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

11.19 Authority to specify timeframes and formats of information

- (1) This clause 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**.

Compare: Electricity Governance Rules 2003 rule 20 part E

11.20 Registry must be open between 0730 and 1930 each day

- (1) The **registry** must be available to receive and provide information under this Part between 0730 hours and 1930 hours each day.
- (2) Information provided to the **registry** 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** is deemed, for the purposes of this Part, not to have been received until the **registry** has confirmed receipt in accordance with this clause.
- (2) The **registry** must confirm receipt of information received by it in accordance with this Part within 4 hours of the information being provided to it.
- (3) Time when the **registry** is not obliged to be available in accordance with clause 11.20 will not be taken into account in determining whether or not receipt has been confirmed within 4 hours.
- (4) If the **participant** providing the information does not receive confirmation that the **registry** has received the **participant's** information, the **participant** must contact the **registry** to check whether the information has been received.
- (5) If the **registry** has not received the information, the **participant** must re-send the information. This process must be repeated until the **registry** has confirmed receipt of the information in accordance with this clause.

Compare: Electricity Governance Rules 2003 rules 22.1 and 22.2 part E

11.22 Registry must maintain a database of information

- (1) The **registry** must maintain a register of information received by it and updated in accordance with this Code.
- (2) The **registry** 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 the registry

By 1600 hours on the 6th **business day** of each **reconciliation period**, the **registry** must **publish** a report containing the following information:

- (a) the number of **ICPs** notified to the **registry** and contained on its register at the end of the immediately preceding **consumption period**:
- (b) the number of notifications received by the **registry** 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** and the **Authority**.

Compare: Electricity Governance Rules 2003 rule 23 part E

11.24 Registry reports to specific participants

The **registry** must deliver the reports specified in clauses 11.25 to 11.27 in the manner specified in those clauses.

Compare: Electricity Governance Rules 2003 rule 24.1A part E

11.25 Reports to the 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** must provide the report by 1000 hours on the 1st **business day** of the calendar month following the calendar 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 notification to the **registry** 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** must comply with a request made in accordance with subclause (5) by 1000 hours on the 1st **business day** of the calendar month following the calendar month in which the request was made.

Compare: Electricity Governance Rules 2003 rule 24.1 part E

11.26 Reports to the 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** 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 by the **registry** in respect of all **trading periods**:
- (c) a report detailing the **balancing area** to which each **NSP** belongs recorded by 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

11.27 Reports to the market administrator

By 1600 hours on the 1st **business day** of each calendar month, the **registry** must deliver to the **market administrator** a report summarising the number of events that have not been notified to the **registry**, of which it is aware, within the timeframes specified in this Part.

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 by the **registry**.
- (2) If the **Authority** grants a **participant's** application, the **Authority** must specify terms and conditions under which access to information is to be provided.
- (2A) The **participant** must comply with the terms and conditions specified by the **Authority** under subclause (2).
- (3) The **registry** must provide to the **participant** access to information held by the **registry** in accordance with those terms and conditions.

- (4) If a **participant** has been provided access to information in the **registry** and requests a report, the **registry** must provide a copy of the report to the **participant** within 4 hours of receiving the request.
- (5) In determining whether a copy of a report has been provided 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(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** must, within 1 **business day** of receiving the information, advise affected **participants** of the change.

Compare: Electricity Governance Rules 2003 rule 26 part E

Clause 11.29: substituted, on 29 August 2013, by clause 15 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

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** 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

11.33 Authority may direct registry to be suspended *[Expired]*

Clause 11.33: inserted, from 24 May 2013 to 29 December 2013, by clause 4 of the Electricity Industry Participation (Transitional Provisions for New Metering Arrangements) Code Amendment 2013.

11.34 Registry manager, distributors, and traders not required to comply with obligations when registry suspended *[Expired]*

Clause 11.34: inserted, from 24 May 2013 to 29 December 2013, by clause 4 of the Electricity Industry Participation (Transitional Provisions for New Metering Arrangements) Code Amendment 2013.

11.35 Registry manager and traders not required to comply with specified provisions after registry resumes operation *[Expired]*

Clause 11.35: inserted, from 24 May 2013 to 29 December 2013, by clause 4 of the Electricity Industry Participation (Transitional Provisions for New Metering Arrangements) Code Amendment 2013.

11.36 Clauses to expire *[Expired]*

Clause 11.36: inserted, from 24 May 2013 to 29 December 2013, by clause 4 of the Electricity Industry Participation (Transitional Provisions for New Metering Arrangements) Code Amendment 2013.

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:

xxxxxxxxxxxccc

where

xxxxxxxxxx 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 **market administrator**.

- (2) The **ICP identifier** must be used by a **participant** in all communications with the **registry** 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

Clause 2(2): inserted, on 29 August 2013, by clause 6 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

3 De-energisation

Each **ICP** created after 7 October 2002 must be able to be **de-energised** without **de-energisation** of 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 difference between the total consumption for the **embedded network** and all other **ICPs** on the **embedded network**.

Compare: Electricity Governance Rules 2003 clause 1.3 schedule E1

4 Authority may grant dispensation

The **Authority** may, by notification in writing, grant a dispensation from the requirements of clause 3 for an **ICP** that cannot be **de-energised** without **de-energisation** of another **ICP**.

Compare: Electricity Governance Rules 2003 clause 1.4 schedule E1

5 Electrical load

The electrical load associated with an **ICP** is deemed to be supplied through 1 **network supply point** only.

Compare: Electricity Governance Rules 2003 clause 1.5 schedule E1

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**.

Compare: Electricity Governance Rules 2003 clause 1.6 schedule E1

Provision of ICP information to the registry

7 Distributors to provide ICP information to registry

- (1) A **distributor** must, for each **ICP** on the **distributor's network**, provide the following information to the **registry**:
 - (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 a value 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 can be determined from the **metering information**, no **chargeable capacity**:
 - (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 **energised**.
- (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** 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** no later than 10 **business days** after the date on which the **ICP** is initially **energised**.

- (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 **energised** is earlier than 29 August 2013.
- (3) The **distributor** must provide the following information to the **registry** 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 10MW 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** 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** 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)(a): amended, on 29 August 2013, by clause 16 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

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(1A): inserted, on 29 August 2013, by clause 7(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

Clause 7(2): amended, on 29 August 2013, by clause 5(2) of the Electricity Industry Participation (Additional Registry Fields) Code Amendment 2012.

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(6): amended, on 21 September 2012, by clause 15(1) of the Electricity Industry Participation (Minor Amendments) 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.

Clause 7(1): amended, on 15 May 2014, by clause 23 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

8 Distributors to change ICP information provided to registry

- (1) If information about an **ICP** provided to the **registry** in accordance with clause 7 changes, the **distributor** in whose **network** the **ICP** is located must notify the **registry** of the change.
- (2) The **distributor** must give the notification—
 - (a) in the case of a change to the information referred to in clause 7(1)(b) (other than a change that is the result of the **commissioning** or decommissioning of an **NSP**), no later than **8 business days** after the change takes effect; and
 - (b) in every other case, no later than **3 business days** after the change takes effect.
- (3) A **distributor** is not required to notify 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

- (1) Each **trader** must provide the following information to the **registry** 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 **market administrator** 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**;
 - (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);
 - (h) *[Revoked]*
 - (i) *[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 **publicised** 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** 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** 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): amended, on 29 August 2013, by clause 8(1) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

Clause 9(1)(c): amended, on 29 August 2013, by clause 8(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

Clause 9(1)(d): substituted, on 1 December 2011, by clause 14 of the Electricity Industry Participation Code (Distributor Use-of-System Agreements and Distributor Tariffs) Amendment 2011.

Clause 9(1)(d): amended, on 21 September 2012, by clause 15(2) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 9(1)(d): revoked, on 29 August 2013, by clause 8(3) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

Clause 9(1)(ea): inserted, on 29 August 2013, by clause 8(5) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

Clause 9(1)(f): amended, on 29 August 2013, by clause 8(6) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

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(1)(k): inserted, on 29 August 2013, by clause 5(5) of the Electricity Industry Participation (Additional Registry Fields) Code Amendment 2012 and Clause 8(9) 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): amended, on 29 August 2013, by clause 8(10) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

Clause 9(3): inserted, on 29 August 2013, by clause 8(11) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

Clause 9(1)(e): revoked, on 15 May 2014, by clause 24 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

10 Traders to change ICP information provided to registry

- (1) If information about an **ICP** provided to the **registry** in accordance with clause 9 changes, the **trader** who trades at the **ICP** must notify the **registry** of the change.
- (2) The **trader** must give the notification no later than **5 business days** after the change.
- (3) Despite subclause (2), if the **trader** is not able to give the notification 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 notification 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.

Compare: Electricity Governance Rules 2003 clause 3A schedule E1

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.

11 Correction of errors in the registry

- (1) By 0900 hours on the 1st **business day** of each **reconciliation period**, the **registry** 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.

Compare: Electricity Governance Rules 2003 clause 3B schedule E1

Management of ICP status

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.

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 activation by a **trader**.

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 activation by a **trader**.
- (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

Clause 14(1)(a): amended, on 15 May 2014, by clause 25 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

15 "New" or "Ready" status for 24 calendar months or more

- (1) Subclause (2) applies if—
 - (a) an **ICP** has had the status of "New" for 24 calendar months or more; or
 - (b) an **ICP** has had the status of "Ready" for 24 calendar 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

Clause 15: substituted, on 15 May 2014, by clause 26 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 **energised**; 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 **customer, embedded generator, or direct purchaser**; 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

Clause 17(1)(a): amended, on 29 August 2013, by clause 18 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

18 [Revoked]

Compare: Electricity Governance Rules 2003 clause 4.6A schedule E1

Clause 18: revoked, on 29 August 2013, by clause 5(7) of the Electricity Industry Participation (Additional Registry Fields) Code Amendment 2012.

19 "Inactive" status

The **ICP** status of "Inactive" must be managed by the relevant **trader** and indicates that—

- (a) the **ICP** is **de-energised**; 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** on 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 1 **distributor's network** to another **distributor's network**.
- (8) The **registry** must publish an updated schedule of all **loss category** codes and the **loss factors** for each **loss category** code no later than 1 **business day** after being notified of a change.

Compare: Electricity Governance Rules 2003 clause 5A schedule E1

Clause 22(8): amended, on 21 September 2012, by clause 15(3) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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 2 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 1 **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 **notify** 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 **notify** the **reconciliation manager** of any change to the information provided under subclause (1).
- (3) The notification must—
 - (a) specify the date and **trading period** from which the change takes effect; and
 - (b) be given no later than 3 **business days** after the change takes effect.
- (4) The **reconciliation manager** must **notify** the **registry** of changes to **balancing areas** within 1 **business day** after receiving the notification.
- (5) The **registry** must **publish** an updated schedule of the mapping between **NSPs** and **balancing areas** within 1 **business day** after receiving the notification.
- (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 notify the **reconciliation manager** of the creation or decommissioning; and
 - (b) the **reconciliation manager** must notify the **market administrator** and affected **reconciliation participants** of the creation or decommissioning no later than 1 **business day** after receiving the notification 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 notify the **reconciliation manager**, the **market administrator**, and each affected **reconciliation participant** of the transfer.
- (3) The notification 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 notify a transfer under subclause (2) or subclause (3)(d) must comply with Schedule 11.2.

Compare: Electricity Governance Rules 2003 clause 8 schedule E1

26 Information to be provided if NSPs are created or ICPs are transferred from 1 distributor's network to another distributor's network

- (1) If a **participant** gives a notification under clause 25(1) or (2) of the creation of an **NSP** or the transfer of an **ICP** from 1 **distributor's network** to another **distributor's network**, the **participant** must request that the **reconciliation manager** create a unique **NSP identifier** for the **NSP**.
- (2) The **participant** must make the request—
 - (a) in the case of a notification given under clause 25(3)(b) or (c), at least 10 **business days** before the **NSP** is electrically connected; and
 - (b) in every other case, at least 1 calendar month before the **NSP** is electrically connected or the **ICP** is transferred.
- (3) If a **participant** gives a **notification** 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) notification that the **NSP** to be created is to be assigned to the new **balancing area**; and
- (b) in every other case, notification of the **balancing area** in which the **NSP** is located.
- (4) If a **participant** gives a notification 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 notify 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 notification at least 1 calendar month before the creation or transfer.

Compare: Electricity Governance Rules 2003 clause 9 schedule E1

Clause 26(3): amended, on 21 September 2012, by clause 15(4) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

27 Information to be provided if ICPs become NSPs

- (1) If a transfer notified 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 notify any **trader** trading at the **ICP** of the transfer.
- (2) The **distributor** must give the notification at least 1 calendar 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 a notification under clause 25(1) or (2), allocate a unique **NSP identifier** to each **point of connection** or **interconnection point** to which the notification relates in accordance with the following format:

bbbqqqz nnnn

where

bbbqqqz 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**

where

bbb	is a combination of 3 alpha characters that form a unique location identifier
qqq	is the voltage in kV of the supply bus
z	is a numeral allocated to distinguish it from any other supply bus of the same voltage at the same location
nnnn	is a participant identifier for the network owner who from time to time owns the network being supplied.

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 notify the following of the acquisition:
 - (a) the previous **network** owner;
 - (b) the **reconciliation manager**;
 - (c) the **market administrator**;
 - (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 notification at least 1 calendar month before the acquisition.
- (3) The notification 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

30 Reconciliation manager to advise registry

- (1) The **reconciliation manager** must—
 - (a) advise the **registry** of any new or deleted **NSP identifier** no later than 1 **business day** after being notified of its creation or decommissioning; and
 - (b) advise the **registry** 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 notification.
- (2) The **registry** must **publish** an updated schedule of all **NSP identifiers** and supporting information within 1 **business day** of any change being notified to it in accordance with subclause (1).

Compare: Electricity Governance Rules 2003 clause 13 schedule E1

Schedule 11.2

Transfer of ICPs between distributors' networks

cls 25 and 29 of Schedule 11.1

- 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
- 2 The applicant **distributor** must notify the **market administrator** of the transfer.
Compare: Electricity Governance Rules 2003 clause 2 schedule E1A
- 3 The notification must be in the **prescribed form**.
Compare: Electricity Governance Rules 2003 clause 3 schedule E1A
- 4 The notification 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 **market administrator** 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 notification, except if the notification relates to the creation of an **embedded network**; and
 - (b) every **trader** who trades **electricity** at any **ICP** nominated at the time of notification as being supplied from the same **NSP** to which the notification relates.
Compare: Electricity Governance Rules 2003 clause 5 schedule E1A
- 6 If a notification 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 **market administrator** must not authorise the change of any information on the **registry** if clauses 2 to 5 are not complied with.
Compare: Electricity Governance Rules 2003 clause 7 schedule E1A
Clause 7: amended, on 29 August 2013, by clause 10 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.
Clause 7: amended, on 15 May 2014, by clause 27 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.
- 7A Despite clause 7, the **market administrator** may authorise the change if the applicant **distributor** has not notified the **market administrator** within the time frame required under clause 4, if—

- (a) the applicant **distributor** has complied with clauses 2, 3 and 5; and
- (b) the **market administrator** considers that it has not been materially disadvantaged by the applicant **distributor's** failure to comply with clause 4.

Clause 7A: inserted, on 15 May 2014, by clause 28 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

- 8 The notification must include any information requested by the **Authority** from time to time.

Compare: Electricity Governance Rules 2003 clause 8 schedule E1A

- 9 The **registry** must remove any information that has been notified to the **registry** under clause 7 of Schedule 11.1 relating to an **ICP** for which a transfer has been notified under this Schedule, if the information was to have come into effect after the date on which the **market administrator** authorises the change of information on 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 it is notified only with the consent of the **market administrator**.

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

cl 11.15

Standard switching process

1 Standard switching process for ICPs

- (1) This clause and clauses 2 to 7 apply 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**") supplies **electricity**, and the **ICP** is recorded on the **registry** with—
 - (i) a submission type of non **half hour**; or
 - (ii) a submission type of **half hour** and an AMI flag of "Y"; or
 - (b) assume responsibility under clause 11.18(1) for such an **ICP**.
- (2) If the Door to Door Sales Act 1967 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 7 of the Door to Door Sales Act 1967; 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(1)(a): substituted, on 29 August 2013, by clause 11(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

2 Inform registry of switch request for ICPs

For each **ICP** to which a switch relates, the gaining **trader** must advise the **registry** of the switch no later than **2 business days** after the arrangement with the **customer** or **embedded generator** comes into effect.

Compare: Electricity Governance Rules 2003 clause 1.1 schedule E2

3 Losing trader response to switch request

Within **3 business days** after receipt of notification from the **registry** in accordance with clause 22, for each **ICP** the losing **trader** must establish an expected **event date** and must—

- (a) provide acknowledgement of the switch request by—
 - (i) providing the expected **event date** to the **registry**; and
 - (ii) if relevant for that **ICP**, providing a valid switch response code approved by the **market administrator**, to the gaining **trader**; or
- (b) provide final information to complete the switch by—
 - (i) providing confirmation of the actual **event date** to the **registry**; and

- (ii) providing to the gaining **trader** confirmation of the actual **event date** and a switch meter read, comprising either the **validated meter reading** or a **permanent estimate**, as at the actual **event date**; or
- (c) provide a request for withdrawal of the switch in accordance with clause 17.

Compare: Electricity Governance Rules 2003 clause 1.2 schedule E2

4 Event dates

- (1) The losing **trader** must establish **event dates** under clause 3 so that—
 - (a) no **event date** is more than 10 **business days** after the date of notification from the **registry** 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 of notification.
- (2) When calculating an **event date** under this clause, the losing **trader** must disregard every **event date** established by the losing **trader** for a **customer** who, at the time that the **event date** is established, has been a **customer** of the losing **trader** for less than 2 calendar months.

Compare: Electricity Governance Rules 2003 clause 1.2A schedule E2

Clause 4(1)(a): amended, on 15 May 2014, by clause 29 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

5 Losing trader must provide final information

- If the losing **trader** provides information to the **registry** in accordance with clause 3(a) and 4, then within 3 **business days** after the actual **event date**, the losing **trader** must—
- (a) provide confirmation of the actual **event date** to the **registry**; and
 - (b) provide the actual **event date** and either the **validated meter reading** or a **permanent estimate** as at the actual **event date** to the gaining **trader**.

Compare: Electricity Governance Rules 2003 clause 1.3 schedule E2

6 Traders must use same reading

The losing **trader** and the gaining **trader** must both use the same **validated meter reading** or **permanent estimate** as determined by the following procedure:

- (a) if the **validated meter reading** or **permanent estimate** 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 validated meter reading** or **permanent estimate**; or
- (b) if the **validated meter reading** or **permanent estimate** 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 **validated meter reading** or **permanent estimate**. In this case, the **gaining trader** must, within 4 calendar months of the actual **event date**, 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,—
 - (i) within 5 **business days** after receiving the **validated meter readings** or **permanent estimate** from the gaining **trader**, the losing **trader**, if it does

not accept the **validated meter readings** or **permanent estimate**, must **notify** the gaining **trader** (giving all relevant details); or

- (ii) if the losing **trader** notifies its acceptance of the **validated meter readings** or **permanent estimate** received from the gaining **trader**, or does not provide any response, the losing **trader** must use the **validated meter readings** or **permanent estimate** supplied by the gaining **trader** in accordance with this paragraph.

Compare: Electricity Governance Rules 2003 clause 1.4 schedule E2

7 Disputes

- (1) A losing **trader** or a gaining **trader** may notify the other **trader** that it disputes a **validated meter reading** or **permanent estimate** notified 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) This clause and clauses 9 to 12 apply 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** for which no **trader** has an agreement to trade **electricity** and the **ICP** is recorded on the **registry** with—
 - (i) a submission type of non **half hour**; or
 - (ii) a submission type of **half hour** and AMI flag of "Y"; or
 - (b) assume responsibility under clause 11.18(1) for such an **ICP**.
- (2) If the Door to Door Sales Act 1967 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 7 of the Door to Door Sales Act 1967; 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)(a): substituted, on 29 August 2013, by clause 12(2) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

9 Gaining trader informs registry of switch request

For each **ICP**, the gaining **trader** must advise the **registry** of the switch type and the proposed **event date** no later than 2 **business days** after the arrangement with the **customer** or **embedded generator** comes into effect.

Compare: Electricity Governance Rules 2003 clause 2.1 schedule E2

10 Losing trader provides information

Within 3 **business days** after receipt of notification from the **registry** in accordance with clause 22(a), the **trader** who is recorded on the **registry** as being responsible for the **ICP** (the “losing **trader**”) must confirm the proposed **event date** or set another expected **event date** (that must not precede the gaining **trader’s** proposed **event date** and must be no more than 10 **business days** after the date of such notification), and must—

- (a) provide acknowledgement for the switch move by—
 - (i) providing confirmation of the expected **event date** to the **registry**; and
 - (ii) if relevant for the **ICP**, provide a valid switch response code approved by the **Authority** to the gaining **trader**; or
- (b) provide final information to complete the switch move by—
 - (i) providing confirmation of the actual **event date** to the **registry**; and
 - (ii) providing, either the **validated meter reading** or a **permanent estimate** as at the actual **event date** to the gaining **trader**, and if a **permanent estimate** is supplied, the date of the last **validated meter reading** at the **ICP**; or
- (c) providing a request for withdrawal of the switch in accordance with clause 17.

Compare: Electricity Governance Rules 2003 clause 2.2 schedule E2

11 Losing trader must provide final information

If the losing **trader** has provided information to the **registry** in accordance with clause 10(a), then within 3 **business days** after the later of the actual **event date** or date of receipt of the switch request, the losing **trader** must—

- (a) provide confirmation of the actual **event date** to the **registry**; and
- (b) provide the actual **event date** and either the **validated meter reading** or a **permanent estimate** as at the actual **event date** to the gaining **trader**.

Compare: Electricity Governance Rules 2003 clause 2.3 schedule E2

12 Gaining trader may change validated meter reading or permanent estimate

- (1) The gaining **trader** may use the **validated meter reading** or **permanent estimate** supplied by the losing **trader** or may, at its own cost, obtain its own **validated meter reading** or **permanent estimate**.
- (2) If the gaining **trader** elects to use the new **validated meter reading** or **permanent estimate**, the gaining **trader** must **notify** the losing **trader** of the new **validated meter reading** or **permanent estimate** and the actual **event date** to which it refers as follows:
 - (a) if the **validated meter reading** or **permanent estimate** established by the gaining **trader** differs by less than 200 kWh from that provided by the losing **trader**, both **traders** must use the **validated meter reading** or **permanent estimate** provided by the gaining **trader** as the **validated meter reading** or **permanent estimate**; or
 - (b) if the **validated meter reading** or **permanent estimate** 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 **validated meter reading** or **permanent estimate**.

- (3) If the gaining **trader** disputes a **validated meter reading** or **permanent estimate** under subclause (2)(b), the gaining **trader** must, within 4 calendar months of the actual **event date**, 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) within 5 **business days** after receiving the **validated meter reading** or **permanent estimate** from the gaining **trader**, the losing **trader**, if it does not accept the **validated meter reading** or **permanent estimate**, must **notify** 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** notifies its acceptance of the **validated meter reading** or **permanent estimate** received from the gaining **trader**, or does not provide any response, the losing **trader** must use the **validated meter reading** or **permanent estimate** supplied by the gaining **trader** in accordance with this clause.

Compare: Electricity Governance Rules 2003 clause 2.4 schedule E2

Half-hour switching process

13 Half-hour switching processes

- (1) This clause and clauses 14 to 16 apply if a **trader** (the “gaining **trader**”) has an arrangement with a **customer** or **embedded generator** to—
- (a) trade **electricity** through—
 - (i) a **half-hour metering installation** at an **ICP** with a submission type of **half hour** on the **registry** and an AMI flag of "N" at which another **trader** (the "losing **trader**") trades **electricity** through a **half-hour metering installation** with the **customer** or **embedded generator** with a submission type of **half hour** on the **registry** and an AMI flag of "N"; or
 - (ii) a **half-hour metering installation** at an **ICP** with a submission type of **half hour** on the **registry** and an AMI flag of "N" at which another **trader** (the "losing **trader**") trades **electricity** through a non **half-hour metering installation** with the **customer** or **embedded generator** with a submission type of non **half hour** on the **registry** and an AMI flag of "N"; or
 - (iii) a non **half-hour metering installation** at an **ICP** at which another **trader** (the "losing **trader**") trades **electricity** through a **half-hour metering installation** with an AMI flag of "N" with the **customer** or **embedded generator**; or
 - (b) assume responsibility under clause 11.18(1) for such an **ICP**.
- (2) If the Door to Door Sales Act 1967 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 7 of the Door to Door Sales Act 1967; 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)(a): substituted, on 29 August 2013, by clause 13 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

14 Gaining trader informs registry of switch request

For each **ICP** to which the switch relates, the gaining **trader** must advise the **registry** of the expected **event date** and switch type no later than 3 **business days** after the arrangement with the **customer** or **embedded generator** comes into effect.

Compare: Electricity Governance Rules 2003 clause 3.2 schedule E2

15 Losing trader provides information

Within 3 **business days** after the losing **trader** receives information from the **registry** in accordance with clause 22(a), and if relevant for that **ICP**, the losing **trader** must—

- (a) provide to the **registry** a valid switch response code approved by the **Authority**;
or
- (b) provide a request for withdrawal of the switch in accordance with clause 17.

Compare: Electricity Governance Rules 2003 clause 3.3 schedule E2

16 Gaining trader to notify registry

The gaining **trader** must notify the **registry** of the actual **event date** no later than 3 **business days** after the actual **event date**.

Compare: Electricity Governance Rules 2003 clause 3.4 schedule E2

Withdrawing a switch request

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 **calendar months** after the **event date** of the switch.

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;
- (c) for each **ICP**, the **trader** withdrawing the switch request must provide the **registry** with the following information:
 - (i) the **participant identifier** of the **trader**; and
 - (ii) the withdrawal advisory code **published** by the **Authority** in accordance with paragraph (b):

- (d) within 5 **business days** after receiving a notification from the **registry** in accordance with clause 22(b), the **trader** receiving the withdrawal must notify the **registry** that the switch withdrawal request is accepted or rejected. A switch withdrawal request must not become effective until accepted by the **trader** who received the withdrawal;
- (e) on receipt of a rejection notification from the **registry** 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 within 10 **business days** after the date of the initial switch withdrawal request;
- (f) if a **trader** requests that a switch request be withdrawn and the resolution of that switch withdrawal request results in the switch proceeding, within 2 **business days** after receipt of notification from the **registry** 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.

Compare: Electricity Governance Rules 2003 clause 4 schedule E2

Clause 18(b): amended, on 21 September 2012, by clause 16(1) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 18(c)(i): amended, on 21 September 2012, by clause 16(2) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Exchange of information

19 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**.

Compare: Electricity Governance Rules 2003 clause 5.1 schedule E2

20 Method of exchanging files

- (1) 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.
- (2) The **Authority** must **publish** the file formats.

Compare: Electricity Governance Rules 2003 clause 5.2 schedule E2

Clause 20(1): substituted, on 15 May 2014, by clause 30 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

21 Metering information

For an **interrogation** or **validated meter reading** or **permanent estimate** carried out in accordance with this Schedule,—

- (a) the **trader** who carries out the **interrogation** or **validated meter reading** or **permanent estimate** must ensure that the **interrogation** is as accurate as possible, or that the **validated meter reading** or **permanent estimate** is fair and reasonable; and

- (b) the cost of each **interrogation** or **validated meter reading** or **permanent estimate** carried out in accordance with clauses 5(b) or 10(b)(ii) must be met by the losing **trader**; and
- (c) the costs of every other **interrogation** or **validated meter reading** or **permanent estimate** must be met by the gaining **trader**.

Compare: Electricity Governance Rules 2003 clause 5.3 schedule E2

22 Registry notifications

The **registry** must provide notifications 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** must notify 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** must notify 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** must notify the gaining **trader** of the information received:
- (d) on receipt of information about a switch completion in accordance with clauses 5, 10 and 16, the **registry** must notify 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

Clause 22(d): amended, on 29 August 2013, by clause 14 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

Schedule 11.4

cls 11.8A and 11.15A

Metering equipment provider switching and registry metering records

Schedule 11.4: inserted on 29 August 2013, by clause 22 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.

1 Metering equipment provider receives notification for ICP identifier

- (1) Within 10 **business days** of being advised by the **registry** 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** 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** in the **prescribed form** that it declines to accept responsibility for each **metering installation** for the **ICP**.
- (2) The **registry** 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 declination.
- (3) The **registry** 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**.

Clause 1(1): amended, on 29 August 2013, by clause 49 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2).

2 Gaining metering equipment provider to advise registry 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** of the **registry metering records** for the **metering installation**.

3 Metering equipment provider to advise registry of changes to registry metering records

A **metering equipment provider** must advise the **registry** of the **registry metering records**, or any change to the **registry metering records**, for a **metering installation** for which it is responsible, no later than 10 **business days** following:

- (a) the **electrical connection** of an **ICP** that is not also an **NSP**;
- (b) any subsequent change in any matter covered by the **metering records**.

Clause 3(a): amended, on 29 August 2013, by clause 50 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

4 Registry requirement to advise

The **registry** 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 metering registry records for ICP identifier

The **registry** 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** of any necessary changes to the **registry metering records**.

- 7 Metering equipment provider to provide registry metering records to registry**
- (1) A **metering equipment provider** must, if required under this Part, provide to the **registry** 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** 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.

Clause 7(2): amended, on 29 August 2013, by clause 51 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Table 1: Registry metering records

The following table sets out the **registry metering records**:

No	Registry term	Description	Fully certified metering installation	Interim certified metering installation
For each ICP identifier				
1	the metering equipment provider participant identifier	participant identifier	Required	Required
For each metering installation for an ICP				
2	metering installation number	a sequential number that is unique to the ICP's identifier , to identify the metering installation	Required	Required
3	highest metering category	the category recorded in the metering installation certification report	Required	Required
4	metering installation location code	a code from the list of codes in the registry , that identifies the location of the metering installation on a premises	Required	Required
5	the ATH participant identifier	the participant identifier of the ATH who certified the metering installation	Required	Optional

No	Registry term	Description	Fully certified metering installation	Interim certified metering installation
6	metering installation type	the certification type of the metering installation , which may be either half hour or non half hour identified in the metering installation certification report	Required	Required
7	metering installation certification date	the effective certification date identified in the metering installation certification report	Required	Optional
8	the metering installation certification expiry date	the metering installation certification expiry date, identified in the metering installation certification report , or the date that the metering installation certification is cancelled	Required	Required
9	control device certification	confirmation that the control device used in the metering installation is included in the metering installation certification report	Required	Optional

Electricity Industry Participation Code 2010
Schedule 11.4

No	Registry term	Description	Fully certified metering installation	Interim certified metering installation
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
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

No	Registry term	Description	Fully certified metering installation	Interim certified metering installation
14	price code	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	Optional	Optional
The following details for each metering component in the metering installation for each ICP				
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 .

No	Registry term	Description	Fully certified metering installation	Interim certified metering installation
17	meter or data storage device type	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	Required for meter or data storage device .	Required for meter or data storage device .
18	AMI type	an identifier to identify if the metering component is an advanced metering infrastructure device	Required for meter or data storage device . Optional for all other metering components .	Required for meter or data storage device . Optional for all other metering components .
19	compensation factor	the compensation factor , which in the case of a complex compensation factor , must be obtained from the metering equipment provider	Required for meter or data storage device . Optional for all other metering components .	Required for meter or data storage device . Optional for all other metering components .
20	owner of a metering component	a free text field to identify the owner of a metering component , which may be a participant identifier if the owner is a participant	Optional	Optional
21	removal date of a meter or data storage device	a date that a meter or data storage device is removed	Required for meter or data storage device	Optional for meter or data storage device

No	Registry term	Description	Fully certified metering installation	Interim certified metering installation
The following details for each metering component identified in rows 15 to 21 above				
22	metering component type	the metering component type identifier selected from the list of codes in the registry	Required	Required
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 or control device . Optional for all other metering components .	Required for meter or data storage device or control device . Optional for all other metering components .
24	number of dials	the number of dials or digits that relate to the data channel	Required for meter . Optional for all other metering components .	Required for meter . Optional for all other metering components .
25	register content code	an identifier for the contents of a channel or a data channel, selected from a list in the registry	Required for meter or data storage device . Optional for all other metering components .	Required for meter or data storage device . Optional for all other metering components .

No	Registry term	Description	Fully certified metering installation	Interim certified metering installation
26	period of availability	an identifier for the period of availability for which a control device is configured, selected from a list in the registry	Required for meter or data storage device . Optional for all other metering components .	Required for meter or data storage device . Optional for all other metering components .
27	unit of measurement	an identifier for the units recorded in a data channel, selected from a list in the registry	Required for meter or data storage device . Optional for all other metering components .	Required for meter or data storage device . Optional for all other metering components .
28	energy flow direction	an identifier for the import or export recording in the data channel, selected from a list in the registry	Required for meter or data storage device . Optional for all other metering components .	Required for meter or data storage device . Optional for all other metering components .
29	accumulator type	an identifier for either absolute or cumulative recording in the data channel, selected from a list in the registry	Required for meter or data storage device . Optional for all other metering components .	Required for meter or data storage device . Optional for all other metering components .

No	Registry term	Description	Fully certified metering installation	Interim certified metering installation
30	settlement indicator	<p>an identifier that,—</p> <p>(a) for a meter or data storage device with an AMI flag of "Y", indicates that—</p> <p>(i) the cumulative data channel must be included in the trader's submission information; and</p> <p>(ii) any absolute data channel must not be included in the trader's submission information; or</p> <p>(b) for any other meter or data storage device, or for a load control device, indicates whether the data channel must be included in the trader's submission information, selected from a list in the registry</p>	Required for meter, data storage device , or load control device	Required for meter, data storage device , or load control device

Electricity Industry Participation Code 2010
Schedule 11.4

No	Registry term	Description	Fully certified metering installation	Interim certified metering installation
31	event reading	the event meter read of a meter or data storage device	Optional	Optional

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 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)

Schedule 11.5

Process for retailer event of default

cl 11.15C

Schedule 11.5: inserted, on 16 December 2013, by clause 7 of the Electricity Industry Participation (Managing Retailer Default Situations) Code Amendment 2013.

1 Purpose

The purpose of this Schedule is to set out the process that the **Authority** and each **participant** must comply with when a **retailer** commits an **event of default** under paragraph (a) or (b) or (f) or (h) of clause 14.55.

2 Notice to retailer who has committed event of default

- (1) If a **retailer** ("defaulting **retailer**") commits an **event of default** under paragraph (a) or (b) or (f) or (h) of clause 14.55 the **Authority** must give notice to the defaulting **retailer** that—
 - (a) the defaulting **retailer** must—
 - (i) remedy the **event of default**; or
 - (ii) assign its rights and obligations under every contract under which a **customer** of the defaulting **retailer** purchases **electricity** from the defaulting **retailer** to another **retailer**, and assign to another **retailer** all **ICPs** for which the defaulting **retailer** is recorded in the **registry** as being responsible; and
 - (b) if the defaulting **retailer** 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 require the defaulting **retailer** to provide to the **Authority**, within a time specified by the **Authority**, information about the defaulting **retailer's customers**.
- (3) The defaulting **retailer** must provide the information requested by the **Authority** under subclause (2) within the time specified by the **Authority**.

3 Authority may require distributor and registry to provide information

- (1) The **Authority** may, by notice in writing to a **distributor** on whose **network** a defaulting **retailer** trades **electricity**, require the **distributor** to provide to the **Authority** the information about the defaulting **retailer'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**, require the **registry** to provide to the **Authority** information about **ICPs** for which the defaulting **retailer** is recorded in the **registry** as being responsible, within the period specified in the notice.
- (4) The **registry** must provide the information requested by the **Authority** under subclause (3) within the time specified by the **Authority**.

4 Failure to remedy event of default

- (1) This clause applies if—
 - (a) 7 days have elapsed since the defaulting **retailer** was given notice under clause 2(1); and
 - (b) the **Authority** considers that—
 - (i) the defaulting **retailer** has not remedied the **event of default** or, in the case of an **event of default** under clause 14.55(b) in respect of which there is an unresolved invoice dispute under clause 14.64, has not reached an agreement with the **Authority** to resolve the **event of default**; and
 - (ii) the defaulting **retailer** still has 1 or more contracts under which a **customer** of the defaulting **retailer** purchases **electricity** from the defaulting **retailer** or is still recorded in the **registry** as being responsible for 1 or more **ICPs**.
- (2) The **Authority** must—
 - (a) give notice to the defaulting **retailer** that the **Authority** considers that this clause applies; and
 - (b) attempt to advise **customers** of the defaulting **retailer** that—
 - (i) the defaulting **retailer** has committed an **event of default**; and
 - (ii) the **customer** should enter into a contract for the purchase of **electricity** with another **retailer** within 7 days; and
 - (iii) if the **customer** fails to enter into a contract with another **retailer**, the **Authority** may assign the defaulting **retailer's** rights and obligations under the **customer's** contract with the defaulting **retailer** to another **retailer** under clause 5.
- (3) The **Authority** may, by notice to the **registry**, direct the **registry** not to—
 - (a) complete the switch of any **ICP** to the defaulting **retailer**; or
 - (b) accept a request from the defaulting **retailer** to withdraw a switch under clauses 17 and 18 of Schedule 11.3.
- (4) If the **Authority** gives notice under subclause (3), the **registry** must not—
 - (a) complete the switch of any **ICP** to the defaulting **retailer**; or
 - (b) accept a request from the defaulting **retailer** to withdraw a switch under clauses 17 and 18 of Schedule 11.3.

5 Authority may assign contracts

- (1) This clause applies if, by the end of the 17th day after the defaulting **retailer** was given notice under clause 2(1),—
 - (a) the defaulting **retailer** has not remedied the **event of default** or, in the case of an **event of default** under clause 14.55(b) in respect of which there is an unresolved invoice dispute under clause 14.64, has not reached an agreement with the **Authority** to resolve the **event of default**; and
 - (b) the defaulting **retailer** continues to have 1 or more contracts under which a **customer** of the defaulting **retailer** purchases **electricity** from the defaulting **retailer** or 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 **retailer** to assign the rights and obligations of the defaulting **retailer** under the contract to a recipient **retailer** in accordance with the contract; and
 - (b) assign an **ICP** to a recipient **retailer** and direct the **registry** to amend the record in the **registry** so that the recipient **retailer** is recorded as being responsible for the **ICP**; and
 - (c) specify the recipient **retailer** 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 **retailer**, direct the recipient **retailer** to accept an assignment under subclause (2).
- (4) Before the **Authority** gives notice to a recipient **retailer** under subclause (3), the **Authority** may decide not to assign rights and obligations of the defaulting **retailer** under a contract or an **ICP** to a recipient **retailer** if the recipient **retailer** satisfies the **Authority** that the assignment would pose a serious threat to the financial viability of the recipient **retailer**.
- (5) A recipient **retailer** must comply with a direction given to it under subclause (3).
- (6) The **registry** 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 **retailer** 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 **retailers** by undertaking a tender or other competitive process.

6 Authority must provide information to recipient retailer

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 **retailer**:

- (a) the number of **customer** contracts (to the extent that the **Authority** has the information) and **ICPs** assigned to the **retailer**; and
- (b) any information that the **Authority** holds about the **customers** and **ICPs** assigned to the **retailer**.

7 Registry may complete switch without required information

If the **Authority** gives notice under clause 2, the **registry** may complete the switch of any **ICP** for which the defaulting **retailer** is recorded in the **registry** as being responsible even if the defaulting **retailer** 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 **retailer** must use reasonable endeavours to advise the **customer** of those terms.

Electricity Industry Participation Code 2010

Part 12 Transport

Contents

Subpart 1—General

- 12.1 Contents of this Part
- 12.2 Discretion to waive Code requirements
- 12.3 Interaction between Parts 7 and 8 and this Part

Subpart 2—Transmission agreements

- 12.4 Contents of this subpart
- 12.5 Structure for transmission agreements
- 12.6 Review of structure for transmission agreements
- 12.7 Categories of participants required to enter into transmission agreements

Transpower and designated transmission customers must enter transmission agreements

- 12.8 Obligation to enter transmission agreements
- 12.9 When designated transmission customer must enter into transmission agreement
- 12.10 Benchmark agreements to be default transmission agreements
- 12.11 Subsequent transmission agreements
- 12.12 Changes to connection assets under default transmission agreements
- 12.13 Expiry or termination of transmission agreements

Content of transmission agreements

- 12.14 Transmission agreements to be consistent with benchmark agreements and grid reliability standards
- 12.15 Transmission agreements to be provided to the Authority and published

Connection Code

- 12.16 Connection Code
- 12.17 Purpose of Connection Code
- 12.18 Review of Connection Code
- 12.19 Transpower to submit Connection Code
- 12.20 Required content of Connection Code
- 12.21 Principles for developing Connection Code
- 12.22 Authority may initially approve proposed Connection Code or refer back to Transpower
- 12.23 Amendment of proposed Connection Code by Authority
- 12.24 Authority must consult on proposed Connection Code
- 12.25 Decision on Connection Code
- 12.26 Incorporation of Connection Code by reference

Benchmark agreements for connection and/or use of the grid

- 12.27 Benchmark agreement
- 12.28 Authority may initiate review
- 12.29 Purpose of benchmark agreements
- 12.30 Principles for benchmark agreements

- 12.31 Contents of benchmark agreements
- 12.32 Authority must consult on draft benchmark agreement
- 12.33 Decision on benchmark agreement
- 12.34 Incorporation of benchmark agreement by reference

Variations from benchmark agreements and grid reliability standards and enhancement and removal of connection assets

- 12.35 Increased service levels and reliability
- 12.36 Decreased service levels and reliability
- 12.37 Variations that may increase or decrease reliability
- 12.38 Other variations from terms of benchmark agreements
- 12.39 Customer specific value of unserved energy
- 12.40 Replacement and enhancement of shared connection assets
- 12.41 Removal of shared connection assets from service
- 12.42 Reconfiguration of shared connection assets
- 12.43 Net benefits test
- 12.44 Request to the Commerce Commission to request an investment proposal be submitted

Resolutions of disputes

- 12.45 Certain disputes relating to transition agreements may be referred to Rulings Panel
- 12.46 Rulings Panel has discretion to determine dispute
- 12.47 Determinations by Rulings Panel
- 12.48 Status of default transmission agreement while Rulings Panel determining dispute

Existing agreements not affected

- 12.49 Existing agreements
- 12.50 Copies of other agreements to be provided to the Authority
- 12.51 Application to Rio Tinto agreements[Revoked]

Subpart 3—Grid reliability and industry information

- 12.52 Contents of this subpart
- 12.53 Purpose of the reliability and industry information clauses
- 12.54 Obligations to provide information

Grid reliability standards

- 12.55 Authority determines grid reliability standards
- 12.56 Purpose of grid reliability standards
- 12.57 Principles of grid reliability standards
- 12.58 Content of grid reliability standards

Review of grid reliability standards

- 12.59 Interested parties may request review of grid reliability standards
- 12.60 Authority review of grid reliability standards
- 12.61 Authority must publish draft grid reliability standards
- 12.62 Decision on grid reliability standards

Core grid determination

- 12.63 Authority determines core grid determination
- 12.64 Purpose of core grid determination

- 12.65 Objectives of core grid determination
Review of core grid determination
- 12.66 Interested parties may request review of core grid determination
- 12.67 Authority review of grid determination
- 12.68 Authority must publish draft core grid determination
- 12.69 Decision on core grid determination
Investment contracts
- 12.70 Purpose
- 12.71 Investment contracts
Centralised data set
- 12.72 Authority to establish and maintain centralised data set
- 12.73 Purpose of centralised data set
- 12.74 Contents of centralised data set
- 12.75 Public access to centralised data set
Grid reliability reporting
- 12.76 Transpower to publish grid reliability report
Subpart 4—Transmission pricing methodology
- 12.77 Recovery of investment costs by Transpower
- 12.78 Purpose for establishing transmission pricing methodology
- 12.79 Statutory objective
- 12.80 Application and interpretation of pricing principles *[Revoked]*
- 12.81 Authority must prepare an issues paper
- 12.82 Authority must consult on issues paper
- 12.83 Authority must publish process and guidelines for development of transmission pricing methodology
Development of transmission pricing methodology by Transpower
- 12.84 A Transmission pricing methodology
Review of an approved transmission pricing methodology
- 12.85 Review by Transpower
- 12.86 Review by the Authority
- 12.87 Process for review
- 12.88 Transpower to submit methodology
- 12.89 Form of proposed transmission pricing methodology
- 12.90 Authority may decline to consider proposed transmission pricing methodology
Process for Authority determination of transmission pricing methodology
- 12.91 Authority may approve proposed transmission pricing methodology or refer back to Transpower
- 12.92 Authority must publish proposed transmission pricing methodology
- 12.93 Decision on transitional pricing methodology
- 12.94 Authority to determine commencement date
Application of approved transmission pricing methodology
- 12.95 Charges to comply with approved transmission methodology
- 12.96 Development of transmission prices

Audit of transmission prices

- 12.97 Audit of transmission prices
- 12.98 Transpower may respond to auditor's report
- 12.99 Final auditor report to the Authority
- 12.100 Transpower to redetermine transmission prices
- 12.101 Auditor's costs
- 12.102 Enforcement of transmission charges
- Subpart 5—Financial transmission rights *[Revoked]*
- 12.103 Contents of this subpart *[Revoked]*
- 12.104 Design *[Revoked]*
- Subpart 6—Interconnection asset services
- 12.105 Purpose of this subpart
- 12.106 Interconnection asset capacity and grid configuration
- 12.107 Transpower to identify interconnection branches, and propose service measures and levels
- 12.108 Consultation on proposed interconnection asset capacity and grid configuration
- 12.109 Decision on interconnection asset capacity and grid configuration
- 12.110 Incorporation of interconnection asset capacity and grid configuration by reference
- 12.111 Transpower to make interconnection branches and other assets available and keep grid configuration
- 12.112 Exceptions to clause 12.111
- 12.113 Transpower to maintain interconnection assets

Transpower to propose investments

- 12.114 Investments to meet the grid reliability standards
- 12.115 Other investments
- 12.116 Information on capacities of individual interconnection assets
- 12.116AA Temporary removal of interconnection assets from service or temporary grid reconfiguration
- 12.116AB *[Expired]*
- 12.116AC Information to be made publicly available
- 12.116A *[Expired]*
- 12.116B *[Expired]*
- 12.116C *[Expired]*
- 12.117 Permanent removal of interconnection assets from service
- 12.118 Transpower to provide and publish annual report on interconnection asset capacity and grid configuration

Reporting on availability and reliability

- 12.119 Index measures for availability and reliability
- 12.120 Updating of availability and reliability index measures
- 12.121 Transpower to submit draft index measures for availability and reliability
- 12.122 Requirements for index measures
- 12.123 Authority may initially approve proposed index measures or refer back to Transpower

- 12.124 Amendment of proposed index measures by the Authority
- 12.125 Authority must consult on proposed index measures
- 12.126 Decision on index measures
- 12.127 Transpower to report on availability and reliability
- 12.128 Transpower and designated transmission customers may agree on other requirements
- Subpart 7—Preparation of Outage Protocol
- 12.129 Purpose of this subpart
- 12.130 Definition of outage
- 12.131 Outage protocol
- Review of Outage Protocol*
- 12.132 Review of Outage Protocol
- 12.133 Transpower to submit proposed Outage Protocol
- Principles and required content of Outage Protocol*
- 12.134 Principles for developing Outage Protocol
- 12.135 Required content of Outage Protocol
- 12.136 Planning for outages
- 12.137 Transpower and designated transmission customers to act reasonably and in good faith
- 12.138 Reconsideration of planned outages
- 12.139 Variations to planned outages
- 12.140 Net benefit principle, requirements and methodologies
- 12.141 Consideration of the likely effects of planned outages
- 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
- 12.149 Decision on Outage Protocol
- 12.150 Incorporation of Outage Protocol by reference
- 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

HVDC charge

Transmission alternatives

Prudent Discount Policy

Appendix A: Allocation of Transpower's AC Revenue and HVDC Revenue to its charges

Appendix B: Regions

Appendix C: Information Required to Support a Prudent Discount Application

Schedule 12.5
Availability and reliability index measures

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).

Compare: Electricity Governance Rules 2003 rule 1 section I part F

Clause 12.1(d): revoked, on 1 October 2011, by clause 5 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

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.

Compare: Electricity Governance Rules 2003 rule 2 section I part F

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 notify **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.

Compare: Electricity Governance Rules 2003 rules 2.1.3 to 2.1.5 section II part F

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 facsimile number 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 facsimile number 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

Clause 12.10(1): amended, on 16 December 2013, by clause 5 of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.

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 facsimile number 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 facsimile number 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 and the licence charges under 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 Transmission agreements to be provided to the Authority and published

- (1) **Transpower** must provide the **Authority** with a copy of each **transmission agreement** executed by **Transpower** as soon as reasonably practicable.
- (2) The copy that is provided must be—
 - (a) a copy of the complete **transmission agreement**; and
 - (b) certified by a director or the chief executive of **Transpower** or the **designated transmission customer**, 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) The **Authority** must **publish** all **transmission agreements** between **Transpower** and **designated transmission customers** within a reasonable time of their receipt.

Compare: Electricity Governance Rules 2003 rule 3.2.2 section II part F

Connection Code

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.

Compare: Electricity Governance Rules 2003 rule 3.3.1 section II part F

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.

Compare: Electricity Governance Rules 2003 rule 3.3.10 section II part F

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 proposed **Connection Code**.

Compare: Electricity Governance Rules 2003 rule 3.3.2 section II part F

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 connection with 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 3.3.3 section II part F

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** notifies **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** for the time being in effect 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.

Benchmark agreements for connection to and/or use of the grid

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.

Compare: Electricity Governance Rules 2003 rule 7 section II part F

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**.

Compare: Electricity Governance Rules 2003 rule 4.1 section II part F

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.

Compare: Electricity Governance Rules 2003 rule 4.2 section II part F

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 notify **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** for the time being in effect 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 must certify in writing to the **Authority** that they have consulted with affected end use customers in relation to the proposed service levels or the proposed increase in reliability, and any resulting price implications, and that 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

Clause 12.35 Heading: amended, on 15 May 2014, by clause 32(a) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

Clause 12.35(1)(a): amended, on 15 May 2014, by clause 32(b) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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

Clause 12.36 Heading: amended, on 15 May 2014, by clause 33(a) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

Clause 12.36(1)(a): amended, on 15 May 2014, by clause 33(b) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 unserved energy

- (1) In this clause, a reference to the value of unserved energy must be read as a reference to the value of **expected unserved energy** in clause 4 of Schedule 12.2.
- (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 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 unserved energy from 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** apply for approval of a different value of 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 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 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 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 unserved energy proposed by **Transpower** or the **designated transmission customer** under subclause (2)(a), that value of unserved energy applies for the purposes of applying the **grid reliability standards** under clause

4 of Schedule 12.2 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 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 notified 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 notifying 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** notified 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 permanently remove a **connection asset** at that **point of connection** from service only—
 - (a) if the **designated transmission customers** unanimously agree with the permanent removal 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 permanent removal, if the permanent removal 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
- (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 **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** 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

Resolutions of disputes

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.

Compare: Electricity Governance Rules 2003 rules 6.3 and 6.4 section II part F

Clause 12.47(1)(c): amended, on 16 December 2013, by clause 6 of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.

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

12.51 Application to Rio Tinto agreements [Revoked]

Compare: Electricity Governance Rules 2003 rule 8.3 section II part F

Clause 12.51: revoked, on 16 December 2013, by clause 7 of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.

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) **centralised data set**; and
- (d) grid reliability reporting.

Compare: Electricity Governance Rules 2003 rule 1 section III part F

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.

Compare: Electricity Governance Rules 2003 rule 2 section III part F

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.

Compare: Electricity Governance Rules 2003 rule 3 section III part F

Grid reliability standards

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 notify **registered participants** of 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
 - (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.

Compare: Electricity Governance Rules 2003 rule 5B.2 section III part F

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 notify **registered participants** of 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.

Compare: Electricity Governance Rules 2003 rules 5A.4 and 5A.5 section III part F

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 the draft **core grid determination** and consider whether to include the **core grid determination** in a schedule to this Part.

Compare: Electricity Governance Rules 2003 rule 5A.6 section III part F

Investment contracts

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**.

Compare: Electricity Governance Rules 2003 rule 8.1 section III part F

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** notifies the **Authority** of the proposed **investment contract**.

Compare: Electricity Governance Rules 2003 rule 8.2 section III part F

Centralised data set

12.72 Authority to establish and maintain centralised data set

- (1) The **Authority** must establish and maintain a **centralised data set**.
- (2) The **centralised data set** at the commencement of this Code is the **centralised data set**

published by the Electricity Commission under rule 11 of section II of part F of the **rules** immediately before this Code came into force.

Compare: Electricity Governance Rules 2003 rule 11.1 section III part F

12.73 Purpose of centralised data set

The purpose of the **centralised data set** is to support efficient planning processes by ensuring collection and ongoing maintenance by the **Authority** of the factual and historical information required to make efficient and effective decisions on transmission and **transmission alternatives**.

Compare: Electricity Governance Rules 2003 rule 11.2 section III part F

12.74 Contents of centralised data set

A **centralised data set** should include—

- (a) provisions for updating and maintenance of data; and
- (b) information on **network** capabilities, performance and **constraints**.

Compare: Electricity Governance Rules 2003 rule 11.3 section III part F

12.75 Public access to centralised data set

Subject to clause 12.54(4), the **Authority** must **publish** the **centralised data set**.

Compare: Electricity Governance Rules 2003 rule 11.4 section III part F

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

Clause 12.76(2): amended, on 21 September 2012, by clause 17 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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

Clause 12.78: amended, on 1 June 2011, by clause 4 of the Electricity Industry Participation (Transmission Pricing) Code Amendment 2011.

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

Clause 12.79: substituted, on 1 June 2011, by clause 5 of the Electricity Industry Participation (Transmission Pricing) Code Amendment 2011.

12.80 Application and interpretation of pricing principles

[Revoked]

Compare: Electricity Governance Rules 2003 rule 3 section IV part F

Clause 12.80: revoked, on 1 June 2011, by clause 6 of the Electricity Industry Participation (Transmission Pricing) Code Amendment 2011.

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

Clause 12.81: substituted, on 1 June 2011, by clause 7 of the Electricity Industry Participation (Transmission Pricing) Code Amendment 2011.

12.82 Authority must consult on issues paper

- (1) When the **Authority** publishes the issues paper, the **Authority** must notify **registered**

participants 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.

Compare: Electricity Governance Rules 2003 rule 5 section IV part F

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**.

Compare: Electricity Governance Rules 2003 rule 6 section IV part F

Clause 12.83: heading amended, on 1 June 2011, by clause 8(1) of the Electricity Industry Participation (Transmission Pricing) Code Amendment 2011.

Clause 12.83(b): amended, on 1 June 2011, by clause 8(2) of the Electricity Industry Participation (Transmission Pricing) Code Amendment 2011.

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

Heading: amended, on 1 June 2011, by clause 9 of the Electricity Industry Participation (Transmission Pricing) Code Amendment 2011.

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**.

Compare: Electricity Governance Rules 2003 rule 11.1 section IV part F

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.

Compare: Electricity Governance Rules 2003 rule 11.2 section IV part F

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 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

Clause 12.89 (1)(b): substituted, on 1 June 2011, by clause 10 of the Electricity Industry Participation (Transmission Pricing) Code Amendment 2011.

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 notify **registered participants** 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 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

Clause 12.95(1): amended, on 16 December 2013, by clause 8(1) of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.

Clause 12.95(2): revoked, on 16 December 2013, by clause 8(2) of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.

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) The **auditor's** report must consider 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 be provided with the opportunity to respond in writing to the **auditor's** report within 15 **business days** of receiving the report, before the finalization of the **audit** report.

Compare: Electricity Governance Rules 2003 rule 9.4 section IV part F

12.99 Final auditor report to the Authority

- (1) Within 10 **business days** after receipt of **Transpower's** response under clause 12.98, the **auditor** must report to the **Authority** certifying that either—
 - (a) **Transpower** had applied correctly the approved **transmission pricing methodology**; or
 - (b) material errors remained in the application by **Transpower** 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]*

Subpart 5: revoked, on 1 October 2011, by clause 6 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

12.103 Contents of this subpart

[Revoked]

Compare: Electricity Governance Rules 2003 rule 1 section V part F

Clause 12.103: revoked, on 1 October 2011, by clause 6 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

12.104 Design

[Revoked]

Compare: Electricity Governance Rules 2003 rule 2 section V part F

Clause 12.104: revoked, on 1 October 2011, by clause 6 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Subpart 6—Interconnection asset services

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

Clause 12.105(d): amended, from 2 March 2012 to 3 December 2012, by clause 4 of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2012.

Clause 12.105(d): amended, from 15 March 2013 to 15 December 2013, by clause 4 of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2013.

Clause 12.105(d): amended, 16 December 2013, by clause 6 of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.

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) The interconnection asset capacity and grid configuration referred to in subclause (1) must be provided in the form required 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 levels:
 - (i) overall continuous capacity rating of the **interconnection circuit branch**, for both summer and winter periods in MVA and amperes:

- (ii) 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) nominal high voltage rating of each interconnection **circuit branch** in kV:
- (iv) 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**:
 - (i) 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**, overall 24 hour post contingency capacity rating in the units described above:
 - (B) for 3 Winding **interconnection transformer branches**, overall 24 hour post contingency capacity rating in the units described above, at HV, MV, and LV:
 - (ii) continuous capacity rating of the **interconnection transformer branch** in amperes and MVA as follows:
 - (A) for 2 Winding **interconnection transformer branches**, continuous capacity rating in the units described above:
 - (B) for 3 Winding **interconnection transformer branches**, continuous capacity rating in the units described above, at HV, MV, and LV:
 - (iii) 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**, level of impedance of the **interconnection transformer branch** in the units described above:
 - (B) for 3 Winding **interconnection transformer branches**, level of impedance of the **interconnection transformer branch** in the units described above, at HV, MV, and LV:
 - (iv) nominal high voltage rating of the interconnection **transformer branch** in kV:
 - (v) 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) **number** of tapping steps:
 - (C) the size of each tapping step as a percentage of 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 rule 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 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),—
- (a) in the case of information provided under subclause (4)(a), (c) and (d), must 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), must 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), must 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 for the time being in effect 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) apply, 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 make publicly available 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(1)(b): amended, from 2 March 2012 to 3 December 2012, by clause 5(1) of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2012.

Clause 12.112(1)(b)(i): amended, from 15 March 2013 to 15 December 2013, by clause 5(1)(a) of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2013.

Clause 12.112(1)(b)(i): amended, on 16 December 2013, by clause 7(1) of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.

Clause 12.112(1)(b)(iaa): inserted, from 15 March 2013 to 15 December 2013, by clause 5(1)(b) of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2013.

Clause 12.112(1)(b)(iaa): inserted, on 16 December 2013, by clause 7(2) of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.

Clause 12.112(1)(b)(ii): amended, from 15 March 2013 to 15 December 2013, by clause 5(1)(c) of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2013.

Clause 12.112(1)(b)(ii): amended, on 16 December 2013, by clause 7(3) of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.

Clause 12.112(1)(ea): inserted, on 26 September 2013, by clause 4 of the Electricity Industry Participation (HVDC Link Bipole Control System Testing) Code Amendment 2013.

Clause 12.112(2): amended, from 2 March 2012 to 3 December 2012, by clause 5(2) of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2012.

Clause 12.112(2): amended, from 15 March 2013 to 15 December 2013, by clause 5(2) of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2013.

Clause 12.112(2): amended, on 16 December 2013, by clause 7(4) of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.

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.

Clause 12.112(2A) and (2B): inserted, from 2 March 2012 to 3 December 2012, by clause 5(3) of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2012.

Clause 12.112(3): amended, from 15 March 2013 to 15 December 2013, by clause 5(4) of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2013.

Clause 12.112(3): amended, on 16 December 2013, by clause 7(6) 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 provided in a form that allows the **branch** to which each **asset** belongs to be easily identified; and
 - (c) must be published either in the **centralised data set** maintained under clause 12.72 or

some other form, if the **Authority** so determines. If the **Authority** determines that the information must be published in different form, **Transpower** must publish the information in that form as soon as reasonably possible after the **Authority** has determined the different form.

Compare: Electricity Governance Rules 2003 rule 7 section VI part F

Clause 12.116A: inserted, from 2 March 2012 to 3 December 2012, by clause 6 of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2012.

Clause 12.116B: inserted, from 2 March 2012 to 3 December 2012, by clause 6 of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2012.

Clause 12.116C: inserted, from 2 March 2012 to 3 December 2012, by clause 6 of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2012.

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** for the purposes of 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.

Clause 12.116AA: inserted, from 15 March 2013 to 15 December 2013, by clause 6 of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2013.

Clause 12.116AA: inserted, on 16 December 2013, by clause 8 of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.

12.116AB [Expired]

Clause 12.116AB: inserted, from 15 March 2013 to 15 December 2013, by clause 6 of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2013.

12.116AC Information to be made publicly available

If **Transpower** receives a notice given in accordance with clause 9.13B, **Transpower** must make publicly available at no cost, on an Internet site maintained by or on behalf of **Transpower**,—

- (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.

Clause 12.116AC: inserted, from 15 March 2013 to 15 December 2013, by clause 6 of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2013.

Clause 12.116AC: inserted, on 16 December 2013, by clause 8 of the Electricity Industry Participation (Urgent

Temporary Grid Reconfiguration) Code Amendment 2013.

12.116A [Expired]

Clause 12.116A: inserted, from 2 March 2012 to 3 December 2012, by clause 6 of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2012.

12.116B [Expired]

Clause 12.116B: inserted, from 2 March 2012 to 3 December 2012, by clause 6 of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2012.

12.116C [Expired]

Clause 12.116C: inserted, from 2 March 2012 to 3 December 2012, by clause 6 of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2012.

12.117 Permanent removal of interconnection assets from service

- (1) **Transpower** may permanently remove **interconnection assets** from service or permanently reconfigure the **grid** for the purposes of clause 12.112(1)(b) only if removal of the **asset** or the reconfiguration 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**.

- (8) 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.
- (9) 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** and **Transpower's** estimate of the **expected unserved energy** in respect of each affected **designated transmission customer** and end use **customer**.
- (10) 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**.

Compare: Electricity Governance Rules 2003 rule 8 section VI part F

Clause 12.117(1): amended, from 2 March 2012 to 3 December 2012, by clause 7 of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2012.

Clause 12.117(1): amended, from 15 March 2013 to 15 December 2013, by clause 7 of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2013.

Clause 12.117: substituted, on 16 December 2013, by clause 9 of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.

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**, 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** 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**; 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**.

- (2) The report referred to in subclause (1) must be provided and published by **Transpower** 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

Clause 12.118(1)(g): amended, from 2 March 2012 to 3 December 2012, by clause 8 of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2012.

Clause 12.118(1)(g): amended, from 15 March 2013 to 15 December 2013, by clause 8 of the Electricity Industry Participation (Temporary Grid Reconfiguration) Code Amendment 2013.

Clause 12.118(1)(g): amended, on 16 December 2013, by clause 10 of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.

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.

Compare: Electricity Governance Rules 2003 rule 10.9 section VI part F

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 (2), **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**, 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**, 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** 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** 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**.

Compare: Electricity Governance Rules 2003 rule 10.1 section VI part F

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 (being 1 July to 30 June **years**) 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** 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** 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** 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**; 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** in the **preceding year**; and
 - (e) total unserved energy in the **preceding year** 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** 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**; 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**; 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;
 - (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
 - (k) information on its performance against the reliability and availability index measures for aggregated **interconnection branches** included in a schedule to this Part under clause 12.126.
- (2) The information **published** under subclause (1) must be specified in the same units of measurement as the corresponding index measures included in a schedule to this Part under clause 12.126.
- (3) **Transpower** does not breach this Code by reason of a failure to meet the index measures included in a schedule to this Part under clause 12.126.

Compare: Electricity Governance Rules 2003 rule 10.8 section VI part F

12.128 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 may not exclude the application of clause 12.118(1)(h) 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** certifying 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 notify the **Authority** as soon as practicable in the event that **Transpower** enters into an agreement with a **designated transmission customer** under this clause.

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, 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 other relevant cost to a person that produces, transmits, retails or consumes **electricity** in New Zealand; and
 - (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
 - (iii) carry out the **outage** only if the costs estimated under subparagraph (i) are less than the benefits estimated under subparagraph (ii); 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 subparagraph (A), the **value of expected unserved energy** 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**; 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.

Compare: Electricity Governance Rules 2003 rule 5.6 section VII part F

Clause 12.141(2) to (4): substituted, on 16 December 2013, by clause 11 of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.

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** for the time being in effect is incorporated by reference in this Code in accordance with section 32 of the Act.
- (2) Subclause (2) 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** may not exclude the application of clause 12.118(1)(h) 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 notify the **Authority** as soon as practicable if **Transpower** enters into an agreement with a **designated transmission customer** in respect of specified **assets** in accordance with subclause (1).

Compare: Electricity Governance Rules 2003 rule 15 section VII part F

Schedule 12.1
Categories of designated transmission customers

cl 12.7

- 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) **direct consumers** that have a **point of connection** to the **grid**; and
 - (b) **distributors**; and
 - (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(1): amended, on 16 December 2013, by clause 9(1) of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.

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

cl 12.55

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 **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** 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

cl 12.63

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

North Island core grid links	South Island core grid links
220kV Huapai-Marsden	220kV Islington-Kikiwa
220kV Huapai-Bream Bay	220kV Kikiwa-Stoke
220kV Bream Bay-Marsden	220kV Twizel-Tekapo B
110kV Marsden-Maungatapere	220kV Tekapo B-Islington
220 kV Henderson-Huapai	220kV Twizel-Opihi-Timaru-Ashburton
220 kV Albany-Huapai	220kV Ashburton-Bromley
220 kV Albany-Henderson	220kV Bromley-Islington
110kV Albany-Henderson	220kV Twizel-Opihi-Timaru-Islington
110kV Henderson-Hepburn Rd	220kV Livingstone-Islington
220kV Otahuhu-Henderson	220kV Benmore-Ohau B
220kV Otahuhu-Southdown	220kV Ohau B-Twizel
220kV Southdown-Henderson	220kV Benmore-Twizel
220kV Otahuhu-Penrose	220kV Benmore-Ohau C
110kV Mangere-Roskill	220kV Ohau C-Twizel
110kV Otahuhu-Roskill	220kV Benmore-Aviemore
110kV Otahuhu-Pakuranga	220kV Clyde-Cromwell
110kV Otahuhu-Wiri	220kV Cromwell-Twizel
220kV Otahuhu-Takanini	220kV Roxburgh-Clyde
220kV Huntly-Takanini	220kV Naseby-Livingstone
110kV Wiri-Bombay	220kV Roxburgh-Naseby
220kV Huntly-Glenbrook	220kV Roxburgh-Three Mile Hill

North Island core grid links	South Island core grid links
220kV Glenbrook-Takanini	220kV Three Mile Hill-Half Way Bush
220kV Otahuhu-Whakamaru	220kV Three Mile Hill-Sth Dunedin
220kV Otahuhu-Huntly	220kV Sth Dunedin-Half Way Bush
220kV Huntly-Hamilton	220kV Manapouri-Invercargill
110kV Mt Maunganui-Tarukenga	220kV Manapouri-Nth Makarewa
110kV Tarukenga-Tauranga	220kV Nth Makarewa-Invercargill
220kV Tarukenga-Edgecumbe	220kV Invercargill-Roxburgh
220kV Edgecumbe-Kawerau	220kV Invercargill-Tiwai Pt
220kV Kawerau-Ohakuri	220kV Nth Makarewa-Tiwai Pt
220kV Wairakei-Ohakuri	220/66kV interconnection Islington
220kV Ohakuri-Atiamuri	66kV Islington-Addington
220kV Atiamuri-Tarukenga	220/66kV interconnection Bromley
220kV Atiamuri-Whakamaru	
220kV Wairakei-Redclyffe	
220kV Wairakei-Whirinaki	
220kV Whirinaki-Redclyffe	
220kV Hamilton-Whakamaru	
220kV Tokaanu-Whakamaru	
220kV Bunnythorpe-Tokaanu	
220kV Bunnythorpe-Tangiwai	
220kV Rangipo-Tangiwai	
220kV Rangipo-Wairakei	
220kV Wairakei-Poihipi	
220kV Poihipi-Whakamaru	
220kV Stratford-New Plymouth	
110kV New Plymouth-Carrington St	
220kV Bunnythorpe-Haywards	
220kV Haywards-Wilton	
220kV Haywards- Linton	
220kV Wilton-Linton	
220kV Bunnythorpe-Linton	
110kV Wilton-Central Park	
110kV Takapu Rd-Wilton	
220kV Bunnythorpe-Brunswick	
220kV Brunswick-Stratford	
110kV Otahuhu-Mangere	
110kV Haywards-Takapu Rd	
220/110kV interconnection Marsden	
220/110kV interconnection Albany	
220/110kV interconnection Henderson	
220/110kV interconnection Penrose	
220/110kV interconnection Otahuhu	
220/110kV interconnection Hamilton	

North Island core grid links	South 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	

Compare: Electricity Governance Rules 2003 clauses 3 and 4 schedule F3A part F

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

Schedule 12.4 Transmission Pricing Methodology

cl 12.84

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 33 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).

Compare: Electricity Governance Rules 2003 clause 2 schedule F5 part F

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 any **pricing year**, the 12 month period starting 1 September and ending 31 August inclusive, immediately before the commencement of the **pricing year**

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**

historical anytime maximum injection or **HAMI** for a **customer** at a **South Island generation connection location** means either the average of the 12 highest injections at that **South Island generation connection location** during the **capacity measurement period** for the relevant **pricing year**; or the average of the 12 highest **injections** at that **South Island generation connection location** during any of the four immediately preceding **pricing years**, whichever is highest. This definition is subject to clause 34 of this **transmission pricing methodology** and any prudent discount agreement

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**

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 identified in Appendix B as—

- (a) Upper North Island; and
- (b) Lower North Island; and
- (c) Upper South Island; and
- (d) Lower South Island;

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

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:

- (a) in relation to the Upper North Island and the Upper South Island **regions**, a **half hour** in which any of the 12 highest **regional demands** occurs during the **capacity measurement period** for the relevant **pricing year**; and
- (b) in relation to the Lower North Island and the Lower South Island **regions**, a **half hour** in which any of the 100 highest **regional demands** occur 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

regional coincident peak *[Revoked]*

Clause 3 **regional coincident peak**: revoked, on 15 May 2014, by clause 34(a) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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

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 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

transition date means the date of the last ODV report published on **Transpower's** website before the date on which this **transmission pricing methodology** takes effect

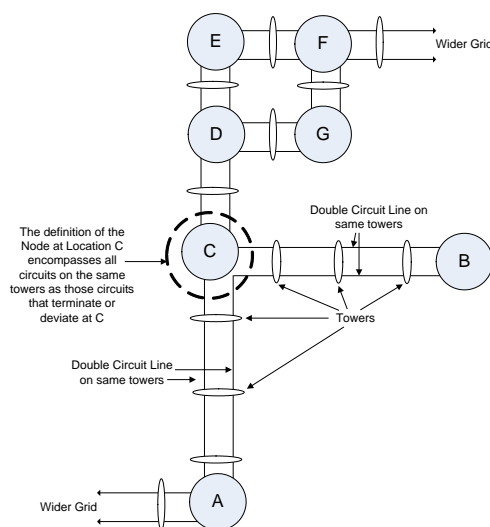
weighted average cost of capital means, for any **pricing year**, the pre-tax nominal weighted average cost of capital used by **Transpower** to determine **AC revenue** or **HVDC revenue** (as the case may be) for that **pricing year**.

Compare: Electricity Governance Rules 2003 clauses 3.1 to 3.53 schedule F5 part F

4 Definition of Nodes and Links

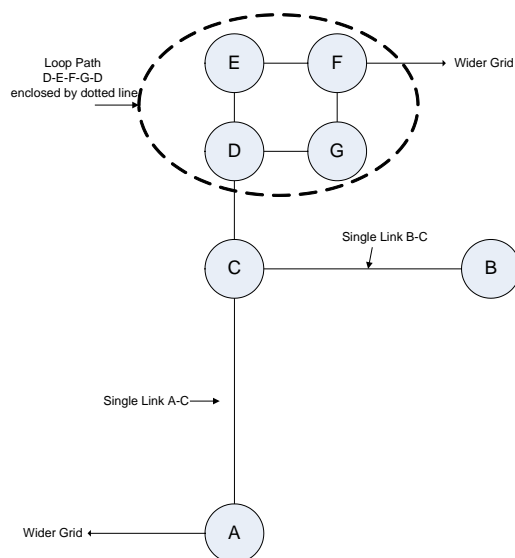
- (1) A **node** is any of the following:
 - (a) a **connection location**:
 - (b) a location where a circuit, which is connected to 2 or more other **nodes**, diverges or terminates (such as a “tee” point or a deviation):
 - (c) any **substation** or switching station.
- (2) Any **node** which connects 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**.

Figure 2 – Illustration of links and loop path



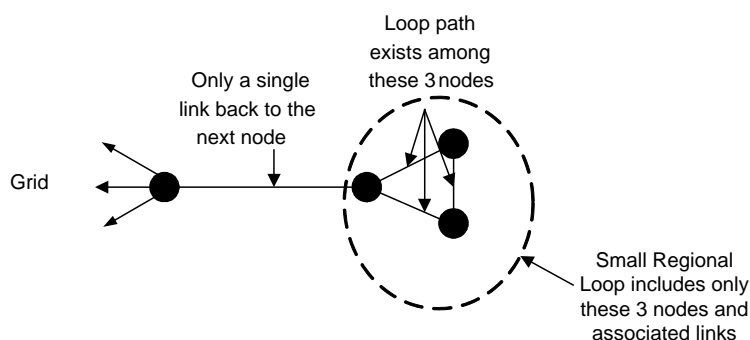
Compare: Electricity Governance Rules 2003 clauses 3.54 to 3.57 schedule F5 part F

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 rules:

- (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



- (c) a **connection link** is a **link** with a **connection node** at one or more of its ends;
- (d) an **interconnection link** is a **link** that connects 2 **interconnection nodes**;
- (e) **links** and **nodes** that comprise a “small regional loop” are **connection links** and **connection nodes**.

Compare: Electricity Governance Rules 2003 clause 3.58 schedule F5 part F

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:

$$\text{connection charge} = (A_{\text{conn}} + M_{\text{conn}} + O_{\text{conn}} + IO_{\text{conn}}) \times CA_{\text{conn}}$$

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 $M_{\text{conn subs}}$ or $M_{\text{conn line type}}$ 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(2)(d) 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

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.
- (2) The rates for each component of the connection charge are recalculated for each **pricing year**.

Compare: Electricity Governance Rules 2003 clauses 4.4 and 4.5 schedule F5 part F

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.

Compare: Electricity Governance Rules 2003 clause 4.6 schedule F5 part F

11 Asset Return Rate

The asset return rate used to calculate the asset component is referred to as **ARR_{conn}** and is expressed as a proportion. **ARR_{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:

$$ARR_{conn} = \frac{WACC \times RAV_{conn} + D_{conn}}{\sum_{conn} RC_{conn}}$$

where

WACC is the **weighted average cost of capital** (expressed as a percentage)

RAV_{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_{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)

$\sum_{\text{conn}} RC_{\text{conn}}$ is the total **replacement cost** of all **connection assets**.

Compare: Electricity Governance Rules 2003 clause 4.7 schedule F5 part F

12 Calculation of Asset Component

The **asset component** of a connection charge is calculated by multiplying ARR_{conn} by the **replacement cost** of the **connection asset** for which the connection charge is being calculated as follows:

$$A_{\text{conn}} = ARR_{\text{conn}} \times RC_{\text{conn}}$$

where

RC_{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 tower lines;
 - (b) other tower lines; 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:

$$MRR_{\text{conn subs}} = \frac{MC_{\text{conn subs}}}{\sum_{\text{subs conn}} RC_{\text{conn subs}}}$$

where

$MC_{\text{conn subs}}$ 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)

$\sum_{\text{subs}} \sum_{\text{conn}} RC_{\text{conn subs}}$ is the sum of the **replacement costs** of all **connection assets** located at all **substations**.

Compare: Electricity Governance Rules 2003 clause 4.11 schedule F5 part F

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 $MRR_{\text{conn subs}}$ by the **replacement cost** of the **connection asset** for which the connection charge is being calculated as follows:

$$M_{\text{conn subs}} = MRR_{\text{conn subs}} \times RC_{\text{conn subs}}$$

where

$RC_{\text{conn subs}}$ is the **replacement cost** of the **connection asset** for which the connection charge is being calculated (expressed in dollars).

Compare: Electricity Governance Rules 2003 clause 4.12 schedule F5 part F

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 $MRR_{\text{conn line type}}$ and is expressed as a dollar cost per length (expressed in km) of line for each line type. $MRR_{\text{conn line type}}$ 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 $MRR_{\text{conn line type}}$ is being calculated in each of the preceding 4 **financial years** divided by the total line length of line of that type as follows:

$$MRR_{\text{conn line type}} = \frac{MC_{\text{conn line type}}}{TL_{\text{conn line type}}}$$

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 recorded in a **Transpower** asset register at the end of the immediately preceding **financial year** (expressed in km).

Compare: Electricity Governance Rules 2003 clause 4.13 schedule F5 part F

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 $MRR_{\text{conn line type}}$ by the length of the line which is the **connection asset** for which the connection charge is being calculated as follows:

$$M_{\text{conn line type}} = MRR_{\text{conn line type}} \times L_{\text{conn line}}$$

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).

Compare: Electricity Governance Rules 2003 clause 4.14 schedule F5 part F

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.

Compare: Electricity Governance Rules 2003 clause 4.15 Schedule F5 part F

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:

$$ORR = \frac{OC}{TS}$$

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_{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 OHC_{inj} . OHC_{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:

$$OHC_{inj} = OHC_{AC} \times \frac{MC_{inj}}{MC_{AC}}$$

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:

$$IOR = \frac{OHC_{inj}}{\sum_{conn\ inj} RC_{conn\ inj} \times CA_{conn\ inj}}$$

where

$RC_{conn\ inj}$ is the **replacement cost** of a **connection asset** connecting **injection customer** assets at a point of injection to the **interconnection assets**

$CA_{conn\ inj}$ is the **customer allocation** of the relevant **connection asset** for the relevant **injection customer** at the relevant **connection location**

$\sum_{conn\ inj} RC_{conn\ inj} \times CA_{conn\ inj}$ is the sum of all amounts calculated as $RC_{conn\ inj} \times CA_{conn\ inj}$ 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) included in the **annual 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

Customer: Southern Electric

Substation: Johnston Load Type: OFT

Asset	Asset Id	Physical Location	Recovery			Asset Value	Asset Component	Maintenance Component	Operating Component	Customer Allocation	Connection Charge
			A	M	O						
						\$	\$	\$	\$	%	\$
LINE	JTN-PVL A		TPM	-TPM		4,513,794	393,151	187,603	0	4.27	24,798
LAND/BLDGS	JTN	JTN	TPM	-TPM		1,343,443	117,014	14,106	0	100.00	131,120
TRAN	T1	JTN	NIC	-TPM		694,012	0	7,287	0	100.00	7,287
SWIT	1	JTN	TPM	-TPM-TPM		113,644	9,898	1,193	1,104	100.00	12,195
SWIT	2	JTN	TPM	-TPM-TPM		113,664	9,898	1,193	1,104	100.00	12,195
SWIT	3	JTN	NIC	-TPM-TPM		113,664	0	1,193	1,104	100.00	2,297
SWIT	92	PVL	TPM	-TPM-TPM		344,087	29,970	3,613	2,208	100.00	35,791
Annual Connection Charge											225,683

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_{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

AC revenue is **Transpower's AC revenue** for the relevant **pricing year**

\sum 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:

$$IR = \frac{R_{IC}}{\sum_{\text{regions}} \sum_{\text{cust}} \sum_{\text{loc}} \frac{1}{N_{\text{reg}}} \sum_{i=1}^{N_{\text{reg}}} RCPD_i}$$

where

R_{IC} is the interconnection revenue calculated in accordance with clause 28

$\sum_{\text{regions}} \sum_{\text{cust}} \sum_{\text{loc}} \frac{1}{N_{\text{reg}}} \sum_{i=1}^{N_{\text{reg}}} RCPD_i$ 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:

$$\text{interconnection charge} = IR \times \frac{1}{N_{\text{reg}}} \sum_{i=1}^{N_{\text{reg}}} RCPD_i$$

where

IR is IR

$\frac{1}{N_{\text{reg}}} \sum_{i=1}^{N_{\text{reg}}} RCPD_i$ 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 $\frac{1}{12}$ 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

The HVDC rate used to calculate HVDC charges is referred to as **DCR** and expressed as \$/kW. **DCR** is calculated for each **pricing year** by dividing the **HVDC revenue** by the sum of the **HAMI** for the relevant **pricing year** for all **HVDC customers** at all **points of injection** where **South Island generation** connects (directly or indirectly) to the **grid assets** as follows:

$$DCR = \frac{R_{HVDC}}{\sum_{HVDC} HAMI_{HVDC}}$$

where

R_{HVDC} is **HVDC revenue** (expressed in dollars)

$\sum_{HVDC} HAMI_{HVDC}$ is the sum of **HAMI** (expressed in kW) of all **HVDC customers** at all **points of injection** where **South Island generation** connects (directly or indirectly) to the **grid assets**.

Compare: Electricity Governance Rules 2003 clause 6.2 schedule F5 part F

33 Calculating the HVDC Charge

The **annual HVDC charge** is calculated for each **HVDC customer** at each **South Island generation connection location** by multiplying **DCR** by the **HAMI** for the **HVDC customer** in respect of whom the **annual HVDC charge** is being calculated at each **South Island generation connection location** as follows:

$$\text{HVDC charge} = \text{DCR} \times \text{HAMI}$$

where

DCR is **DCR**

HAMI is the **HAMI** for the **HVDC customer** in respect of whom the **annual HVDC charge** is being calculated at that **South Island generation connection location**.

Compare: Electricity Governance Rules 2003 clause 6.3 schedule F5 part F

34 Adjustments to AMD, AMI, HAMI 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 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 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** 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** 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** and **RCPD** quantities, 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 notified 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** 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
 - (d) exceeds the maximum de-rated capacity,—
- will be deemed to be equal to the maximum de-rated capacity.

(4) If not less than 6 months before the start of a **pricing year**, **Transpower**—

- (a) is notified 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** 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 **generating 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** 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 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)(b), 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** 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** 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.

Compare: Electricity Governance Rules 2003 clause 7 schedule F5 part F

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** is made according to the rules set out in 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 assessment 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 notified 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

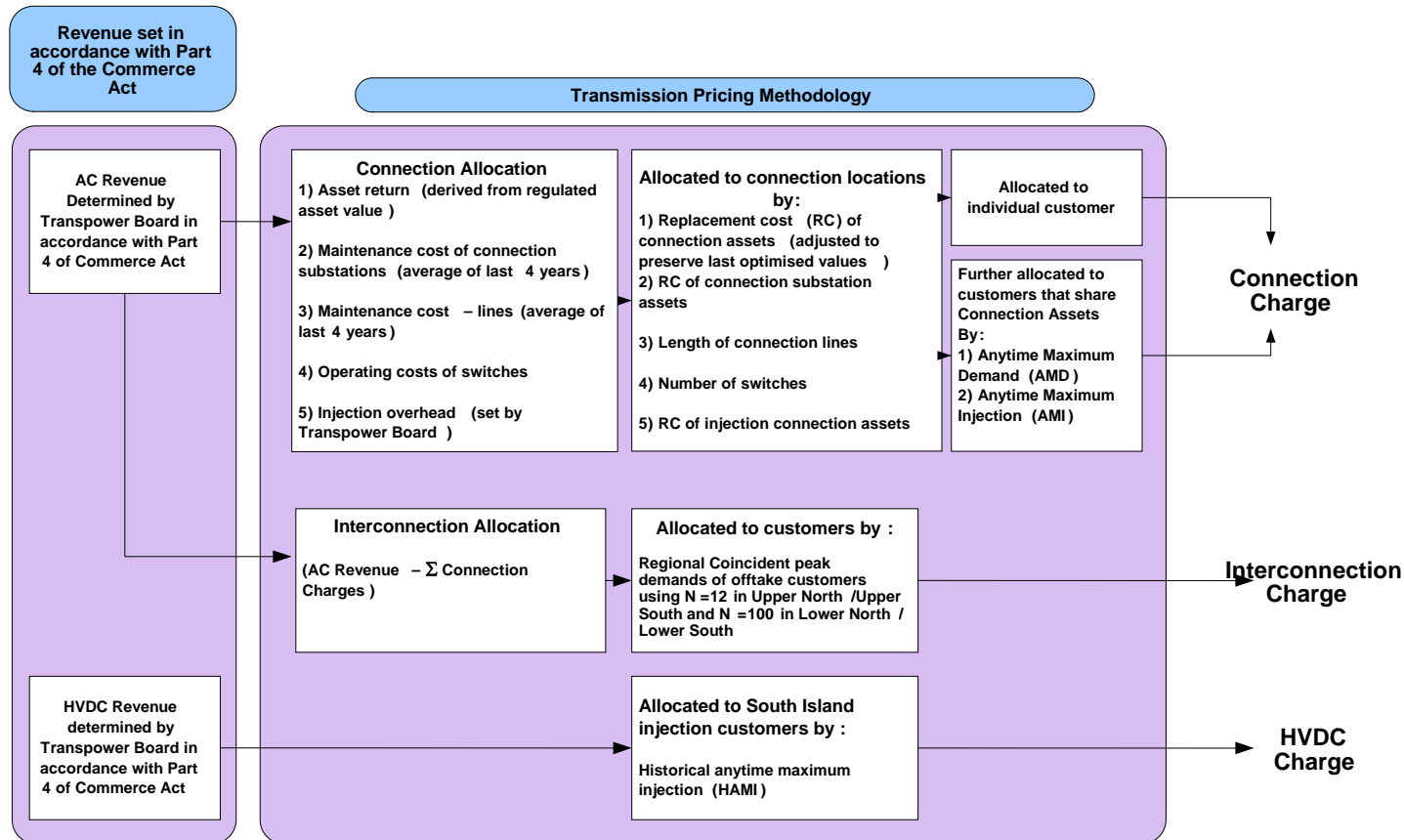
42 Prudent Discount Details to be Published

- (1) As soon as reasonably practicable after concluding a prudent discount agreement with a **customer**, **Transpower** must publish on its website 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 Charges



Compare: Electricity Governance Rules 2003 appendix A schedule F5 part F

Appendix B Regions

North Island

The Upper North Island (UNI) is described in the Annual Planning Report (APR) as “the geographical area north of Huntly, including Glenbrook, Takanini, Auckland and the Northern Isthmus”.

The **connection locations** in the UNI region are:

Code	Name
ALB	Albany
BOB	Bombay
BRB	Bream Bay
DAR	Dargaville
GLN	Glenbrook
HEN	Henderson
HEP	Hepburn Rd
HLY	Huntly
KEN	Kensington
KOE	Kaikohe
KTA	Kaitaia
MDN	Marsden
MER	Meremere
MNG	Mangere
MPE	Maungatapere
MTO	Maungaturoto
OTA	Otahuhu
PAK	Pakuranga
PEN	Penrose
ROS	Mt Roskill
SVL	Silverdale
SWN	Southdown
TAK	Takanini
TWH	Te Kowhai
WEL	Wellsford
WES	Western Rd
WIR	Wiri

The remainder of the **connection locations** in the North Island are in the LNI region.

South Island

The USI is defined in terms of all GXPs supplied from the major concentration of generation in the Waitaki Valley and south of the Waitaki Valley. These GXPs are supplied by the 220kV system from Tekapo B, Twizel and Livingstone (refer Fig 5-19 in the APR).

The **connection locations** in the USI region are:

Code	Name
ABY	Albury
ADD	Addington
APS	Arthurs Pass
ARG	Argyle
ASB	Ashburton
ASY	Ashley
BLN	Blenheim
BRY	Bromley
CLH	Castle Hill
COB	Cobb
COL	Coleridge
CUL	Culverden
DOB	Dobson
GYM	Greymouth
HKK	Hokitika
HOR	Hororata
ISL	Islington
KAI	Kaiapoi
KIK	Kikiwa
KKK	Kaikoura
KUM	Kumara
MCH	Murchison
MOT	Motueka
MPI	Motupipi
ORO	Orowaiti
OTI	Otira
PAP	Papanui
RFT	Reefton
SBK	Southbrook
SPN	Springston
STK	Stoke
UTK	Upper Takaka
TIM	Timaru
TKA	Tekapo A
TMK	Temuka
WPR	Waipara
WPT	Westport

The remainder of the **connection locations** in the South Island are in the LSI region.

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

cls 12.119 and 120

Asset type	Asset category		Planned unavailability	Unplanned unavailability	Number of planned interruptions	Planned unserved energy MWh	Number of unplanned interruptions	Unplanned unserved energy MWh
Interconnection transformer branches	220/110 kV interconnecting transformers and associated equipment		1.56%	0.06%	0.03	0.10	0.02	0.72
	220/066 kV interconnecting transformers and associated equipment		0.66%	0.02%	0.00	0.00	0.00	0.00
	110/066 kV interconnecting transformers and associated equipment		2.25%	0.02%	0.00	0.00	0.00	0.00
Interconnection circuit branches	220 kV interconnection circuit branches and associated line end equipment		0.88%	0.05%	0.00	0.00	0.13	9.87
	110 kV interconnection circuit branches and associated line end equipment		1.67%	0.07%	0.08	0.50	0.28	10.45
	66 kV interconnection circuit branches and associated line end equipment		1.25%	0.08%	0.14	0.46	1.31	1.88
Shunt assets	Capacitor banks and associated equipment	High (220kV – 66kV)	0.81%	1.33%	0.00	0.00	0.02	0.03
		Low (33kV – 11kV)	0.81%	1.33%	0.00	0.00	0.02	0.03

Electricity Industry Participation Code 2010
Schedule 12.5

Asset type	Asset category	Planned unavailability	Unplanned unavailability	Number of planned interruptions	Planned unserved energy MWh	Number of unplanned interruptions	Unplanned unserved energy MWh
	Reactors and associated equipment	1.33%	0.31%	0.00	0.00	0.00	0.00
	Synchronous condensers and associated equipment	2.00%	1.00%	0.00	0.00	0.00	0.00
	Static var compensators and associated equipment	0.82%	0.04%	0.00	0.00	0.00	0.00
	Filter banks and associated equipment	1.03%	1.71%	0.00	0.00	0.00	0.00
HVDC Link Pole 2	One category including associated equipment	1.27%	0.51%	0.00	0.00	0.20	0.85

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*
- 12A.2 Negotiating use-of-system agreements
- 12A.3 Mediation
- 12A.4 Prudential requirements
- 12A.5 Requirements if distributors require additional security
- 12A.6 Distributor indemnity
- Changes to tariff structures*
- 12A.7 Distributors must consult concerning changes to tariff structures
- Changes to tariff rates [Revoked]*
- 12A.8 Changes to tariff rates *[Revoked]*
- 12A.9 Requirement to comply with EIEP12 *[Revoked]*
- 12A.10 Requirement to use standard tariff codes *[Revoked]*
- Exchange of information*
- 12A.11 Application of clauses 12A.12 to 12A.14
- 12A.12 Distributor or trader may require provision of information
- 12A.13 Authority may publicise EIEPs that must be used
- 12A.14 Distributors and traders must comply with EIEPs
- 12A.15 Authority may publicise voluntary EIEPs
- 12A.16 Transitional provision relating to EIEPs

Schedule 12A.1

Distributor indemnity in use-of-system agreements

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) requires that an indemnity be included in every **use-of-system agreement** unless agreed otherwise; and
- (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]*

(f) *[Revoked]*

(g) provides that the **Authority** may **publicise EIEPs** that **distributors** and **traders** must comply with when exchanging information.

Clause 12A.1(f): revoked, on 21 October 2013, by clause 4 of the Electricity Industry Participation (Revocation of Standard Tariff Codes Requirement) Code Amendment 2013.

Clause 12A.1(e): revoked, on 16 December 2013, by clause 5(a) of the Electricity Industry Participation (Electricity Information Exchange Protocols) Code Amendment 2013.

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) This clause does not apply to an amendment to a **use-of-system agreement** if—
 - (a) the **use-of-system agreement** was in force before 1 December 2011; and
 - (b) the amendment is made before 1 July 2013.

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) This clause does not apply to an amendment to a **use-of-system agreement** if—
 - (a) the **use-of-system agreement** was in force before 1 December 2011; and
 - (b) the amendment is made before 1 July 2013.

12A.4 Prudential requirements

- (1) This clause and clause 12A.5 apply 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** must comply with prudential requirements.
- (2) Subject to subclause (7), the **use-of-system agreement** must provide that the **trader** can elect to comply with the prudential requirements under the **use-of-system agreement** in either of the following ways:
 - (a) the **trader** must maintain an acceptable credit rating in accordance with subclause (4); 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).
- (3) The **use-of-system agreement** must provide that the **trader**—
 - (a) must make the elections referred to in subclause (2) before the commencement of the **use-of-system agreement**; and
 - (b) may change an election at any time.
- (4) For the purposes of this clause, an acceptable credit rating means that the **trader** or the third party (as the case may be)—
 - (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) if the **trader** or the third party (as the case may be) carries a credit rating at the minimum level required by paragraph (a), is not subject to negative credit watch or any similar arrangement by the agency that gave it the credit rating.
- (5) Subject to clause 12A.5, the value of the acceptable security described in subclause (2)(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.
- (6) A **use-of-system agreement** must specify that, if the **trader** elects to provide acceptable security as described in subclause (2)(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.
- (7) Despite subclauses (2) to (6), a **distributor** and a **trader** may agree prudential requirements that are less onerous on the **trader** than the requirements described in subclauses (2) to (6).
- (8) This clause and clause 12A.5 do not apply, until 1 May 2012, to a **use-of-system agreement** that was in force before 1 December 2011.

Clause 12A.4(6)(a): amended, on 15 May 2014, by clause 35 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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.4(2)(b), the **trader** must provide acceptable security that is additional to the amount provided for in clause 12A.4(5);
 - (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** in accordance with paragraph (a) or paragraph (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.

12A.6 Distributor indemnity

- (1) Every **use-of-system agreement** must include the clause specified in Schedule 12A.1.
- (2) Every **use-of-system agreement** that does not include the clause specified in Schedule 12A.1 is deemed to include that clause.
- (3) A **distributor** may include in a **use-of-system agreement** an indemnity that is more favourable to the **trader** than the indemnity specified in Schedule 12A.1, and, in that case, subclauses (1) and (2) do not apply to the **use-of-system agreement**.
- (4) This clause does not apply to a **use-of-system agreement** if the **distributor** and the **trader** who are parties to the **use-of-system agreement** agree to omit the clause specified in Schedule 12A.1 from the **use-of-system agreement**.
- (5) Subclause (1) does not apply, until 1 May 2012, to a **use-of-system agreement** that was in force before 1 December 2011.

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) This clause does not apply to a change to a tariff structure that is made by a **distributor** before 1 May 2012.

[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(1): amended, on 21 October 2013, by clause 5(a) of the Electricity Industry Participation (Revocation of Standard Tariff Codes Requirement) Code Amendment 2013.

Clause 12A.8(2): revoked, on 21 October 2013, by clause 5(b) of the Electricity Industry Participation (Revocation of Standard Tariff Codes Requirement) Code Amendment 2013.

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]*

Clause 12A.9: revoked, on 16 December 2013, by clause 6(2) of the Electricity Industry Participation (Electricity Information Exchange Protocols) Code Amendment 2013.

12A.10 Requirement to use standard tariff codes *[Revoked]*

Clause 12A.10: revoked, on 21 October 2013, by clause 6 of the Electricity Industry Participation (Revocation of Standard Tariff Codes Requirement) Code Amendment 2013.

Exchange of information

Cross heading: inserted, on 16 December 2013, by clause 7 of the Electricity Industry Participation (Electricity Information Exchange Protocols) Code Amendment 2013.

12A.11 Application of clauses 12A.12 to 12A.14

Clauses 12A.12 to 12A.14 apply to —

- (a) a **distributor** who has 1 or more **consumers** connected to its **network** to whom the **distributor** does not send accounts for **line function services** directly; and
- (b) a **trader** trading on the **network** of the **distributor** described in paragraph (a).

Clause 12A.11: inserted, on 16 December 2013, by clause 7 of the Electricity Industry Participation (Electricity Information Exchange Protocols) Code Amendment 2013.

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**, to enable the **distributor** to invoice and reconcile charges for **line function services**.
- (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) Nothing in this clause prevents the **distributor** and **trader** agreeing to provide **volume information** to each other for a purpose other than to enable invoicing and reconciling of charges for **line function services**.

Clause 12A.12: inserted, on 16 December 2013, by clause 7 of the Electricity Industry Participation (Electricity Information Exchange Protocols) Code Amendment 2013.

12A.13 Authority may publicise EIEPs that must be used

- (1) The **Authority** may **publicise** 1 or more **EIEPs** that set out standard formats that **distributors** and **traders** must use when exchanging information.
- (2) When **publicising** an **EIEP** under subclause (1), the **Authority** must specify the date on which the **EIEP** will come into effect, which must be no earlier than 1 November 2014.
- (3) The information to which an **EIEP publicised** 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** **publicises** an **EIEP** under subclause (1), or amends an **EIEP** it has **publicised** 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 publicised** 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) Despite subclause (4), the **Authority** may **publicise** the **EIEPs** described as EIEP1, EIEP2 and EIEP3 under this clause, despite the **Authority** having consulted with **participants** that the **Authority** considers likely to be affected by those EIEPs, before this clause came into force.

Clause 12A.13: inserted, on 16 December 2013, by clause 7 of the Electricity Industry Participation (Electricity Information Exchange Protocols) Code Amendment 2013.

Clause 12A.13(6):inserted, on 15 May 2014, by clause 36 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

12A.14 Distributors and traders must comply with EIEPs

- (1) If the **Authority** has **publicised** an **EIEP** under clause 12A.13, the **distributor** and the **trader** must, when exchanging information to which the **EIEP** applies, comply with the **EIEP** from the date on which the **EIEP** comes into effect.
- (2) Subclause (1) does not apply—
 - (a) if—
 - (i) the **distributor** and **trader** agree to exchange the information in any other way; and

- (ii) that agreement is recorded in the **use-of-system agreement** between the **distributor** and the **trader**; or
- (b) to an **EIEP publicised** under clause 12A.15.

Clause 12A.14: inserted, on 16 December 2013, by clause 7 of the Electricity Industry Participation (Electricity Information Exchange Protocols) Code Amendment 2013.

12A.15 Authority may publicise voluntary EIEPs

The **Authority** may **publicise** 1 or more **EIEPs** that set out standard formats that **distributors** and **traders** may, but are not required to, use when exchanging information.

Clause 12A.15: inserted, on 16 December 2013, by clause 7 of the Electricity Industry Participation (Electricity Information Exchange Protocols) Code Amendment 2013.

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 publicised** 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) If a **distributor** and a **trader** agree to exchange information in a way other than in accordance with an **EIEP** to which this clause applies, the **distributor** and **trader** need not comply with the requirement in clause 12A.14(2)(a)(ii) to record that agreement in the **use-of-system agreement** between the **distributor** and **trader** until 1 November 2014.

Clause 12A.16: inserted, on 16 December 2013, by clause 7 of the Electricity Industry Participation (Electricity Information Exchange Protocols) Code Amendment 2013.

Schedule 12A.1

Distributor indemnity in use-of-system agreements

cl 12A.7

Every **use-of-system agreement** is deemed to include the following clause:

Distributor indemnity

- (1) If—
 - (a) there has been a failure of the acceptable quality guarantee in section 6 of the Consumer Guarantees Act 1993 in the supply of electricity to a Consumer by the Retailer (a "failure"); and
 - (b) the failure was wholly or partially the result of an event or condition associated with the Distributor's Network; and
 - (c) the failure was not a result of the Distributor complying with a rule or order with which it was legally obliged to comply; and
 - (d) the Consumer obtains a remedy under Part 2 of the Consumer Guarantees Act 1993 in relation to the failure against the Retailer; and
 - (e) that remedy is a cost to the Retailer (a "remedy cost"),
the Distributor indemnifies the Retailer for the remedy cost.
- (2) The amount of the Distributor's liability under this indemnity is limited to the proportion of the remedy cost that is attributable to the event or condition associated with the Distributor's Network.
- (3) However,—
 - (a) if the Distributor pays compensation to a Consumer ("payment A") in respect of a service provided directly by the Distributor to the Consumer; and
 - (b) the Retailer incurs remedy costs in relation to the Consumer for a failure of acceptable quality that arose from the same event or circumstance that led to the payment of payment A; then
 - (c) the amount that the Retailer would otherwise recover from the Distributor in respect of that Consumer must be reduced by the amount of payment A.
- (4) If a Consumer makes a claim against the Retailer that the Retailer wishes to be indemnified for under this indemnity (a "claim"), the Retailer will:
 - (a) as soon as reasonably practicable, give written notice of the claim to the Distributor specifying the nature of the claim in reasonable detail; and
 - (b) consult with and keep the Distributor informed in relation to the claim.

Electricity Industry Participation Code 2010

Part 13 Trading arrangements

Contents

- 13.1 Contents of this Part
- 13.2 Misleading, deceptive, or incorrect information
- 13.2A Participant must make disclosure information readily available
- 13.3 Approval process for industrial co-generating stations
- 13.3A Approval process for dispatch-capable load stations
- 13.3B Changes to dispatch-capable load station must be notified to system operator
- 13.3C System operator to publish dispatch-capable load station approval process guidelines

Subpart 1—Bids and offers

- 13.4 Contents of this subpart
- 13.5 Bids and offers must be lawful
- 13.5A Conduct in relation to generators' offers and ancillary service agents' reserve offers
- 13.5B Safe harbours for clause 13.5A

Bids and offer preparation

- 13.6 Generators
- 13.7 Purchaser to submit bids for dispatch-capable load station
- 13.7AA Purchaser to submit bids for non-dispatch-capable load
- 13.7AB Timeframe for submitting bids to system operator
- 13.7AC Submitting bid for first time
- 13.7A System operator to prepare forecast of non-dispatch-capable load at conforming GXPs
- 13.7B Authority may request system operator to report on accuracy of forecasts of non-dispatch-capable load at conforming GXPs
- 13.8 Deemed offers
- 13.8A Deemed nominated bids
- 13.8B Deemed reserve offers
- 13.9 Information that offers must contain
- 13.10 Generators must specify units in offers
- 13.11 Offers may be made by unit or plant
- 13.12 Offers may contain up to 5 price bands
- 13.13 Information to be contained in bids
- 13.14 Nominated bids may contain up to 10 price bands
- 13.14A Difference bids may contain up to 10 price bands
- 13.15 How price is to be specified in bids or offers
- 13.16 How quantity is to be specified in bids or offers
- 13.17 Offers may be revised or cancelled
- 13.18 When revised offers must be submitted
- 13.19 Offer quantity changes may be made within 2 hours before trading period
- 13.19A Bids may be revised or cancelled
- 13.20 System operator notified of revised or cancelled nominated bids or offers in certain circumstances

- 13.21 Authority notified of revised or cancelled bid or offer inside the 2 hour period
- 13.22 Transmission of information through information system
- 13.23 Backup procedures if information system is unavailable
- 13.24 Plant with special circumstances
- 13.25 Exception for small generation
- 13.26 Exception for embedded generation
- 13.27 System operator to retain bids and offers

Process for determining conforming and non-conforming grid exit points

- 13.27A Authority determines conforming and non-conforming GXPs on own initiative
- 13.27B Authority to determine conforming and non-conforming GXPs if requested
- 13.27C Process for making a determination
- 13.27D System operator to provide advice within reasonable time
- 13.27E Authority may publicise criteria for determining GXP to be non-conforming
- 13.27F GXP deemed to be conforming GXP before determination is made
- 13.27G Authority must publicise and maintain list of non-conforming and conforming GXPs
- 13.27H Right to request determination or reconsideration of determination
- 13.27I Effect of determination
- 13.27J New GXPs
- 13.27K Authority to provide information at purchaser's request

Special treatment of some grid exit points

- 13.28 Special treatment of some grid exit points
- 13.29 Standing data on grid capability to be provided to system operator
- 13.30 Standing data on HVDC capability to be provided to system operator
- 13.31 Standing data on transformer capability to be provided to system operator
- 13.32 Transmission grid capability information to be updated
- 13.33 Grid owners must submit revised information to system operator
- 13.34 Changes may be made within 2 hours before trading period
- 13.35 Transmission of grid owner information through information system
- 13.36 Backup procedures if information system is unavailable

Offering instantaneous reserve

- 13.37 System operator to approve ancillary service agents wishing to make reserve offers
- 13.38 Ancillary service agents to submit reserve offers to system operator
- 13.39 Inter-relationship between reserve and energy offers
- 13.40 Inter-relationship between reserve offers of interruptible load and bids
- 13.41 Reserve offers may contain up to 3 price bands
- 13.42 How price to be specified in reserve offers
- 13.43 *[Revoked]*
- 13.44 How quantity is to be specified in reserve offers
- 13.45 Reserve offers revised if energy offers revised
- 13.46 Reserve offers may be revised or cancelled
- 13.47 Quantity changes may be made within 2 hours before trading period
- 13.48 System operator notified of revised reserve offers in certain circumstances
- 13.49 Authority notified of revised reserve offer inside 2 hour period
- 13.50 System operator to advise Authority of cancellation or revision of reserve offers
- 13.51 Transmission of reserve offers through information system
- 13.52 Backup procedures if information system is unavailable

- 13.53 Additional information to be provided by participants
- 13.54 System operator to retain reserve offers
- 13.55 Availability of bids, offers, and reserve offers
- 13.55A System operator to make information available

Subpart 2—Scheduling and dispatch

- 13.56 Contents of this subpart
- 13.57 The dispatch objective
- 13.58 Process for preparing price-responsive schedule and non-response schedule
- 13.58A Inputs for price-responsive schedule and non-response schedule
- 13.59 Contents of each price-responsive schedule and non-response schedule
- 13.60 Block dispatch may occur
- 13.61 System operator to notify block security constraints
- 13.62 Frequency of price-responsive schedules and non-response schedules
- 13.63 Trading period information to be given to pricing manager and clearing manager
- 13.64 Station dispatch may occur
- 13.65 System operator to notify station security constraints
- 13.66 Generator notifies change from station to unit dispatch
- 13.67 Transmission of information through information system

The dispatch process

- 13.68 Receipt of new non-response schedule supersedes old schedule *[Revoked]*
- 13.69 System operator may adjust dispatch schedule *[Revoked]*
- 13.69A System operator to prepare dispatch schedule
- 13.70 System operator may depart from dispatch schedule
- 13.71 System operator to use certain things
- 13.72 System operator to issue dispatch instructions
- 13.73 Content of dispatch instructions to generators, ancillary service agents, and dispatchable load purchasers
- 13.74 Content of dispatch instructions to reserve, interruptible load, and frequency keeping suppliers *[Revoked]*
- 13.75 Form of dispatch instruction
- 13.76 Dispatch instructions to be logged
- 13.77 Dispatch instructions to plant required by system operator *[Revoked]*
- 13.78 Active power dispatch instructions to clearing manager *[Revoked]*
- 13.79 Acknowledgement of dispatch instructions
- 13.80 Dispatch instructions provided to grid owner
- 13.81 Backup procedures if communication not possible
- 13.82 Dispatch instructions to be complied with
- 13.83 Generators to make staff or facilities available to meet dispatch instructions
- 13.83A Dispatchable load purchasers to make staff or facilities available to meet dispatch instructions
- 13.84 Ancillary service agents to make staff or facilities available to meet dispatch instructions
- 13.85 Generators have flexibility within block dispatch group or station dispatch group
- 13.86 Generators and ancillary service agents not obliged to comply with dispatch instructions below threshold
- 13.87 *[Revoked]*

Real time prices

- 13.88 Preparation of schedule of real time prices
- 13.89 Publication of schedule of real time prices
- 13.90 Process for publishing real time prices
- 13.91 Transmission of information through information system
- 13.92 Transmission of information through website
- 13.93 Market administrator to appoint person to monitor and assess demand side participation and real time prices
- 13.94 System operator may suspend publication of real time prices
- 13.95 Real time prices not binding
- 13.96 Purchaser to co-operate with system operator to manage response to real time prices

Grid emergencies

- 13.97 Grid emergency situations
- 13.98 Generators and ancillary service agents may change other parameters
- 13.99 Effect of grid emergency on total quantities bid
- 13.99A Effect of grid emergency on nominated dispatch bids
- 13.100 Purchasers may change other parameters
- 13.101 Reporting requirements in respect of grid emergencies
- 13.102 Reporting obligations of system operator

System operator to publish information

- 13.103 *[Revoked]*
- 13.104 Information to be published
- 13.105 *[Revoked]*
- 13.105A Information to be provided to purchasers, generators, and ancillary service agents
- 13.106 Transmission of information through information system

Subpart 3—Must-run dispatch auction

- 13.107 Contents of this subpart
- 13.108 Clearing manager to hold must-run dispatch auctions
- 13.109 Clearing manager authorises generators
- 13.110 Clearing manager must calculate amounts payable
- 13.111 Purchasers must receive auction revenue
- 13.112 Clearing manager must calculate amounts receivable
- 13.113 Generators choose grid injection points at which they will exercise rights conferred
- 13.114 Information to be transmitted through information system
- 13.115 Trading in auction rights permitted
- 13.116 Offers at 0

Must-run auction process

- 13.117 Clearing manager must conduct auctions
- 13.118 Exchange information
- 13.119 Historic load data
- 13.120 Quantity available for auction
- 13.121 Notice of auction and deadline for auction bids
- 13.122 Revising, cancelling and extending auction bids
- 13.123 Contents of auction bids
- 13.124 Ranking of auction bids
- 13.125 Matching auction bids to rights

- 13.126 Similar and identical auction bids
- 13.127 Auction payment
- 13.128 Results
- 13.129 Authorisation to successful bidders
- 13.130 Records

Subpart 4—Pricing

- 13.131 Contents of this subpart
- 13.132 Purpose of the pricing process
- 13.133 Trigger ratio for high spring washer price situation
- 13.134 Methodology to resolve high spring washer price situation
 - Rules governing the preparation of provisional, interim, and final prices*
- 13.135 Methodology used to prepare provisional, interim, and final prices
- 13.135A Notice of scarcity pricing situation
- 13.135B Methodology to prepare interim prices and interim reserve prices if scarcity pricing situation exists
- 13.135C Limitation on application of scarcity pricing provisions
 - Generators to give pricing manager half-hour metering information*
- 13.136 Generators to provide half-hour metering information
- 13.137 Unoffered and intermittent generation to provide metering information
- 13.138 Generator's half-hour metering information to be adjusted for losses
- 13.138A Dispatchable load purchaser's half-hour metering information to be adjusted for losses
- 13.138B System operator to give list of trading periods
- 13.139 Half-hour metering information part of input information
- 13.140 Generators and dispatchable load purchasers to notify provision of half-hour metering information
- 13.141 Pricing manager to use certain input information
- 13.142 Pricing manager to publish interim prices unless provisional price situation or shortage situation notified
- 13.143 Grid owners to notify SCADA situation
- 13.144 Pricing manager to give notice of infeasibility situation, metering situation, high spring washer price situation, or shortage situation
- 13.145 Grid owner to give notice that estimated data given
- 13.146 Requirements if provisional price situation or shortage situation exists
- 13.147 Revised data to be accompanied by notice
- 13.148 Failure to give revised data and notice not breach
- 13.149 Pricing manager to publish provisional prices and provisional reserve prices if revised data and notice not given in relation to provisional price situation arising on business day
- 13.150 Pricing manager to publish provisional prices and provisional reserve prices if revised data and notice not given in relation to provisional price situation arising on day other than business day
- 13.151 Data to be used by pricing manager to determine provisional prices and provisional reserve prices
- 13.152 Pricing manager to publish interim prices and interim reserve prices if revised data resolves provisional price situation
- 13.153 Revised data gives rise to provisional price situation

- 13.154 Grid owner, generators, dispatchable load purchasers, and system operator to give revised data if provisional prices and provisional reserve prices have been published
- 13.155 Revised data to be accompanied by notice
- 13.156 Pricing manager to publish interim prices following publication of provisional prices and provisional reserve prices unless further provisional price situation arises
- 13.157 Requirements if infeasibility situation or high spring washer price situation exists
- 13.158 Revised data to be accompanied by notice
- 13.159 Pricing manager to publish interim prices or publish notice that high spring washer price situation exists
- 13.160 Prohibition on notice of high spring washer price situation
- 13.161 System operator to apply high spring washer price relaxation factor and give notice
- 13.162 Pricing manager to publish interim prices
- 13.163 Revised data cannot be given or revised data gives rise to provisional price situation (other than high spring washer price situation)
- 13.164 If provisional price situation (other than high spring washer price situation) continues
- 13.165 Authority notified if provisional price situation not resolved
- 13.166 Generator, grid owner, or dispatchable load purchaser to give revised metering information following initial estimate
- 13.166A Pricing manager to recalculate and publish interim prices if infeasibility situation caused by shortage of instantaneous reserve

Interim pricing period

- 13.167 Pricing manager to publish interim prices
- 13.168 When pricing error may be claimed
- 13.169 Error claimant materially affected by pricing error
- 13.170 Method and timing for claiming pricing error has occurred
- 13.171 Pricing manager must publish final prices if no pricing error claimed
- 13.172 Effect of pricing error being claimed
- 13.173 Process when pricing error claimed
- 13.174 Recommendation to Authority
- 13.175 Authority to accept or reject recommendations
- 13.176 Pricing manager to publish notice
- 13.177 Pricing manager to implement Authority's decision
- 13.178 Effect of republishing interim prices
- 13.179 Timing for resolution of pricing error claim process
- 13.180 Actions Authority may take to resolve pricing error
- 13.181 Obligation to comply with pricing manager
- 13.182 No pricing errors notified after final prices calculated

Publication of final prices

- 13.183 Republication of final prices
- 13.184 Authority may order delay of publication of final prices
- 13.185 Final prices for more than 1 trading day

Miscellaneous requirements relating to calculation of prices

- 13.186 Revised data for more than 1 trading day
- 13.187 Daylight saving to be observed
- 13.188 Market administrator to publish annual consumption list

- 13.189 System operator to give pricing manager list of model variable values
- 13.189A Pricing manager to give clearing manager information about dispatch-capable load station from schedule of final prices
- 13.190 All notifications to be unconditional, final and transmitted by information system
- 13.191 Backup procedures if information system is unavailable

Calculation of constrained off amounts

- 13.192 Constrained off situations may occur
- 13.193 Determining affected price bands for block dispatch groups and station dispatch groups
- 13.194 Clearing manager to calculate constrained off amounts
- 13.195 Constrained off amount for block dispatch groups and station dispatch groups
- 13.196 Calculation of amounts attributable to system operator
- 13.197 Calculation of constrained off amounts
- 13.198 Clearing manager to send constrained off information to system operator
- 13.199 Clearing manager to publish details of constrained off amounts
- 13.200 Authority, generators and purchasers have rights to constrained off information
- 13.201 Generators do not get paid constrained off compensation
- 13.201A Dispatched purchasers entitled to constrained off compensation and purchasers to pay constrained off compensation

Calculation of constrained on amounts

- 13.202 Constrained on situations may occur
- 13.203 Determining affected price bands for block dispatch groups or station dispatch groups
- 13.204 Calculation of constrained on amounts
- 13.205 Calculation of constrained on amounts attributable to system operator
- 13.206 Time frame for calculating constrained on amounts
- 13.207 Clearing manager to send constrained on information to system operator
- 13.208 Clearing manager to publish details of constrained on amounts
- 13.209 Authority, generators, ancillary service agents, and purchasers have rights to constrained on information
- 13.210 Transmission of information through information system
- 13.211 Backup procedures if information system is unavailable
- 13.212 Payment of constrained on compensation

Pricing manager's reporting obligations

- 13.213 Daily reports
- 13.214 Market administrator to publish pricing manager reports
- 13.215 Generators and purchasers have right to information concerning pricing manager's action
- 13.216 Daily situation report

Subpart 5—Hedge arrangement disclosure

- 13.217 Contents of this subpart
- 13.218 Parties required to submit information
- 13.219 Information that must be submitted
- 13.220 Calculation of contract price
- 13.221 Node and grid zone area information
- 13.222 Other information that must be submitted

- 13.223 Modified or amended information
- 13.224 Correction of information
- 13.225 Timeframes for submitting information
- 13.226 Information system will make information publicly available
- 13.227 Verification of information
- 13.228 Confirmation of information submitted to information system
- 13.229 Submitting party to check if no confirmation received
- 13.230 Certification of information
- 13.231 Audit of information
- 13.232 Payment of costs relating to audits
- 13.233 Information system and Authority must not publish certain information and may use information only under this subpart
- 13.234 No misleading information
- 13.235 Risk management contracts must be lawful
- 13.236 Availability of information

Subpart 5A—Spot price risk disclosure

- 13.236A Disclosing participants must prepare and submit spot price risk disclosure statements
- 13.236B Authority must appoint a person to receive and analyse spot price risk disclosure statements
- 13.236C Authority may approve consolidated spot price risk disclosure statements
- 13.236D Authority must publicise base case, stress test, and method for calculating target cover ratio
- 13.236E Content of spot price risk disclosure statements
- 13.236F Certification of spot price risk disclosure statement
- 13.236G Authority may require disclosing participant to submit new spot price risk disclosure statement
- 13.236H Authority may require independent audit of spot price risk disclosure statement or certificate
- 13.236I Payment of auditor's costs

Subpart 6—Financial transmission rights

- 13.237 Contents of this subpart

FTR allocation plan

- 13.238 Preparation and publication of FTR allocation plan
- 13.239 FTR manager gives draft FTR allocation plan to Authority
- 13.240 Authority approves FTR allocation plan
- 13.241 Variations to FTR allocation plan

Creation and allocation of FTRs

- 13.242 FTR manager must create and allocate FTRs
- 13.243 Participation in FTR auction
- 13.244 Acceptance of bids in FTR auction

Auction revenue and FTR receipts and payments

- 13.245 Clearing manager must collect and allocate auction revenue
- 13.246 Clearing manager must deal with FTR receipts and payments

FTR register

- 13.247 FTR manager must operate FTR register

Assignment of FTRs

- 13.248 Assignment of FTRs
13.249 Liability for FTR payments when FTR assigned and price disclosed
13.250 Liability for FTR payments when FTR assigned and price not disclosed

Provision of information to the FTR manager and clearing manager

- 13.251 Information to be provided to FTR manager
13.252 Information to be provided to clearing manager
13.253 Transmission of information to FTR manager and clearing manager
13.254 Publication of results of FTR auctions

Suspension of FTR allocation

- 13.255 Authority may direct FTR manager to suspend allocation of FTRs

Schedule 13.1

Forms 1 to 9

Schedule 13.2

Model parameters

Schedule 13.3

The Modelling System

Inputs into the modelling system

Inputs used at each stage

The objective function

Schedule 13.3A

Calculation of interim prices and interim reserve prices in scarcity pricing situation

Schedule 13.4

Approval of industrial co-generating stations

Schedule 13.5

Requirements for FTR allocation plan

Schedule 13.6

Assignment of FTR

Schedule 13.7

Methodology for Determining Conforming and Non-Conforming GXPs

Schedule 13.8

Approval of dispatch-capable load station

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**

- GXPs**, 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** apply for approval from the **Authority** to have **co-generator** status; 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.

Clause 13.1(da): inserted, on 28 June 2012, by clause 5(b) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.1(db) and (fa): inserted, on 15 May 2014, by clause 37 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

Clause 13.1(g)-(i): inserted, on 1 October 2011, by clause 7 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 13.1(j): inserted, on 15 May 2014, by clause 6 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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 immediately—
 - (a) disclose further information so that the person is not misled or deceived by the information; or
 - (b) disclose corrected information to the person.

Clause 13.2: substituted, on 1 October 2013, by clause 5 of the Electricity Industry Participation (Disclosure Obligations) Code Amendment 2013.

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) doing so will commercially disadvantage the participant in a material manner; 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.

Clause 13.2A: inserted, on 1 October 2013, by clause 6 of the Electricity Industry Participation (Disclosure Obligations) Code Amendment 2013.

13.3 Approval process for industrial co-generating stations

A **generator** may apply to the **Authority** for approval for 1 or more **generating units** to be an **industrial co-generating station** in accordance with 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.

Clause 13.3A: inserted, on 15 May 2014, by clause 7 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.3B Changes to dispatch-capable load station must be notified to system operator

- (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.

Clause 13.3B: inserted, on 15 May 2014, by clause 7 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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

Clause 13.5: amended, on 28 June 2012, by clause 6 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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, revises, or cancels an **offer**; or
 - (b) an **ancillary service agent** submits, revises, or cancels a **reserve offer**.

Clause 13.5A: inserted, on 17 July 2014, by clause 5 of the Electricity Industry Participation Code Amendment (Pivotal Supply) 2014.

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, revise, or cancel 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, revise, or cancel 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.

Bids and offer preparation

13.6 Generators

- (1) Each **generator** (other than an **embedded generator** submitting an **offer** in accordance with subclause (2) or an **intermittent generator** submitting an **offer** in accordance with subclause (3)) must—
 - (a) submit to the **system operator** an **offer**—
 - (i) for each **trading period** in the **schedule period**; and
 - (ii) 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** applies.
- (2) Despite subclause (1), each **embedded generator** required by the **system operator** to provide an **offer** in accordance with clause 8.25(5) (other than an **embedded generator** who is also an **intermittent generator** submitting an **offer** in accordance with subclause (3)), must—
 - (a) submit to the **system operator** an **offer**—
 - (i) for each **trading period** of the **schedule period**; and
 - (ii) under which the **generator** is intending to generate **electricity**; and
 - (b) ensure that the **system operator** receives the **offer** at least 71 **trading periods** before the beginning of the **trading period** to which the **offer** applies.
- (3) Despite subclauses (1) and (2), each **intermittent generator** with a **point of connection** to the **grid**, and each **intermittent generator** with a **point of connection** to a **local network**, required by the **system operator** to provide an **offer** under clause 8.25(5), must—
 - (a) submit to the **system operator** an **offer**—
 - (i) for each **trading period** of the **schedule period**; and
 - (ii) which is based on the **intermittent generator's** forecast of the **electricity** that it expects to be able to generate; and

- (b) ensure that the **system operator** receives the **offer** at least 71 **trading periods** before the beginning of the **trading period** to which the **offer** applies.
- (4) Despite subclauses (1) to (3), a **generator** must give not less than 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 a **generating plant**. The notice must include advice as to which **grid injection point** the **generating plant** is connected to and whether the **generating plant** is an **intermittent generating station**. The **generator** must comply with any request the **system operator** may make for information concerning the **generating plant** that the **system operator** may reasonably require for the purposes of scheduling and **dispatch** in accordance with this Code.

Compare: Electricity Governance Rules 2003 rules 3.1 and 3.2 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.

13.7 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 13.7 Heading and (1): 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.

Clause 13.7(2): amended, on 28 June 2012, by clause 8(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.7: substituted, on 15 May 2014, by clause 8 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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**.

Clause 13.7AA: inserted, on 15 May 2014, by clause 8 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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.

Clause 13.7AB: inserted, on 15 May 2014, by clause 8 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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).

Clause 13.7AC: inserted, on 15 May 2014, by clause 8 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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) make available to the public on the **system operator's** website at all reasonable times, 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 to make information available under subclause (2) only if the information—
 - (a) is available to the **system operator**; and

(b) is not confidential or commercially sensitive.

Clause 13.7A: inserted, on 28 June 2012, by clause 9 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.7A Heading: amended, on 15 May 2014, by clause 9(a) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.7A: amended, on 15 May 2014, by clause 9 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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.

Clause 13.7B: inserted, on 28 June 2012, by clause 9 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.7B Heading: amended, on 15 May 2014, by clause 10(a) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.7B(1): amended, on 15 May 2014, by clause 10(b) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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 13.9(b) applies accordingly.
- (3) A deemed **offer** under subclause (2) applies until the **generator** cancels or 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 15 May 2014, by clause 11 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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** cancels or 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: inserted, on 28 June 2012, by clause 10 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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.

Clause 13.8A(4): inserted, on 15 May 2014, by clause 12(c) 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** cancels or revises the **reserve offer** in accordance with clauses 13.46 to 13.49.

Clause 13.8B: inserted, on 1 November 2012, by clause 4 of the Electricity Industry Participation (Part 13 Minor Amendments) Code Amendment 2012.

13.9 Information that offers must contain

Each **offer** submitted by a **generator** must—

- (a) other than for **intermittent generators** and **co-generators**, contain all information required by Form 1 in Schedule 13.1; and
- (b) in relation to the **generating plant** that is the subject of the **offer**, not exceed, for each **trading period**, the **generator's** reasonable estimate of the quantity of **electricity** capable of being supplied at that **grid injection point** by the relevant **generating plant** for the relevant **trading period**; and
- (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 **co-generator** for an **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

13.10 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]*

- (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

Clause 13.13: substituted, on 28 June 2012, by clause 11 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.13(1)(aa): inserted, on 15 May 2014, by clause 13(a) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.13(1)(b): revoked, on 15 May 2014, by clause 13(b) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.13(2): substituted, on 15 May 2014, by clause 13(c) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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

Clause 13.14: substituted, on 28 June 2012, by clause 12 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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.

Clause 13.14A: inserted, on 28 June 2012, by clause 13 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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

Clause 13.16: amended, on 21 September 2012, by clause 18 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

13.17 Offers may be revised or cancelled

- (1) Subject to clauses 13.19 and 13.97 to 13.101, each **generator** (other than an **embedded generator** submitting an **offer** in accordance with subclause (2) or an **intermittent generator** submitting an **offer** in accordance with subclause (3)) may—
 - (a) revise any of its **offer** prices or **offer** quantities, as the case may be, for any **trading period** by submitting a new **offer** to the **system operator**. A revised **offer** may be made up to 2 hours before the beginning of the **trading period** in respect of which the **offer** was made; or
 - (b) cancel any of its **offers** by notice in writing to the **system operator**. Any such cancellation of an **offer** may be made up to 2 hours before the beginning of the **trading period** in respect of which the **offer** was made.
- (2) Despite subclause (1), and subject to clauses 13.19 and 13.97 to 13.101, an **embedded generator** required to submit an **offer** in accordance with clause 8.25(5) (other than an **embedded generator** who is also an **intermittent generator** submitting an **offer** in accordance with subclause (3)) must use reasonable endeavours to submit any revised **offers** at least 2 hours before the beginning of the **trading period** in respect of which the **offer** is made, but may—
 - (a) revise any of its **offer** quantities for any **trading period** by submitting a new **offer** to the **system operator**. Any revised **offer** may be made up to 30 minutes before the beginning of the **trading period** in respect of which the **offer** was made; or
 - (b) cancel any of its **offers** by notice in writing to the **system operator**. Any such cancellation of an **offer** may be made up to 30 minutes before the beginning of the **trading period** in respect of which the **offer** was made.
- (3) Despite subclauses (1) and (2), and subject to clauses 13.19 and 13.97 to 13.101, each **intermittent generator** must submit any revision to the **offer** price at least 2 hours before the beginning of the **trading period** in respect of which the **offer** was made. In addition, the **intermittent generator**—
 - (a) must revise the quantity of each **offer** made under this subclause during the 2 hours immediately before the **trading period** in respect of which the **offer** is made, in order to comply with clause 13.9(b). Each revised **offer** must be based on a persistence model using actual output from the **intermittent generating station** at the time the revised **offer** is submitted, unless otherwise agreed with the **Authority**; and

- (b) may cancel any **offer** by notice in writing to the **system operator**. Any such cancellation may be made up to 30 minutes before the beginning of the **trading period** in respect of which the **offer** was made.

Compare: Electricity Governance Rules 2003 rule 3.14 section II part G

Clause 13.17 Heading: amended, on 28 June 2012, by clause 14(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.17(1): amended, on 28 June 2012, by clause 14(2) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.18 When revised offers must be submitted

- (1) Before the beginning of the **trading period** to which an **offer** applies, and despite subclause (2) and clause 13.19, a **generator** (other than an **intermittent generator** submitting an **offer** under clause 13.17(3)) must immediately submit revised **offer** quantities to the **system operator** if—
- (a) *[Revoked]*
- (b) in relation to the quantities specified in the last **non-response schedule published** by the **system operator**, the ability of a **generator's generating plant** to generate the quantity scheduled for a **trading period** at a **grid injection point** is expected by that **generator** to change by more than 10 MW or 10% of the quantity scheduled (whichever is smaller); or
- (c) the ability of a **generator** to generate the total quantity offered for a **trading period** at a **grid injection point** is expected by that **generator** to change by more than 10 MW or 10% of the total quantity offered by that **generator** (whichever is smaller).
- (1A) Despite subclause (1), a **generator** is not required to submit a revised **offer** quantity if the expected change in the quantity is less than 5 MW.
- (2) A **generator** may not revise the price in its **offer** later than 2 hours before the relevant **trading period** in which that price has been **offered**.

Compare: Electricity Governance Rules 2003 rules 3.15 and 3.16 section II part G

Clause 13.18 Heading: amended, on 28 June 2012, by clause 15(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.18(1): amended, on 28 June 2012, by clause 15(2) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.18(1A): inserted, on 28 June 2012, by clause 15(3) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.18(2): amended, on 28 June 2012, by clause 15(4) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.19 Offer quantity changes may be made within 2 hours before trading period

- (1) Despite clauses 13.17, 13.18(2), and 13.97 to 13.101, a **generator** may—
- (a) cancel or revise an **offer** or submit a new **offer** to the **system operator** within 2 hours, or in the case of an **embedded generator** within 30 minutes, before the relevant **trading period** only if—
- (i) a **bona fide physical reason** necessitates the cancellation or revision; or
- (ii) the **system operator** issues a **formal notice** under clause 5 of **Technical Code B** of Schedule 8.3; or

- (iii) the **generator** is an **intermittent generator** submitting revised **offers** under clause 13.17; and
- (b) submit a new or revised **offer** to the **system operator** within 2 hours, or in the case of an **embedded generator** within 30 minutes, before the relevant **trading period** if—
 - (i) a **bona fide physical reason** that necessitates a cancellation or revision under paragraph (a)(i) ceases to exist sooner than was expected at the time it arose; and
 - (ii) the 1st **trading period** after the original **bona fide physical reason** ceases to exist is within 24 hours of the original **bona fide physical reason** occurring; and
 - (iii) the total change in quantity in the **offer** in a **trading period** 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 quantity in the **offer** that was made for the same **trading period** as a result of the original **bona fide physical reason**.
- (2) Whether or not the cancellation, revision, or new **offer** was in accordance with this clause must be determined in accordance with clause 13.21(2).

Compare: Electricity Governance Rules 2003 rule 3.17 section II part G

Clause 13.19 Heading: amended, on 28 June 2012, by clause 16(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.19: amended, on 28 June 2012, by clause 16(2) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.19A Bids may be revised or cancelled

- (1) Each **purchaser** may—
 - (a) revise any of its **bid** prices or **bid** quantities 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**; or
 - (b) cancel any of its **bids** by notice in writing to the **system operator**.
- (2) Despite subclause (1), a **purchaser** must not do any of the following within the 2 hours before the beginning of the **trading period** in respect of which a **bid** is made:
 - (a) revise the **bid** price:
 - (b) revise the **bid** quantity:
 - (ba) 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**:
 - (c) cancel the **bid**.
- (3) Despite subclause (2),—

- (a) a **purchaser** may do any of the following within the 2 hours before the beginning of the **trading period** in respect of which a **bid** is made, if the **purchaser** has a **bona fide physical reason** necessitating the **purchaser** to do so:
 - (ia) revise a **nominated bid**—
 - (A) from being a **nominated dispatch bid** to being a **nominated non-dispatch bid**; or
 - (B) from being a **nominated non-dispatch bid** to being a **nominated dispatch bid**;
 - (i) revise its **bid** quantities;
 - (ii) cancel the **bid**;
 - (b) before the beginning of the **trading period** to which a **nominated bid** applies, the **purchaser** that submitted the **nominated bid** must immediately submit a revised **nominated bid** quantity to the **system operator** if the **purchaser** expects, or ought reasonably to expect, that the quantity of **electricity** likely to be purchased by the **purchaser** at the prices indicated in the **nominated bid** will,—
 - (i) if the **nominated bid** is a **nominated non-dispatch bid**, differ from the quantity in the **nominated bid** by more than the lesser of—
 - (A) 20MW; and
 - (B) 20% of the **nominated bid** quantity; or
 - (ii) if the **nominated bid** is a **nominated dispatch bid**, differ from the quantity in the **nominated bid** by more than the lesser of—
 - (A) 10MW; and
 - (B) 10% of the **nominated bid** quantity; or
 - (c) if the **system operator** declares a **grid emergency**, a **purchaser** must comply with clauses 13.99 to 13.100.
- (4) Despite subclause (3)(b), a **purchaser** is not required to submit a revised **nominated bid** quantity, if the expected change in the quantity is less than 5 MW.
- (5) Whether or not the cancellation or revision was in accordance with this clause must be determined in accordance with clause 13.21(2).

Clause 13.19A: inserted, on 28 June 2012, by clause 17 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.19A(1)(aa): inserted, on 15 May 2014, by clause 14(1) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.19A(2)(ba): inserted, on 15 May 2014, by clause 14(2) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.19A(3)(a)(ia): inserted, on 15 May 2014, by clause 14(3) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.19A(3)(b): substituted, on 15 May 2014, by clause 14(4) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.19A(3)(c): amended, on 15 May 2014, by clause 14(5) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.20 System operator notified of revised or cancelled nominated bids or offers in certain circumstances

- (1) Subclause (2) applies if a **purchaser** at a **GXP** or a **generator** submits a revised **nominated bid** or **offer**, or cancels a **nominated bid** or **offer**, within 15 minutes before the relevant **trading period**.

- (2) If this subclause applies, before submitting a revision or cancellation, a **purchaser** or **generator** (other than an **intermittent generator** submitting a revised **offer** under clause 13.17), must immediately notify the **system operator** of the revision or cancellation by telephone or electronic means (if the electronic means have been agreed between the **system operator** and the **purchaser** or **generator** before the **purchaser** or **generator** notified the revision or cancellation).

Compare: Electricity Governance Rules 2003 rule 3.18 section II part G

Clause 13.20: substituted, on 28 June 2012, by clause 18 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.20(1): amended, on 15 May 2014, by clause 15 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.21 Authority notified of revised or cancelled bid or offer inside the 2 hour period

- (1) A **purchaser** or **generator** (other than an **intermittent generator** submitting a revised **offer** under clause 13.17) who cancels a **bid** or **offer** or revises a **bid** or **offer** to the **system operator** within 2 hours before the relevant **trading period**, or in the case of an **embedded generator** within 30 minutes before the relevant **trading period**, must report each cancellation or revision to the **Authority** in writing together with an explanation of the reasons for the cancellation or revision. The **purchaser** or **generator** must report the cancellation or revision to the **Authority** by 1700 hours on the 1st **business day** following the **trading day** on which the cancellation or revision was made.
- (2) The **Authority** must consider every report made to it under subclause (1) and determine whether the cancellation or revised **bid** or **offer** made by the **purchaser** or **generator** complied with clause 13.19A (in the case of **bids**) or clause 13.19 (in the case of **offers**) and, if not, any action the **Authority** should take in relation to the non-compliance.

Compare: Electricity Governance Rules 2003 rules 3.19 and 3.20 section II part G

Clause 13.21 Heading: amended, on 28 June 2012, by clause 19(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.21(1): amended, on 28 June 2012, by clause 19(2) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.21(2): amended, on 28 June 2012, by clause 19(3) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.22 Transmission of information through information system

- (1) All information required to be submitted by a **purchaser** or **generator** under clauses 13.6 to 13.27 must be transmitted to the **system operator** through the electronic facility contained in the **information system**.
- (2) The **system operator** must immediately confirm receipt of any information received by it from a **purchaser** or **generator** through the electronic facility contained in the **information system**. 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 after that information has been sent, the **purchaser** or **generator** must telephone the **system operator** to check whether the information has been received. If it has not, the **purchaser** or **generator** must resend the information. The process set out in this clause

must then be repeated 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

Clause 13.22(3): amended, on 28 June 2012, by clause 20 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.23 Backup procedures if information system is unavailable

- (1) If the **information system** 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 **market administrator**.
- (2) The backup procedures referred to in subclause (1) must be specified by the **market administrator** following consultation with each **purchaser**, **generator** and the **system operator**. The **market administrator** must ensure that there is always a backup procedure notified to 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) to (3), 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** and all cancelled **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

Heading: inserted, on 28 March 2012, by clause 21 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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.

Clause 13.27A: inserted, on 28 March 2012, by clause 21 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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 notify the requester in writing 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.

Clause 13.27B: inserted, on 28 March 2012, by clause 21 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.27C Process for making a 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**.
- (2) 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 **publicised** criteria under clause 13.27E; and
 - (e) making a determination that the **GXP** is a **non-conforming GXP** is in accordance with the criteria.
- (3) If paragraphs (a) to (e) in subclause (2) apply, the **Authority** may make a determination in accordance with the criteria **publicised** under clause 13.27E.
- (4) As soon as practicable after making a determination, the **Authority** must—
- (a) advise the wholesale information trading system provider, 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 **publicised** 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.

Clause 13.27C: inserted, on 28 March 2012, by clause 21 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.27C(4): amended, on 27 June 2012, by clause 7 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011, Amendment 2012.

13.27D System operator to provide advice within reasonable time

The **system operator** must provide the advice requested under clause 13.27C(1)(b) within a reasonable time specified by the **Authority**.

Clause 13.27D: inserted, on 28 March 2012, by clause 21 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.27E Authority may publicise criteria for determining GXP to be non-conforming

- (1) The **Authority** may **publicise** criteria that set out the circumstances in which the **Authority** may make a determination that does not follow the methodology set out in Schedule 13.7.
- (2) The **Authority** must consult with **participants** before—
 - (a) **publicising** the criteria under subclause (1);
 - (b) amending the criteria **publicised** under subclause (1).

Clause 13.27E: inserted, on 28 March 2012, by clause 21 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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.

Clause 13.27F: inserted, on 28 March 2012, by clause 21 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.27G Authority must publicise and maintain list of non-conforming and conforming GXPs

The **Authority** must **publicise** 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.

Clause 13.27G: inserted, on 28 March 2012, by clause 21 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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.

Clause 13.27H: inserted, on 28 March 2012, by clause 21 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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.

Clause 13.27I: inserted, on 28 March 2012, by clause 21 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.27J New GXPs

At least 1 calendar 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**.

Clause 13.27J: inserted, on 28 March 2012, by clause 21 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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.

Clause 13.27K: inserted, on 28 March 2012, by clause 21 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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 notify **participants** in writing 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 notify each **participant** of the date from which its decision takes effect.

Compare: Electricity Governance Rules 2003 rule 4 section II part G

Clause 13.28(1): amended, on 28 June 2012, by clause 23 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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

Clause 13.30: substituted, on 1 November 2012, by clause 4 of the Electricity Industry Participation (HVDC Link Pole 3 Standing Data) Code Amendment 2012.

Clause 13.30(2)(d): amended, on 26 September 2013, by clause 5 of the Electricity Industry Participation (HVDC Link Bipole Control System Testing) Code Amendment 2013.

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

Clause 13.32: amended, on 28 June 2012, by clause 24 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.33 Grid owners must submit revised information to system operator

Up to 2 hours 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 2 hours before trading period

- (1) A **grid owner** may update the information submitted under clause 13.33 later than 2 hours 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 notified by the **grid owner** 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 notify 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) A **grid owner** who submits revised information to the **system operator** later than 2 hours before the relevant **trading period** must report each revision to the **Authority** in writing together with an explanation of the reasons for the revision. The **grid owner** must report each revision to the **Authority** by 1700 hours on the 1st **business day** following the **trading day** on which the revision was made.
- (4) The **Authority** must consider every report made to it under subclause (3) and assess whether the revision made by the **grid owner** complied with subclause (1) and if not, any action the **Authority** should take in relation to the non-compliance.

Compare: Electricity Governance Rules 2003 rules 5.6 to 5.9 section II part G

13.35 Transmission of grid owner information through information system

- (1) All information required to be submitted by a **grid owner** under clauses 13.29 to 13.36 must be transmitted to the **system operator** through the electronic facility contained in the **information system**.
- (2) The **system operator** must immediately confirm to each **grid owner** receipt of all information received from that **grid owner** through the electronic facility contained in the **information system**. 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 Backup procedures if information system is unavailable

- (1) If the **information system** is unavailable to receive information or confirm the receipt of information, the **grid owner** or the **system operator**, as the case may be, must follow the backup procedures specified by the **market administrator**.
- (2) The backup procedures referred to in subclause (1) must be specified by the **market administrator** following consultation with **grid owners** and the **system operator**. The **market administrator** must ensure that there is always a backup procedure notified to **grid owners** and the **system operator**.

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.

Compare: Electricity Governance Rules 2003 rules 6.2 to 6.4 section II part G

Clause 13.38(1): substituted, on 28 June 2012, by clause 25 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.38(1A): inserted, on 28 June 2012, by clause 25 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.38(1A): amended, on 1 November 2012, by clause 5 of the Electricity Industry Participation (Part 13 Minor Amendments) Code Amendment 2012.

Clause 13.38(3): amended, on 15 May 2014, by clause 38 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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.

Compare: Electricity Governance Rules 2003 rule 6.5 section II part G

Clause 13.39: amended, on 15 May 2014, by clause 39 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

13.40 Inter-relationship between reserve offers of interruptible load and bids

Bids and **reserve offers of interruptible load** are inter-related in that the disconnection of **demand** 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 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

Clause 13.40 Heading: amended, on 15 May 2014, by clause 16(a) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.40: amended, on 28 June 2012, by clause 26 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.40: amended, on 15 May 2014, by clause 16(b) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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

Clause 13.42: substituted, on 1 November 2012, by clause 6 of the Electricity Industry Participation (Part 13 Minor Amendments) Code Amendment 2012.

13.43 *[Revoked]*

Compare: Electricity Governance Rules 2003 rule 6.9 section II part G

Clause 13.43: revoked, on 1 November 2012, by clause 7 of the Electricity Industry Participation (Part 13 Minor Amendments) Code Amendment 2012.

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 0.001 **MW**.

Compare: Electricity Governance Rules 2003 rule 6.10 section II part G

Clause 13.44: amended, on 15 May 2014, by clause 40 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

13.45 Reserve offers revised if energy offers revised

Subject to clause 13.46(1) and (2) an **ancillary service agent** who has made a **reserve offer** must revise or cancel the **reserve offer** if it has, in accordance with clauses 13.6 to 13.27, revised or cancelled 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 or cancelled

- (1) An **ancillary service agent** (other than an **ancillary service agent** who is an **embedded generator**) may—
 - (a) revise its **reserve offer** prices or its **reserve offer** quantities, as the case may be, for any **trading period** by submitting a new **reserve offer** to the **system operator**. A revised **reserve offer** may be made up to 2 hours before the beginning of the **trading period** in respect of which the **reserve offer** is made; or
 - (b) cancel a **reserve offer** by notifying the **system operator**. Any such cancellation may be made up to 2 hours before the beginning of the **trading period** in respect of which the **reserve offer** was made.
- (2) Despite subclause (1), and subject to clauses 13.47 and 13.97 to 13.101, an **ancillary service agent** who revises a **reserve offer** associated with an **embedded generating station** must use reasonable endeavours to submit the revised **reserve offer** at least 2

hours before the beginning of the **trading period** in respect of which the **reserve offer** is made, and may—

- (a) revise any of its **reserve offer** quantities for any **trading period** by submitting a new **reserve offer** to the **system operator**. A revised **reserve offer** may be made up to 30 minutes before the beginning of the **trading period** in respect of which the **reserve offer** was made; or
 - (b) cancel any of its **reserve offers** by notice in writing to the **system operator**. A cancellation of a **reserve offer** may be made up to 30 minutes before the beginning of the **trading period** in respect of which the **reserve offer** was made.
- (3) Before the beginning of the **trading period** to which the **reserve offer** applies, and despite subclause (4) and clauses 13.47 and 13.97 to 13.101, an **ancillary service agent** must immediately submit revised **reserve offer** quantities to the **system operator** if—
- (a) the quantities specified in the **reserve offer** no longer represent a reasonable estimate of the quantity of **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 quantities specified in the **non-response schedule** most recently **published** by the **system operator** are 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) An **ancillary service agent** may not revise the price for its **reserve offer** later than 2 hours before the beginning of the **trading period** in which that price has been **offered**.

Compare: Electricity Governance Rules 2003 rules 6.12 and 6.13 section II part G

Clause 13.46(3)(b): amended, on 28 June 2012, by clause 27 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.47 Quantity changes may be made within 2 hours before trading period

- (1) Despite clauses 13.46 and 13.97 to 13.101, an **ancillary service agent** may—
- (a) cancel or revise a **reserve offer** or submit a new **reserve offer** to the **system operator** later than 2 hours, or in the case of a **reserve offer** associated with an **embedded generating station** later than 30 minutes, before the **trading period** in respect of which the **reserve offer** is made only if—
 - (i) a **bona fide physical reason** necessitates the cancellation or revision; or
 - (ii) the **system operator** issues a **formal notice** under clause 5 of **Technical Code B** of Schedule 8.3; or
 - (b) submit a **reserve offer** or revise a **reserve offer** to the **system operator** later than 2 hours, or in the case of a **reserve offer** associated with an **embedded generating station** later than 30 minutes, before the **trading period** in respect of which the **reserve offer** is made if—
 - (i) a **bona fide physical reason** that necessitates a cancellation or revision under paragraph (a)(i) ceases to exist sooner than was expected at the time it arose; and
 - (ii) the 1st **trading period** after the original **bona fide physical reason** ceases to exist is within 24 hours of the original **bona fide physical reason** occurring; and

- (iii) the total change in quantity for the **reserve offer** in a **trading period** 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 quantity for the **reserve offer** that was made for the same **trading period** as a result of the original **bona fide physical reason**.
- (2) Whether or not the cancellation, revision or new submission was in accordance with this clause (including, if applicable, whether it was necessitated by a **bona fide physical reason**) must be determined in accordance with clause 13.50(2).

Compare: Electricity Governance Rules 2003 rule 6.14 section II part G

Clause 13.47(2): amended, on 15 May 2014, by clause 41 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

13.48 System operator notified of revised reserve offers in certain circumstances

If a cancellation, revision or new submission of a **reserve offer** is sent to the **system operator** under clause 13.47 and the cancellation, revision or new submission is submitted later than 15 minutes before the relevant **trading period**, before sending that cancellation, revision or new submission the **ancillary service agent** must immediately notify the **system operator** of the cancellation, revision or new submission by telephone or electronic means (if electronic means have been agreed between the **system operator** and the **ancillary service agent** before the **ancillary service agent** notifying the **system operator** of the cancellation, revision or new submission).

Compare: Electricity Governance Rules 2003 rule 6.15 section II part G

13.49 Authority notified of revised reserve offer inside 2 hour period

An **ancillary service agent** who cancels a **reserve offer** or submits a new or revised **reserve offer** to the **system operator** later than 2 hours, or in the case of a **reserve offer** associated with an **embedded generating station** 30 minutes, before the **trading period** in respect of which the **reserve offer** is made must report each cancellation, revision or new submission to the **Authority** in writing together with an explanation of the reasons for the cancellation, revision or new submission. The **ancillary service agent** must report a cancellation, revision or new submission to the **Authority** by 1700 hours on the 1st **business day** following the **trading day** on which the cancellation, revision or new submission was made.

Compare: Electricity Governance Rules 2003 rule 6.16 section II part G

13.50 System operator to advise Authority of cancellation or revision of reserve offers

- (1) The **system operator** must advise the **Authority** of any cancellation or revision of the availability of reserves that are provided under **ancillary services** contracts not covered by clauses 13.37 to 13.54. The **system operator** must advise the **Authority** of a cancellation or revision by 1700 hours on the 1st **business day** following the **trading day** on which the cancellation or revision was made.
- (2) The **Authority** must consider every report made to it under clause 13.49 or subclause (1) and assess whether the cancellation, revision or new submission made by the **ancillary service agent** complied with clause 13.47 and if not, any action the **Authority** should take in relation to the non-compliance.

Compare: Electricity Governance Rules 2003 rules 6.17 and 6.18 section II part G

13.51 Transmission of reserve offers through information system

- (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 the electronic facility contained in the **information system**.
- (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 the electronic facility contained in the **information system**. 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 its **reserve offer** or cancellation of a **reserve offer** has been received by the **system operator** within 10 minutes after the **reserve offer** or cancellation of a **reserve offer** has been sent, the **ancillary service agent** must telephone the **system operator** to check whether the **reserve offer** or cancellation of a **reserve offer** has been received. If it has not, 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 information system is unavailable

- (1) If the **information system** 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 **market administrator**.
- (2) The backup procedures referred to in subclause (1) must be specified by the **market administrator** following consultation with **ancillary service agents** and the **system operator**. The **market administrator** must ensure that there is always a backup procedure notified to the **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

Clause 13.53: amended, on 15 May 2014, by clause 42 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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** and all cancelled **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 **market administrator** must, within 24 hours of the end of each day, make available all final **bids**, final **offers** and final **reserve offers** received for the **trading periods** of the previous **trading day**.
- (2) All information to be made available by the **market administrator** under this clause must be—
 - (a) transmitted to **participants** through the electronic facilities contained in the **information system**; and
 - (b) placed on a publicly accessible website—
and must remain available for inspection through the electronic facilities contained in the **information system** and on the publicly accessible website, for a period of at least 4 weeks.
- (3) If the **information system** is unavailable to send information under subclause (2)(a), the **market administrator** must follow the backup procedures specified by the **market administrator** from time to time.
- (4) The backup procedures referred to in subclause (3) must be put in place by the **market administrator** in consultation with **purchasers**, **generators** and **ancillary service agents**. The **market administrator** must ensure that there is always a backup procedure notified to the **purchasers**, **generators** and **ancillary service agents**.
- (5) If the publicly accessible website on which information is placed under subclause (2)(b) is not available the **market administrator** is not obliged to follow any backup procedures, but the **market administrator** must make the information available as soon as practicable once the publicly accessible website becomes available.
- (6) *[Revoked]*
- (7) *[Revoked]*

Compare: Electricity Governance Rules 2003 rule 7 section II part G

Clause 13.55 Heading: amended, on 28 June 2012, by clause 28(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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.

Clause 13.55A: inserted, on 28 June 2012, by clause 29 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.55A(1)(b): amended, on 15 May 2014, by clause 17 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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

Clause 13.56: substituted, on 28 June 2012, by clause 30 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.56(e): amended, on 15 May 2014, by clause 18 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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

Clause 13.57(a): amended, on 15 May 2014, by clause 19 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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 send the **price-responsive schedule** and the **non-response schedule** to the **clearing manager**.

Compare: Electricity Governance Rules 2003 rules 3.1 to 3.4 section III part G

Clause 13.58(1): substituted, on 28 June 2012, by clause 31 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.58(1A): inserted, on 28 June 2012, by clause 31 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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.

Clause 13.58(4): substituted, 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
 - (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**.

Clause 13.58A: inserted, on 28 June 2012, by clause 32 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.58A(1)(e)(ii): substituted, on 1 November 2012, by clause 5(1) of the Electricity Industry Participation (HVDC Link Pole 3 Standing Data) Code Amendment 2012.

Clause 13.58A(2)(d)(ii): substituted, on 1 November 2012, by clause 5(2) of the Electricity Industry Participation (HVDC Link Pole 3 Standing Data) Code Amendment 2012.

Clause 13.58A(1)(c): amended, on 15 May 2014, by clause 20 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.58A(2)(a) – (c): amended, on 15 May 2014, by clause 20 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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
 - (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: substituted, on 28 June 2012, by clause 33 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.59(a)(iv): amended, on 3 October 2013, by clause 5 of the Electricity Industry Participation (Technology Neutral Language in Frequency Keeping) Code Amendment 2013.

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.

Clause 13.59(c): substituted, on 15 May 2014, by clause 21 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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 notify the **system operator** and 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 notify the **system operator** and 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

Clause 13.60(2)(b): amended, on 28 June 2012, by clause 34 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.60(3): inserted, on 15 May 2014, by clause 43 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

13.61 System operator to notify block security constraints

- (1) The **system operator** must notify **generators** of the implication of any **block security constraints** that apply within the **block dispatch group**. The notification must include—
 - (a) the **trading periods** for which the **constraint** applies; and
 - (b) how the **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) notification from the **system operator** that the **constraint** no longer exists; or
 - (d) receipt of an instruction from the **system operator** in accordance with clause 13.75(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(3): revoked, on 15 May 2014, by clause 44 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 71 **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

Clause 13.62: substituted, on 28 June 2012, by clause 35 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.63 Trading period information to be given to pricing manager and clearing manager

The **system operator** must, by 0730 hours of each **trading day**, send to the **pricing manager** and **clearing manager** the final information provided to the **system operator** under subpart 1 in relation to each **trading period** of the previous **trading day**.

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 notify 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 notify station security constraints

- (1) The **system operator** must notify the **generator** of the implication of any **station security constraints** that apply within a **station dispatch group**. The notification 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) notification 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(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 notifies 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 notify 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 through information system

- (1) All information to be made available by the **system operator** to the **clearing manager** or the **pricing manager** under clauses 13.58 to 13.66 must be transmitted through the electronic facility contained in the **information system**.

- (2) If the **information system** is unavailable to send information under clauses 13.58 to 13.66 the **system operator** must follow the backup procedures specified by the **market administrator**.
- (3) The backup procedures referred to in subclause (2) must be specified by the **market administrator** following consultation with the **system operator**, the **clearing manager**, and the **pricing manager**. The **market administrator** must ensure that there is always a backup procedure notified to 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

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

Clause 13.68 Heading: amended, on 28 June 2012, by clause 36(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.68(1): amended, on 28 June 2012, by clause 36(2) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.68: revoked, on 15 May 2014, by clause 22 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.69 System operator may adjust dispatch schedule [Revoked]

Compare: Electricity Governance Rules 2003 rule 4.2 section III part G

Clause 13.69: revoked, on 15 May 2014, by clause 22 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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.

Clause 13.69A: inserted, on 15 May 2014, by clause 23 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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** notified 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** notified 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** notified 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

Clause 13.71(d): amended, on 28 June 2012, by clause 37 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.71: substituted, on 15 May 2014, by clause 24 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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

Clause 13.72: substituted, on 15 May 2014, by clause 25 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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 notified 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.

Clause 13.73: substituted, on 15 May 2014, by clause 26 of the Electricity Industry Participation (Modified Dispatchable Demand) 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

Clause 13.74: substituted, on 3 October 2013, by clause 7 of the Electricity Industry Participation (Technology Neutral Language in Frequency Keeping) Code Amendment 2013.

Clause 13.74: revoked, on 15 May 2014, by clause 27 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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) the **block security constraints** that occur within a **block dispatch group** and how that **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) the **station security constraints** that occur within a **station dispatch group** and how that **constraint** divides the **generating stations or generating units** of a **station dispatch group** into **sub-station dispatch groups**.
 - (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(a): amended, on 3 October 2013, by clause 8 of the Electricity Industry Participation (Technology Neutral Language in Frequency Keeping) Code Amendment 2013.

Clause 13.75(1): amended, on 15 May 2014, by clause 28(a) & (b) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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.

Clause 13.75(2): inserted, on 15 May 2014, by clause 28(d) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.76 Dispatch instructions to be logged

- (1) The **system operator** must issue **dispatch instructions** using the electronic facilities specified in the **information system** to—
 - (a) each **generator**; and
 - (b) each **dispatchable load purchaser** that has submitted a **nominated dispatch bid**.

- (2) The **system operator** must use either voice communication or electronic communication (if such facility exists) to issue **dispatch instructions** to each **ancillary service agent**.
- (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) By 1600 hours on the 7th **business day** of each **billing period**, the **system operator** must provide to the **clearing manager** a copy of each **dispatch instruction** that the **system operator**—
 - (a) issued during the previous **billing period**; and
 - (b) has logged and recorded under subclause (3).
- (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

Clause 13.76: substituted, on 15 May 2014, by clause 29 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.76(6): amended, on 15 May 2014, by clause 45 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

13.77 Dispatch instructions to plant required by system operator *[Revoked]*

Compare: Electricity Governance Rules 2003 rule 4.9.1 section III part G

Clause 13.77: revoked, on 15 May 2014, by clause 30 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.78 Active power dispatch instructions to clearing manager *[Revoked]*

Compare: Electricity Governance Rules 2003 rule 4.9.2 section III part G

Clause 13.78: revoked, on 15 May 2014, by clause 30 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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

Clause 13.79: amended, on 21 September 2012, by clause 19 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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

Clause 13.80(1): amended, on 21 September 2012, by clause 20 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 13.80(1): amended, on 15 May 2014, by clause 31 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.80(1): amended, on 15 May 2014, by clause 46 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

13.81 Backup procedures if communication not possible

- (1) The **system operator** must follow the back-up 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 send, using the electronic facilities specified under clause 13.76(1), a **dispatch instruction** 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

Clause 13.81(1)(a): substituted, on 15 May 2014, by clause 32(a) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.81(1)(b): amended, on 15 May 2014, by clause 47 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

Clause 13.81(2): inserted, on 15 May 2014, by clause 32(b) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.82 Dispatch instructions to be complied with

- (1) This clause applies to—
- (a) a **generator**; and
 - (b) an **ancillary service agent**; and
 - (c) a **dispatched purchaser**.
- (2) 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 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 of a disconnection of **demand** under clause 7(20) of **Technical Code B** of Schedule 8.3; 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 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 or test plan; and
 - (iii) has no reasonable means of complying with the **dispatch instruction** while acting in accordance with the commissioning or test plan.
- (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(h): inserted, on 18 April 2013, by clause 4 of the Electricity Industry Participation (Dispatch Compliance Minor Amendment) Code Amendment 2013.
- Clause 13.82: substituted, on 15 May 2014, by clause 33 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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.

Clause 13.83A: inserted, on 15 May 2014, by clause 34 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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 **co-generators**, 1 MW from the last **dispatch instruction** that the **generator** complied with; or
- (c) for **co-generators**, 5 MW from the last **dispatch instruction** that the **generator** complied with.

Compare: Electricity Governance Rules 2003 rule 4.16 section III part G

Clause 13.86: amended, on 15 May 2014, by clause 35 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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

Clause 13.88 Heading: amended, on 28 June 2012, by clause 39(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.88 (1)-(4): amended, on 28 June 2012, by clause 39(2)-(4) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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

Clause 13.89 Heading: amended, on 28 June 2012, by clause 40(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.89: amended, on 28 June 2012, by clause 40(2) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.90 Process for publishing real time prices

- (1) The **system operator** must use reasonable endeavours to **publish**, 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) The **system operator** must use reasonable endeavours to make available to **participants**, for each **grid injection point** and each **grid exit point**, 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

Clause 13.90(1): amended, on 28 June 2012, by clause 41 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.90(1)(b)(ii): substituted, on 15 May 2014, by clause 48 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

Clause 13.90(1)(b)(iii): amended, on 15 May 2014, by clause 36 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.90(1)(b)(iii)(A): amended, on 21 September 2012, by clause 21 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

13.91 Transmission of information through information system

- (1) All information that must be made available by the **system operator** under clauses 13.89 to 13.96 must be transmitted through the electronic facility contained in the **information system**.
- (2) If the **information system** is unavailable to send information under clauses 13.89 to 13.96, the **system operator** must follow the backup procedures specified by the **market administrator**.
- (3) The backup procedures referred to in subclause (2) must be specified by the **market administrator** following consultation with **purchasers, generators** and the **system operator**. The **market administrator** must ensure that there is always a backup procedure notified to **purchasers, generators** and the **system operator**.

Compare: Electricity Governance Rules 2003 rules 7.3 to 7.5 section III part G

13.92 Transmission of information through website

- (1) The information (if any) received from the **system operator** under clause 13.90 must be made available by the **market administrator** by placing that information on a publicly accessible website.
- (2) If the publicly accessible website upon which information is placed under subclause (1) is no longer available, the **market administrator** is not required to follow any backup procedures, and the **market administrator** is not required to make the information available on the publicly accessible website at a later time.

Compare: Electricity Governance Rules 2003 rules 7.6 and 7.7 section III part G

13.93 Market administrator to appoint person to monitor and assess demand side participation and real time prices

- (1) The **market administrator** may, or may 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 **market administrator** or the person appointed by the **market administrator** under subclause (1), in a manner agreed between the **system operator** and that person,—
 - (a) if that person is not the **market administrator**, the information the **system operator** makes available to the **participants** and the **market administrator** 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

Clause 13.96: substituted, on 15 May 2014, by clause 37 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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, if the **system operator** has declared a **grid emergency**,—
- (a) a **generator**, other than an **intermittent generator**, may not reduce the aggregate quantity of **electricity** specified in all 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 necessitates the reduction; and
- (b) an **ancillary service agent** may not reduce the aggregate quantity of **instantaneous reserve** specified in all 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 necessitates the reduction; 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 quantities of **electricity** offered in respect of certain **generating plant**, if equivalent increased quantities are, 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 notified by the **system operator** under clause 5(1) of **Technical Code** of in Schedule 8.3; and
- (b) an **ancillary service agent** may reduce the quantities of **instantaneous reserves** offered, if equivalent increased quantities are, in substitution, offered by that **ancillary service agent** at **points of connection** with the **grid** in the electrical or geographical region affected as notified by the **system operator** 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 quantity 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 13.18(2), a **generator** may submit a new price band or bands for new **offers** or revised **offers** in respect of the increased quantity made under paragraph (c), but may not revise the price band or bands in respect of the quantity of **electricity** 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 quantity of **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(4), 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 quantity made under paragraph (e), but may not revise the type of **instantaneous reserve** or the price band or bands in respect of the quantity of **instantaneous reserve** offered before the notice of the **grid emergency**.

Compare: Electricity Governance Rules 2003 rule 8.3 section III part G

13.99 Effect of grid emergency on total quantities bid

Despite clauses 13.6 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

Clause 13.99(a): amended, on 28 June 2012, by clause 42 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.99(a): amended, on 15 May 2014, by clause 38 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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**.

Clause 13.99A: inserted, on 15 May 2014, by clause 39 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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(a): amended, on 15 May 2014, by clause 40(a) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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**, provide a written report to the **Authority** setting out the basis on which the decision to declare the **grid emergency** was made. The **Authority** must **publish** this report through the **information system**; and
- (b) a **generator** who reduced the aggregate quantity of **electricity** specified in **offers**, and an **ancillary service agent** who reduced the **instantaneous reserve** specified in **reserve offers**, 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 first **business day** after the **trading day** on which the reduction was made; and
- (c) a **purchaser** who increased the aggregate quantity of **electricity** specified in **nominated bids** made by the **purchaser** in respect of the **non-conforming GXPs** and **trading periods** affected by the **grid emergency** must report the increase to the **Authority** in writing together with details of the **bona fide physical reason** for the increase claimed by the **purchaser** under clause 13.99(a). An increase must be reported to the **Authority** by 1700 hours on the first **business day** after the **trading day** on which the increase was made.
- (2) The **Authority** must consider each report made to it under subclause (1)(b) and (1)(c) and assess whether the reduced **offer** made by the **generator**, the reduced **reserve offer** made by the **ancillary service agent**, or the increased **bid** made by the **purchaser**, as the case may be, was necessitated by a **bona fide physical reason**, and whether the **purchaser, generator** or **ancillary service agent** complied with clauses 13.97(2) or 13.99 as the case may be, and if not, any action the **Authority** should take in relation to the non-compliance.

Compare: Electricity Governance Rules 2003 rules 8.6 and 8.7 section III part G

Clause 13.101(1)(b): amended, on 28 June 2012, by clause 44(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.101(1)(c): substituted, on 28 June 2012, by clause 44(2) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.102 Reporting obligations of system operator

- (1) On each **trading day** the **system operator** must report to the **market administrator** in writing. The report must include—
- (a) information on any situations in relation to which the **system operator** believes, on reasonable grounds, that it or another **participant** has breached this Code, including—
- (i) the time at which the alleged breach took place; and
- (ii) the nature of the alleged breach and of any **participant** alleged to be in breach; and
- (iii) the reason for the alleged breach, if the **system operator** is aware of the reason,—
- unless exceptional circumstances exist (in which case the report is to be provided as soon as reasonably practicable) the report must be provided on each **trading day** even if the **system operator** has no adjustments or alleged breaches of this Code to report; and
- (b) details of any adjustment to the **non-response schedule** made by the **system operator** during the 48 **trading periods** beginning at 0700 hours of the previous **trading day**; and
- (c) any situations in relation to which discretionary action under clause 13.70 required divergence from the **dispatch schedule** during any of the 48 **trading periods** beginning at 0700 hours of the previous **trading day**; and

- (d) a summary of any **block security constraint** and **station security constraint** notices issued to **generators** in accordance with clauses 13.61(1), and 13.75(f) and (g) during the previous **trading day**.
- (2) By the 15th **business day** of each calendar month, the **market administrator** must **publish** any sections of the reports of the **system operator** received in the previous calendar month under subclause (1)(a) that relate to breaches of this Code by the **system operator**. By the 15th **business day** of each calendar month the **market administrator** must refer the reports received in the previous calendar month under subclause (1) to the **Authority**.
- (3) A **purchaser** or **generator** may, by notice in writing to the **system operator**, request further information from the **system operator** relating to any situation set out in a **system operator's** report **published** under subclause (2) that has materially affected that **purchaser** or **generator**.
- (4) The **system operator** must provide information requested under subclause (3) to the **purchaser** or **generator**, except to the extent that the requested information includes another **participant's** confidential information.

Compare: Electricity Governance Rules 2003 rule 9 section III part G.

Clause 13.102(1)(b): amended, on 28 June 2012, by clause 45 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

System operator to publish information

13.103 [Revoked]

Clause 13.103: revoked, on 28 June 2012, by clause 46 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.104 Information to be published

- (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 **publish**, 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 are **disconnected**; 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 **publish** 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: substituted, on 28 June 2012, by clause 47 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.104(1)(a)(x): revoked, on 1 November 2012, by clause 8(1) of the Electricity Industry Participation (Part 13 Minor Amendments) Code Amendment 2012.

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.

Clause 13.104(1)(a) & (b): amended, on 15 May 2014, by clause 41 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.104(1)(c): inserted, on 1 November 2012, by clause 8(2) of the Electricity Industry Participation (Part 13 Minor Amendments) Code Amendment 2012.

Clause 13.104(1)(c): amended, on 3 October 2013, by clause 9 of the Electricity Industry Participation (Technology Neutral Language in Frequency Keeping) Code Amendment 2013.

13.105 *[Revoked]*

Clause 13.105: revoked, on 28 June 2012, by clause 48 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

13.105A Information to be provided to purchasers, generators, and ancillary service agents

- (1) At the same time as the **system operator** is required to **publish** information in accordance with clause 13.104, the **system operator** must—
 - (aa) send to 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) send to 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) send to 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) send to 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 send 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).

Clause 13.105A: inserted, on 28 June 2012, by clause 49 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 13.105A(1)(aa): inserted, on 15 May 2014, by clause 42 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.106 Transmission of information through information system

- (1) The information required to be **published** by the **system operator** under clauses 13.104 to 13.105A must be transmitted through the electronic facility contained in the **information system**.
- (2) If the **information system** is unavailable to send information the **system operator** must follow the backup procedures specified by the **market administrator**.
- (3) The backup procedures referred to in subclause (2) must be specified by the **market administrator** following consultation with the **system operator, pricing manager, clearing manager, purchasers, generators and ancillary service agents**. The **market administrator** must ensure that there is always a backup procedure notified to the **system operator, pricing manager, clearing manager, purchasers, generators and ancillary service agents**.

Compare: Electricity Governance Rules 2003 rules 10.5 to 10.7 section III part G

Clause 13.106(1): amended, on 28 June 2012, by clause 50 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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 payable

- (1) The **clearing manager** must calculate the amount payable by each **generator** for the **auction rights** the **generator** has acquired in the previous **billing period**.
- (2) Any **auction revenue** payable by a **generator** in relation to a **billing period** must be included in an invoice issued to the **generator** by the **clearing manager** under clause 14.45(d).

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:

$$AR_p = (TAR_g/APB)*(P_q/TP_q)$$

where

AR_p is the **auction revenue** receivable by a **purchaser**

TAR_g	is the total auction revenue for a time block payable 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** payable to a **purchaser** in relation to a **billing period** must be included in an invoice issued to the **purchaser** by the **clearing manager** under clauses 14.36 and 14.40.

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 Information to be transmitted through information system

- (1) All information exchanged in relation to clauses 13.108 to 13.116 must be sent electronically using the facility contained in the **information system**.
- (2) If the **information system** is not available to send information under this clause the **clearing manager** must follow the backup procedures specified by the **market administrator**.
- (3) The backup procedures referred to in subclause (2) must be specified by the **market administrator** following consultation with **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 Exchange information

All information relating to **auctions** must be exchanged through the **information system**.

Compare: Electricity Governance Rules 2003 rule 3.4 section IV part G

13.119 Historic load data

By 1100 hours 2 days before each **auction**, each **grid owner** must advise the **clearing manager** the total load of the **preceding year day** for the day following the **auction**.

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:

$$\text{quantity of auction rights available in each time block} = 0.8 \cdot \text{ldf}_{\text{tb}}$$

where

ldf_{tb} is the lowest demand forecast for a **time block**, which is the lowest demand in any **trading period** on the **preceding year day** (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 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 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 payable 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 notify—

- (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 issue an authorisation 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 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 price situation** is resolved, but before **publishing final prices** or **final reserve prices**, the **pricing manager** must **publish interim prices** and **interim reserve prices**; 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

Clause 13.132(a): amended, on 1 June 2013, by clause 8 of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

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(2): substituted, on 23 December 2011, by clause 4 of the Electricity Industry Participation (High Spring Washer Price Situation) Code Amendment 2011.

Clause 13.134(2A) and (2B): inserted, on 23 December 2011, by clause 4 of the Electricity Industry Participation (High Spring Washer Price Situation) Code Amendment 2011.

Clause 13.134(1): amended, on 21 September 2012, by clause 5(1) of the Electricity Industry Participation (High Spring Washer Price Situation) Code Amendment 2012.

Clause 13.134(2): substituted, on 21 September 2012, by clause 5(2) of the Electricity Industry Participation (High Spring Washer Price Situation) Code Amendment 2012.

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.

Clause 13.134(4), (5) and (6): inserted, 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.

Compare: Electricity Governance Rules 2003 rule 3.1 section V part G

Clause 13.135: amended, on 1 June 2013, by clause 9 of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

13.135A Notice of scarcity pricing situation

- (1) This clause applies if the **pricing manager**, in relation to a **trading period**, gives 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**.
- (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) **publish** notice of the **scarcity pricing situation**; and
 - (b) 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**.

Clause 13.135A: inserted, on 1 June 2013, by clause 10 of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

13.135B Methodology to prepare interim prices and interim reserve prices if scarcity pricing situation exists

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) **publish interim prices** and **interim reserve prices** for the **trading period** by—
 - (i) if no **provisional price situation** is notified, 1200 hours in the following **trading day**; or
 - (ii) if a **provisional price situation** is notified, 2.5 hours after the **provisional price situation** is resolved.

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 pricing manager half-hour metering information

13.136 Generators to provide half-hour metering information

- (1) Each **generator** must give the **pricing manager**, and each **embedded generator** must give the **pricing manager** and the **grid owner** connected to the **local network** in which the **embedded generator** is located, **half-hour metering information** in accordance with 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
 - (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**.
- (2) To avoid doubt, subclause (1) excludes any **unoffered generation** or **electricity** supplied from an **intermittent generating station**.

Compare: Electricity Governance Rules 2003 rule 3.2.1 section V part G

13.137 Unoffered and intermittent generation to provide metering information

- (1) Each **generator** must give the **pricing manager** and 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**.
- (2) To avoid doubt, each **generator** must give the **pricing manager** and 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 **pricing manager** and the relevant **grid owner** a reasonable estimate of such data.

Compare: Electricity Governance Rules 2003 rule 3.2.2 section V part G

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 **pricing manager** 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

Clause 13.138 Heading: amended, on 15 May 2014, by clause 43 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.138A Dispatchable load purchaser's half-hour metering information to be adjusted for losses

- (1) Each **dispatchable load purchaser** must provide **half-hour metering information** to the **pricing manager** and 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 **pricing manager**; 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.

Clause 13.138A: inserted, on 15 May 2014, by clause 44 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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**.

Clause 13.138B: inserted, on 15 May 2014, by clause 44 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.139 Half-hour metering information part of input information

The adjusted embedded **half-hour metering information** forms part of 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 notify provision of 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 the **pricing manager** and a **grid owner** under clauses 13.136 to 13.138, or 13.138A, the **participant** must **publish** a notice—
 - (a) specifying that it has given **half-hour metering information** to the **pricing manager** and the relevant **grid owner**; and
 - (b) by 0730 hours on the day the **participant** provided the **half-hour metering information** to the **pricing manager** and the relevant **grid owner**.

Compare: Electricity Governance Rules 2003 rule 3.2.5 section V part G

Clause 13.140: substituted, on 15 May 2014, by clause 45 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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:

$$L_{MA} = G_{EA} + L_{MX} - L_{DCLS} \text{ (for a grid exit point)}$$

$$L_{MA} = G_{EA} - L_{MI} - L_{DCLS} \text{ (for a grid injection point)}$$

$$L_{MA} = L_{MX} - L_{DCLS} - UI_{GEA} \text{ (for an intermittent generating station with a point of connection to the grid and/or unoffered generation from a generating station with a point of connection to the grid)}$$

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 **pricing manager** under clause 13.136

UIG_{EA} is the information given to the **pricing manager** 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 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. The **pricing manager** must remove all **offers** from **intermittent generators** from this information before using it in the pricing process:
 - (ca) the final submitted **nominated dispatch bid** for 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** that the **system operator** notifies in accordance with clause 13.63.
- (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 **publish** the information 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 13.135 to 13.140, and if the revised information resolves a **provisional price situation**, the **pricing manager** must **publish** the revised demand **half-hour metering information** no later than the time at which it is required to **publish interim prices** and **interim reserve prices**.
- (5) If the **pricing manager** receives the revised information after it has **published** information in accordance with subclauses (1)(b) and (2) to (4), it must **publish** the revised information by replacing the previously **published** information with the revised information.

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.

Clause 13.141(1)(ca): inserted, on 15 May 2014, by clause 46(b) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.141(1)(e): amended, on 15 May 2014, by clause 46(c) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.141(1A): inserted, on 15 May 2014, by clause 46(d) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.141(5): amended, on 21 September 2012, by clause 22 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

13.142 Pricing manager to publish interim prices unless provisional price situation or shortage situation notified

- (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 **published** for the previous **trading day**:
 - (a) a notice **published** by a **grid owner**, in accordance with clause 13.143, which specifies that a **SCADA situation** exists;
 - (b) a notice **published** 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 **published** for the previous **trading day**, the **pricing manager** must **publish interim prices** and **interim reserve prices** for the previous **trading day** by 1200 hours.

Compare: Electricity Governance Rules 2003 rule 3.4 section V part G

Clause 13.142 Heading: amended, on 1 June 2013, by clause 11(1) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

Clause 13.142(1): amended, on 1 June 2013, by clause 11(2) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

Clause 13.142(1)(b): amended, on 1 June 2011, by clause 5 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2011.

13.143 Grid owners to notify 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) **publish** notice that it 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 **publish** further notices 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 **publish** each notice **published** in accordance with subclause (3) no later than 0900 hours on the same day that it gave notice under subclause (1)(a).

Compare: Electricity Governance Rules 2003 rule 3.5 section V part G

13.144 Pricing manager to give 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, no later than 0900 hours on the day that the **pricing manager** receives the **input information** or notice,—
- (a) **publish** 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**.
- (2) The **pricing manager** must not give 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.

Compare: Electricity Governance Rules 2003 rules 3.6 and 3.6A section V part G

Clause 13.144 Heading: amended, on 1 June 2013, by clause 12(1) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

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(1)(c): amended, on 1 June 2013, by clause 12(2)(d) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

Clause 13.144(1)(d): inserted, on 1 June 2013, by clause 12(2)(e) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

Clause 13.144(2): amended, on 1 June 2013, by clause 12(3) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

13.145 Grid owner to give notice that estimated data given

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) **publish** notice 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.

Compare: Electricity Governance Rules 2003 rule 3.7 section V part G

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**.
- (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**.
- (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 supply **half-hour metering information** to the **pricing manager** or to a **grid owner** in accordance with clauses 13.136 to 13.140, and the **pricing manager** has notified 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 Heading: amended, on 1 June 2013, by clause 13(1) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

Clause 13.146(2A): inserted, on 1 June 2013, by clause 13(2) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

Clause 13.146(4): amended, on 15 May 2014, by clause 47 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.147 Revised data to be accompanied by notice

- (1) This clause applies to—
 - (a) a **grid owner**; and
 - (b) a **generator**; and
 - (c) the **system operator**; and
 - (d) a **dispatchable load purchaser**.

- (2) If a **participant** to which this clause applies gives revised data to the **pricing manager** under clause 13.146, the **participant** must—
- (a) **publish** a notice specifying that it has given revised data; 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** to which this clause applies 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.

Compare: Electricity Governance Rules 2003 rule 3.9 section V part G

Clause 13.147: substituted, on 15 May 2014, by clause 48 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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.

Compare: Electricity Governance Rules 2003 rule 3.10 section V part G

Clause 13.148: amended, on 15 May 2014, by clause 49 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.149 Pricing manager to publish provisional prices and provisional reserve prices if revised data and notice not given in relation to 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, **publish** notice of the **provisional price situation** and each **trading period** affected; and
 - (b) by 1200 hours on that day, **publish provisional prices** and **provisional reserve prices**; and
 - (c) by 0900 hours on the following day, inform the **Authority** of the **provisional price situation** in the daily report submitted under clause 13.213.

Compare: Electricity Governance Rules 2003 rule 3.11 section V part G

Clause 13.149: amended, on 15 May 2014, by clause 50 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.150 Pricing manager to publish provisional prices and provisional reserve prices if revised data and notice not given in relation to 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, **publish** notice of the **provisional price situation** and each **trading period** affected; and
 - (b) by 1000 hours on that day **publish provisional prices** and **provisional reserve prices**; and
 - (c) by 0900 hours on the following day inform the **Authority** of the **provisional price situation** in the daily report submitted under clause 13.213.

Compare: Electricity Governance Rules 2003 rule 3.12 section V part G

Clause 13.150: amended, on 15 May 2014, by clause 51 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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 publish interim prices and interim reserve prices 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) **publishes** a notice in accordance with clause 13.147.
- (2) If this clause applies, the **pricing manager** must **publish interim prices** and **interim reserve prices** for each **trading period** of the previous **trading day**.
- (3) The **pricing manager** must **publish** the **interim prices** and **interim reserve prices** 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

Clause 13.152: substituted, on 15 May 2014, by clause 52 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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 **publish provisional prices** and **provisional reserve prices** 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 published

- (1) This clause applies if the **pricing manager publishes provisional prices** and **provisional reserve prices** under clause 13.149 or 13.150.
- (1A) If **provisional prices** and **provisional reserve prices** are **published** 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**; 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**.
- (2) The revised data required by subclause (1A) must be provided to the **pricing manager** by 1200 hours on the 2nd **business day** following the **publication** of the **provisional prices** and **provisional reserve prices**.

Compare: Electricity Governance Rules 2003 rule 3.16 section V part G

Clause 13.154 Heading: amended, on 15 May 2014, by clause 53(a) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.154(1): substituted, on 15 May 2014, by clause 53(b) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.154(1A): inserted, on 15 May 2014, by clause 53(b) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.154(2): amended, on 15 May 2014, by clause 53(c) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.155 Revised data to be accompanied by notice

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) **publish** notice that revised data has been given; 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.

Compare: Electricity Governance Rules 2003 rule 3.17 section V part G

Clause 13.155: amended, on 15 May 2014, by clause 54 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.156 Pricing manager to publish interim prices following publication of provisional prices and provisional reserve prices 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 **publish interim prices** and **interim reserve prices** 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 **published**, **publish interim prices** and **interim reserve prices** 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 **published**, **publish interim prices** and **interim reserve prices** 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 **published**, **publish** 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 **published**, **publish** 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 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 notice that a **high spring washer price situation** exists in that **trading period**.

Compare: Electricity Governance Rules 2003 rules 3.18 and 3.18A section V part G

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 **published**, exercise reasonable endeavours to resolve the **provisional price situation** and provide revised data to the **pricing manager**.
- (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 **published**, 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**.

Compare: Electricity Governance Rules 2003 rule 3.19 section V part G

13.158 Revised data to be accompanied by notice

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) **publish** notice that revised data has been given; 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.

Compare: Electricity Governance Rules 2003 rule 3.20 section V part G

13.159 Pricing manager to publish interim prices or publish 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 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**, **publish interim prices** and **interim reserve prices** for all **trading periods** of the relevant **trading day**;
or

- (ii) if an **infeasibility situation** arises from that data, **publish interim prices and interim reserve prices** 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 **published**, **publish** 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 notice in accordance with clause 13.158,—
 - (i) in relation to an **infeasibility situation**, the **pricing manager** must **publish interim prices and interim reserve prices** in accordance with clauses 13.163 and 13.164; or
 - (ii) in relation to a **high spring washer price situation**, the **pricing manager** must **publish interim prices and interim reserve prices** by 1800 hours on the 2nd **business day** after the **provisional prices** and **provisional reserve prices** were **published**, 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 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 **published**,—
 - (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**.
- (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) **publish** notice that the revised data has been given; 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.

Compare: Electricity Governance Rules 2003 rule 3.21B section V part G

13.162 Pricing manager to publish interim prices

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 **published**, **publish interim prices** and **interim reserve prices** 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 **published**, **publish interim prices** and **interim reserve prices** 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

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 **publish interim prices** and **interim reserve prices** and must give 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 **publishes provisional prices** and **provisional reserve prices**.

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 **publish interim prices** under clause 13.163, **publish** notice that it 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 **publish interim prices** 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 it **publishes provisional prices** and **provisional reserve prices**; 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 it **publishes provisional prices** and **provisional reserve prices**; and
- (d) **publish** notice of all **interim prices** and **interim reserve prices** by 1800 hours on the 2nd **business day** after it **publishes provisional prices** and **provisional reserve prices**.

Compare: Electricity Governance Rules 2003 rule 3.23 section V part G

13.165 Authority notified 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 notify 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

Clause 13.166 Heading: amended, on 15 May 2014, by clause 55 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.166 (1) and (2): amended, on 15 May 2014, by clause 55 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.166A Pricing manager to recalculate and publish interim prices 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 **publish interim prices** 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**.

Clause 13.166A: inserted, on 1 June 2013, by clause 14 of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

Interim pricing period

13.167 Pricing manager to publish interim prices

The **pricing manager** must **publish interim prices** and **interim reserve prices**—

- (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 **publishing final prices** or **final reserve prices**.

Compare: Electricity Governance Rules 2003 rule 3.26A section V part G

Clause 13.167(aa): inserted, on 1 June 2013, by clause 15 of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

Clause 13.167(c): amended, on 21 September 2012, by clause 23 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

13.168 When pricing error may be claimed

Once the **pricing manager** has **published interim prices** and **interim reserve prices**, 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) email the completed form to an email address notified by the **pricing manager** for that purpose; 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** published the **interim price** or **interim reserve price** that contains the **pricing error**.

Compare: Electricity Governance Rules 2003 rule 3.26D section V part G

Clause 13.170(b): amended, on 21 September 2012, by clause 24 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

13.171 Pricing manager must publish final prices if no pricing error claimed

- (1) This clause applies if, by 1200 on the 1st **business day** following the **trading day** on which the **pricing manager** published the **interim price** or **interim reserve price**, no **pricing error** is claimed in respect of the **interim prices** or **interim reserve prices**.
- (2) The **pricing manager** must **publish** 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** published the **interim prices** or **interim reserve prices**.

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 **publish final prices** or **final**

reserve prices 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** published the **interim prices** or **interim reserve prices** in respect of which the **pricing error** has been claimed, **publish** a 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 notify 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 publish notice

As soon as practicable after the **Authority** has notified the **pricing manager** of its decision under clause 13.175, the **pricing manager** must **publish** a notice 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** to correct the **pricing error**; and
 - (b) direct a **participant** to take any action notified by the **Authority** under clause 13.175(c)(ii) to correct the **pricing error**; and
 - (c) once those actions have been completed, **republish interim prices** and **interim reserve prices**, using any updated **metering information**.
- (2) If the **Authority** decides that a **pricing error** has not occurred, the **pricing manager** must **publish** the **interim prices** and **interim reserve prices** as **final prices** and **final reserve prices**.

Compare: Electricity Governance Rules 2003 rule 3.26K section V part G

13.178 Effect of republishing interim prices

If the **pricing manager** is required to **republish interim prices** and **interim reserve prices** 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 **republished interim prices** and **interim reserve prices**.

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 publishes** the notice under clause 13.176, the **pricing manager**—

- (a) republishes **interim prices** and **interim reserve prices** in accordance with clause 13.177(1)(c); or
- (b) publishes **final prices** and **final reserve prices** in accordance with clause 13.177(2).

Compare: Electricity Governance Rules 2003 rule 3.26M section V part G

Clause 13.179: amended, on 21 September 2012, by clause 25 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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 the **publication** of **interim prices**, **interim reserve prices**, **final prices** and **final reserve prices** 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 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, 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 notified 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 **final prices** or **final reserve prices** are **published**, no further **pricing errors** can be claimed in respect of those prices.

Compare: Electricity Governance Rules 2003 rule 3.26P section V part G

Publication of final prices

13.183 Republication of final prices

Unless directed to do so by the **Authority** under clause 5.2, the **pricing manager** must not **republish** the **final price** or **final reserve price** 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 of publication of final prices

Despite clauses 13.135 to 13.191 the **Authority** may order that the **publication** of **interim prices**, **interim reserve prices**, **final prices**, or **final reserve prices** be delayed.

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 **publish** 1 or more of the following prices for more than 1 **trading day** at a time, the **pricing manager's publishing** deadline 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

Clause 13.185: substituted, on 21 September 2012, by clause 26 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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:

Electricity Industry Participation Code 2010
Part 13

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	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
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	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46

- (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		
Recorded	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	25
Recorded	1	2	3	4	5	6	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
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	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48

- (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:

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
Record	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
Record	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50

Compare: Electricity Governance Rules 2003 rule 3.31 section V part G

13.188 Market administrator to publish annual consumption list

- (1) At least once every 6 months, the **reconciliation manager** must give the **market administrator** 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 **market administrator** must **publish** the list within 1 **business day** of receiving it.

Compare: Electricity Governance Rules 2003 rule 3.32 section V part G

13.189 System operator to give pricing manager list of model variable values

- (1) The **system operator** must provide the **pricing manager** with a list of the values of the model parameters used by the **software** to produce **final prices** and **final reserve prices** as listed in Schedule 13.2.
- (2) If the value of the model parameters listed in Schedule 13.2 are to be changed, the **system operator** must immediately give the **pricing manager** an updated list of values.
- (3) The **pricing manager** 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 the **pricing manager's** agreement in writing.

Compare: Electricity Governance Rules 2003 rule 3.33 section V part G

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**.

Clause 13.189A: inserted, on 15 May 2014, by clause 56 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.190 All notifications to be unconditional, final and transmitted by information system

- (1) All information and every notice to be given under clauses 13.135 to 13.191 must be **published** through the **information system**.
- (2) Except as provided for in this Code, **participants** may treat any such information and notices as final.

Compare: Electricity Governance Rules 2003 rule 3.34 section V part G

13.191 Backup procedures if information system is unavailable

- (1) If the **information system** is unavailable to send information under clauses 13.135 to 13.191, each **grid owner** and the **pricing manager** must follow the backup procedures specified by the **market administrator**.

- (2) The backup procedures referred to in subclause (1) must be specified by the **market administrator** following consultation with **generators, purchasers, ancillary service agents, the grid owners and the pricing manager**.
- (3) The **market administrator** must ensure that there is always a backup procedure notified to all **generators, purchasers, ancillary service agents, grid owners and the pricing manager**.

Compare: Electricity Governance Rules 2003 rules 3.35 and 3.36 section V part G

Calculation of constrained off amounts

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 **dispatched purchaser**, 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): inserted, on 15 May 2014, by clause 57 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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:

$$COF_g = Q_{cof} * (P_f - P_o)$$

where

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:

$$ConOffAmt_{disp} = ConOffQ * (P_b - P_f)$$

where

$ConOffAmt_{disp}$ is the **constrained off amount** for a **dispatch-capable load station** for the **nominated dispatch bid** price band

$ConOffQ$ 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**
- P_b is the price bid for the **nominated dispatch bid price band** for the **dispatch-capable load station** that was constrained off
- P_f 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 **generation units** 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

Clause 13.194(1): amended, on 15 May 2014, by clause 58(1) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.194(1A): inserted, on 15 May 2014, by clause 58(2) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.194(2)(b) & (c): amended, on 15 May 2014, by clause 58(3) & (4) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.194(2)(b)(ii): amended, on 21 September 2012, by clause 27 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 13.94(2)(c): amended, on 15 May 2014, by clause 49 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 amounts attributable to system operator

If a **constrained off situation** occurs during any **trading period** in the previous **billing period**, and the **constrained off situation** was notified to the **clearing manager** 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:

$$\text{SOCOFNS}_{\text{so}} = \text{TCOFP} * (\text{SOQcoffns} / \text{TQcoff})$$

where

$\text{SOCOFNS}_{\text{so}}$ 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:

$$\text{SOCOFFK}_{\text{so}} = \text{TCOFP} * (\text{SOQcofffk} / \text{TQcoff})$$

where

$\text{SOCOFFK}_{\text{so}}$ 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

Clause 13.196(c): amended, on 15 May 2014, by clause 59 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.197 Calculation of constrained off amounts

By 1600 hours on the 8th **business day** of 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.

Compare: Electricity Governance Rules 2003 rule 4.4 section V part G

Clause 13.197: amended, on 21 September 2012, by clause 28 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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

Clause 13.198(1): amended, on 15 May 2014, by clause 60 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.199 Clearing manager to publish details of constrained off amounts

The **clearing manager** must, at the time specified in clause 13.197, **publish** the details of **constrained off amounts** 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

Clause 13.199: amended, on 15 May 2014, by clause 61 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.200 Authority, generators and purchasers have rights to constrained off information

- (1) In addition to the information **published** by the **clearing manager** 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 entitled to be paid **constrained off compensation** for the **constrained off amounts** calculated under clause 13.194(1A).
- (2) A **purchaser** that purchases **electricity** at a **grid exit point** must pay **constrained off compensation**, calculated under subclause (6), to the **clearing manager**.
- (3) The **clearing manager** must pay **constrained off compensation** received under subclause (2)—
- (a) in accordance with clauses 14.36 to 14.43; and
 - (b) for each **dispatch-capable load station**, to the **dispatched purchaser** that purchased **electricity** for the **dispatch-capable load station**.
- (4) The **clearing manager** must include all **constrained off compensation** payable to a **dispatched purchaser** in relation to a **billing period** in the invoice it issues to the **dispatched purchaser** under clause 14.44(a).
- (5) The **clearing manager** must pay the **constrained off compensation** it receives under subclause (2) to the **dispatched purchaser** at the same time as any other amount owing under clause 14.46 is payable to the **dispatched purchaser**.
- (6) The **clearing manager** must calculate and invoice **constrained off compensation** to be paid by each **purchaser** under subclause (2) for each **trading period** using the following formula:

$$\text{ConOffC}_p = \text{ConOffC}_{\text{DLPs}} * (\text{Pur}_i / \text{TotPur})$$

where

ConOffC_p is the **constrained off compensation** payable by a **purchaser**

$\text{ConOffC}_{\text{DLPs}}$ is the sum of **constrained off compensation** owing to all **dispatched purchasers** for the **trading period**

Pur_i 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.

Clause 13.201A: inserted, on 15 May 2014, by clause 62 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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**.
 - (d) in relation to a **dispatched purchaser**, 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

Clause 13.202(1): amended, on 1 June 2013, by clause 16(a) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

Clause 13.202(1)(d): inserted, on 15 May 2014, by clause 63 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.202(2): inserted, on 1 June 2013, by clause 16(b) of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

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(a) or (b) for each **generator** for each affected price band in accordance with the following formula:

$$\text{COC} = Q_{\text{con}} * (P_o - P_f)$$

where

COC is the **constrained on amount** for a **generator**

Q_{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:

$$\text{ConOnAmt} = \text{ConOnQ} * (P_f - P_b)$$

where

ConOnAmt is the **constrained on amount** for a **dispatch-capable load station** for the **nominated dispatch bid** price band

ConOnQ is the amount in **MWh** by which the lowest of Q_{disp} and Q_{rec} exceeds Q_{fp}

where

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**

Q_{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** 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:

$$\text{COC} = Q_{\text{con}} * (P_o - P_f)$$

where

COC is the **constrained on amount** for an **ancillary service agent**

Q_{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_{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.

Clause 13.204(1)(b)(ii): amended, on 15 May 2014, by clause 64(b) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.204(1)(c): amended, on 21 September 2012, by clause 29 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

13.205 Calculation of constrained on amounts attributable to system operator

If a **constrained on situation** occurs during a **trading period** during a previous **billing period**, and that **constrained on situation** is notified to the **clearing manager** 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:

$$\text{SOCONNS}_{\text{go}} = \text{TCOMP} * (\text{SOQconns} / \text{TQcon})$$

where

$\text{SOCONNS}_{\text{go}}$ is the **constrained on amount** attributable to the **system operator** for that non-security **constrained on situation**

TCOMP 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:

$$\text{SOCONFK}_{\text{go}} = \text{TCOMP} * (\text{SOQconfk} / \text{TQcon})$$

where

$\text{SOCONFK}_{\text{go}}$ is the **constrained on amount** attributable to the **system operator** for that **frequency keeping constrained on situation**

TCOMP is the total constrained on payment for the **generator** for the **trading period**

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

TQcon is the total quantity constrained on for the **generator**.

Compare: Electricity Governance Rules 2003 rule 5.4 section V part G

Clause 13.205: amended, on 15 May 2014, by clause 65 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.206 Time frame for calculating constrained on amounts

The **clearing manager** must calculate **constrained on amounts**—

- (a) by 1600 hours on the 8th **business day** of each **billing period** for the previous **billing period** in accordance with clauses 13.204 and 13.205; or
- (b) 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**.

Compare: Electricity Governance Rules 2003 rule 5.5 section V part G

Clause 13.206: substituted, on 15 May 2014, by clause 4 of the Electricity Industry Participation (Time Frames for Invoicing) Code Amendment 2014.

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 publish details of constrained on amounts

The **clearing manager** must, at the time specified in clause 13.206, **publish** the details of **constrained on amounts** 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

Clause 13.208: amended, on 15 May 2014, by clause 66 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

13.209 Authority, generators, ancillary service agents, and purchasers have rights to constrained on information

- (1) In addition to the information **published** by the **clearing manager** 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 Transmission of information through information system

Information sent to **generators, ancillary service agents, or purchasers** by the **clearing manager** under clauses 13.199 and 13.208 must be transmitted through the electronic facility contained in the **information system**.

Compare: Electricity Governance Rules 2003 rule 5.9 section V part G

13.211 Backup procedures if information system is unavailable

- (1) If the **information system** is unavailable to send information under clauses 13.199 and 13.208 the **clearing manager** must follow the backup procedures specified by the **market administrator** from time to time.
- (2) The backup procedures referred to in subclause (1) must be specified by the **market administrator** following consultation with **generators, ancillary service agents, purchasers** and the **clearing manager**. The **market administrator** must ensure that there is always a backup procedure notified to **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 entitled to be paid **constrained on compensation** for **constrained on amounts** determined under clauses 13.204 and 13.205; and
 - (b) a **dispatched purchaser** is entitled to be paid **constrained on compensation** for **constrained on amounts** determined under clause 13.204.
- (1A) **Constrained on compensation** for each **dispatch-capable load station** must be paid 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) **Constrained on compensation**, except that payable by the **system operator** under subclause (2), owing to a **generator, ancillary service agent, or dispatched purchaser** for a **billing period**, must be included in any invoice issued to the **generator, ancillary service agent, or dispatched purchaser** by the **clearing manager** under clause 14.44(a).
- (4) **Constrained on compensation** received by the **clearing manager** is payable to the **generator, ancillary service agent, or dispatched purchaser** at the same time as any other amounts owing to the **generator, the ancillary service agent, or the dispatched purchaser** as set out in clause 14.46 are payable.
- (5) Each **purchaser** that purchases **electricity** at a **grid exit point** must pay **constrained on compensation**, calculated under subclause (7), to—

- (a) each **generator** that generated **electricity** at a **grid injection point**; and
 - (b) each **dispatched purchaser**.
- (5A) A payment under subclause (5) must be made in accordance with clauses 14.36 to 14.43.
- (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 and invoice **purchasers** for **constrained on compensation** for each **trading period** using the following formula:

$$\text{COC}_p = (\text{COC}_g - \text{COC}_{so}) * (P_q / \text{TP}_q)$$

where

COC_p is the **constrained on compensation** payable by a **purchaser**
 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)

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) Any **constrained on compensation** owing by a **purchaser** in relation to a **billing period** must be included in the invoice issued to the **purchaser** by the **clearing manager** under clause 14.36(1). **Constrained on compensation** is payable by the **purchaser** at the same time as any other amounts owing by that **purchaser** are payable under clause 14.37.

Compare: Electricity Governance Rules 2003 rule 6 section V part G

Clause 13.212(1): substituted, on 15 May 2014, by clause 67(a) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.212(1A): inserted, on 15 May 2014, by clause 67(a) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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.

Clause 13.212(5): substituted, on 15 May 2014, by clause 67(d) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.212(5A): inserted, on 15 May 2014, by clause 67(d) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 13.212(7): amended, on 15 May 2014, by clause 67(e) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Pricing manager's reporting obligations

13.213 Daily reports

- (1) On each **trading day** the **pricing manager** must provide the **market administrator** with a written report for the **trading periods** beginning at 0700 hours on the previous **trading day** and ending with the **trading period** beginning at 0630 hours on the **trading day** the report is due to be given, specifying—
 - (a) any **provisional prices published**; and
 - (b) any **pricing errors** claimed; and
 - (c) any situation where the **pricing manager** believes, on reasonable grounds, that it or another **participant** has breached this Code.
- (2) In relation to each alleged breach the report must give details of—
 - (a) occasions when prices were or will be **published** late and whether the delay was caused by the **pricing manager**; and
 - (b) the time at which the alleged breach took place; and
 - (c) the nature of the alleged breach, including details of the person alleged to be in breach and any **generator** or **purchaser** believed to be affected by the alleged breach; and
 - (d) the reason for the alleged breach, if the **pricing manager** is aware of the reason.

Compare: Electricity Governance Rules 2003 rule 7.1 section V part G

13.214 Market administrator to publish pricing manager reports

- (1) By the 15th **business day** of each calendar month, the **market administrator** must **publish** the sections of the reports of the **pricing manager** given in the previous calendar month under clause 13.213 that relate to any alleged breaches of this Code by the **pricing manager**.
- (2) By the 15th **business day** of each calendar month the **market administrator** must refer the reports received in the previous calendar month to the **Authority**.

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 a **purchaser** may, by notice in writing to the **pricing manager**, request further information relating to any situation set out in a **pricing manager's** report **published** under clause 13.214 that has materially affected the **generator** or **purchaser**.
- (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 following **publication** of **final prices** and **final reserve prices** in respect of the **trading day** to which the **published** prices relate, the **pricing manager** must give the **market administrator** 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:

- (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

Clause 13.218(a): amended, on 21 September 2012, by clause 30 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

13.219 Information that must be submitted

- (1) The following information must be submitted to the **information 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 **information 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 **information 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 **information 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 **information 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 **information 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 **information 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**,—

- (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_i is the price specified in the contract

TP_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 to provide assistance to **sellers** and **buyers** in determining what information must be submitted to the **information 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 **Authority** must **publish** annually, on the **information system**,—
 - (a) a list of all **nodes** at which the **pricing manager publishes final prices**; 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 publishes final prices**, 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:

$$LF = A/B$$

where

- A is the average **final price published** 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 published** 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 **information 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 **information system**, and the effect of the modification or amendment is that the information submitted to the **information system** is no longer correct or complete, the modified or amended information must be submitted to the **information system**.
- (2) 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 **information 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 **information 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 **information 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 **information system** no later than 5pm, 5 **business days** after the amendment or modification to the **risk management contract** is made.
- (3) The **participant** who discovered, in accordance with clause 13.224, that any information was incorrect or incomplete must submit the corrected information to the **information 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 **information 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 publicly 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 Information system will make information publicly available

- (1) The information submitted under clauses 13.219, 13.223(1), and 13.224 must be made publicly available on the **information system** as soon as practicable.
- (2) At the same time that it makes the submitted information publicly available in accordance with subclause (1), for all information other than that submitted under clause 13.224, the **information system** must—
 - (a) indicate that the information is unverified; and
 - (b) if the contract is a **contract for differences** or an **options contract**, send a 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 **information 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 **information 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**, send a notice to the **other party** giving the **other party** the option to submit a **verification notice** to the **information system** within 2 **business days** confirming whether or not the information is correct.
- (3) A **participant** who receives a **verification notice** under subclause (2)(b)(i) must comply with the 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 **information system** within 2 **business days** of receiving notice under clause 13.226(2) confirming that the information made publicly available under clause 13.226(1) is correct, the **information system** must indicate that the information made publicly available under clause 13.226(1) is verified.
- (2) The **information system** must indicate that the information made publicly 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 **information 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 **information 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 **information system** within 2 **business days** of receiving notice under clause 13.226(2) advising that the information made publicly available under clause 13.226(1) is not correct, the **information 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 **information system** must—
 - (a) indicate that the information made publicly available in accordance with clause 13.226(1) is pending verification; and
 - (b) send the **other party** a reminder notice requiring the **other party** to submit a **verification notice** as soon as possible.
- (5) If the information made publicly available under clause 13.226(1) is disputed, the **information system** must—
 - (a) indicate that the information is disputed; and
 - (b) send the **parties** to the relevant **risk management contract** a 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 issued 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 publicly available in accordance with clause 13.226(1) is correct, the **other party** must submit a **verification notice** to the **information 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 publicly available in accordance with clause 13.226(1) is not correct, the **party** that submitted that information to the **information 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 publicly available in accordance with clause 13.226(1) is correct, despite using all reasonable endeavours, the **information system** must indicate 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 to information system

- (1) The **information system** must confirm receipt of any information received by it under clauses 13.21, or 13.222 to 13.224.
- (2) Each confirmation must contain a copy of the information received by the **information 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 submitted information to the **information system** has not received confirmation that its information has been received by the **information system** within 6 hours of submitting the information to the **information system**, that **party** must, within 1 **business day** of the expiry of that 6 hour period, contact the **market administrator** to check whether the information has been received by the **information system**.
- (2) If the **information system** has not received the information, the **party** must resubmit the information.
- (3) This process must be repeated until the **information system** 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

13.230 Certification of information

- (1) Each **participant** who has submitted information to the **information system** in accordance with clause 13.225 in a particular **year** must provide, within 3 months of the end of the **year**, a certificate to the **Authority** verifying that the information submitted was correct.
- (2) The certificate must be—
 - (a) in the form of a declaration; and
 - (b) in the form specified by the **Authority**; and

- (c) signed and dated by either—
 - (i) 2 directors of the **participant**; or
 - (ii) the chief financial officer, or person holding an equivalent position, of the **participant**; or
 - (iii) the chief executive officer, or person holding an equivalent position, of the **participant**.

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 require the **participant** to nominate an appropriate **auditor**. The **participant** must provide that nomination 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 **auditor** must produce an **audit** report on the **participant's** compliance with this subpart. Before the **audit** report is submitted to the **Authority**, any non-compliance must be referred back to the **participant** for comment. The comments of the **participant** must be included in the **audit** report.
- (5) The **auditor** must not provide the **Authority** with a copy of 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 Information system and Authority must not publish certain information and may use information only under this subpart

- (1) The **Authority** must keep, and ensure that the **information system** and each **auditor** appointed under clause 13.231(2) keep, information submitted to the **information 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 publicly available in accordance with clause 13.226(1).
- (2) The **Authority** may use the information submitted to the **information system** 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

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 **information 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

Subpart 5A: inserted on 1 December 2011, by clause 5 of the Electricity Industry Participation Code (Spot Price Risk Disclosure) Amendment 2011.

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 calendar 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 **working days** before the beginning of the quarter to which the statement relates.

Clause 13.236A: inserted on 1 December 2011, by clause 5 of the Electricity Industry Participation Code (Spot Price Risk Disclosure) Amendment 2011.

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.

Clause 13.236B: inserted on 1 December 2011, by clause 5 of the Electricity Industry Participation Code (Spot Price Risk Disclosure) Amendment 2011.

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**.

Clause 13.236C: inserted on 1 December 2011, by clause 5 of the Electricity Industry Participation Code (Spot Price Risk Disclosure) Amendment 2011.

13.236D Authority must publicise base case, stress test, and method for calculating target cover ratio

- (1) The **Authority** must **publicise** 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 **publicised** a notice under subclause (1) at least 30 **working 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** **publicises** an amendment to a notice, or revokes and replaces a notice, within 30 **working 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.

Clause 13.236D: inserted on 1 December 2011, by clause 5 of the Electricity Industry Participation Code (Spot Price Risk Disclosure) Amendment 2011.

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 **publicised** by the **Authority** under clause 13.236D for the quarter to which the statement relates.
- (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 **working days** and no later than 5 **working 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**.

Clause 13.236E: inserted on 1 December 2011, by clause 5 of the Electricity Industry Participation Code (Spot Price Risk Disclosure) Amendment 2011.

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 provide a certificate to the **Authority**—
 - (a) verifying 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 certificate 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) certifying that the **disclosing participant** has provided to each of the **disclosing participant's** customers who, in the period to which the certificate 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 certificate must be submitted as follows:
 - (a) in the case of the first certificate 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 certificate 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 certificate, no later than the end of the fifth quarter following the quarter in which the last certificate was submitted (in which case the

certificate must relate to every **spot price risk disclosure statement** made by the **disclosing participant** since the last certificate was submitted).

- (3) The certificate must be—
- (a) in the form specified by the **Authority**; and
 - (b) signed and dated by a director of the **disclosing participant** and 1 of the following:
 - (i) another director of the **disclosing participant**;
 - (ii) the chief executive officer, or person holding an equivalent position, of the **disclosing participant**;
 - (iii) the chief financial officer, or person holding an equivalent position, of the **disclosing participant**.

Clause 13.236F: inserted on 1 December 2011, by clause 5 of the Electricity Industry Participation Code (Spot Price Risk Disclosure) Amendment 2011.

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 **working 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.

Clause 13.236G: inserted on 1 December 2011, by clause 5 of the Electricity Industry Participation Code (Spot Price Risk Disclosure) Amendment 2011.

13.236H Authority may require independent audit of spot price risk disclosure statement or certificate

- (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 certificate submitted 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 **working 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 certificate submitted under clause 13.236F (as the case may be).
- (8) The **disclosing participant** must provide the information no later than 10 **working 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 certificate submitted 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 certificate submitted 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: inserted on 1 December 2011, by clause 5 of the Electricity Industry Participation Code (Spot Price Risk Disclosure) Amendment 2011.

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 certificate submitted 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 certificate submitted under clause 13.236F (as the case may be) has complied with this subpart, the **Authority** must pay the **auditor's** costs.

Clause 13.236I: inserted on 1 December 2011, by clause 5 of the Electricity Industry Participation Code (Spot Price Risk Disclosure) Amendment 2011.

Clause 13.236I(3): amended, on 21 September 2012, by clause 31 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Subpart 6—Financial transmission rights

Heading: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

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** creates and allocates **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**.

Clause 13.237: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

FTR allocation plan

Heading: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

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 make the **FTR allocation plan** available to the public at no cost on the **FTR manager's** website at all reasonable 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.

Clause 13.238: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

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**.

Clause 13.239: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

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 **notify** 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**.

Clause 13.240: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

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.

Clause 13.241: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Creation and allocation of FTRs

Heading: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

13.242 FTR manager must create and allocate FTRs

- (1) The **FTR manager** must create and allocate **FTRs** in accordance with the **FTR allocation plan** approved under clause 13.240.
- (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**.

Clause 13.242: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 13.242(2): substituted, on 1 June 2012, by clause 4 of the Electricity Industry Participation (Removal of Quantity Limit for Financial Transmission Rights) Code Amendment 2012.

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 meets the prudential security requirements in Part 14.

Clause 13.243: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

13.244 Acceptance of bids in FTR auction

- (1) The **FTR manager** must not accept a bid in an **FTR auction** if the **FTR manager** considers that the bid, if accepted, would cause the person making the bid to incur an obligation for which it does not have sufficient acceptable security under Part 14.
- (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 in the auction.

Clause 13.244: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Auction revenue and FTR receipts and payments

Heading: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

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.

Clause 13.245: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

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.

Clause 13.246: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

FTR register

Heading: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

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.
- (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 an up to date copy of the **FTR register** and make it available to the public at no cost on the **FTR manager's** website at all reasonable times.

Clause 13.247: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 13.247(1)(d): inserted, on 1 June 2012, by clause 5 of the Electricity Industry Participation (Removal of Quantity Limit for Financial Transmission Rights) Code Amendment 2012.

Clause 13.247(1)(b): amended, on 1 November 2012, by clause 5 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Assignment of FTRs

Heading: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

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 form may be transmitted in electronic form through the **information system** 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 meets the prudential security requirements in Part 14.
- (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.

Clause 13.248: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 13.248(1): amended, on 1 June 2012, by clause 6(1) of the Electricity Industry Participation (Removal of Quantity Limit for Financial Transmission Rights) Code Amendment 2012.

Clause 13.248(4A): inserted, on 1 June 2012, by clause 6(2) of the Electricity Industry Participation (Removal of Quantity Limit for Financial Transmission Rights) Code Amendment 2012.

Clause 13.248(5): amended, on 1 June 2012, by clause 6(3) of the Electricity Industry Participation (Removal of Quantity Limit for Financial Transmission Rights) Code Amendment 2012.

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 becomes liable for the price 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 due on settlement of the **FTR**, the assignor becomes liable to pay 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 include the amount payable under subclause (4) in the invoice for the **billing period** in which the assignment took place.
- (6) The **clearing manager** must transfer to the **FTR account** any amount received pursuant to an invoice issued under this clause, but that amount must not be applied for the settlement of **FTRs** until the **billing period** in which the **FTR** to which the payment relates is due to be 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 due on settlement of the **FTR**, the assignor becomes entitled to be paid by the **clearing manager** 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**.

Clause 13.249: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 13.249 Heading: amended, on 1 November 2012, by clause 6(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 13.249(1)(b): amended, on 1 November 2012, by clause 6(2) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 13.249(4): amended, on 1 November 2012, by clause 6(3) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 13.249(7): amended, on 1 November 2012, by clause 6(4) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

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 becomes liable to pay the **FTR acquisition cost** in respect of the **FTR** that has been assigned when it becomes due on settlement of the **FTR**.

Clause 13.250: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 13.250 Heading: amended, on 1 November 2012, by clause 7(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 13.250(3): amended, on 1 November 2012, by clause 7(2) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Provision of information to the FTR manager and clearing manager

Heading: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

13.251 Information to be provided to FTR manager

- (1) Each **grid owner** must provide a 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**—
 - (a) whether a person who has applied to participate in an **FTR auction** meets the prudential security requirements in Part 14; 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 Part 14.
- (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 to the **FTR manager**.
- (7) The **clearing manager** must inform the **FTR manager**, 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 14.

Clause 13.251: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

13.252 Information to be provided to clearing manager

- (1) The **FTR manager** must provide the following information to the **clearing manager** 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**.

Clause 13.252: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 13.252(1): amended, on 1 November 2012, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

13.253 Transmission of information to FTR manager and clearing manager

The information required to be provided to the **FTR manager** and the **clearing manager** under clauses 13.251 and 13.252 must be transmitted through the **information system**, except as otherwise agreed by the parties providing and receiving the information.

Clause 13.253: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

13.254 Publication of results of FTR auctions

The **FTR manager** must, as soon as practicable after each **FTR auction**, make the results of each **FTR auction** available to the public at no cost on the **FTR manager's** website in accordance with the **FTR allocation plan**.

Clause 13.254: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Suspension of FTR allocation

Heading: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

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.

Clause 13.255: inserted, on 1 October 2011, by clause 8 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 13.255: amended, on 18 July 2013, by clause 9(1) of the Electricity Industry Participation (Undesirable Trading Situation) Code Amendment 2013.

Clause 13.255(a): substituted, on 18 July 2013, by clause 9(2) of the Electricity Industry Participation (Undesirable Trading Situation) Code Amendment 2013.

Clause 13.255(b): amended, on 18 July 2013, by clause 9(3) of the Electricity Industry Participation (Undesirable Trading Situation) Code Amendment 2013.

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: _____

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: _____

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
Co-generator Offer

Date: _____

Co-generator: _____

Co-generator Name: _____

Grid Injection Point: _____

Generator Category (clause 13.10 of the Code): ☐ Unit ☐ Station

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

Schedule 13.1 Form 4: amended, on 28 June 2012, by clause 51 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Schedule 13.1 Form 4: substituted, on 15 May 2014, by clause 68 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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

Schedule 13.1 Form 4A: inserted, on 28 June 2012, by clause 52 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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 @ \$ _____ per MW

_____% of electricity (MW), up to a maximum of ____ MW as Sustained Instantaneous
Reserve @ \$ _____ per MW

Band 2:

_____% of electricity (MW), up to a maximum of ____ MW as Fast Instantaneous
Reserve @ \$ _____ per MW

_____% of electricity (MW), up to a maximum of ____ MW as Sustained Instantaneous
Reserve @ \$ _____ per MW

Band 3:

_____% of electricity (MW), up to a maximum of ____ MW as Fast Instantaneous
Reserve @ \$ _____ per MW

_____% of electricity (MW), up to a maximum of ____ MW as Sustained Instantaneous
Reserve @ \$ _____ per MW

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

Electricity Industry Participation Code 2010
Schedule 13.1

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

Schedule 13.1 Form 5: amended, on 15 May 2014, by clause 50 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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

Schedule 13.1 Form 6: amended, on 15 May 2014, by clause 51 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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

Schedule 13.1 Form 7: amended, on 15 May 2014, by clause 52 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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:

Grid Injection Point (GIP)	Station/ generating unit name

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

Schedule 13.1 Form 9: amended, on 15 May 2014, by clause 53 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

Schedule 13.2 Model parameters

cl 13.189

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

cls 13.29, 13.33, 13.57, 13.58, 13.69, 13.83, 13.87, 13.88, 13.90, 13.135, 13.193, and 13.203

Heading: amended, on 28 June 2012, by clause 53 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Heading: substituted, on 15 May 2014, by clause 54(1) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 Heading: amended, on 15 May 2014, by clause 54(2) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

Clause 1(1): amended, on 28 June 2012, by clause 54(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 1(1): amended, on 21 September 2012, by clause 32(1) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 1(2): substituted, on 15 May 2014, by clause 69 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 1(2A): inserted, on 15 May 2014, by clause 69 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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
- (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 Heading: amended, on 28 June 2012, by clause 55(1) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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.

Clause 2(b): revoked, on 28 June 2012, by clause 55(2)(c) of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 2(c): amended, on 15 May 2014, by clause 70 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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

Clause 3: substituted, on 28 June 2012, by clause 56 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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: amended, on 28 June 2012, by clause 58(2) 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.

Clause 6(c): amended, on 15 May 2014, by clause 54(3) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

7 Dispatch schedule

For a **dispatch schedule**, the schedule must use—

- (a) from **generators** and **ancillary service agents**, **generator offers** (clause 13.6(1) to (3), excluding **offers** made by **intermittent generators** under clause 13.6(3)) and revised **offers** (clause 13.17(1) and (2), excluding **offers** made by **intermittent generators** under clause 13.17(3)) and **ancillary service agent reserve offers** (clause 13.38(1)) and revised **reserve offers** (clause 13.46(1) and (2)); and
- (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.

The objective function

8 The objective function

- (1) The objective function of the modelling system is described mathematically as:

$$\begin{array}{c}
 \text{Gross Consumer Benefit} \\
 \left. \begin{array}{c}
 \sum_{i,j} D_{i,j} \times BP_{i,j} \\
 \text{minus} \\
 \text{Cost of Generation} \\
 \sum_{i,j} G_{i,j} \times OP_{i,j} \\
 \text{minus} \\
 \text{Cost of Fast Instantaneous Reserves} \\
 \sum_{i,j} R_{i,j}^{PLSR,f} \times OP_{i,j}^{PLSR,f} + \sum_{i,j} R_{i,j}^{TWD,f} \times OP_{i,j}^{TWD,f} + \sum_{i,j} R_{i,j}^{IL,f} \times OP_{i,j}^{IL,f} \\
 \text{minus} \\
 \text{Cost of Sustained Instantaneous Reserves} \\
 \sum_{i,j} R_{i,j}^{PLSR,s} \times OP_{i,j}^{PLSR,s} + \sum_{i,j} R_{i,j}^{TWD,s} \times OP_{i,j}^{TWD,s} + \sum_{i,j} R_{i,j}^{IL,s} \times OP_{i,j}^{IL,s}
 \end{array} \right\} \text{Maximise}
 \end{array}$$

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
$R_{i,j}^{IL,f}$	is the scheduled fast IL corresponding to price band i of the reserve offer for purchaser j
$R_{i,j}^{IL,s}$	is the scheduled sustained IL corresponding to price band i of the reserve offer for purchaser j
$OP_{i,j}^{IL,f}$	is the reserve offer price corresponding to price band i of the fast IL reserve offer for purchaser j
$OP_{i,j}^{IL,s}$	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 Dij: amended, on 28 June 2012, by clause 60 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 8(1) definition of Dij: amended, on 15 May 2014, by clause 73 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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

Clause 9: amended, on 28 June 2012, by clause 61 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 9: amended, on 15 May 2014, by clause 74 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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**.

Clause 9A: inserted, on 15 May 2014, by clause 75 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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

Clause 10: substituted, on 28 June 2012, by clause 62 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 10: substituted, on 15 May 2014, by clause 76 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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 Heading: amended, on 15 May 2014, by clause 77 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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 notified 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

Clause 12(2)(b): amended, on 21 September 2012, by clause 32(2) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 12 Heading: amended, on 15 May 2014, by clause 78 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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 notify **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.

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

Clause 14(b): amended, on 28 June 2012, by clause 64 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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

Clause 15: amended, on 28 June 2012, by clause 65 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

Clause 15(aa): inserted, on 15 May 2014, by clause 79(a) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 15(d)(ii): substituted, on 1 November 2012, by clause 6(2) of the Electricity Industry Participation (HVDC Link Pole 3 Standing Data) Code Amendment 2012.

Clause 15(e): amended, on 15 May 2014, by clause 79(b) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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 is **disconnected**.
- (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(3): amended, on 28 June 2012, by clause 66 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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.

Clause 16(1)(a): amended, on 21 September 2012, by clause 32(3) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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.

Schedule 13.3A

Calculation of interim prices and interim reserve prices in scarcity pricing situation

cl 13.135B

Schedule 13.3A: inserted, on 1 June 2013, by clause 17 of the Electricity Industry Participation (Scarcity Pricing) Code Amendment 2011.

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:

$$\text{GWAP}_{\text{ISL}} = \frac{\sum_{g=1}^n (Q_g * P_g)}{\sum_{g=1}^n Q_g}$$

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 **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

GWAP_{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

GWAP_{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:

$$\text{GWAP}_{\text{NAT}} = \frac{\sum_{g=1}^n (Q_g * P_g)}{\sum_{g=1}^n Q_g}$$

where

$GWAP_{NAT}$ is the **national GWAP**

Q_g is the scheduled quantity of generation for **generator g** in both **islands**

P_g is the **interim price** at the **node** where **generator g** injects **electricity** in both **islands**

- (3) The scarcity pricing factor is determined as follows:
- (a) if the **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 **national GWAP** is less than \$10,000/MWh, the scarcity pricing factor is calculated in accordance with the following formula:

$$X = \frac{\$10,000}{GWAP_{NAT}}$$

where

X is the scarcity pricing factor

$GWAP_{NAT}$ is the **national GWAP**

- (c) if the **national GWAP** is greater than \$20,000/MWh, the scarcity pricing factor is calculated in accordance with the following formula:

$$X = \frac{\$20,000}{GWAP_{NAT}}$$

where

X is the scarcity pricing factor

$GWAP_{NAT}$ is the **national GWAP**

Schedule 13.4

Approval of industrial co-generating stations

cl 13.3

1 Authority to approve industrial co-generating stations

A **generator** may apply to the **Authority** for approval as an **industrial co-generating station**.

Compare: Electricity Governance Rules 2003 clause 1 schedule G9 part G

2 Applications for approval

Each application for approval as an **industrial co-generating station** must be in writing and—

- (a) must state each **generating unit** that the applicant wishes to have approved as an **industrial co-generating station**; and
- (b) must include information related to any seasonal operation of the **generating units**; and
- (c) may include any supporting information for the application that may assist the **Authority** to consider the application.

Compare: Electricity Governance Rules 2003 clause 2 schedule G9 part G

3 Authority must publicise each application for approval

On receipt of an application, the **Authority** must—

- (a) **publicise** 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 a **generating unit**, 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** within the time specified by the **Authority** when it **publicised** the application in accordance with clause 3(a); and
- (d) how the application complies with paragraphs (a) to (c) of the definition of **industrial co-generating station** set out in Part 1; 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

The applicant may, at any time, withdraw or amend an application being considered by the **Authority**. An amendment or withdrawal must be made in writing and submitted to the **Authority** and 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

The **Authority** must, as soon as practicable after granting an approval, notify the granting of the approval, and conditions that apply to the approval, and the **Authority's** reasons for granting the approval—

- (a) to the applicant, in writing; and
- (b) by notice in the *Gazette*.

Compare: Electricity Governance Rules 2003 clause 8 schedule G9 part G

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 granted, the name of the **co-generator**, the date of the approval, the duration of the approval and the nature of the approval, including any conditions.

Compare: Electricity Governance Rules 2003 clause 9 schedule G9 part G

10 Effect of approval

Approval of an **industrial co-generating station** takes effect from the date specified in the approval (which may be no earlier than the date of the *Gazette* notice).

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) details of seasonal co-generation, being limited parts of the year during which the **generating units** are approved as **industrial co-generating stations**;
- (c) requiring the **co-generator** to comply with specific instructions from the **system operator** during a **grid emergency**.

Compare: Electricity Governance Rules 2003 clause 11 schedule G9 part G

12 Authority must provide reasons for declining approval

If the **Authority** declines an application it must provide its reasons for doing so to the applicant.

Compare: Electricity Governance Rules 2003 clause 12 schedule G9 part G

13 Authority may rescind or amend approval

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.

Compare: Electricity Governance Rules 2003 clause 13 schedule G9 part G

14 Notice and reasons for rescinding or amending approval

If the **Authority** amends or rescinds an approval, it must—

- (a) give the **co-generator** 3 months' notice of rescinding or amending the approval;
and
- (b) advise the **co-generator** of the reasons for rescinding or amending the approval.

Compare: Electricity Governance Rules 2003 clause 14 schedule G9 part G

Schedule 13.5

cl 13.238

Requirements for FTR allocation plan

Schedule 13.5: inserted, on 1 October 2011, by clause 9 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

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** rules.
- (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

cl 13.248

Schedule 13.6: inserted, on 1 October 2011, by clause 9 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Schedule 13.6: amended, on 1 June 2012, by clause 7 of the Electricity Industry Participation (Removal of Quantity Limit for Financial Transmission Rights) Code Amendment 2012.

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.

Schedule 13.7

cls 13.27C, 13.27E, 13.27G, and 13.27K

Schedule 13.7: inserted, on 28 March 2012, by clause 67 of the Electricity Industry Participation (Demand-side Bidding and Forecasting) Code Amendment 2011.

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

Category for mean demand (in MW) for a GXP over relevant 12 months (clause 1(b)) (d)	Category for unpredictability measure (clause 1(c)) (p)	Resulting classification of the GXP
Where $d < 10\text{MW}$	For all p	Conforming GXP
Where $10\text{MW} \leq d < 20\text{MW}$	For $p < 0.15$	Conforming GXP
	For $p \geq 0.15$	Non-conforming GXP
Where $20\text{MW} \leq d < 250\text{ MW}$	For $p < 0.10$	Conforming GXP
	For $p \geq 0.10$	Non-conforming GXP
Where $d \geq 250\text{ MW}$	For all p	Non-conforming GXP

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.

Clause 3(2): amended, on 15 May 2014, by clause 80 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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

Schedule 13.8: inserted, on 15 May 2014, by clause 81 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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) the **distributor** from whose **network** the **dispatch-capable load station** draws **electricity**;
 - (iii) the **pricing manager**;
 - (iv) the **clearing manager**;
 - (v) the **reconciliation manager**;
 - (vi) the wholesale information trading system provider.

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) that have been notified to the **Authority** by the **system operator**.
- (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

Contents

- 14.1 Contents of this Part
 - Form of prudential requirements*
 - 14.2 Object and administration of prudential requirements
 - 14.3 Payers must satisfy prudential requirements
 - 14.4 Acceptable credit rating satisfies prudential requirements
 - 14.5 Acceptable forms of security
 - 14.6 Acceptable credit rating and security
 - Cash deposits to be held on trust*
 - 14.7 Cash deposit accounts to be established by clearing manager
 - 14.8 Cash deposits to be paid into cash deposit accounts
 - 14.9 Cash deposits to be applied subject to conditions
 - 14.10 Interest will be earned on cash deposits
 - 14.11 Fees and taxes payable by payers
 - 14.12 Clearing manager must issue trust account statements each month
 - 14.13 Payer may change form of security
 - 14.14 Reductions and releases
 - 14.15 Hedge settlement agreements
 - 14.16 Release of security on ceasing to be participant
 - 14.17 Clearing manager to release security within 1 business day
 - Level of security*
 - 14.18 Clearing manager to assess and call for minimum level of security
 - 14.19 Determination of security level
 - 14.19A Methodology for determining minimum level of security required in respect of FTRs
 - 14.19B Approval of methodology for determining minimum level of security required in respect of FTRs
 - 14.9C Variations to methodology for determining minimum level of security required in respect of FTRs
 - 14.20 Information to be considered by clearing manager
 - 14.21 Hedge settlement agreements, under-frequency events or other liability
 - 14.22 Washup amounts not to be considered
 - Information, monitoring and reporting*
 - 14.23 Information required from new purchasers
 - 14.24 Payers must provide information to clearing manager
 - 14.25 System operator to provide information
 - 14.26 Adverse information will be notified in advance
 - 14.27 Clearing manager must keep information confidential
 - 14.28 Clearing manager must report weekly

Disputes

- 14.29 Disputes regarding prudential requirements
Formation of contracts for the sale and purchase of electricity
- 14.30 Mandatory sale by generators with point of connection to the grid
14.31 Sale by generators with point of connection to a local network or embedded network
14.32 On sale by participants
14.33 Mandatory purchase of offtake through point of connection with the grid
14.34 Purchase for offtake through local network by embedded generator
14.35 Setting price and quantity

Invoices to and payments by payers

- 14.36 Issue of invoices
14.37 Payment of invoices
14.38 Failure to pay invoice amount
14.39 If money is owed to payer then deemed to be payee
14.40 Content of invoice
14.41 Procedure for invoice distribution
14.42 Payer to confirm receipt
14.43 Clearing manager must establish operating account
14.43A Clearing manager must establish FTR account

Payments to and from payees

- 14.44 Issue of invoices to payees
14.45 Content of pro forma invoice
14.46 Clearing manager to make payments
14.47 Clearing manager to prioritise payment of funds
14.47A Payments in respect of FTRs
14.48 Payment from operating account
14.48A Payment from FTR account
14.48B Allocation of funds to FTR account
14.48C Inadequate funds in respect of FTRs
14.49 Inadequate funds reduces amounts paid to generators and dispatched purchasers
14.50 Interest is payable to generators and dispatched purchasers
14.51 Further funds paid according to priority
14.51A Late payments in respect of FTR
14.52 Payer to remain in default
14.53 Clearing manager to exercise rights to recover amounts outstanding
14.54 Generators and dispatched purchasers assigned or subrogated to all clearing manager's rights of recovery

Default

- 14.55 Definition of an event of default
14.56 Anticipated events of default must be referred to Authority
14.57 Procedure upon event of default
14.58 Event of default gives clearing manager certain remedies
14.59 Pro rata call on security
14.60 Clearing manager to specify pro rata proportion
14.61 Pro rata application or demand limited to 7 days
14.62 If security to be pro rated

- 14.62A Allocation of amounts to FTR obligations and other obligations
- 14.63 Rights of generators and dispatched purchasers to exercise rights
- 14.64 Invoice disputes

Washups

- 14.65 Clearing manager must conduct washups
- 14.66 Clearing manager must invoice washup amounts
- 14.67 Washups for payers
- 14.68 Washups for generators
- 14.69 Washups for ancillary service agents
- 14.70 Washups for system operator for corrections to ancillary service administrative costs
- 14.71 Washups for grid owners
- 14.72 Payment where no longer participant
- 14.73 Payment of loss and constraint excess

Reporting obligations of the clearing manager

- 14.74 Monthly divergence reports to be prepared by clearing manager
- 14.75 Market administrator must publish clearing manager reports
- 14.76 Right to information concerning clearing manager's action
- 14.77 Clearing manager to provide copies of payee reports
- 14.78 Clearing manager to publish block dispatch settlement differences
- 14.79 Clearing manager to publish block dispatch settlement differences later if information system is unavailable
- 14.80 Clause 14.78 applies to block dispatch groups only
- 14.81 No washup calculation under clause 14.78 if revised reconciliation information is received
- 14.82 Special requirements applying to clearing manager
- 14.83 Notices

Schedule 14.1

Guarantee

Schedule 14.2

Letter of credit

Schedule 14.3

Deed of guarantee and indemnity

Schedule 14.4

Surety bond

Schedule 14.5

Hedge settlement agreement

Schedule 14.6

Calculation of amount of loss and constraint excess to be paid into FTR account

14.1 Contents of this Part

This Part provides for—

- (a) the process for setting and administering prudential requirements of **payers**; and
- (b) the processes for the settlement of ex-post balances in relation to the sale and purchase of **electricity** and **ancillary services** under this Code; and

- (c) how contracts for the sale and purchase of **electricity** are to be formed, the payments to the **clearing manager** for **electricity** purchased by **purchasers** and the payments from the **clearing manager** to **generators** for their supply of **electricity**; and
- (d) payments to the **clearing manager** for **ancillary services** purchased by **payers** and payments from the **clearing manager** to **ancillary service agents** for their supply of **ancillary services** and payments from the **clearing manager** to the **system operator** for **ancillary service administrative costs**; and
- (e) further payments that may be received or paid by the **clearing manager**, such as the settlement of **hedge settlement agreements** lodged with the **clearing manager**.

Compare: Electricity Governance Rules 2003 rule 1 part H

Form of prudential requirements

14.2 Object and administration of prudential requirements

- (1) The purpose of the prudential requirements in this Part is to ensure that **payers** can meet their financial obligations under this Code.
- (2) The **clearing manager** is responsible for administering the prudential requirements set out in this Part.

Compare: Electricity Governance Rules 2003 rule 2.1 part H

14.3 Payers must satisfy prudential requirements

- (1) Before a **payer** may purchase, and at all times while it purchases, **electricity** or **ancillary services** under this Code, that **payer** must meet the prudential requirements by—
 - (a) maintaining an acceptable credit rating in accordance with clause 14.6; or
 - (b) providing to the **clearing manager**, and maintaining, acceptable security under clause 14.5.
- (2) Before a **payer** may purchase an **FTR**, and at all times while it has any obligations in relation to an **FTR**, the **payer** must meet the prudential requirements as set out in subclause (1).

Compare: Electricity Governance Rules 2003 rule 2.2 part H

Clause 14.3(2): inserted, on 1 October 2011, by clause 10 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

14.4 Acceptable credit rating satisfies prudential requirements

If a **payer** satisfies the **clearing manager** that it has an acceptable credit rating, the **payer** is not required to provide any security under clause 14.5 at the same time.

Compare: Electricity Governance Rules 2003 rule 2.3 part H

14.5 Acceptable forms of security

A **payer** who is required to provide acceptable security under clause 14.3(1)(b) must—

- (a) pay a **cash deposit**, of the amount required by clauses 14.18 to 14.22, into the **cash deposit accounts** or to the clearing manager and provide and maintain an

- acceptable **payer's** security agreement in respect of that **cash deposit**; or
- (b) procure the provision and maintenance of an unconditional guarantee or letter of credit in favour of the **clearing manager** for the amount required by clauses 14.18 to 14.22. The guarantee or letter of credit must be on the terms set out in Schedule 14.1 or Schedule 14.2, or as otherwise approved by the **Authority**, and be provided by a **bank** that maintains an acceptable credit rating as defined in clause 14.6; or
 - (c) procure the provision and maintenance of an unconditional third party guarantee in favour of the **clearing manager** for the amount required by clauses 14.18 to 14.22 provided the guarantee is on the terms set out in Schedule 14.3 or as otherwise approved by the **Authority**, and the third party guarantor maintains an acceptable credit rating as defined in clause 14.6; or
 - (d) procure the provision and maintenance of a security bond in favour of the **clearing manager** for the amount required by clauses 14.18 to 14.22, provided the bond is on the terms set out in Schedule 14.4 or as otherwise approved by the **Authority**, and the surety maintains an acceptable credit rating as defined in clause 14.6; or
 - (e) lodge a **hedge settlement agreement** with the **clearing manager**, for settlement by the **clearing manager**, for the amount required by clauses 14.18 to 14.22. The value of the **hedge settlement agreement** for prudential purposes must be determined by the **clearing manager**. Every **hedge settlement agreement** must be approved by the **Authority** before it is lodged under this clause, and must be on the terms set out in Schedule 14.5 or as otherwise approved by the **Authority**, together with any other information reasonably requested by the **clearing manager** in the format prescribed by the **clearing manager** and notified to **payers** from time to time; or
 - (f) provide any security similar to those listed in paragraphs (a) to (e), and approved by the **Authority** as to type, terms, counterparty and amount from time to time, for the amount required by clauses 14.18 to 14.22; or
 - (g) provide any combination of the securities listed in paragraphs (a) to (f), totalling to the **clearing manager's** satisfaction the amount required by clauses 14.18 to 14.22; and
 - (h) take any other action the **Authority** reasonably requires in respect of the validity, enforceability and effectiveness of the security being provided under this clause.

Compare: Electricity Governance Rules 2003 rule 2.4 part H

Clause 14.5: amended, on 1 October 2011, by clause 11 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

14.6 Acceptable credit rating and security

- (1) For the purposes of clauses 14.3(1)(a), 14.4, 14.5(b) to (d), and 14.7(2)(a), an acceptable credit rating means that a **payer**, surety, **bank** or guarantor of the **payer** (as the case may be)—
 - (a) must carry a long term credit rating of at least—
 - (i) A3 (Moody's Investor Services Inc.); or
 - (ii) A- (Standard & Poors Ratings Group); or

- (iii) B+ (AM Best); or
 - (iv) A- (Fitch Ratings); and
- (b) if it carries a credit rating at the minimum level required by paragraph (a), must not be subject to negative credit watch or any similar arrangement by the agency that gave it the credit rating.
- (2) Each **payer** must provide such evidence as the **clearing manager** may from time to time reasonably require in order to determine whether that **payer**, surety, **bank** or guarantor of that **payer** has an acceptable credit rating in terms of this clause.
- (3) For the purposes of clause 14.3(1)(b), “acceptable security” means valid, effective and enforceable security set out in, and complying with, clause 14.5.
- (4) For the purposes of clause 14.5(a), “payer’s security agreement” means a security agreement as defined in the Personal Properties Securities Act 1999 securing the payment and performance of the obligations of the **payer** to the **clearing manager** under this Part on terms approved by the **Authority**.

Compare: Electricity Governance Rules 2003 rule 2.5 part H

Clause 14.6(1): amended, on 1 July 2011, by clause 4 of the Electricity Industry Participation (Credit Rating) Code Amendment 2011.

Clause 14.6(1): amended, on 1 October 2011, by clause 12(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.6(3): amended, on 1 October 2011, by clause 12(2) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Cash deposits to be held on trust

14.7 Cash deposit accounts to be established by clearing manager

- (1) The **clearing manager** must establish, in its name, 2 or more interest bearing **cash deposit accounts**.
- (2) The **cash deposit accounts** must be—
 - (a) held with **banks** that have and maintain acceptable credit ratings as defined in clause 14.6; or
 - (b) with more than 1 such **bank**; and
 - (c) clearly identified as such and entirely separate from the **operating account**, the **FTR account**, and 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 the **cash deposits** are held on trust in the **cash deposit accounts** for the purposes set out in clause 14.9 and that the **bank** has no right of set-off or right of combination in relation to the **cash deposits**.

Compare: Electricity Governance Rules 2003 rules 2.6.1 to 2.6.3 part H

Clause 14.7(2)(c): amended, on 1 October 2011, by clause 13 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

14.8 Cash deposits to be paid into cash deposit accounts

All **cash deposits** received by the **clearing manager** must be paid by the **clearing manager** immediately into the **cash deposit accounts**. Each **cash deposit** must be held equally between **cash deposit accounts**.

Compare: Electricity Governance Rules 2003 rule 2.6.4 part H

14.9 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 transfer to the **operating account** such amount on account of the defaulter'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 defaulter to the **clearing manager** under this Code that have not been transferred in accordance with paragraph (aa). **Cash deposit accounts** must be debited on a pro rata basis:
- (aa) following any **event of default**, the **clearing manager** must transfer to the **FTR account** such amount on account of the defaulter'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 defaulter to the **clearing manager** in respect of **FTRs** under this Code in accordance with clause 14.62A:
- (b) if there has been no unremedied **event of default**, the **payer** that provided the **cash deposit** is entitled to be paid the part of the **cash deposit** that has not been transferred under paragraph (a) in accordance with clauses 14.13, 14.14, 14.16, and 14.29:
- (c) the **payer** is not entitled to receive back any part of its **cash deposit**, other than in accordance with this clause, irrespective of whether the **payer** is in liquidation, receivership, or subject to statutory management or other analogous situation.

Compare: Electricity Governance Rules 2003 rule 2.6.5 part H

Clause 14.9(a): amended, on 1 October 2011, by clause 14(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.9(aa): inserted, on 1 October 2011, by clause 14(2) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

14.10 Interest will be earned on cash deposits

- (1) Subject to clauses 14.9(a) and 14.11, a **payer** is entitled to the interest earned in accordance with subclause (2) on its **cash deposit**. If a **payer** does not wish the interest to accumulate in the **cash deposit accounts**, then the **clearing manager** must, at the request of the **payer**, provided that the **payer** has not committed an unremedied **event of default**, pay the interest (less any deduction for resident withholding tax) within 2 **business days** of the end of the month to a **bank** account nominated by the **payer** for this purpose.
- (2) Interest on **cash deposits** accrues daily and must be calculated at the **cash interest rate**.

Compare: Electricity Governance Rules 2003 rules 2.6.6 and 2.6.7 part H

Clause 14.10(1): amended, on 15 May 2014, by clause 55 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

14.11 Fees and taxes payable by payers

- (1) A **payer** 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 **payer** under clause 14.10(1).
- (3) If the amounts are less than the payments owed by that **payer** under this clause, then the shortfall must be invoiced in accordance with clause 14.36.

Compare: Electricity Governance Rules 2003 rule 2.6.8 part H

14.12 Clearing manager must issue trust account statements each month

Each month the **clearing manager** must issue or procure the issue of statements to each **payer** who has provided a **cash deposit** regarding the balance of its **cash deposit**.

Compare: Electricity Governance Rules 2003 rule 2.6.9 part H

14.13 Payer may change form of security

The **clearing manager** must release the **payer's** existing security upon provision by the **payer** of the different form of security notified under this clause, if a **payer**—

- (a) gives the **clearing manager** at least 2 **business days'** notice of its intention to substitute a different form of security for any security provided by it to the **clearing manager**; and
- (b) has not committed an unremedied **event of default**; and
- (c) satisfies the **clearing manager** that the proposed new form of security meets the requirements in clauses 14.5 and 14.18 to 14.22.

Compare: Electricity Governance Rules 2003 rule 2.7 part H

14.14 Reductions and releases

The **clearing manager** must reduce or release a **payer's** existing security to the extent requested by the **payer**, if the **payer**—

- (a) gives the **clearing manager** at least 2 **business days'** notice that it seeks a partial or complete reduction or release of any security provided by it to the **clearing manager**; and
- (b) has not committed an unremedied **event of default**; and
- (c) satisfies the **clearing manager** that, following the reduction or release of the security, it will continue to meet the requirements in clauses 14.5 and 14.18 to 14.22, or that it will meet the requirements in clause 14.4.

Compare: Electricity Governance Rules 2003 rule 2.8 part H

14.15 Hedge settlement agreements

If a **payer** lodges a **hedge settlement agreement** with the **clearing manager** under clause 14.5(e), a party to that **hedge settlement agreement** may only cancel it, or cancel its lodgement with the **clearing manager**, on giving at least 2 **business days'** notice to the **clearing manager**.

Compare: Electricity Governance Rules 2003 rule 2.9 part H

14.16 Release of security on ceasing to be participant

The **clearing manager** must release a **payer's** existing security if the **payer**—

- (a) ceases to be a **participant** and the **Authority** advises the **clearing manager** that the **payer** has ceased to be a **participant**; and

- (b) gives the **clearing manager** at least 2 **business days**’ notice of it ceasing to be a **participant**; and
- (c) has paid all amounts that it owes under this Code (excluding, for the avoidance of doubt, any **washup** amount that has not yet been invoiced).

Compare: Electricity Governance Rules 2003 rule 2.10 part H

14.17 Clearing manager to release security within 1 business day

- (1) If a **payer** becomes entitled under clauses 14.13, 14.14, 14.16 or 14.29 to a reduction or release of any security, the **clearing manager** must reduce or release that security within 1 **business day** of the **payer** becoming entitled to that 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 **payer** for that purpose.

Compare: Electricity Governance Rules 2003 rules 2.11 and 2.12 part H

Level of security

14.18 Clearing manager to assess and call for minimum level of security

- (1) If a **payer** is required to provide security under clause 14.5, the **clearing manager** must determine, in accordance with clause 14.19, the minimum amount of that security at least once in every week.
- (2) The **clearing manager** must determine the initial amount of security for **ancillary services** for a new **payer** in consultation with the **system operator**.
- (3) Following each determination under subclauses (1) or (2), the **clearing manager** must, unless it determines that the existing minimum level of security should either reduce or remain unchanged, give written notice to the **payer** requiring it to provide security in an amount of at least the minimum determined by the **clearing manager** (a **call**). In making such a **call**, the **clearing manager** must set out the grounds upon which the **clearing manager** has based its determination.
- (4) A **payer** who receives notice of a **call** made under subclause (3) must satisfy that **call** by 1600 hours 3 **business days** following the **business day** on which the notice of the **call** was received.
- (5) Failure to satisfy a **call** made under this clause constitutes an event of default.

Compare: Electricity Governance Rules 2003 rule 3.1 part H

14.19 Determination of security level

The **clearing manager** must determine the minimum level of security required from a **payer** by assessing the expected amount of the **clearing manager**’s financial exposure to that **payer** based on the sum of the following amounts:

- (a) the **clearing manager**’s estimate of the amount (including **GST**) incurred, and to be incurred, by that **payer** in purchasing **electricity**;
- (b) the **clearing manager**’s estimate of the amount (including **GST**) allocated, and to be allocated, to that **payer** in relation to **ancillary services**;
- (c) the **clearing manager**’s estimate of the amount (including **GST**) earned, and to be earned, by that **payer** on account of gross revenue from sales of **electricity**;

- (d) the **clearing manager's** estimate of the amount (including **GST**) incurred or earned, and to be incurred or earned, by that **payer** in respect of any **hedge settlement agreement** lodged with the **clearing manager** under clause 14.5(e);
- (da) the **clearing manager's** estimate of an amount to be required by that **payer** in respect of any **FTR** in respect of which the **payer** is named in the **FTR register**, calculated in accordance with the methodology approved by the **Authority** under clause 14.19B—

during the complete **billing period** that precedes the next date on which invoices are due for payment under clause 14.37(1) (“the next invoice payment date”), the period from the end of that **billing period** up to and including the next invoice payment date and the 7 days following the next invoice payment date:

- (db) the amount of any **FTR acquisition cost** due in respect of an **FTR**;
- (dc) any amount payable by that **payer** to the **clearing manager** under clause 13.249(4) minus any amount payable by the **clearing manager** to that **payer** under clause 13.249(7);
- (e) any amount that the **system operator** advises the **clearing manager** that a **payer** has incurred as a result of that **payer** causing an **under-frequency event**, where the **payer** has not yet paid that liability.

Compare: Electricity Governance Rules 2003 rule 3.2 part H

Clause 14.19(da): inserted, on 1 October 2011, by clause 15(a) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.19(db): inserted, on 1 October 2011, by clause 15(b) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.19(db): amended, on 1 November 2012, by clause 9(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 14.19(dc): inserted, on 1 November 2012, by clause 9(2) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

14.19A Methodology for determining minimum level of security required in respect of FTRs

- (1) The **clearing manager** must formulate and **publish** a methodology for determining the minimum level of security required from a **payer** in relation to a matter set out in clause 14.19(da).
- (2) The methodology formulated by the **clearing manager** under subclause (1) must comply with the principle that the amount taken into account under clause 14.19(da) 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 prior to settlement.

Clause 14.19A: inserted, on 1 October 2011, by clause 16 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.19A(2): amended, on 1 November 2012, by clause 10 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

14.19B Approval of methodology for determining minimum level of security required in respect of FTRs

- (1) The **clearing manager** must submit to the **Authority** for approval a draft methodology for determining the minimum level of security required from a **payer** in relation to a matter set out in clause 14.19(da).
- (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.
- (6) When the **Authority publishes** the changes that the **Authority** wishes the **clearing manager** to make to the draft methodology under subclause (5), the **Authority** must **notify** the **clearing manager** and interested parties of the date by which submissions on the changes must be received by the **Authority**.
- (7) 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 (6).
- (8) The **Authority** must—
 - (a) provide a copy of each submission received to the **clearing manager**; and
 - (b) **publish** the submissions.
- (9) The **clearing manager** may make its own submission on the changes to the draft methodology and the submissions received in relation to the changes. The **Authority** must **publish** the **clearing manager's** submission when it is received.
- (10) The **Authority** must consider the submissions made to it on the changes to the draft methodology.
- (11) Following the consultation required by subclauses (6) to (10), the **Authority** may approve the methodology subject to the changes that the **Authority** considers appropriate being made by the **clearing manager**.

Clause 14.19B: inserted, on 1 October 2011, by clause 16 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

14.19C Variations to methodology for determining minimum level of security required in respect of FTRs

- (1) A **participant** or the **Authority** may submit a proposal for a variation to the methodology formulated under clause 14.19A.
- (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 clause 14.19B 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.

Clause 14.19C: inserted, on 1 October 2011, by clause 16 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

14.20 Information to be considered by clearing manager

In estimating the amounts described in clause 14.19, the **clearing manager** may take into account—

- (a) a substantial change to a **payer's business**; and
- (b) a substantial change in the price of **electricity**; and
- (c) any information that is relevant obtained by the **clearing manager** under clauses 14.23 to 14.26; and
- (d) quantities of **electricity** being purchased or generated by the **payer** in its capacity as a **purchaser** or **generator** under this Code, compared with any quantity previously purchased or generated or previously estimated (as the case may be); and
- (e) any advice from the **system operator** of any significant change in the costs of **ancillary services** allocated under clauses 8.55 to 8.59, 8.64 and 8.67.

Compare: Electricity Governance Rules 2003 rule 3.3 part H

14.21 Hedge settlement agreements, under-frequency events or other liability

If a **generator** is liable, under a **hedge settlement agreement**, or under an **FTR**, or as the **causer** of an **under-frequency event**, or under any other liability it has incurred or amount it owes under this Code, to pay more to the **clearing manager** for a **billing period** than it is to be paid under this Code for that **billing period**, the **generator** is deemed to be a net **purchaser** and may be called upon by the **clearing manager** to provide security under clauses 14.3 to 14.20.

Compare: Electricity Governance Rules 2003 rule 3.4 part H

Clause 14.21: amended, on 1 October 2011, by clause 17 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

14.22 Washup amounts not to be considered

To avoid doubt, the **clearing manager** must not take **washup** amounts into account in estimating the amounts described in clauses 14.19 or 14.21.

Compare: Electricity Governance Rules 2003 rule 3.5 part H

Information, monitoring and reporting

14.23 Information required from new purchasers

Before a new **purchaser** commences **trading**, it must submit to the **clearing manager** either—

- (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 the 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.

Compare: Electricity Governance Rules 2003 rule 4.1 part H

14.24 Payers must provide information to clearing manager

Each **payer** must provide any information that the **clearing manager** or the **Rulings Panel** may from time to time reasonably require, and must provide the following information to the **clearing manager** immediately upon the **payer** becoming aware of the situation:

- (a) if the **payer** is a **purchaser**, any significant changes to that **purchaser's business**, including a merger or acquisition, loss or gain of a **customer**, or sale or purchase of assets, that would significantly affect the quantity of **electricity** purchased or generated by the **payer** in its capacity as a **purchaser** or **generator** over the course of any **billing period**;
- (b) any change or likely change to the **payer's** credit rating (if the **payer** has a credit rating), regardless of whether or not that the **payer** is relying on a credit rating as a prudential requirement in terms of clause 14.4;
- (c) if a letter of credit, guarantee or bond is provided, or **hedge settlement agreement** is lodged, in respect of the **payer** in accordance with clause 14.5—
 - (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 14.6; or
 - (ii) any claim by the provider of the guarantee, letter of credit, bond or **hedge settlement agreement** that the guarantee, letter of credit, bond or **hedge settlement agreement** provided has ceased to be valid and enforceable.

Compare: Electricity Governance Rules 2003 rule 4.2 part H

14.25 System operator to provide information

The **system operator**, immediately upon becoming aware of the information set out in this clause, must provide the **clearing manager** with the following information:

- (a) any likely significant change to any amount to be allocated to a **payer** in respect of **ancillary services**;
- (b) the amount incurred by a **payer** as a result of that **payer** causing an **under-frequency event**.

Compare: Electricity Governance Rules 2003 rule 4.3 part H

14.26 Adverse information will be notified in advance

If, at any time, a **payer** reasonably believes that its financial position is likely to be materially adversely affected so that its ability to purchase **electricity** or **ancillary services** will be consequently affected, the **payer** must provide the **clearing manager** with details of that fact immediately.

Compare: Electricity Governance Rules 2003 rule 4.4 part H

14.27 Clearing manager must keep information confidential

The **clearing manager** must keep all information received by it under clauses 14.23 to 14.26 confidential and the information must not be disclosed to any other person except with the written consent of the person who provided it, except if that information is required to be disclosed to or by the **Rulings Panel** or the **Authority** under this Code or regulations made under section 112 of the **Act**.

Compare: Electricity Governance Rules 2003 rule 4.5 part H

14.28 Clearing manager must report weekly

Each week the **clearing manager** must provide—

- (a) each **payer** with a report detailing the amount estimated by the **clearing manager** under clause 14.19. The report must also state whether the **clearing manager** considers that an adjustment to the current level of security is likely to be required within the current or next **billing periods**. The **clearing manager** must summarise the grounds for its opinion in the weekly report; and
- (b) each **payee** with a report containing a summary of the position of all **payers**. The report must not identify any individual **payer**, unless identification is authorised by the **Authority**. Each report must include—
 - (i) information of any increased or decreased levels of security required by the **clearing manager** under clauses 14.18 to 14.22, provided that, in the case of a decrease, the **payer** elects to withdraw the refund or reduce the amount or value of its guarantee, letter of credit, bond or **hedge settlement agreement**; and
 - (ii) information relating to the behaviour of a **payer** that the **Authority** has authorised to be **published**; and
 - (iii) notice of the occurrence of an **event of default** in relation to any **payer**.

Compare: Electricity Governance Rules 2003 rule 4.6 part H

Disputes

14.29 Disputes regarding prudential requirements

- (1) If a **participant** disputes a decision of the **clearing manager** made under clauses 14.2 to 14.28, it may refer the matter to the **Rulings Panel**.
- (2) Until such time as the **Rulings Panel** makes a decision on the matter, all **payers** must comply with the decisions 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 clauses 14.2 to 14.28.
- (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.

Compare: Electricity Governance Rules 2003 rule 5 part H

Formation of contracts for the sale and purchase of electricity

14.30 Mandatory sale by generators with point of connection to the grid

- (1) Each **generator** that has a **generating station** or **generating unit** with a **point of connection** to the **grid** must sell to the **clearing manager** the **electricity** generated by that **generating station** or **generating unit** injected during a **trading period** through a **point of connection** with the **grid** and reconciled in accordance with this Code.
- (2) The **clearing manager** must purchase **electricity** as set out in this Code.

Compare: Electricity Governance Rules 2003 rule 6.1 part H

14.31 Sale by generators with point of connection to local network or embedded network

- (1) Each **generator** that has an **embedded generating station** (other than an **embedded generating station** in relation to a **point of connection** for which a notification under clause 15.14 is in force) must sell, to either the **clearing manager** or a **participant** trading on the **local network** or **embedded network** to which the **embedded generating station** is connected, the **electricity** generated by that **embedded generating station** and injected during a **trading period** through a **point of connection** with the **local network** or **embedded network** and reconciled in accordance with this Code.
- (2) The **clearing manager** or **participant** must purchase the **electricity** as set out in this Code.
- (3) Despite anything to the contrary in this Code, the relevant **point of connection** with the **grid** is, for the purposes of reconciliation under this Code, deemed to be a **grid injection point**.

Compare: Electricity Governance Rules 2003 rule 6.2 part H

14.32 On sale by participants

- (1) If, under clause 14.31, an **embedded generator** sells **electricity** to a **participant**, the **participant** must at the same time on-sell that **electricity** to the **clearing manager**. The **clearing manager** must purchase the **electricity** as set out in this Code.
- (2) The price payable by the **clearing manager** for such **electricity** is the **final price** for the relevant **trading period** for that **point of connection** plus any **constrained on compensation** payable in respect of that **trading period**.
- (3) The consideration for the sale of **electricity** by the **generator** must be determined by the amount paid by the **clearing manager** to the **generator** in accordance with clause 14.35.

Compare: Electricity Governance Rules 2003 rules 6.3 and 6.4 part H

14.33 Mandatory purchase of offtake through point of connection with the grid

Each **purchaser** must purchase from the **clearing manager** the **electricity** taken by the **purchaser** during a **trading period** through a **point of connection** with the **grid** and reconciled in accordance with this Code. The **clearing manager** must sell the **electricity** as set out in this Code.

Compare: Electricity Governance Rules 2003 rule 6.5 part H

14.34 Purchase for 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 14.31 and reconciled in accordance with this Code, must purchase that **electricity** from the same **participant** it sold its **electricity** to under clause 14.31. That **participant** must sell the **electricity** as set out in this Code.
- (2) The price payable by the **purchaser** for such **electricity** is the sum of—
 - (a) the **final price** for the relevant **trading period** for that **point of connection**; and
 - (b) any **constrained off compensation** owing in respect of that **trading period**; and
 - (c) any **constrained on compensation** owing in respect of that **trading period**.

Compare: Electricity Governance Rules 2003 rules 6.6 and 6.7 part H

Clause 14.34(2): substituted, on 15 May 2014, by clause 82 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

14.35 Setting price and quantity

The quantity of **electricity** either bought by a **purchaser** or sold by a **generator** under clauses 14.30 to 14.34 must be determined in accordance with clauses 15.20A to 15.26, the **final price** must be determined in accordance with clauses 13.135 and 13.171 to 13.185, and **constrained off compensation** and **constrained on compensation** must be calculated in accordance with clauses 13.192 to 13.212.

Compare: Electricity Governance Rules 2003 rule 6.8 part H

Clause 14.35: amended, on 15 May 2014, by clause 83 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Invoices to and payments by payers

14.36 Issue of invoices

- (1) The **clearing manager** must issue an invoice to each **purchaser** no later than 2 **business days** after the **clearing manager** has received from the **reconciliation manager**, in respect of the prior **billing period**, both—
 - (a) **reconciliation information** in accordance with clause 28(c) of Schedule 15.4; and
 - (b) **dispatchable load information** under clause 15.20C(a).
- (2) At the same time as the **clearing manager** issues invoices under subclause (1), the **clearing manager** must issue an invoice to each person to whom **ancillary service** costs have been allocated.
- (3) At the same time as the **clearing manager** issues invoices under subclause (1), the **clearing manager** must issue an invoice in respect of any amount due in respect of an **FTR**.
- (3A) Despite subclauses (1) to (3), the **clearing manager** may issue an invoice at any time on or before the day that is 2 **business days** before the 20th calendar day of the month following the relevant **billing period** if the **clearing manager**—
 - (a) has not received all information necessary to issue the invoice in respect of every **trading period** in the **billing period** by the time specified in subclause (1); and
 - (b) receives all necessary information in time to issue the invoice before the day that is 2 **business days** before the 20th calendar day of the month.
- (3B) However, if the **clearing manager** receives the information later than 2 **business days** before the 20th calendar 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 issue the invoice; and
 - (c) the **clearing manager** must issue the invoice by the time directed by the **Authority**.
- (3A) *[Expired]*
- (3B) *[Expired]*
- (3C) *[Expired]*
- (4) If the **clearing manager** receives from the **reconciliation manager** revised **reconciliation information** relating to a **billing period** after the **clearing manager** has issued invoices for that **billing period**,—
 - (a) if the **clearing manager** receives the revised **reconciliation information** on or before the day that is 2 **business days** before the 20th calendar day of the month following the relevant **billing period**, the **clearing manager** must use the revised **reconciliation information** to prepare revised invoices for **purchasers**; or
 - (b) if the **clearing manager** receives the revised **reconciliation information** after the day that is 2 **business days** before the 20th calendar day of the month following the relevant **billing period**,—
 - (i) the **clearing manager** must refer the matter to the **Authority**; and
 - (ii) the **Authority** must direct the **clearing manager** as to the time by which the **clearing manager** must issue the invoice; and

(iii) the **clearing manager** must issue the invoice by the time directed by the **Authority**.

Compare: Electricity Governance Rules 2003 rule 7.1 part H

Clause 14.36(3): inserted, on 1 October 2011, by clause 18 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.36(3): substituted, on 1 November 2012, by clause 11 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 14.36(3A) to (3C): inserted, from 19 July 2013 to 19 April 2014, by clause 4(1) of the Electricity Industry Participation (Time Frames for Invoicing) Code Amendment 2013.

Clause 14.36(4): inserted, on 13 June 2013, by clause 4 of the Electricity Industry Participation (Information Flows) Code Amendment 2013.

Clause 14.36(4): substituted, from 19 July 2013 to 19 April 2014, by clause 4(2) of the Electricity Industry Participation (Time Frames for Invoicing) Code Amendment 2013.

Clause 14.36(1): amended, on 15 May 2014, by clause 84(a) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 14.36(3A) and (3B): inserted, on 15 May 2014, by clause 5(1) of the Electricity Industry Participation (Time Frames for Invoicing) Code Amendment 2014.

Clause 14.36(4): amended, on 15 May 2014, by clause 84(b) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 14.36(4): substituted, on 15 May 2014, by clause 5(2) of the Electricity Industry Participation (Time Frames for Invoicing) Code Amendment 2014.

14.37 Payment of invoices

- (1) Subject to clause 14.39, for each **billing period**, payment of an invoice issued in accordance with clauses 14.36, 14.40, and 14.64(8) must be made by each **payer** in **cleared funds** into the **operating account** by 1400 hours on the 20th calendar day of the month following the **billing period** in respect of which the invoice was issued. If that day is not a **business day**, payment must be made by 1400 hours on the next **business day**. If the **clearing manager** does not issue an invoice by the time specified in clause 14.36(1), or the invoice is delayed for any other reason, payment may, if the **payer** so elects, be delayed for a period corresponding to the period of delay in the issue of the invoice. In the case of a late invoice, the **clearing manager** must notify the **payer** of the new payment date.
- (2) The allocation by the **clearing manager** of a payment received from a **payer** in respect of an invoice must be dealt with in accordance with subclause (3), and clauses 14.47 and 14.47A. A **payer** may not direct the **clearing manager** to apply any funds paid in respect of an invoice other than in accordance with clauses 14.47 and 14.47A.
- (3) The **clearing manager** must transfer to the **FTR account** any amount received under subclause (1) in respect of an amount referred to in clause 14.40(fa) or (fb).

Compare: Electricity Governance Rules 2003 rule 7.2 part H

Clause 14.37(1): amended, on 15 May 2014, by clause 85 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 14.37(2): substituted, on 1 October 2011, by clause 19 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.37(3): inserted, on 1 October 2011, by clause 19 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.37(3): substituted, on 1 November 2012, by clause 12 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

14.38 Failure to pay invoice amount

Failure of a **payer** to pay an invoice in accordance with clause 14.37 constitutes an **event of default**.

Compare: Electricity Governance Rules 2003 rule 7.4 part H

14.39 If money is owed to payer then deemed to be payee

If a **payer** is issued with an invoice by the **clearing manager**, and the total sum of the items specified in the invoice is a credit so that the **clearing manager** is obliged to pay that total sum to the **payer**, the **payer** must, for the purpose of clauses 14.36 to 14.54 only, be deemed to be, in relation to that invoice, a **payee**. Clauses 14.36 to 14.54 therefore, apply to the **payer** as if it were a **payee** for the purposes of issue and payment of the invoice.

Compare: Electricity Governance Rules 2003 rule 7.5 part H

14.40 Content of invoice

Invoices issued to **payers** in accordance with clause 14.36 must specify the following as is relevant to the extent that the **clearing manager** has received the necessary information:

- (a) payment under the contracts formed in accordance with clauses 14.30 to 14.35 as determined by the following formula:

$$Q_f * P_f$$

where

Q_f is the final quantity of **electricity** purchased at the relevant **grid exit point** obtained from **reconciliation information** and summarised and loss adjusted **dispatchable load information** for a **trading period** of the **billing period**

P_f is the **final price** at that **grid exit point** for that **trading period** of the **billing period**:

- (b) the amount to be debited for—
 - (i) **constrained off compensation** calculated in accordance with clause 13.201A(6); and
 - (ii) **constrained on compensation** calculated in accordance with clause 13.212(7)::
- (c) the sum of the **washup** amount and any interest payable on that amount to be credited or debited in accordance with clauses 14.65 to 14.72 as a result of the **clearing manager** receiving corrected information in accordance with clauses 8.68, 8.69, 14.64(13) or (14), 15.20C(b), 15.26(4), 15.29, or clause 28 of Schedule 15.4;
- (d) the **auction revenue** calculated in accordance with clause 13.112(1);
- (e) the amount of any **costs** to pay or be paid for any **ancillary services** under clauses 8.6, 8.31(1)(a), and 8.68;
- (f) the amount to pay, or to be paid, as a result of settlement for that **billing period** of any **hedge settlement agreements** lodged with the **clearing manager**;
- (fa) for each **FTR** applying to that **billing period** in respect of which the **payer** 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:

- (fb) any amount payable to the **clearing manager** under clause 13.249(4):
- (g) the amount to pay, or to be paid, for fees and taxes under clause 14.11:
- (h) the amount of **GST** payable (**GST** will be charged on each supply made under this Code):
- (i) the total sum of the amounts referred to in paragraphs (a) to (h).

Compare: Electricity Governance Rules 2003 rule 7.6 part H

Clause 14.40 (a), (b) & (c): amended, on 15 May 2014, by clause 86 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 14.40(fa): inserted, on 1 October 2011, by clause 20 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.40(fa): substituted, on 1 November 2012, by clause 13(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 14.40(fb): inserted, on 1 November 2012, by clause 13(2) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

14.41 Procedure for invoice distribution

The **clearing manager** must comply with the following procedure when issuing invoices under clauses 14.36 and 14.44. Proof of dispatch by the electronic facility contained in the **information system** for this purpose or facsimile is deemed to be proof of the issue of the invoice, despite the procedures set out in this clause and in clause 14.42(1) and (2). The **clearing manager** must—

- (a) post the invoice to each **payer** through the electronic facility contained in the **information system** for this purpose; or
- (b) if the electronic facility, referred to in paragraph (a), is not available, transmit the invoice to the **payer** by facsimile; and
- (c) in either case, if the **payer** requests, post or hand deliver the original invoice to the **payer**.

Compare: Electricity Governance Rules 2003 rule 7.7 part H

14.42 Payer to confirm receipt

- (1) Each **payer** must immediately confirm, through either the electronic facility contained in the **information system** for this purpose or by facsimile, receipt of any invoice sent by the **clearing manager** under clause 14.41(a) or (b).
- (2) If the **clearing manager** has not received a confirmation that an invoice has been received by a **payer** by 1200 hours on the **business day** after the day of dispatch of the invoice, the **clearing manager** must telephone the **payer** to check if the invoice has been received. If the invoice has not been received by the **payer**, the **clearing manager** must resend the invoice.
- (3) Delayed confirmation by a **payer** that an invoice has been received does not extend the payment period for that invoice set out in clause 14.37.

Compare: Electricity Governance Rules 2003 rules 7.8 to 7.10 part H

14.43 Clearing manager must establish operating account

- (1) The **clearing manager** must establish, in its name, an **operating account** with a **bank**. The **operating account** must be held by the **clearing manager** as a trust account for the benefit of the persons referred to in clause 14.47, must be clearly identified as such and, subject to this Code, be entirely separate from the **cash deposit accounts** and any other account of the **clearing manager**. Subject to this Code, payments from the **operating account** may only be made in accordance with clause 14.48.
- (2) The **clearing manager** must obtain an acknowledgement from the **bank** with which the **operating account** is held that the funds in that account are held on trust for the purposes set out in clause 14.47 and that the **bank** has no right of set-off or combination in relation to the funds.

Compare: Electricity Governance Rules 2003 rules 7.11 and 7.12 part H

14.43A Clearing manager must establish FTR account

- (1) The **clearing manager** must establish, in its name, an **FTR account** with a **bank**.
- (2) The **FTR account** must—
 - (a) be held by the **clearing manager** as a trust account for the benefit of the persons who are entitled to any payment from the **FTR account**; 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) Subject to this Code, the **clearing manager** may only make payments from the **FTR account** in accordance with clause 14.48A.
- (4) The **clearing manager** must obtain an acknowledgement from the **bank** with which the **FTR account** is held that—
 - (a) the funds in that account are held on trust for the purposes set out in clause 14.47A; and
 - (b) the **bank** has no right of set-off or combination in relation to the funds.

Clause 14.43A: inserted, on 1 October 2011, by clause 21 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Payments to and from payees

14.44 Issue of invoices to payees

Payee invoices must be issued as follows:

- (a) concurrently with issuing invoices to **payers**, the **clearing manager** must issue pro forma invoices to each **payee**. Each such pro forma invoice must detail the amount that the **clearing manager** must pay in respect of a **billing period** upon receiving payment from the **payers**, subject to clause 14.47 and clause 14.47A and the issue of an actual **GST** invoice for the amount payable to that **payee**. **Payees** must not issue **GST** invoices for supplies of **electricity** or **ancillary services** or **ancillary service administrative costs** to the **clearing manager**:
- (b) if the **clearing manager** issues a pro forma invoice to a **payee** and the total sum of the items specified in that pro forma invoice is such that the **payee** is obliged to pay the **clearing manager**, the **payee** is deemed to have been issued with an

invoice, and the **payee** is deemed to be, in relation to that invoice, a **payer**.

Clauses 14.36 to 14.54 apply to the **payee** as if it were a **payer** for the purposes of issue and payment of the invoice.

Compare: Electricity Governance Rules 2003 rule 8.1 part H

Clause 14.44(a): amended on 1 October 2011, by clause 22 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

14.45 Content of pro forma invoice

Pro forma invoices issued to **payees** in accordance with clause 14.44 must specify such of the following as is relevant to the extent that the **clearing manager** has received the necessary information:

- (a) payment for the contracts formed in accordance with clauses 14.30 to 14.35 as determined by the following formula:

$$Q_f * P_f$$

where

Q_f is the final quantity of **electricity** sold at the relevant **grid injection point** obtained from **reconciliation information** for a trading period of the **billing period**

P_f is the final price at that grid injection point for that trading period of the billing period:

- (b) **constrained on compensation** being—
- (i) **constrained on amounts** for the relevant **generator** calculated in accordance with clause 13.204(1)(a) less any **constrained on amounts** calculated in accordance with clause 13.205; and
- (ii) **constrained on amounts** for the relevant **dispatched purchaser** calculated in accordance with clause 13.204(1)(aa):
- (ba) **constrained off compensation** being **constrained off amounts** calculated in accordance with clause 13.194(1A):
- (c) the sum of the **washup** amount and any interest payable on that amount to be credited or debited in accordance with clauses 14.65 to 14.72 as a result of the **clearing manager** receiving corrected information in accordance with clauses 8.68, 8.69, 14.64(13) or (14), 15.20C(b), 15.26(4), 15.29, or clause 28 of Schedule 15.4:
- (d) the sum calculated in accordance with clause 13.110(1):
- (e) the amount to pay, or to be paid, to **ancillary service agents** in relation to **ancillary services** under clause 8.55(a):
- (f) the amount to pay, or to be paid, to the **system operator** for **ancillary services administrative costs** under clause 8.55(b):
- (g) the amount to pay, or be paid, as a result of the settlement for that **billing period** of any **hedge settlement agreements** lodged with the **clearing manager**:
- (ga) for each **FTR** applying to that **billing period** in respect of which the **payee** is registered as the holder of the **FTR**, the net amount of the **FTR hedge value**

- minus the **FTR acquisition cost** for the **FTR**, if that net amount is positive:
- (gb) any amount payable by the **clearing manager** under clause 13.249(7);
 - (h) the amount of **GST** payable (**GST** will be charged on each supply made under to this Code);
 - (i) the total sum of the amounts referred to in paragraphs (a) to (h).

Compare: Electricity Governance Rules 2003 rule 8.2 part H

Clause 14.45(b) and (c): amended, on 15 May 2014, by clause 87 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 14.45(ga): inserted, on 1 October 2011, by clause 23 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011. Clause 14.45(ga): substituted, on 1 November 2012, by clause 14(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 14.45(gb): inserted, on 1 November 2012, by clause 14(2) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

14.46 Clearing manager to make payments

- (1) The **clearing manager** must pay each **payee** the amount invoiced to the **payee** in accordance with clause 14.44.
- (2) The **clearing manager** must pay each **payee** in **cleared funds**.
- (3) The **clearing manager** must pay the amount by 1630 hours on the final **business day** for payment under clause 14.37.
- (4) Subclause (1) applies subject to clauses 14.47, 14.48C, and 14.49.

Compare: Electricity Governance Rules 2003 rule 8.3 part H

Clause 14.46(4): amended, on 1 October 2011, by clause 24 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.46(4): amended, on 1 November 2012, by clause 15 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

14.47 Clearing manager to prioritise payment of funds

The **clearing manager** must hold each amount paid into the **operating account** by or on behalf of a **payer** in payment or part payment of an invoice rendered under clauses 14.36 or 14.44 (excluding any amount referred to in clause 14.40(fa) or (fb)) upon trust for those persons who are entitled to receive payment from the **clearing manager**, in relation to that invoice and as identified or referred to in paragraphs (a) to (d), and must make such payments in the following order of priorities:

- (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 invoices issued under clauses 14.36, 14.44, 14.69(b), 14.70(b), or 14.71(b), taking into account any **GST** input tax credits available to the **clearing manager** in respect of payments to the **system operator** for **ancillary services** under paragraph (b), payment of the **loss and constraint excess** under paragraph (c) and payments to **generators** and **purchasers** under paragraph (d);
- (b) to satisfy any amounts due to the **system operator** for **ancillary services** under clauses 8.6, 8.31(1)(a), and 8.55 to 8.67, as set out in the invoice;
- (c) to satisfy any amounts due to each **grid owner** for **loss and constraint excesses** in accordance with clause 14.73. The **clearing manager** may rely on information provided by the **Authority** to determine what payments are required to be made under this clause;

- (d) to satisfy any amounts due to—
- (i) **generators** determined under clause 14.45, excluding any amounts specified for **ancillary services** in accordance with clause 14.45(e); and
 - (ii) **purchasers** in relation to—
 - (A) **constrained on compensation** determined under clause 14.45(b)(ii); and
 - (B) **constrained off compensation** determined under clause 14.45(ba)—
- and the balance, if any, consisting of interest payments on the amounts deposited in the **operating account**, must be paid to those persons listed in this clause in proportion to the amounts held on trust in respect of each such person in that account in respect of the previous **billing period**.

Compare: Electricity Governance Rules 2003 rule 8.4 part H

Clause 14.47: amended, on 1 October 2011, by clause 25 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.47: amended, on 1 November 2012, by clause 16 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 14.47: amended, on 15 May 2014, by clause 88 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

14.47A Payments in respect of FTRs

- (1) The **clearing manager** must calculate the total amount payable by the **clearing manager** in respect of **FTRs** in respect of the current **billing period**.
- (2) The **clearing manager** must **publish** the amount payable by a person or to a person per **MW** in respect of **FTRs** in respect of the current **billing period**.
- (3) The **clearing manager** must pay any amount payable in respect of **FTRs** in respect of the current **billing period** from the **FTR account**, in accordance with the terms of the **FTR**.
- (4) Subclause (5) applies if, in respect of a **billing period**, the total amount to be invoiced by the **clearing manager** under clause 14.45(ga) and (gb) exceeds the sum of the following amounts:
 - (a) the total amount to be invoiced by the **clearing manager** under clause 14.40(fa);
 - (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 paid into the **FTR account** under clause 14.73(2C) or (2D).
- (5) The **clearing manager** must, in calculating the amount included on an invoice in respect of each **FTR** under clause 14.40(fa) or 14.45(ga), use an amended **FTR hedge value** scaled according to the following formula:

$$A = B \times (C/D)$$

where

A is the scaled **FTR hedge value**

B is the original **FTR hedge value** that would be invoiced if this subclause did not apply

C is the amount calculated in accordance with the formula in subclause (6)

D is the amount calculated in accordance with the formula in subclause (7)

(6) The value for C in the formula in subclause (5) is as follows:

$$C = E + F + G - H - I$$

where

E is the amount of the **loss and constraint excess** to be paid into the **FTR account** under clause 14.73(2C) or (2D)

F is the sum of any **FTR acquisition costs** payable to the **clearing manager**

G is the sum of any amounts payable to the **clearing manager** under clause 13.249(4)

H is the sum of any **FTR acquisition costs** payable by the **clearing manager**

I is the sum of any amounts payable by the **clearing manager** under clause 13.249(7)

(7) The value for D in the formula in subclause (5) is as follows:

$$D = J - K$$

where

J is the sum of any **FTR hedge values** payable by the **clearing manager**

K is the sum of any **FTR hedge values** payable to the **clearing manager**

Clause 14.47A: inserted, on 1 October 2011, by clause 26 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.47A(4) and (5): substituted, on 1 November 2012, by clause 17 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 14.47A(6) and (7): inserted, on 1 November 2012, by clause 17 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

14.48 Payment from operating account

Subject to clause 14.46, all payments required to be made by the **clearing manager** from the **operating account** to the persons entitled to the payments must be made by direct payment to the **bank** accounts that the persons entitled to the payments may notify the **clearing manager** in writing from time to time. Except as expressly permitted by this Code or as required by law, the payments must be free and clear of any withholding or deduction and without any set-off or counter claim.

Compare: Electricity Governance Rules 2003 rule 8.5 part H

14.48A Payment from FTR account

- (1) Subject to clause 14.46, each payment required to be made by the **clearing manager** from the **FTR account** 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) Except as expressly permitted by this Code or as required by law, all payments from the **FTR account** must be free and clear of any withholding or deduction and without any set-off or counter claim.

Clause 14.48A: inserted, on 1 October 2011, by clause 27 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

14.48B Allocation of funds to FTR account

- (1) This clause applies if—
 - (a) a **payer** pays an amount in respect of an invoice that is less than the amount of the invoice; and
 - (b) the amount of the invoice includes an amount referred to in clause 14.40(fa) or (fb).
- (2) The **clearing manager** must apportion the amount to be transferred to the **FTR account** and the amount in respect of other amounts invoiced according to the proportion that each amount bears to the total amount invoiced.

Clause 14.48B: inserted, on 1 October 2011, by clause 27 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.48B(1)(b): amended, on 1 November 2012, by clause 18 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

14.48C Inadequate funds in respect of FTRs

- (1) Subclauses (2) to (4) apply if, in respect of a **billing period**,—
 - (a) a **payer** fails to pay an amount invoiced in respect of an **FTR**; and
 - (b) as a result, the total amount required to be paid by the **clearing manager** in respect of **FTRs** and any amount to be paid under clause 14.73(4)(b) exceeds the amount of all funds in the **FTR account** available for the settlement of **FTRs** in the relevant **billing period**.
- (2) The **clearing manager** must first apply the funds in the **FTR account** available for the settlement of **FTRs** in the relevant **billing period** to satisfy each amount payable to a person in respect of an **FTR**.
- (3) If there are any funds remaining in the **FTR account** available for settlement of **FTRs** in the relevant **billing period** after the **clearing manager** has satisfied each amount payable to a person in respect of an **FTR**, the **clearing manager** must pay those funds to each **grid owner** under clause 14.73(4)(b).
- (4) If there are insufficient funds to satisfy each amount payable under subclause (2), the **clearing manager** must adjust each amount payable to a person in respect of an **FTR** according to the following formula:

$$A = B \times (C/D)$$

where

- A is the amount payable in respect of the **FTR**
- B is the amount specified in a pro forma invoice issued under clause 14.44 as being payable to the **payee** in respect of that **billing period** in respect of an amount specified in clause 14.45(ga) or (gb)
- C is the total amount in the **FTR account** available for the settlement of **FTRs** in the relevant **billing period**
- D is the sum of all amounts required to settle **FTRs** in respect of the **billing period**

Clause 14.48C: inserted, on 1 November 2012, by clause 19 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

14.49 Inadequate funds reduces amounts paid to generators and dispatched purchasers

If, in respect of any **billing period**, a **payer** fails to pay the total amount invoiced by the **clearing manager** (excluding any amount referred to in clause 14.40(fa) or (fb)),—

- (a) payment to each **generator**, and to each **dispatched purchaser** to which **constrained on compensation** or **constrained off compensation** is payable, must be calculated according to the following formula:

$$\text{InvG} * (\text{RecP} / \text{TotInvG})$$

where

- InvG is the amount specified in a pro forma invoice issued under clause 14.44(a) as being payable to the **generator** or **dispatched purchaser** (as the case may be) in respect of that **billing period**, excluding any amount specified for **ancillary services** in accordance with clause 14.45(e) or **ancillary service administrative costs** in accordance with clause 14.45(f)
- RecP is the total amount actually received by the **clearing manager** from **payers** for that **billing period**, excluding all payments that have been made by the **clearing manager** in accordance with clause 14.47(a) to (c)
- TotInvG is the sum of all amounts determined under clause 14.44(a) as being payable to all **generators**, and to all **dispatched purchasers** to which **constrained on compensation** or **constrained off compensation** is payable, in respect of that **billing period**, excluding any amounts specified for **ancillary services** in accordance with clause 14.45(e) or **ancillary service administrative costs** in accordance with clause 14.45(f); and

- (b) if a payment is calculated under paragraph (a) as a result of a **payer** failing to pay the total amount invoiced by the **clearing manager**, the amount payable to each

generator must be adjusted by reducing payments for items contained in the pro forma invoice issued under clause 14.45 using the following order of priorities:

- (i) by reducing any payment for the sale of **electricity** determined in accordance with clause 14.45(a);
- (ii) by reducing, on a pro rata basis,—
 - (A) **constrained on compensation** determined in accordance with clause 14.45(b); and
 - (B) **constrained off compensation** determined under clause 14.45(ba);
- (iii) by reducing any **washup** amounts, if the total amount is payable to the **generator**, determined in accordance with clause 14.45(c);
- (iv) by reducing a **hedge settlement agreement** amount, if the total amount is payable to the **generator**, determined in accordance with clause 14.45(g).

Compare: Electricity Governance Rules 2003 rule 8.6 part H

Clause 14.49 Heading: amended, on 15 May 2014, by clause 89(1) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 14.49: amended, on 1 October 2011, by clause 28 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.49: amended, on 1 November 2012, by clause 20 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 14.49(a): amended, on 15 May 2014, by clause 89(2)(a) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 14.49(b)(ii): substituted, on 15 May 2014, by clause 89(2)(b) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

14.50 Interest is payable to generators and dispatched purchasers

- (1) Subject to clause 14.53, if a **generator** or a **dispatched purchaser** does not receive the full amount specified in a pro forma invoice issued under clause 14.44(a), the **clearing manager** is liable to pay interest on the unpaid amount. 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 **generator** or the **dispatched purchaser** and compounded at the end of each calendar month.
- (2) If a **payer** has not paid any amount due in respect of an invoice after the due date for payment, interest must be payable on the unpaid amount. 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.

Compare: Electricity Governance Rules 2003 rules 8.7 and 8.8 part H

Clause 14.50 Heading: amended, on 15 May 2014, by clause 90(1) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 14.50(1): amended, on 15 May 2014, by clause 90(2) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

14.51 Further funds paid according to priority

- (1) As further funds constituting late payments in respect of any **billing period** are received by the **clearing manager** (excluding any amount referred to in clause 14.40(fa) or (fb)), those funds must be paid in accordance with the priorities set out in clause 14.47.

- (2) If funds received by the **clearing manager** are identifiable as relating to a specific **billing period**, then 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**. However, 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 **payees** in relation to the relevant invoice.

Compare: Electricity Governance Rules 2003 rule 8.9 part H

Clause 14.51(1): amended, on 1 October 2011, by clause 29 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.51(1): amended, on 1 November 2012, by clause 21 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

14.51A Late payments in respect of FTRs

- (1) As further funds constituting late payments (including any interest payable under clause 14.50(2)) in respect of any **billing period** are received by the **clearing manager** in respect of an amount referred to in clause 14.40(fa) or (fb), the **clearing manager** must pay those funds into the **FTR account**.
- (2) The **clearing manager** must apply late payments received under subclause (1) in satisfaction or part satisfaction of amounts payable (including interest calculated on the same basis as set out in clause 14.50(2) if interest is paid under that subclause) by the **clearing manager** under clause 14.47A in respect of the **billing period** in which the late payments were owed by paying the persons who have received adjusted payments under clause 14.48C in proportion to the amounts owed to each person.
- (3) To avoid doubt,—
- (a) the **clearing manager** must first apply late payments received under subclause (1) to satisfy amounts owed to a person in respect of an **FTR**; and
 - (b) if the amount received under subclause (1) exceeds the amount required to satisfy amounts owed to a person in respect of an **FTR**, the **clearing manager** must pay the residual late payments to each **grid owner** under clause 14.73(4)(b).

Clause 14.51A: inserted, on 1 October 2011, by clause 30 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.51A(1): amended, on 1 November 2012, by clause 22(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 14.51A(2): amended, on 1 November 2012, by clause 22(2) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 14.51A(3): inserted, on 1 November 2012, by clause 22(3) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

14.52 Payer to remain in default

Despite anything else in this Code, the application of money under clauses 14.46 to 14.49 and 14.51 (provided that a **payer** has still not paid the full amount invoiced and any interest due on that amount) does not—

- (a) satisfy the obligation of the **payer** to pay the full amount invoiced together with the interest due on that amount to—
 - (i) the **clearing manager**; or

- (ii) the **generators** acting in accordance with clause 14.54; or
 - (iii) the **dispatched purchasers** acting in accordance with clause 14.54; or
- (b) prejudice any remedies available to—
 - (i) the **clearing manager** in an **event of default**; or
 - (ii) the **generators**, under clause 14.54; or
 - (iii) the **dispatched purchasers** under clause 14.54.

Compare: Electricity Governance Rules 2003 rule 8.10 part H

Clause 14.52(a) and (b): substituted, on 15 May 2014, by clause 91 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

14.53 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 **payer** in default.

Compare: Electricity Governance Rules 2003 rule 8.11 part H

14.54 Generators and dispatched purchasers assigned or subrogated to all clearing manager's rights of recovery

If a **payer's** default means that the **clearing manager** is unable to pay a **generator** or a **dispatched purchaser** the full outstanding amount that would otherwise be payable to the **generator** or **dispatched purchaser** so that any amount paid to the **generator** or **dispatched purchaser** is reduced under clause 14.49, the **generator** or the **dispatched purchaser** is 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 **payer** which, if paid, would have been required to be held on trust by the **clearing manager** for the **generator** or **dispatched purchaser** in accordance with this Code. The **clearing manager** must do all that is reasonably necessary, including the granting of a power of attorney in favour of a **generator** or a **dispatched purchaser** (as the case may be), to assist the **generator** or **dispatched purchaser** in the exercise of the rights. The **generator** or **dispatched purchaser** may then—

- (a) in the name of the **clearing manager** (if requested), 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** from a **payer** in default or a guarantor of any **payer** or any person that has provided a letter of credit or bond in favour of the **clearing manager** in respect of the **payer**; and
- (b) directly or indirectly, in the name of the **clearing manager** (if requested), prove in, claim, share in or receive the benefit of any distribution, dividend or payment arising out of any insolvency of a **payer** in default or a guarantor of a **payer** in default or any person that has provided a letter of credit or bond in favour of the **clearing manager** in respect of a **payer** in default.

Compare: Electricity Governance Rules 2003 rule 8.12 part H

Clause 14.54 Heading: amended, on 15 May 2014, by clause 92(1) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 14.54: amended, on 1 October 2011, by clause 31 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.54(a): amended, on 21 September 2012, by clause 33 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 14.54: amended, on 15 May 2014, by clause 92(2) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Default

14.55 Definition of an event of default

Each of the following events constitutes an **event of default**:

- (a) the failure of a **payer** to comply with clauses 14.2 to 14.17 or to satisfy a **call** in accordance with clause 14.18(4);
- (b) the failure of a **payer** to pay the full amount invoiced to it in accordance with clauses 14.36 to 14.54;
- (c) any action taken for, or with a view to, the declaration of a **payer** as a corporation at risk under the Corporations (Investigation and Management) Act 1989;
- (d) a statutory manager being appointed under the Corporations (Investigation and Management) Act 1989 (or a recommendation or submission is made by a person to the Securities Commission supporting such an appointment);
- (e) a person being appointed under section 19 of the Corporations (Investigation and Management) Act 1989 to investigate the affairs or run the **business** of the **payer**;
- (f) if a **payer** 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, 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 takes possession of, or a receiver, manager, receiver and manager, liquidator, provisional liquidator, trustee, statutory or official manager or inspector, administrator or similar officer is appointed in respect of the whole or any part of the assets of the **payer** or if the **payer** requests that such an appointment be made;
- (h) termination of a **retailer's use-of-system agreement** with a **distributor** because of a **serious financial breach** if—
 - (i) the **retailer** continues to have a **customer** or **customers** on the **distributor's local network**; and
 - (ii) there are no unresolved disputes between the **retailer** 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 clause applies.

Compare: Electricity Governance Rules 2003 rule 9.1 part H

Clause 14.55(h): inserted, on 16 December 2013, by clause 8 of the Electricity Industry Participation (Managing Retailer Default Situations) Code Amendment 2013.

14.56 Anticipated events of default must be referred to Authority

If the **clearing manager** has reasonable grounds to believe that an **event of default** is likely to occur, the **clearing manager** must refer the matter to the **Authority** for its

urgent consideration and instruction of an appropriate course of action to minimise the risk of default occurring.

Compare: Electricity Governance Rules 2003 rule 9.2 part H

14.57 Procedure upon event of default

- (1) Upon an **event of default** under paragraphs (a) to (g) of clause 14.55 occurring, the **clearing manager** must, without prejudice to its rights under clause 14.58, notify the person in default that it has committed an **event of default**.
- (2) Without prejudice to its rights under clause 14.58, the **clearing manager** must refer an issue concerning an **event of default** to the **Authority**.

Compare: Electricity Governance Rules 2003 rule 9.3 part H

Clause 14.57(1): amended, on 16 December 2013, by clause 9 of the Electricity Industry Participation (Managing Retailer Default Situations) Code Amendment 2013.

14.58 Event of default gives clearing manager certain 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 **payer** in accordance with clauses 14.9(a), 14.9(aa) and 14.47. In such a case, the **clearing manager** must give notice to the **payer**, and the **payer** must comply with the notice, requiring the **payer** to reinstate the **cash deposit** to at least the level of the **cash deposit** before the application of the **cash deposit** was made in accordance with the following procedure:
 - (i) if notice is given before 1200 hours on a **business day**, the **payer** must reinstate the **cash deposit** no later than 1600 hours on that same **business day**:
 - (ii) if notice is given between 1200 hours and 1700 hours on a **business day**, the **payer** must make reinstatement of the **cash deposit** no later than 1200 hours on the next **business day** following the notice:
 - (b) a demand may be made by the **clearing manager** under a guarantee, letter of credit or bond provided under this Part in respect of the **payer**, and the **clearing manager** must pay any amounts received as a consequence of the demand into the **operating account**. In such a case, the **payer** must procure the reinstatement of the guarantee, letter of credit or bond to at least the level of that guarantee, letter of credit or bond before the demand was made in accordance with the following procedures:
 - (i) if a demand is made before 1200 hours on a **business day**, reinstatement of the level of the security must be procured by the **purchaser** no later than 1600 hours on that same **business day**:
 - (ii) if a demand is made between 1200 hours and 1700 hours on a **business day**, reinstatement of the level of security must be procured by the **payer** no later than 1200 hours on the next **business day** following the demand:
 - (c) if a **generator** has not paid an amount due in respect of an invoice by the due date for payment (whether the amount became owing in its capacity as a **generator** or

otherwise), the **clearing manager** may set-off the unpaid amount against any amount payable by the **clearing manager** to the **generator**. The amount payable by the generator to the **clearing manager** in respect of the invoiced amounts must be reduced by the amount set-off in accordance with this paragraph:

- (d) if any other **payer** has not paid an amount due in respect of an invoice by the due date for payment (whether the amount became owing in its capacity as a **purchaser, distributor** or **grid owner** or otherwise), the **clearing manager** may set-off any amount payable by the **clearing manager** (whether the amount became payable to the **payer** in its capacity as a **purchaser, distributor, grid owner** or otherwise) to the **payer** against the unpaid amount payable by the **payer** to the **clearing manager** in accordance with clauses 14.39 or 14.40:
 - (e) take possession of any **FTRs** held by the defaulting **payer** in accordance with subclauses (2) and (3).
- (2) 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 subclause (1)(e) without any further authorisation than this subclause.
 - (3) If the **FTR hedge values** or estimated **FTR hedge values** held by the defaulting **payer** 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**.
 - (4) If the amount received by the **clearing manager** on settlement or sale of an **FTR** taken possession of under subclause (1)(e) exceeds the amount required to remedy the **event of default**, the **clearing manager** must repay the excess amount to the defaulting **payer**.
 - (5) If the **clearing manager** holds an **FTR** in respect of which an amount would be payable if the **FTR** was held by another person, no amount is payable by the **clearing manager**.

Compare: Electricity Governance Rules 2003 rule 9.4 part H

Clause 14.58(a): amended, on 1 October 2011, by clause 32(a) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.58(e): inserted, on 1 October 2011, by clause 32(b) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.58(2)-(5): inserted, on 1 October 2011, by clause 32(c) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.58(1): amended, on 21 September 2012, by clause 34 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 14.58(3): amended, on 1 November 2012, by clause 23 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

14.59 Pro rata call on security

If the **clearing manager** exercises any of the remedies under clause 14.58(1)(a) or (b) against a **payer**, and the **payer** has procured the provision of a combination of securities to meet any prudential requirements in this Part, the **clearing manager** must, for a period of 7 days from the time the **event of default** occurred, exercise its remedies against each of any **cash deposits**, guarantees, letters of credit or bonds provided by or on behalf of that **payer** on a pro rata basis in accordance with the following formula:

$$SA/TS \quad \times DA = \$ML$$

where

SA is the total amount of any **cash deposits** provided by or for the **payer** or the maximum liability of any person under a guarantee, letter of credit or bond provided in respect of the **payer**

TS is the total amount of all **cash deposits**, guarantees, letters of credit and bonds provided by or in respect of the **payer**

DA is the amount required to be paid to remedy the **payer's event of default**

\$ML is the maximum amount that can be utilised or claimed against that security during the first 7 days after the **event of default** occurs.

Compare: Electricity Governance Rules 2003 rule 9.5.1 part H

Clause 14.59: amended, on 1 October 2011, by clause 33 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

14.60 Clearing manager to specify pro rata proportion

Upon application of any part of a **cash deposit** under clause 14.58(1)(a), and in any demand made under clause 14.58(1)(b), the **clearing manager** must specify in writing to the providers of the relevant security the total amount required from the **payer** to remedy the **event of default** (the “default amount”) and the pro rata proportion of any **cash deposit** applied under clause 14.58(1)(a) or the pro rata proportion of the default amount demanded under clause 14.58(1)(b), as appropriate.

Compare: Electricity Governance Rules 2003 rule 9.5.2 part H

Clause 14.60: amended, on 1 October 2011, by clause 34 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

14.61 Pro rata application or demand limited to 7 days

If, after 7 days, the default amount has not been recovered by the pro rata **call** methodology in clause 14.59, the **clearing manager** may **call** all or part of any security provided by the defaulting **payer** to meet any part of the default amount still outstanding.

Compare: Electricity Governance Rules 2003 rule 9.5.3 part H

14.62 If security to be pro rated

The **clearing manager** may only follow the procedures set out in clauses 14.59 to 14.61 if the **payer** against which the **clearing manager** is exercising any of the remedies under clause 14.58(1)(a) or (b), and which has procured the provision of a combination of securities, has previously notified the **clearing manager** that it wishes to have those procedures followed in respect of its combination of securities.

Compare: Electricity Governance Rules 2003 rule 9.5.4 part H

Clause 14.62: amended, on 1 October 2011, by clause 35 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

14.62A Allocation of amounts to FTR obligations and other obligations

- (1) If the **clearing manager** exercises any of the remedies under clause 14.58(1)(a) or (b) against a **payer**, the **clearing manager** must transfer to the **FTR account** any amounts recovered to satisfy amounts that may be due and owing by the defaulting **payer** in respect of **FTRs** in accordance with the following formula:

$$C_{\text{FTR}} = C_{\text{TOT}} \times (O_{\text{FTR}}/O_{\text{TOT}})$$

where

C_{FTR} is the amount that must be transferred to the **FTR account**

C_{TOT} is the total amount recovered under clause 14.58(1)(a) and (b)

O_{FTR} is the amount owing in respect of **FTRs** held by the defaulting **payer**

O_{TOT} is the total amount owing by the defaulting **payer** under this Code

- (2) The **clearing manager** must apply any amounts recovered under subclause (1) that have not been transferred in accordance with subclause (1) to satisfy any amounts that may be due and owing by the defaulting **payer** to the **clearing manager** under this Code.

Clause 14.62A: inserted, on 1 October 2011, by clause 36 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

14.63 Rights of generators and dispatched purchasers to exercise rights

- (1) A **generator** or a **dispatched purchaser** is entitled to exercise its rights under clause 14.54, 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 clause 14.58; or
 - (b) the **clearing manager** has failed within 2 months of an **event of default** to collect all amounts (other than an amount referred to in clause 14.40(fa) or (fb)) due from the defaulting **payer**.
- (2) Nothing in subclause (1) or clauses 14.55 to 14.62 limits the statutory right of the **clearing manager** to apply to the Court for the appointment of a receiver, interim liquidator or liquidator.

Compare: Electricity Governance Rules 2003 rules 9.6 and 9.7 part H

Clause 14.63 Heading: amended, on 15 May 2014, by clause 93(1) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 14.63(1): amended, on 21 September 2012, by clause 35 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 14.63(1): amended, on 15 May 2014, by clause 93(2) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 14.63(1)(b): amended, on 1 October 2011, by clause 37 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.63(1)(b): amended, on 1 November 2012, by clause 24 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

14.64 Invoice disputes

- (1) A **payee** or **payer** may dispute an invoice issued by the **clearing manager** under clauses 14.36 to 14.54 by notice in writing to the **clearing manager**.
- (2) A **payee** or **payer** may not dispute an invoice under subclause (1) after the expiry of 2 years after the date of issue of the invoice.
- (3) A **payee** or **payer** may not commence a dispute under subclause (1) if the **payee** or **payer** has commenced a dispute in relation to the **volume information** on which the invoice is based under clause 15.29.
- (4) The **clearing manager** must notify all **participants** affected by the dispute and the **Authority** of the dispute no later than 1 **business day** after the dispute is notified to the **clearing manager** under subclause (1).
- (5) On receiving a notification of a dispute that relates to **volume information** under subclause (4), the **Authority** may direct that no further action be taken in respect of the dispute.
- (6) If the **Authority** gives a direction under subclause (5), subclauses (7) to (14) cease to apply to the dispute. However, a direction under subclause (5) does not affect the validity of an invoice issued under subclause (8) or clause 14.66 before the direction was given.
- (7) The disputing **payee** or **payer** and the **clearing manager** must use reasonable endeavours to resolve the dispute.
- (8) The **clearing manager** must reissue the disputed invoice and any other affected invoices if—
 - (a) the dispute is resolved by the parties to the dispute agreeing that information used to prepare the invoice is incorrect; and
 - (b) the dispute is resolved 2 **business days** or more before the invoiced amount is due to be paid or received by the disputing **payee** or **payer**; and
 - (c) the **clearing manager** has received all information necessary to reissue the invoice and any other affected invoices (including revised **volume information** if necessary).
- (9) If the **payee** or **payer** and the **clearing manager** do not resolve the dispute 2 **business days** or more before the invoiced amount is due to be paid or received, the disputing **payee** or **payer** must pay or receive the invoiced amount in accordance with clauses 14.37, 14.39, 14.44, and 14.46.
- (10) If the dispute is not resolved within 15 **business days** after the date on which the dispute was notified to the **clearing manager** under subclause (1), the disputing **payee** or **payer** or the **clearing manager** may refer the dispute to the **Rulings Panel** for resolution.
- (11) The **Rulings Panel** may make such determination as it thinks fit.
- (12) The **Rulings Panel** must give notice of its determination to the parties to the dispute and affected **participants**.
- (13) If a dispute (other than a dispute resolved 2 **business days** or more before the invoiced amount is due to be paid or received) is resolved by the parties to the dispute agreeing, or the **Rulings Panel** determining, that information used to prepare an invoice 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 (14):
 - (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**.
- (14) 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** does not need 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 being notified of the resolution of the dispute:
 - (c) the **reconciliation manager** must provide the corrected **volume information** to the **clearing manager**.
- (15) If corrected information is provided to the **clearing manager** under subclauses (13) or (14), the **clearing manager** must conduct **washups** in accordance with clauses 14.65 to 14.72.

Compare: Electricity Governance Rules 2003 rule 10 part H

Clause 14.64(14)(b): amended, on 15 May 2014, by clause 94 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Washups

14.65 Clearing manager must conduct washups

If the **clearing manager** receives corrected information in accordance with clauses 8.68, 8.69 14.64(13) or (14), 15.26(4), 15.29, or clause 28 of Schedule 15.4, it must conduct **washups** and issue **payee** and **payer** invoices in accordance with clauses 14.66 to 14.72.

Compare: Electricity Governance Rules 2003 rule 11.1 part H

14.66 Clearing manager must invoice washup amounts

The **clearing manager** must invoice **washup** amounts to the relevant **payees** and **payers** in accordance with clauses 14.36, 14.44 and 14.67 to 14.72, except that the **clearing manager** must, if requested by a **payer** or **payee** affected by the **washup**, issue corrected **payee** or **payer** invoices covered by the **washup**.

Compare: Electricity Governance Rules 2003 rule 11.1A part H

14.67 Washups for payers

All **washup** amounts relating to a **payer** must be expressed as a credit or debit in that **payer's** invoice and must be paid as follows:

- (a) if a **payer's washup** amount is a credit, the **clearing manager** must subtract the credit from the amount invoiced in accordance with clause 14.36 in respect of the then present **billing period**. However, if the **washup** amount is greater than the total sum of the other items to be invoiced for that **billing period**, then payment of the **washup** amount must be made in accordance with clause 14.39:
- (b) if a **payer's washup** amount is a debit, the **clearing manager** must add the debit to the **payer's** invoice issued in accordance with clause 14.36 in respect of the then present **billing period**:
- (c) 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 invoice issued in accordance with clause 14.36 and accrues from the date that payment of the invoice based on the incorrect information to which the **washup** relates was due as set out in clauses 14.37 and 14.46, (as applicable) until the date of issue of the invoice for that **washup** amount in accordance with clause 14.36 and must be compounded at the end of each calendar month.

Compare: Electricity Governance Rules 2003 rule 11.2 part H

14.68 Washups for generators

All **washup** amounts relating to a **generator** must be expressed as a credit or debit in that **generator's** invoice and must be paid as follows:

- (a) if a **generator's washup** amount is a credit, the **clearing manager** must add the credit to the amount invoiced by the **clearing manager** in accordance with clause 14.44(a) in respect of the then present **billing period**:
- (b) if a **generator's washup** amount is a debit, the **clearing manager** must subtract the debit from the amount invoiced in accordance with clause 14.44(a) in respect of the then present **billing period**. However, if the **washup** amount is greater than the total sum of the other items invoiced for that **billing period**, payment of the **washup** amount must be made by the **generator** in accordance with clause 14.44(b):
- (c) 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 invoice issued in accordance with clause 14.44(a) and accrues from the date that payment of the invoice based on the incorrect information to

which the **washup** relates was due as set out in clauses 14.37 and 14.46 (as applicable) until the date of issue of the invoice for that **washup** amount in accordance with clause 14.44, and must be compounded at the end of each calendar month.

Compare: Electricity Governance Rules 2003 rule 11.3 part H

14.69 Washups for ancillary service agents

All **washup** amounts relating to an **ancillary service agent** must be specified as a credit or debit in that **ancillary service agent's** invoice and must be paid as follows:

- (a) if an **ancillary service agent's washup** amount is a credit, the **clearing manager** must add the credit to the amount invoiced by the **clearing manager** in accordance with clause 14.44(a) in respect of the then present **billing period**:
- (b) if an **ancillary service agent's washup** amount is a debit, the **clearing manager** must subtract the debit from the amount invoiced in accordance with clause 14.44(a) in respect of the then present **billing period**. However, if the **washup** amount is greater than the total sum of the other items invoiced for that **billing period**, then payment of the **washup** amount must be made by the **ancillary service agent** in accordance with clause 14.44(b):
- (c) 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 invoice issued in accordance with clause 14.44(a) and accrues from the date that payment of the invoice based on the incorrect information to which the **washup** relates was due as set out in clauses 14.37 and 14.46 (as applicable) until the date of issue of the invoice for that **washup** amount in accordance with clause 14.44, and must be compounded at the end of each calendar month.

Compare: Electricity Governance Rules 2003 rule 11.4 part H

14.70 Washups for system operator for corrections to ancillary service administrative costs

All **washup** amounts relating to **ancillary service administrative costs** must be specified as a credit or debit in the **system operator's** invoice and must be paid as follows:

- (a) if the **system operator's ancillary service administrative cost washup** amount is a credit, the **clearing manager** must add the credit to the amount invoiced by the **clearing manager**, in accordance with clause 14.44(a) in respect of the then present **billing period**:
- (b) if the **system operator's ancillary service administrative cost washup** amount is a debit, the **clearing manager** must subtract the debit from the amount invoiced in accordance with clause 14.44(a) in respect of the then present **billing period**. However, if the **washup** amount is greater than the total sum of the other items invoiced for that **billing period**, payment of the **washup** amount must be made by the **system operator** in accordance with clause 14.44(b):
- (c) 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 invoice issued in accordance with clause 14.44(a) and accrues from the date that payment of the invoice based on the incorrect information to which the **washup** relates was due as set out in clauses 14.37 and 14.46 (as applicable) until the date of issue of the invoice for that **washup** amount in accordance with clause 14.44, and must be compounded at the end of each calendar month.

Compare: Electricity Governance Rules 2003 rule 11.5 part H

14.71 Washups for grid owners

If a **washup** has occurred due to incorrect **consumption information** being used to prepare invoices issued in accordance with clauses 14.36 and 14.44 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 payable to that **grid owner** in accordance with clause 14.73 in respect of the then present **billing period**;
- (b) where a **grid owner's washup** amount is a debit, the **clearing manager** must subtract the debit from any amount payable to the **grid owner** in accordance with clause 14.73 in respect of the then present **billing period**. However, if the **washup** amount is greater than the amount payable, the **clearing manager** must issue an invoice for the **washup** amount concurrently with issuing invoices to **payees** under clause 14.36, and payment of the **washup** amount must be made by the **grid owners** by the time for payment of invoices set out in clause 14.37;
- (c) 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 payable to the **grid owner** in accordance with clause 14.73 and accrues from the date that payment based on the incorrect information to which the **washup** relates was made until the date of issue of the invoices to **payees** and/or **payers** resulting in the **grid owners' washup** amount, and must be compounded at the end of each calendar month.

Compare: Electricity Governance Rules 2003 rule 11.6 part H

14.72 Payment where no longer participant

- (1) Despite clauses 14.67 to 14.71, if a **washup** amount affects a person who is no longer a **participant**, an invoice must be issued by the **clearing manager** specifying the **washup** amount and is payable in accordance with clause 14.37. The person to whom the invoice is issued remains liable for outstanding obligations.
- (2) 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 invoiced in accordance with clause 14.71(a) and accrues from the date that payment of the invoice based on the incorrect information to which the **washup** relates was due as set out in clauses 14.37 and 14.46 (as applicable) until the date of issue of the invoice for that **washup** amount, and must be compounded at the end of each calendar month.

Compare: Electricity Governance Rules 2003 rule 11.7 part H

14.73 Payment of loss and constraint excess

- (1) On the final day for payment under clause 14.37, and when the **clearing manager** has received notification from its **bank** that the **generators** and **purchasers** have deposited **cleared funds** in the **operating account**, the **clearing manager** must, subject to clause 14.47, pay the appropriate **loss and constraint excess** and **residual loss and constraint excess** to each **grid owner** in accordance with subclause (3) and subclause (4).
- (2) A **loss and constraint excess** accrues for a **billing period** when the total amounts to be paid by the **clearing manager** to the **generators** for that **billing period** for the contracts formed in accordance with clause 14.30 differ from the total amounts to be paid to the **clearing manager** by the **purchasers** for that **billing period** for the contracts formed in accordance with clause 14.33.
- (2A) The **FTR manager** must—
 - (a) determine the amount of **loss and constraint excess** that must be retained by the **clearing manager** and paid into the **FTR account** in accordance with Schedule 14.6; 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**.
- (2B) Each **grid owner** and the **pricing manager** must provide information to the **FTR manager** in accordance with Schedule 14.6.
- (2C) The **clearing manager** must retain the amount advised under subclause (2A) and pay the amount into the **FTR account**.
- (2D) If the amount that the **FTR manager** advises the **clearing manager** under subclause (2A) exceeds the amount of the **loss and constraint excess** for the **billing period**, the **clearing manager** must retain all of the **loss and constraint excess** and pay all of the **loss and constraint excess** into the **FTR account**.
- (3) The **Authority** must advise the **clearing manager** of the proportion of the **loss and constraint excess** and **residual loss and constraint excess** each **grid owner** is to be paid.
- (4) Unless the **Authority** has directed otherwise under this clause, the **clearing manager** must pay to each **grid owner** in the proportions advised under subclause (3)—
 - (a) the amount of any **loss and constraint excess** less the amount retained under subclause (2C); and
 - (b) the amount of any **residual loss and constraint excess**.
- (5) Each **grid owner** must treat **residual loss and constraint excess** paid to it under subclause (4) as **loss and constraint excess**.

Compare: Electricity Governance Rules 2003 rule 12 part H

Clause 14.73(1): amended, on 1 October 2011, by clause 38(1) & (2) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.73(2A)-(2D): inserted, on 1 October 2011, by clause 38(3) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.73(2A)(b): substituted, from 19 July 2013 to 19 April 2014, by clause 5 of the Electricity Industry Participation (Time Frames for Invoicing) Code Amendment 2013.

Clause 14.73(2A)(b): substituted, on 15 May 2014, by clause 6 of the Electricity Industry Participation (Time Frames for Invoicing) Code Amendment 2014.

Clause 14.73(2B): amended, on 27 September 2012, by clause 4 of the Electricity Industry Participation (Minor Amendments relating to Financial Transmission Rights) Code Amendment 2012.

Clause 14.73(3): substituted, on 1 October 2011, by clause 38(4) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Clause 14.73(4)&(5): inserted, on 1 October 2011, by clause 38(4) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

Reporting obligations of the clearing manager

14.74 Monthly divergence reports to be prepared by clearing manager

Unless exceptional circumstances exist (in which case the report is to be provided as soon as reasonably practicable), the **clearing manager** must report to the **market administrator** in writing on the 10th **business day** of each calendar month, even if the **clearing manager** has no alleged breaches of this Code to report. The report must include—

- (a) information on any situations where the **clearing manager** believes, on reasonable grounds, that the **clearing manager**, or another **participant**, has breached this Code in the previous calendar month; and
- (b) the date and time at which each alleged breach took place; and
- (c) the nature of each alleged breach, including details of the person alleged to be in breach, any **payees** or **payers** believed to be affected by the alleged breach, and, in the case of a late invoice, the part of the invoice process that was delayed; and
- (d) the reason for the alleged breach occurring if the **clearing manager** is aware of the reason; and
- (e) situations in which an invoice was or will be issued late and whether or not the delay was caused by the **clearing manager**.

Compare: Electricity Governance Rules 2003 rule 13.1 part H

14.75 Market administrator must publish clearing manager reports

- (1) By the 15th **business day** of each calendar month, the **market administrator** must **publish** the sections of the report, received in the previous calendar month from the **clearing manager** in accordance with clause 14.74, that relate to any breaches of this Code by the **clearing manager**.
- (2) By the 15th **business day** of each calendar month the **market administrator** must also refer the report received in the previous calendar month to the **Authority**.

Compare: Electricity Governance Rules 2003 rule 13.2 part H

14.76 Right to information concerning clearing manager's action

- (1) A **payee** or **payer** may, by notice in writing to the **clearing manager**, request further information related to a situation set out in a **clearing manager's** report **published** under clause 14.75 that has materially affected that person.

- (2) The **clearing manager** must provide the requested information to that person, but the information provided must not include any information that is confidential in respect of any other person.

Compare: Electricity Governance Rules 2003 rule 13.3 part H

14.77 Clearing manager to provide copies of payee reports

The **clearing manager** must provide the **Authority** with a copy of the weekly report described in clause 14.28(b), concurrently with providing that report to **payees**.

Compare: Electricity Governance Rules 2003 rule 13.4 part H

14.78 Clearing manager to publish block dispatch settlement differences

- (1) By 0900 hours on the 2nd **business day** after the **clearing manager** has issued pro forma invoices under clause 14.44(a), if 1 or more **trading periods** occurred during the **billing period** to which these pro forma invoices relate, the **clearing manager** must **publish** the following information for **participants** on the **information system**:
- (a) the maximum block dispatch settlement difference for each **block dispatch group** for the previous **billing period** as determined by the following formula:

$$\text{Settlement Difference} = \text{Max} \left\{ \sum_{\text{gip}=1}^{\text{gip}} P_{\text{gip}} \left\{ \text{Gen}_{\text{gip}} - \text{Set}_{\text{gip}} \left\{ \frac{\sum \text{Gen}_{\text{gip}}}{\sum \text{Set}_{\text{gip}}} \right\} \right\} \right\}$$

- (b) the total block dispatch settlement differences for each **block dispatch group** for the previous **billing period** as determined by the following formula:

$$\text{Settlement Difference} = \sum_{i=1}^i \left\{ \sum_{\text{gip}=1}^{\text{gip}} P_{\text{gip},i} \left\{ \text{Gen}_{\text{gip},i} - \text{Set}_{\text{gip},i} \left\{ \frac{\sum \text{Gen}_{\text{gip},i}}{\sum \text{Set}_{\text{gip},i}} \right\} \right\} \right\}$$

where

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**

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**

- 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**
- $Gen_{gip,i}$ 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**
- $Set_{gip,i}$ 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**.

Compare: Electricity Governance Rules 2003 rule 13.5 part H

14.79 Clearing manager to publish block dispatch settlement differences later if information system is unavailable

- (1) If the **information system** is unavailable to **publish** the information set out in clause 14.78 in accordance with that clause, the **clearing manager** is not obliged to follow any backup procedures in respect of **publishing** the information.
- (2) The **clearing manager** must **publish** the information as soon as reasonably possible on the **information system** after the **information system** becomes available.

Compare: Electricity Governance Rules 2003 rule 13.6 part H

14.80 Clause 14.78 applies to block dispatch groups only

The calculation of the block dispatch settlement differences under clause 14.78 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**.

Compare: Electricity Governance Rules 2003 rule 13.7 part H

14.81 No washup calculation under clause 14.78 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 14.78, the **clearing manager** is not required to recalculate any block dispatch settlement differences as a result of subsequently receiving revised **reconciliation information**.

Compare: Electricity Governance Rules 2003 rule 13.8 part H

14.82 Special requirements applying to clearing manager

- (1) The **clearing manager** must be a company limited by shares with a constitution that limits the powers of the **clearing manager** to exercising the rights and performing the obligations of the **clearing manager** as are permitted or prescribed by this Code.
- (2) The constitution of the **clearing manager** must be in a form approved by the **Authority**.

Compare: Electricity Governance Rules 2003 rule 14 part H

14.83 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, electronic address or facsimile number as last advised in writing to the sender and may be posted to such address by prepaid post.
- (2) If any such notice or demand is delivered by hand, it is deemed to be delivered on the date of such delivery, if posted, it is deemed to be delivered on the 2nd **business day** following the date of posting and, if transmitted by facsimile (in good order) or through the **information system**, it is deemed to be delivered on the date it was transmitted, except that 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**.

Compare: Electricity Governance Rules 2003 rule 15 part H

Schedule 14.1 Guarantee

cl 14.5(b)

To: [Clearing manager] [address]

Attention: [name]

Dear Sir/Madam

1. [Bank] (“the Bank”) refers to each and every obligation pursuant to the Electricity Industry Participation Code 2010 (“the Code”) of [**Payer**] (“the Principal”) to pay amounts the Principal, now or at any time, owes to, and is invoiced by, you (whether as principal or agent) together with default interest, if any, in relation to such amounts (“the Obligations”) pursuant to the Code.
2. The Bank hereby unconditionally guarantees the payment to you on demand of an amount specified in each such demand provided that—
 - (a) the aggregate liability of the Bank under this guarantee will not exceed [amount determined from time to time by the clearing manager calculated in accordance with clauses 14.18 to 14.22 of the Code] (the “Maximum Amount”); and
 - (b) your demand is made in writing and is purported to be signed by an authorised signatory; and
 - (c) a certificate purported to be signed by your authorised signatory and certifying that the Principal has failed, in whole or in part, to fulfil the Obligations accompanies your demand, which certificate will be conclusive proof of such failure.
3. This guarantee will not be affected, discharged or diminished by any act or omission which would, but for this provision, have exonerated a guarantor but would not have affected or discharged the Bank’s liability had it been a principal debtor.
4. Subject to paragraph 5 below, this guarantee will continue in force until the date at which the Principal has ceased to be bound by the Code and has discharged its obligations to you pursuant to the Code at which time you will return this guarantee to the Bank.
- [5. Notwithstanding anything else in this guarantee, the Bank may at any time pay you the Maximum Amount less any amount or amounts the Bank may previously have paid under this guarantee or such lesser sum as you may require. Upon payment of that sum, the liability of the Bank under this guarantee will cease and determine].

[Note: Bank to elect either this clause or the following clause as a method of cancellation].

- [5. Notwithstanding anything else in this guarantee, the Bank may cancel this guarantee as to subsequent liability by giving ninety (90) days' notice in writing to [clearing manager]; however, the Bank will remain liable with respect to the Obligations which relate to the period prior to the effective date of the ninety (90) days' notice.]
6. This guarantee may be assigned by you without the Bank's consent. It will bind the successors and assigns of the Bank, as well as any entity with which the Bank may amalgamate.
7. This guarantee will be governed by and interpreted in all respects in accordance with New Zealand law and the parties hereto irrevocably submit to the non-exclusive jurisdiction of the courts of New Zealand.

EXECUTED for and on behalf)
of [BANK])
by its Attorneys)
.....)
[Print Names])

Signature(s)

.....
in the presence of:
.....
Signature
.....
Full Name
.....
Address
.....
Occupation
.....
Signature(s)

Compare: Electricity Governance Rules 2003 schedule H1 part H

Schedule 14.2
Letter of credit

cl 14.5(b)

To: [Clearing manager] [address]

Attention: [name]

Dear Sir/Madam

We, [Bank] (“the Bank”) hereby issue our irrevocable transferable standby letter of credit (“the Letter of Credit”) as follows:

IRREVOCABLE TRANSFERABLE STANDBY LETTER OF CREDIT NO. [number]
DATED [date]

The Account Party: **[Payer]** (“the Account Party”)

Beneficiary: [Clearing manager] (“the Beneficiary”)

Issued in Connection With: Each and every obligation (“the Obligations”) 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 pursuant to the Electricity Industry Participation Code 2010 (“the Code”).

Maximum Amount: [amount determined from time to time by the clearing manager calculated in accordance with clauses 14.18 to 14.22 of the Code] less the amount of any sums drawn under this Letter of Credit.

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 rules and has discharged its obligations to the Beneficiary pursuant to the rules; 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) ninety (90) days after notice in writing of cancellation of this Letter of Credit as to subsequent liability has been given to [Clearing manager]; however, the Bank will remain liable with respect to the Obligations which relate to the period prior to the effective date of the ninety (90) days’ notice.]

("the Expiry Date").

Payable at: Sight.

Available at: [address]

By Drafts on: The Bank.

Enfaced: Drawn under [Bank] Irrevocable 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, draft drawn on the Bank (enfaced as specified above) accompanied by—

- (a) this Letter of Credit; and
- (b) a Certificate purported to be 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 Standby Letter of Credit No [number] ("the Letter of Credit"). Words and expressions defined in the Letter of Credit will have the same meaning herein.

[Payer] ("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 hereby requests payment by [date] of the amount of [amount claimed] to be credited to account number [Beneficiary's trust account number].

The signatory or signatories hereto is/are authorised by the Beneficiary to make the statements herein on behalf of the Beneficiary.

Signed.....
Authorised Signatory

This Letter of Credit is subject to the Uniform Customs and Practice for Documentary Credits (1993 Revision) International Chamber of Commerce Publication No. 500, except as otherwise provided in this Letter of Credit. Subject to that, this Letter of Credit will be governed by, and construed in accordance with, the laws of New Zealand, and the parties hereto irrevocably submit to the non-exclusive jurisdiction of the courts of New Zealand.

The Bank engages with the Beneficiary that drafts drawn under, and in compliance with, this Letter of Credit and, in aggregate, up to the Maximum Amount will be paid on presentation in the manner provided in this Letter of Credit.

EXECUTED for and on behalf)
of [BANK])
by its Attorneys)
.....)
[Print Names]) Signature(s)

.....
in the presence of:
.....
Signature
.....
Full Name
.....
Address
.....
Occupation

Compare: Electricity Governance Rules 2003 schedule H2 part H

Schedule 14.3
Deed of guarantee and indemnity

cl 14.5(c)

DATED

BY

1. [] (the “Guarantor”)

IN FAVOUR OF

2. [Clearing manager] (the “Beneficiary”)

1. Guarantee and indemnity

- (1) The Guarantor—
 - (a) unconditionally and irrevocably guarantees to the Beneficiary the due performance and observance by [Payer] (“the Debtor”) of each and every obligation the Debtor may now or hereafter 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”) pursuant to the Electricity Industry Participation Code 2010 (“the Code”) and promises to pay to the Beneficiary on demand all amounts now or hereafter owing, due or payable by the Debtor to the Beneficiary in respect of the Obligations; and
 - (b) agrees as a primary obligation to indemnify the Beneficiary from time to time on demand from and against any loss incurred by the Beneficiary as a result of any of the Obligations being void, voidable or unenforceable for any reason whatsoever, whether or not known to the Beneficiary, the amount of such loss being the amount which the Beneficiary would otherwise have been entitled to recover from the Debtor.
- (2) This Deed is to be security in respect of each and every one of the Obligations but, nevertheless, the total amount payable by the Guarantor under this Deed will not exceed the aggregate of [amount determined from time to time by the clearing manager calculated in accordance with clauses 14.18 to 14.22 of the Code] (the “Maximum Amount”) and any sums payable pursuant to clauses 1(3) and 9 of this Deed.
- (3) If any moneys payable by the Guarantor under this Deed are not paid on demand, the Guarantor will pay to the Beneficiary interest on such unpaid moneys (both before and after judgement) 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.

- (4) The rate at which interest will be calculated will be the aggregate of 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

- (1) The obligations of the Guarantor under this Deed are in addition to, and not in substitution for, any other security or guarantee which the Beneficiary may at any time hold in respect of the Obligations or any of them 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) Neither the obligations of the Guarantor under this Deed nor the rights, powers and remedies conferred in respect of the Guarantor upon the Beneficiary by this Deed or by law will be discharged, impaired or otherwise affected by anything which might operate to discharge, impair or otherwise affect the same, including—
- (a) the insolvency, liquidation or dissolution of the Debtor or any other person, the appointment of any receiver, manager, receiver and 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) the Obligations or any of them, or the obligations of any person under any security or guarantee held in relation to the Obligations or any of them, 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 the Obligations or any of them 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 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 the Obligations or any of them:

- (f) any failure (whether intentional or not) to take, fully take or perfect any security now or hereafter agreed to be taken by the Beneficiary in relation to the Obligations or any of them; and
 - (g) any other act, event or omission which, 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.
- (3) If any payment to the Beneficiary under this Deed is avoided by law, the Guarantor's obligation to have made such payment will be deemed not to have been affected or discharged and the Guarantor will 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 will 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.
- (4) The Beneficiary is not obliged before exercising any of the rights, powers or remedies conferred upon it in respect of the Guarantor by law to make any demand on the Debtor, take any action or obtain judgement in any court against the Debtor, make or file any claim or prove in any liquidation of the Debtor or enforce or seek to enforce any security or guarantee taken in respect of the Obligations.
- (5) 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 will 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 which 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 which 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 whatsoever.

Any moneys obtained by the Guarantor from the Debtor with such consent or as so required or in breach of this clause will, 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.

- (6) Any moneys received by the Beneficiary which may be applied in or towards discharge of any of the obligations of the Guarantor under this Deed will 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 [New Zealand], 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, by or of 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 hereunder.

4. Payments

All payments to be made by the Guarantor to the Beneficiary under this Deed will be made without set-off or counterclaim and without any deduction or withholding whatsoever. 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 Bank 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 and every one of the Obligations and will 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. Termination

[(1) Notwithstanding anything else in this Deed, the Guarantor may at any time pay to you the Maximum Amount less any amount or amounts the Guarantor may previously have paid under this Deed or such lesser sum as you may require. Upon payment of that sum, the liability of the Guarantor under this Deed will cease and determine.]

[Note: Guarantor to elect either this clause or the following clause as a method of cancellation.]

[(1) Notwithstanding anything else in this Deed the Guarantor may cancel this Deed as to subsequent liability by giving ninety (90) days' notice in writing to [Clearing manager]; however, the Guarantor will remain liable with respect to the Obligations which relate to the period prior to the effective date of the ninety (90) days' notice.]

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, as well as any entity with which the Guarantor may amalgamate.

8. Notices

(1) Any demand to be made on the Guarantor by the Beneficiary under this Deed may be made in writing and delivered to the address set out below or to any other address in New Zealand from time to time notified pursuant to clause 8(2). The Guarantor's address, as at the date of this Deed is: [address]

(2) The Guarantor will immediately notify the Beneficiary of any change in the above address.

9. Costs and expenses

The Guarantor will on demand indemnify and hold harmless the Beneficiary from and against 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, and construed in accordance with New Zealand law, and the Guarantor hereby irrevocably submits to the non-exclusive jurisdiction of the New Zealand Courts.

EXECUTED for and on behalf)
of [Guarantor])
in the presence of:)

.....

.....
Director

Director/Secretary

.....
Signature

.....
Full Name

.....
Address

.....
Occupation

Note I: If two directors sign, no witness is necessary. If a director and secretary sign, both signatories are to be witnessed. If the director and secretary are not signing together, a separate witness will be necessary for each signature.

Note II: If the Guarantor is incorporated outside of New Zealand, insert an appropriate execution clause for the country of incorporation.

Compare: Electricity Governance Rules 2003 schedule H3 part H

Schedule 14.4

Surety bond

cl 14.5(d)

To: [Clearing manager] [address]

Bond Number:

We, Payer as Principal, and name of Surety, as Surety, are held and firmly bound to [Clearing manager], a corporation organised and existing under the laws of New Zealand, its successors and assigns, in the amount of amount in words New Zealand dollars (NZ\$), lawful money of New Zealand for the payment of which the Principal and Surety, their heirs, executors, administrators, successors and assigns are hereby jointly and severally bound.

WHEREAS, the Principal has obligations (the “Obligations”) pursuant to the Electricity Participation Code 2010 (the “Code”) to pay [Clearing manager] amounts invoiced to it by [Clearing manager];

NOW THEREFORE, the Surety agrees to deliver payment to [Clearing manager] of amounts invoiced to the Principal (together with any default interest payable in respect of those invoiced amounts) forthwith upon receipt of written demand for payment issued by a purported authorised representative of [Clearing manager]. Such written demands to be delivered to the Surety at its above address and to certify that the Principal has failed, in whole or in part, to fulfil the Obligations.

PROVIDED FURTHER, that the Surety will not be liable hereunder for a larger amount, in the aggregate, than the amount of this Bond; and

[PROVIDED FURTHER, that the Surety may at any time pay to [Clearing manager] the amount of this Bond less any amount or amounts the Surety may previously have paid under this Bond or such lesser sum as [Clearing manager] may require. Upon payment of that sum, the liability of the Surety under this Bond will cease and determine; and]

[Note: Surety to elect either this proviso or the following proviso as a method of cancellation.]

[PROVIDED FURTHER, that this Bond may be cancelled by the Surety as to subsequent liability by giving ninety (90) days’ notice in writing to [Clearing manager]; however, the Surety will remain liable with respect to the Principal’s Obligations which relate to the period prior to the effective date of the ninety (90) days notice; and]

PROVIDED FURTHER, that this Bond will not be affected, discharged or diminished by any act or omission which would, but for this provision, have exonerated a surety but would not have affected or discharged the Surety’s liability had it been a principal debtor; and

PROVIDED FURTHER, that this Bond will be governed by and interpreted according to, the laws of New Zealand, and the Principal and the Surety thereby agree to submit to the non-exclusive jurisdiction of the Courts of New Zealand.

This Bond may be transferred or assigned by [Clearing manager] without the Surety's consent. Upon cancellation, the Bond will be returned to the Surety.

EXECUTION CLAUSE

Compare: Electricity Governance Rules 2003 schedule H4 part H

Schedule 14.5

Hedge settlement agreement

cl 14.5(e)

[Note: There are a number of gaps for the parties to fill in and alternative wording that needs to be deleted as appropriate by the parties.]

DATED

BY

1. ("Party A")
2. ("Party B")

IN FAVOUR OF

3. [the **clearing manager**], as the **clearing manager** (the "**clearing manager**")

BACKGROUND

- A. Party A and Party B have a hedging arrangement which provides for payments for differences in respect of the price of **electricity**, at specific grid exit points for a particular period (the "CFD").
- B. Party A and Party B wish to—
 - (a) settle the CFD under the Electricity Industry Participation Code 2010 (the "Code"); and
 - (b) allow the CFD to be taken into account when considering the level of security that is required to be provided to satisfy the prudential requirements of either Party A or Party B under the Code,on the terms and conditions of this Agreement.

- C. Party A and Party B acknowledge the possibility that both Parties may be called on by the **clearing manager** to provide a level of security to satisfy the prudential requirements under the Code as a result of the lodgement of this Agreement with the **clearing manager**.

PARTY A AND PARTY B AGREE as follows:

4. Any bolded term in this Agreement has the same meaning as in the Code.
5. For the purpose of the CFD—:
 - (a) Party [A/B] is the Floating Price **Payer**; and
 - (b) Party [A/B] is the Fixed Price **Payer**
- [Note: The parties are to elect the appropriate wording.]
6. The term of this Agreement is from [] hours on [] to [] hours on [].
7. This Agreement applies to the [following **grid injection points** and/or **grid exit point(s)** [] /**grid injection points** and/or **grid exit points** listed in the attached table]. [In addition where a **grid injection point** or **grid exit point** [listed above/included in the attached table] is **disconnected**, then the **grid injection point** or **grid exit point** notified to the **clearing manager** by either party is the relevant **grid injection point** or **grid exit point** (as the case may be) for the purposes of this Agreement from and including the **trading period** during which the **clearing manager** was notified until the **clearing manager** is notified otherwise.] [Note: The parties are to elect the appropriate wording, including the possible deletion of the last sentence of this clause.]
8. This Agreement applies to [[] **MWh** per **trading period** at \$[] per **MWh**/ the quantities of **electricity** per **trading period** and prices per **MWh** listed in the attached table.] [Note: The parties are to elect the appropriate wording.]
9. [Notwithstanding clause 12, for the purposes of calculating the Amount Payable pursuant to this Agreement for a **billing period** (the “Amount Payable”), for the purposes of the “Business day” definition in section 1.3 of the 1993 ISDA Commodity Definition, [] shall be the relevant place.] [Note: The parties should delete this clause if it is not appropriate.]
10. The Amount Payable will be established by the following procedure:
 - (a) the **clearing manager** will, by the 5th **business day** of the **billing period** following the relevant **billing period**, notify Party A and Party B of the Amount Payable:
 - (b) either Party A or Party B may dispute the Amount Payable before or on the 7th **business day** of that **billing period**:

- (c) if neither party disputes the Amount Payable, that amount will be settled under the Code on the Settlement Date and in accordance with the Code:
 - (d) if the Amount Payable is disputed, the **clearing manager** will use its reasonable endeavours to resolve that dispute by the 9th **business day** of the **billing period**. If:
 - (i) the dispute is resolved by the 9th **business day** of the **billing period**, then the Amount Payable so resolved will be settled under the Code on the Settlement Date:
 - (ii) the dispute is not resolved by the end of the 9th **business day** of the **billing period**, the original Amount Payable notified by the **clearing manager** will be settled under the Code on the Settlement Date. For such unresolved disputes, Party A and Party B release the **clearing manager** from any liability or obligation it may have in relation to the calculation of the Amount Payable, and agree that any unresolved dispute will be resolved between them pursuant to the CFD following payment of the Amount Payable under the Code and this Agreement.
11. For the avoidance of doubt, if either Party A or Party B dispute the Amount Payable under clause 10, and that dispute is not resolved within the time specified in clause 10(d), payment of the Amount Payable shall be without prejudice to any other rights or remedies available to Party A or Party B (as the case may be) pursuant to the CFD.
12. In this agreement, “Settlement Date” means, in respect of a **billing period**, the 20th day of the month following that period or where that day is not a **business day**, the next **business day**.
Force Majeure
13. [Party A and Party B confirm that the CFD has no force majeure clause.] [Note: The parties should elect either this clause or the following clause.]
or
[Party A and Party B confirm that the CFD has a force majeure clause, and agree:
- (a) that the party to the CFD invoking the force majeure clause will notify the **clearing manager** in writing (including by electronic means) of:
 - (i) any force majeure event that occurs,
 - (ii) when that force majeure event ceases to apply, and
 - (iii) the total period to the nearest **trading period** during which the force majeure event applied:

- (b) that settlement of this Agreement will occur as if the force majeure event has not occurred, if the **clearing manager** is not notified of a force majeure event.

If a force majeure event is notified to the **clearing manager**, the **clearing manager** will not settle this Agreement for any **trading period** following the **trading period** during which it was notified of that force majeure event until it is notified that the force majeure event has ceased to apply. It is acknowledged that:

- (a) the **clearing manager** will settle this Agreement for the **billing period** in which a force majeure event is notified to it up to and including the trading period it was notified of that force majeure event; and
- (b) the value of this Agreement for prudential purposes may change as a result of notification of a force majeure event.

For the avoidance of doubt, the notification of a force majeure event to the **clearing manager** under this Agreement, and settlement of any Amount Payable pursuant to it, shall be without prejudice to any other claims, rights, obligations or actions of either Party A or Party B under the CFD.]

Security

14. Party A and Party B acknowledge that, under the Code, Amounts Payable by Party A to Party B under this Agreement—
- (a) will be applied on a Settlement Date to satisfy in whole or in part the liability on that Settlement Date pursuant to the Code (the “Liability”) of Party B; and
- (b) will be set off against any amount payable to Party A under the Code,
- and *vice versa*.
15. This Agreement shall be a continuing security to the **clearing manager** in respect of each and every one of the Liabilities and shall not be (or not be construed so as to be) discharged by any intermediate discharge or payment of or on account of the Liabilities or any settlement of accounts between the **clearing manager** and Party B or anyone else.
16. Where at the end of any **billing period** either Party A or Party B—
- (a) is a **generator** and is liable to pay on the next Settlement Date more money pursuant to this Agreement and its other Liabilities in that **billing period** than it is to be paid under the Code, that party is deemed to be a net **purchaser** and may be called upon by the **clearing manager** to provide security under Part 14 of the Code; or
- (b) is a **purchaser** and is liable to pay money to the other party on the next Settlement Date pursuant to this Agreement, then the **clearing manager** may

call upon that **purchaser** to provide additional security under this part of the Code for all or part of the Amount Payable.

Cancellation

17. Notwithstanding anything in this Agreement or in the Code, this Agreement may only be cancelled in relation to **trading days** after the date of cancellation. The date of cancellation will be—
- (a) the date specified by Party A or Party B, with the consent of the other party, in written notice to the **clearing manager**; or
 - (b) the date either Party A or Party B gives written notice to the **clearing manager** in accordance with clauses 14.2 to 14.17 of the Code.
18. For the avoidance of doubt and notwithstanding the fact that the date of cancellation has passed, Party A and Party B agree that the **clearing manager** will settle this Agreement up to and including midnight on the date of cancellation as determined pursuant to clause 17 on the relevant Settlement Date.

Notices

19. Any demand to be made on Party A or Party B by the **clearing manager** under this Agreement may be made in writing and delivered to the address in New Zealand notified to the **clearing manager** from time to time. Party A's and Party B's addresses as at the date of this Agreement are:

Party A: [address]

Party B: [address]

Assignment

20. In the event that the **clearing manager** ceases to be the **clearing manager** under the Code, the **clearing manager** may assign this Agreement to the person appointed as the new **clearing manager** under the Code, without the consent of either Party A or the Party B.

Governing Law

21. This Agreement shall be governed by, and construed in accordance with, New Zealand law.

Limits on Liability

22. Party A and Party B shall indemnify the **clearing manager** from and against any and all liabilities, obligations, losses, damages, penalties, actions, judgements, suits, expenses or disbursements of any kind or nature whatsoever (other than those resulting from the negligence, wilful default or dishonesty of the **clearing manager**), including the **clearing manager's** reasonable costs and expenses in relation to

enforcement of the indemnity which may be imposed on, or incurred by or asserted against, the **clearing manager** solely by reason of the **clearing manager** performing any functions, obligations, discretions or duties of the **clearing manager** under this Agreement.

23. The **clearing manager's** liability under this Agreement is subject to the limitations on the liability of the **clearing manager** as set out in the regulations made under section 112(1)(i) of the Electricity Industry Act 2010.

Executed by:

Signed for and on behalf of Party A by:

in the presence of:

Name:

Occupation:

Address:

Signed for and on behalf of Party B by:

in the presence of:

Name:

Occupation:

Address:

Compare: Electricity Governance Rules 2003 schedule H5 part H

cl 14.73(2A)

Schedule 14.6
**Calculation of amount of loss and constraint excess to be paid
into FTR account**

Schedule 14.6: inserted, on 1 October 2011, by clause 39 of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2011.

1 Purpose

The purpose of this Schedule is to set out the formulae and process for the calculation under clause 14.73(2A) of the amount of the **loss and constraint excess** to be paid into the **FTR account**.

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:

$$\begin{array}{ll}\text{maximise} & c^T x \\ \text{subject to} & Ax \leq b\end{array}$$

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 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 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)

Clause 2(1) **unbalanced**: revoked, on 1 November 2012, by clause 25(1) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

- (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**.

Clause 2(1) **balanced**: amended, on 21 September 2012, by clause 36(1) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 2(1) **simultaneously feasible**: amended, on 21 September 2012, by clause 36(2) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 2(1) **operational system split**: amended, on 27 September 2012, by clause 5 of the Electricity Industry Participation (Minor Amendments relating to Financial Transmission Rights) Code Amendment 2012.

3 Amount of loss and constraint excess to be paid into FTR account

The amount of the **loss and constraint excess** that must be paid into the **FTR account** under clause 14.73(2C) 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**.

Clause 4 Heading: amended, on 27 September 2012, by clause 6(1) of the Electricity Industry Participation (Minor Amendments relating to Financial Transmission Rights) Code Amendment 2012.

Clause 4(1)-(5): amended, on 27 September 2012, by clause 6(2)-(7) of the Electricity Industry Participation (Minor Amendments relating to Financial Transmission Rights) Code Amendment 2012.

Clause 4(3) and (5): amended, on 15 May 2014, by clause 56 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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) *[Revoked]*
(5) *[Revoked]*
(6) 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**.

Clause 5(6)(a): amended, on 27 September 2012, by clause 7 of the Electricity Industry Participation (Minor Amendments relating to Financial Transmission Rights) Code Amendment 2012.

Clause 5(1), (2) and (3): amended, on 1 November 2012, by clause 25(2) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 5(2)(e): amended, on 1 November 2012, by clause 25(3) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 5(4) and (5): revoked, on 1 November 2012, by clause 25(4) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 5(6): amended, on 1 November 2012, by clause 25(5) of the Electricity Industry Participation (Financial Transmission Rights) Code Amendment 2012.

Clause 5(6)(a): amended, on 15 May 2014, by clause 57 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 by 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 by m diagonal matrix formed from the set of m branch susceptances
$[\text{Inc}]$	is the m by 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
- [Impedance] is the n by n matrix formed from the inverse of [AdmittanceNodal] with the columns and rows associated with the reference **nodes** reinserted and filled with zeroes
- [AdmittanceNodal] is the $n-r$ by $n-r$ matrix obtained from [AdmittanceNodalComplete] by deleting the column and row associated with each of the reference **nodes**
- [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 [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:

$$\max \left(\sum_{h \in \text{Hubs}} SF_{k,h} \times Inj_{h,p} : p \in 1, \dots, P \right); \text{ and}$$

- (b) in accordance with the following formula if the **scheduled** flow on the **AC line** is in the conventional reverse flow direction:

$$- \min \left(\sum_{h \in Hubs} SF_{k,h} \times Inj_{h,p} : p \in 1, \dots, P \right)$$

where

$SF_{k,h}$ is the shift factor relating flows on **AC line** k to **injections** at **hub** h , determined under clause 6(1)

$Inj_{h,p}$ 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(4)

- (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:

$$\max \left(\sum_{k \in ACLineGroup_v} \sum_{h \in Hubs} weight_{k,v} \times SF_{k,h} \times Inj_{h,p} : p \in 1, \dots, P \right)$$

where

$SF_{k,h}$ and $Inj_{h,p}$ are as defined in subclause (2)

$ACLineGroup_v$ 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)

$weight_{k,v}$ 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:

$$\max \left(\sum_{k \in ACLineGroup_v} (flowweight_{k,v} \times flow_{k,p} + lossweight_{k,v} \times loss_{k,p}) : p \in 1, \dots, P \right)$$

where

- $ACLineGroup_v$ 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)
- $flowweight_{k,v}$ is the weight associated with the flow on **AC Line** k in **mixed constraint** v expressed in **canonical form**
- $lossweight_{k,v}$ is the weight associated with the variable **losses** on **AC Line** k in **mixed constraint** v expressed in **canonical form**
- $flow_{k,p}$ is the flow on **AC Line** k due to **FTR injection pattern** p , which equals $\sum_{h \in Hubs} SF_{k,h} \times Inj_{h,p}$
- $loss_{k,p}$ is the variable **losses** on **AC Line** k due to $flow_{k,p}$
- $SF_{k,h}$ and $Inj_{h,p}$ 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 paid into the **FTR account** 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 paid into FTR account

- (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 paid into the **FTR account** for each **trading period** of the relevant **billing period** must be calculated in accordance with the following formula:

$$\max \left(0, \sum_{n(NI)} price_n \times \left(\sum_{l \in R_{HVDC}(n)} (HVDCLinkFlow_l - HVDCLinkLosses_l) - \sum_{l \in S_{HVDC}(n)} HVDCLinkFlow_l \right) \right) + \sum_{n(SI)} price_n \times \left(\sum_{l \in R_{HVDC}(n)} (HVDCLinkFlow_l - HVDCLinkLosses_l) - \sum_{l \in S_{HVDC}(n)} HVDCLinkFlow_l \right) \div 2$$

where

$price_n$	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
$HVDCLinkFlow_l$	is the MW flow at the sending end scheduled for HVDC link l
$HVDCLinkLosses_l$	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 paid into the **FTR account** must be calculated in accordance with the following formula:

$$AssignedCapacity_k \times ShadowPrice_k \div 2$$

where

AssignedCapacity_k is the portion of the capacity of **AC line k** assigned under clause 8(1)

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 paid into the **FTR account** must be calculated in accordance with the following formula:

$$AssignedCapacity_v \times ShadowPrice_v \div 2$$

where

AssignedCapacity_v is the portion of the capacity of the **RHS of branch constraint** or **mixed constraint v** assigned under clause 8(1)

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 paid into the **FTR account** must be calculated in accordance with the following formula:

$$\begin{aligned} & \min(ACLineFlowBlock_{k,j}, AssignedCapacity_{k,j}) \times ReceivingEndPrice_k \\ & \times (ACLineLossFactor_{k,margin} - ACLineLossFactor_{k,j}) \div 2 \end{aligned}$$

where

$$ACLineLossFactor_{k,margin} = \min(ACLineLossFactor_{k,j}) \text{ for which } ACLineFlowBlock_{k,j} < ACLineLossMW_{k,j}$$

ACLineFlowBlock_{k,j} is the **MW** flow on the *jth* 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

AssignedCapacity_{k,j} is the portion of the capacity of the *jth* block of the loss curve of **AC line k** assigned under clause 8(1)

$ReceivingEndPrice_k$	is the nodal energy price at the receiving end of the scheduled flow on AC line k
$ACLineLossFactor_{k,j}$	is the loss factor of the j^{th} block of the loss curve of AC line k
$ACLineLossMW_{k,j}$	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 paid into the **FTR account** 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**.

Electricity Industry Participation Code 2010

Part 15 Reconciliation

Contents

- 15.1 Contents of this Part
- 15.2 Requirement to provide complete and accurate information
- 15.3 Provision of trading information at point of connection to network
 - Provision of information to the reconciliation manager*
- 15.4 Submission information to be delivered for reconciliation
- 15.5 Preparing and submitting submission information
- 15.5A Dispatchable load purchaser must prepare dispatchable load information
- 15.5B Deriving volume information if metering installation is within premises that are connected to a point of connection
- 15.5C Aggregating and rounding dispatchable load information
- 15.5D Dispatchable load information to be delivered to reconciliation manager
 - Additional retailer and direct purchaser information*
- 15.6 Retailer and direct purchaser ICP days information
- 15.7 Retailer electricity supplied information
- 15.8 Retailer and direct purchaser half hourly metered ICPs monthly kWh information
 - NSP information*
- 15.9 Grid owner volume information
- 15.10 Local network and embedded network submission information
- 15.11 Grid connected generator
- 15.12 Accuracy of submitted information
- 15.13 Notification by embedded generators
- 15.14 Notification of changes to the grid
 - Notification of outage constraints or alternative supply*
- 15.15 Notification of points of connection subject to outages or alternative supply
- 15.16 Balancing area NSP grouping changes
- 15.17 Submission information to be reviewed in the case of an outage constraint
- 15.18 Reconciliation manager may request additional information
- 15.19 Seasonal adjustment and profiling
- 15.20 Calculation and allocation of unaccounted for electricity
 - Reconciliation manager processes dispatchable load information and provides it to the clearing manager*
- 15.20A Reconciliation manager to update revised dispatchable load information
- 15.20B Reconciliation manager loss adjusts and summarises dispatchable load information
- 15.20C Reconciliation manager to provide loss adjusted and summarised dispatchable load information to clearing manager
- 15.20D Reconciliation manager to provide loss adjusted and summarised dispatchable load information to dispatchable load purchasers
 - Reconciliation information produced by reconciliation manager*
- 15.21 Providing information specific to reconciliation participants
- 15.22 Providing information to reconciliation participants
- 15.23 Reconciliation information is not final
- 15.24 Reconciliation information checked

- 15.25 Reconciliation manager must assess information not supplied
15.26 Reconciliation manager to correct information
Revisions
15.27 Reconciliation manager must reconcile revised information
15.28 Transitional provisions concerning revisions
15.29 Volume information disputes
Reporting obligations of the reconciliation manager
15.30 Alleged Code breaches reported by the reconciliation manager
15.31 Right to information concerning reconciliation manager's actions
15.32 Reconciliation reports
15.33 The Authority publishes reports
15.34 Use of agents by reconciliation participants
15.35 Provision of information
15.36 New Zealand Daylight Time adjustment techniques
15.37 Audits
Certification
15.38 Functions requiring certification
Participant identifiers
15.39 Participants must use participant identifiers

Schedule 15.1

Audit and certification process

Schedule 15.2

Collection of volume information

Meter interrogation for non half hour metering

Validation

Schedule 15.3

Calculation and provision of submission information

Creation of submission information

Schedule 15.4

Reconciliation procedures

Convert non half hour quantities using profiles

Schedule 15.5

Profile administration

New NSP derived profiles

New statistically sampled/engineered profiles

Appendix 1: Profile classes

Participants NSP-derived profiles

Statistically sampled and engineering profile classes

Appendix 2: Determining statistically sampled profiles

15.1 Contents of this Part

This Part provides for the following:

- (a) the improvement of information about **electricity** conveyed as more **volume information** becomes available over time:

- (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 preparation of invoices;
- (g) obligations of the **reconciliation manager** to pass the information to **reconciliation participants**, the **registry** and the **Authority**;
- (h) requirements for the creation, approval and maintenance of **profiles**;
- (i) requirements for **audits**, **auditors**, approvals and **certifications**.

Compare: Electricity Governance Rules 2003 rule 1 part J

Clause 15.1(da): inserted, on 15 May 2014, by clause 95 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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 in providing information under this Part, the **participant** has not complied with subclause (1), the **participant** must, as soon as practicable, provide such further information as is necessary to ensure that the **participant** complies with subclause (1).

Compare: Electricity Governance Rules 2003 rule 1A part J

15.3 Provision of trading information at point of connection to network

- (1) Unless a notification under clause 15.13 is in force, a **trader** must give the **reconciliation manager** a notification 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 notification must ensure that the notification complies with any procedures or other requirements specified by the **reconciliation manager**.
- (3) The **reconciliation manager** must give a copy of every notification to the **clearing manager** and **system operator** no later than 1 **business day** after receiving the notification.

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 held by 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 notification 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 notification relates.

Compare: Electricity Governance Rules 2003 rules 4.1.3 and 4.1.4 part J

Clause 15.5(2): substituted, on 15 May 2014, by clause 96 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 15.5(3): amended, on 21 September 2012, by clause 37 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

15.5A Dispatchable load purchaser must prepare dispatchable load information

- (1) Each **dispatchable load purchaser** must prepare **dispatchable load information**.
- (2) Unless clause 15.5B applies, in preparing **dispatchable load information**, the **dispatchable load purchaser** must use **volume information** prepared under Schedule 15.2.

Clause 15.5A: inserted, on 15 May 2014, by clause 97 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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** must prepare **dispatchable load information** using **volume information** 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.

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 on 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**.

Compare: Electricity Governance Rules 2003 rule 4.2.2 part J

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**.

Compare: Electricity Governance Rules 2003 rule 4.2.3 part J

NSP information

15.9 Grid owner volume information

Each **grid owner** must deliver to the **reconciliation manager**, for each **point of connection** for all of its **GXPs**, 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**.

Compare: Electricity Governance Rules 2003 rule 4.3.1 part J

15.10 Local network and embedded network submission information

A **participant** must provide the following information to the **reconciliation manager** for each **NSP** for which the **participant** has given a notification 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**.

Compare: Electricity Governance Rules 2003 rule 4.3.2 part J

Clause 15.10: amended, on 15 May 2014, by clause 58 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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

Clause 15.12: amended, on 15 May 2014, by clause 98 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

15.13 Notification by embedded generators

An **embedded generator** must give a notification 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 notification relates.

Compare: Electricity Governance Rules 2003 rule 4A part J

15.14 Notification of changes to the grid

- (1) Each **grid owner** must notify 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 calendar 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 **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

Notification of outage constraints or alternative supply

15.15 Notification 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 notify the **reconciliation manager** of the following:
 - (i) each **point of connection** to the **grid** that was **disconnected** 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 **disconnected**; and
- (b) each **grid owner** must notify 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

Clause 15.15: substituted, on 13 June 2013, by clause 5 of the Electricity Industry Participation (Information Flows) Code Amendment 2013.

15.16 Balancing area NSP grouping changes

If an **NSP** has been affected by an **outage constraint**, and the **reconciliation manager** has determined the information notified to it 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 information 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**, notify 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 information notified in accordance with clause 15.16 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.

Compare: Electricity Governance Rules 2003 rule 6.3 part J

Clause 15.17(c): amended, on 13 June 2013, by clause 6 of the Electricity Industry Participation (Information Flows) Code Amendment 2013.

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

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 14.64 or 15.29, or to correct information under clauses 15.21 to 15.26.

Compare: Electricity Governance Rules 2003 rule 8 part J

Clause 15.19(4): amended, on 21 September 2012, by clause 38 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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**.

Compare: Electricity Governance Rules 2003 rule 9 part J

Reconciliation manager processes dispatchable load information and provides it to clearing manager

Cross Heading: inserted, on 15 May 2014, by clause 99 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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 14.64, 15.26(2), or 15.29.

Clauses 15.20A: inserted, on 15 May 2014, by clause 99 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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** 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.

Clause 15.20B: inserted, on 15 May 2014, by clause 99 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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**.

Clauses 15.20C: inserted, on 15 May 2014, by clause 99 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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**.

Clause 15.20D: inserted, on 15 May 2014, by clause 99 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

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 connected with 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 of issue of the invoice to which the incorrect information relates (if any).

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 14.64, 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** (SC_{ri}) 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 (MS_{ri}) 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 notify a dispute under subclause (1) if an invoice based on the **volume information** has been issued.
- (3) The **reconciliation manager** must notify all **participants** affected by the dispute and the **Authority** of the dispute no later than 1 **business day** after the dispute is notified to the **reconciliation manager** under subclause (1).
- (4) On receiving a notification 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 (14) cease to apply to the dispute. However, a direction under subclause (4) does not affect the validity of a **washup** conducted under clauses 14.65 to 14.72 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 dispute was notified to the **reconciliation manager** 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 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** is required to be corrected must provide corrected relevant information to the **reconciliation manager** no later than 4 **business days** after being notified of the resolution of the dispute.
- (13) The **reconciliation manager** must provide the corrected **volume information** to the **clearing manager**.
- (14) If corrected **volume information** is provided to the **clearing manager** under subclause (13), the **clearing manager** must conduct a **washup** in accordance with clauses 14.65 to 14.72.

Compare: Electricity Governance Rules 2003 rule 12 part J

Clause 15.29(12)(b): amended, on 15 May 2014, by clause 59 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

Reporting obligations of the reconciliation manager

15.30 Alleged Code breaches reported by the reconciliation manager

- (1) As soon as possible and by no later than 1300 hours on the 2nd **business day** after the **reconciliation manager** provided **reconciliation information** for a **consumption period** in accordance with clauses 15.21 and 15.22, the **reconciliation manager** must provide a written report to the **Authority** detailing the number and details of any alleged breach of this Code that the **reconciliation manager** is aware of.
- (2) The report must include the matters set out below, and information about any situations when the **reconciliation manager** allegedly breached this Code, or, in the opinion of the **reconciliation manager**, a **reconciliation participant** allegedly breached this Code:
 - (a) the time and, if appropriate, the **consumption period**, during which the alleged breach took place:
 - (b) the nature of the alleged breach, including, in the case of late **submission information** or information in a form that compromises the **reconciliation information**, the **reconciliation participant** allegedly responsible for the information:
 - (c) the reason for the alleged breach including, in the case of late **submission information** or information in a form that compromises the **reconciliation information**, the reason for the delay or the inadequate form, if the **reconciliation manager** is aware of the reason.

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 notice in writing to the **reconciliation manager**, request further information related to any situation set out in the **reconciliation manager's** report provided in accordance with clause 15.30 that has materially affected the **reconciliation participant**.
- (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 The Authority publishes reports

By 0930 hours on the **business day** following the day on which the **Authority** receives the report of the **reconciliation manager** in accordance with clause 15.30, the **Authority** must **publish** the sections of the report that relate to an alleged breach of this Code by the **reconciliation manager** (if any).

Compare: Electricity Governance Rules 2003 rule 14 part J

Clause 15.33: amended, on 15 May 2014, by clause 60 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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 notified by the **Authority**.
- (2) Such information must be delivered in the format determined from time to time by the **Authority**.

Compare: Electricity Governance Rules 2003 rule 16 part J

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) Daylight savings adjustments must be made by using 1 of the following techniques:
 - (a) the “**trading period** run on technique” must be applied if the daylight saving adjustment periods are allocated as consecutive **trading periods** within the relevant day, in the sequence that they occur. The code “TPR” must be used within the data transfer file when this technique is used:
 - (b) the “**trading period** move technique” must be applied if the daylight saving adjustment periods are appended as additional **trading periods** at the end of the relevant day. The code “TPM” must be used within the data transfer file when this technique is used.
- (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

15.37 Audits

- (1) An **audit** to be undertaken in accordance with this Code must be undertaken by an **auditor** included in the list of approved **auditors published** by the **Authority** in accordance with clause 9(7) of Schedule 15.1.
- (2) The **Authority** may require a **participant** to have an **audit** undertaken.
- (3) Clauses 12 to 19 of Schedule 15.1 apply to every such **audit**.

Compare: Electricity Governance Rules 2003 rule 18 part J

Certification

Cross heading Certification: inserted, on 15 May 2014, by clause 61 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

15.38 Functions requiring certification

- (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 **customer** and **embedded generator** 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) calculation of **ICP days**, monthly kWh information of **half hour** metered **ICPs**, and **electricity supplied**:
 - (e) provision of **submission information** for reconciliation:
 - (f) provision of **metering information** to the **pricing manager** 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:
- (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) To avoid doubt, the performance of any of the functions in subclause (1) by a **reconciliation participant**, or its agent or agents, without the **reconciliation participant** having **certification**, is a breach of this Code by the **reconciliation participant**.

Compare: Electricity Governance Rules 2003 rule 19 part J

Clause 15.38(1)(c)(iv): inserted, on 15 May 2014, by clause 101(1) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 15.38(1A): inserted, on 15 May 2014, by clause 101(2) of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013.

Clause 15.38(1B): inserted, on 15 May 2014, by clause 62 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

Participant identifiers

Cross heading Participant identifiers: inserted, on 15 May 2014, by clause 63 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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, from time to time and at any time, by notification 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 notification.

Compare: Electricity Governance Rules 2003 rule 20 part J

Schedule 15.1

Audit and certification processes

cl 15.38

1 Contents of this Schedule

This Schedule sets out—

- (a) the processes by which **audits** must be undertaken by **reconciliation participants**; and
- (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**; and
- (c) the processes by which **Authority audits** and **audits** requested by **participants** are undertaken.

Compare: Electricity Governance Rules 2003 clause 1 schedule J1

2 Requirement for certification

Despite anything else in this Code, a **reconciliation participant** who is required to obtain **certification** under clause 15.38 must obtain **certification** in accordance with this Schedule no later than 3 calendar months after the date on which that **reconciliation participant** becomes a **reconciliation participant** in accordance with this Code.

Compare: Electricity Governance Rules 2003 clause 1A schedule J1

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 clause 11, that the **reconciliation participant** meets the

- requirements relevant to the functions specified in clause 15.38 for which the **reconciliation participant** is seeking **certification**; and
- (b) the **reconciliation participant** has 1 or more of the following forms of quality certification:
- (i) AS/NZS ISO 9001:2000;
 - (ii) AS/NZS ISO 9001:2008;
 - (iii) a quality certification that the **Authority** deems to be equivalent to AS/NZS ISO 9001:2000 or AS/NZS ISO 9001:2008.
- (2) A **reconciliation participant** is responsible for appointing an **auditor** to undertake the **audit** required by subclause (1).
- (3) A **reconciliation participant** is responsible for the costs of the **audit** required by subclause (1).

Compare: Electricity Governance Rules 2003 clause 3.2 schedule J1

6 Lists of certified reconciliation participants and agents

The **Authority** must publish, and keep updated—

- (a) a list of **certified reconciliation participants**, and the period for which each **reconciliation participant** is **certified**; and
- (b) a list of agents used by **certified reconciliation participants**.

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 12 calendar months.
- (2) The **Authority** must renew a **reconciliation participant's certification** for a further term of not more than 12 calendar months if the **Authority** is satisfied on the basis of an **audit** report provided to the **Authority** under clause 11 that the **reconciliation participant** continues to meet the requirements specified in clause 5.

Compare: Electricity Governance Rules 2003 clause 3B schedule J1

8 Changes that affect certification

- (1) If a **reconciliation participant** intends to make a change to any of its facilities, processes or procedures that the **reconciliation participant** considers is material, the **reconciliation participant** must, at least 5 **business days** before the change is to take place,—
 - (a) notify the **Authority** of the change; and
 - (b) submit to the **Authority** an **audit** report confirming that, after the change has come into effect, the **reconciliation participant** will continue to meet the requirements specified in clause 5.
- (2) The **Authority** must, by notice to the **reconciliation participant**, continue a **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 deemed to be revoked if—
 - (a) a **reconciliation participant** fails to give the notice required by subclause (1); or

- (b) the **Authority** notifies 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

8A Timeframe for auditing a change extended

- (1) This clause applies if a **reconciliation participant** intends to make a change to any of its facilities, processes, or procedures that—
 - (a) the **reconciliation participant** considers is material; and
 - (b) is required to implement the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011.
- (2) Despite clause 8(1), a **reconciliation participant** must, no later than 4 months after the amendment comes into force—
 - (a) notify the **Authority** of the change; and
 - (b) submit to the **Authority** an **audit** report confirming that, after the change came into effect, the **reconciliation participant** continued to meet the requirements specified in clause 5.
- (3) Despite clause 8(3), a **reconciliation participant's certification** is only deemed to be revoked if—
 - (a) the **reconciliation participant** fails to give the advice required by subclause (2); or
 - (b) the **Authority** advises the **reconciliation participant** that the **Authority** is not satisfied that the **reconciliation participant** continued to meet the requirements in clause 5 after the change came into effect.
- (4) To avoid doubt, if this clause applies, the **Authority** must comply with clause 8(2).

Clause 8A: inserted, on 24 May 2013, by clause 5 of the Electricity Industry Participation (Transitional Provisions for New Metering Arrangements) Code Amendment 2013.

Clause 8A(3): amended, on 15 May 2014, by clause 64 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

9 Auditors

- (1) The **Authority** may, from time to time, approve persons to act as, and to perform the functions of, **auditors**, for particular types of **audits**, in accordance with this Code.
- (2) An approval may (but does not have to) be given by the **Authority**, at its absolute discretion. If approval is given, it will last for 2 years from the date of the approval unless it is withdrawn in accordance with subclause (8).
- (3) An **auditor** must be approved, in accordance with this clause, at the time it carries out an **audit**, and must not have received notification from the **Authority** of the withdrawal of the approval.
- (4) A person applying to the **Authority** for approval, or the renewal of an existing approval, as an **auditor**—
 - (a) must use the **prescribed form**; and
 - (b) must respond to the **Authority**, as quickly as practicable, providing any clarification, further data or information that the **Authority** may request.

- (5) The **Authority** has not more than 2 calendar months from the date on which the completed application is received by the **Authority**, to assess, and if in the **Authority's** view it is appropriate, to approve, the application.
- (6) The **Authority** may require the person to attend such interviews and undertake such examinations as the **Authority** thinks fit.
- (7) The **Authority** must **publish**, and keep updated, a list of **auditors** approved for particular types of **audits**.
- (8) The **Authority** may, at any time with immediate effect by giving written notice, remove an **auditor** from the list of approved **auditors**.
- (9) The removal of an **auditor** does not invalidate any **audit** previously completed by the **auditor**. However, any **audits** in progress on or completed after the date on which the **auditor** is removed from the list of approved **auditors** is not a valid **audit** for the purposes of this Code.

Compare: Electricity Governance Rules 2003 clause 5 Schedule J1

Clause 9(5): amended, on 29 August 2013, by clause 23 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

Clause 9(7): amended, on 21 September 2012, by clause 39 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

10 Audits

A **reconciliation participant** must ensure that an **auditor** undertaking an **audit** in accordance with this Part 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 **reconciliation participant** to whom the **audit** relates:
- (c) the **auditor** must give the **reconciliation participant** a reasonable opportunity to comment on the draft of the **audit** report:
- (d) the **auditor** must consider any comments it receives from the **reconciliation participant** about the draft of the **audit** report:
- (e) the **auditor** must produce a final **audit** report and provide that report to the **reconciliation participant**:
- (f) the final **audit** report must—
 - (i) specify conditions (if any) that the **auditor** considers the **reconciliation participant** must satisfy in order for the **reconciliation participant** to comply with this Code, and any action that the **reconciliation participant** has taken in respect of those conditions; and
 - (ii) include a list of all agents engaged by the **reconciliation participant** to perform the functions specified in clause 15.38, and details of the functions that each of those agents performs; and
 - (iii) include a summary that specifies—
 - (A) the date of the **audit** report; and
 - (B) the name of the **audited reconciliation participant** or agent; and
 - (C) the scope of the **audit**; and
 - (D) whether or not the **audit** established that the processes and procedures comply with this Code; and

(E) the name of the **auditor**.

Compare: Electricity Governance Rules 2003 clause 6 schedule J1

11 Audit reports provided to Authority

- (1) A **reconciliation participant** who is applying for **certification** or renewal of **certification** must provide a copy of the final **audit** report that relates to the **reconciliation participant's** application to the **Authority** at least 2 months before the intended date of **certification** or renewal of **certification**.
- (2) The **Authority** must publish the summary required under clause 10(f)(iii).
- (3) Except for the summary referred to in subclause (2), an **audit** report is confidential to the **reconciliation participant**, the **auditor**, and the **Authority**, unless otherwise agreed between the **reconciliation participant** and the **Authority**.

Compare: Electricity Governance Rules 2003 clause 6A schedule J1

12 Authority and participant requested audits

- (1) If at any time the **Authority** reasonably considers that a **participant** may not have complied with a clause in this Part or Part 11, the **Authority** may **audit** the **participant** or appoint an auditor to carry out an **audit**.
- (2) If a **participant** reasonably considers that another **participant** may have not complied with a clause in this Part or Part 11, the **participant** may request in writing to the **Authority** that the **Authority** **audit** the **participant** or that the **Authority** appoints an **auditor** to carry out an **audit**.

Compare: Electricity Governance Rules 2003 clauses 8.1 and 8.1A schedule J1

13 Scope of audits

An **audit** must address such matters as the **Authority** reasonably requires, having regard to the reasons for which the **Authority** considers that the **audit** is required under clause 12, and any matters that arise during the **audit**.

Compare: Electricity Governance Rules 2003 clause 8.2 schedule J1

14 Authority may request information

The **Authority** or its **auditor** may request additional information and carry out inspections of the **participant** alleged to be in breach and **audit** the **participant's** facilities, processes, procedures, and any other relevant items used by the **participant** that the **Authority** considers necessary to enable it or the **auditor** to carry out the **audit** and, if appropriate, make recommendations to the **Authority**.

Compare: Electricity Governance Rules 2003 clause 8.2A schedule J1

15 Participants to provide access and information

A **participant** must provide the **Authority** or an **auditor** appointed by the **Authority** for this purpose full access to all relevant facilities, processes, procedures and other relevant items, personnel, records and manuals at any time within normal working hours, and must provide to the **Authority** or **auditor** (as the case may be) any additional information that the **Authority** or **auditor** reasonably considers is necessary.

Compare: Electricity Governance Rules 2003 clause 8.3 schedule J1

16 Production of audit report

The **Authority**, or, if relevant the **auditor**, must produce an **audit** report that addresses the matters required of it and identifies, if the **Authority** so requires, the extent to which the **participant** alleged to be in breach, complied with this Part or Part 11, both at the time of the **audit** and historically, and also identify any areas for improvement.

Compare: Electricity Governance Rules 2003 clause 8.4 schedule J1

17 Authority to make determination

- (1) After consideration of the **audit** finding or any other input as deemed appropriate, the **Authority** must determine any instances of non-compliance and report back to the non-compliant **participant**.
- (2) Details of action that has been taken by the non-compliant **participant** to correct a non-compliance must be submitted to the **Authority** by that **participant** no later than 10 **business days** after the **participant** receives the report.

Compare: Electricity Governance Rules 2003 clause 8.5 schedule J1

18 Authority to publish summary of audit report

The **Authority** must publish a summary of the **audit** report, including if appropriate, any responses from the **participant**.

Compare: Electricity Governance Rules 2003 clause 8.6 schedule J1

19 Costs of audit

Despite clause 5(3), the costs of an **audit** carried out in accordance with clauses 12 to 18 must be paid as follows:

- (a) if an **audit** establishes to the satisfaction of the **Authority** that the **participant** alleged to be in breach has not committed the alleged breach—
 - (i) for an **audit** carried out in accordance with clause 12(1), the **Authority** is responsible for the costs of the **audit**; and
 - (ii) for an **audit** carried out in accordance with clause 12(2), the **participant** who requested the **audit** is responsible for the costs of the **audit**:
- (b) if an **audit** establishes, to the satisfaction of the **Authority**, that the **participant** alleged to be in breach has committed the alleged breach, the costs of the **audit** must be paid by—
 - (i) for an **audit** carried out in accordance with clause 12(1), the **participant** who is the subject of the **audit** and the **Authority**, in proportions determined by the **Authority**; and
 - (ii) for an **audit** carried out in accordance with clause 12(2), the **participant** who is the subject of the **audit** and the **participant** who requested the **audit**, in proportions determined by the **Authority**.

Compare: Electricity Governance Rules 2003 clause 8.7 schedule J1

Schedule 15.2

Collection of volume information

cl 15.5

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

- (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

Metering installation category	Half-hour metering installations (seconds)	Non half-hour metering installations (seconds)
1	±30	±60
2	±10	±60
3	±10	NA
4	±10	NA
5	±5	NA

Compare: Electricity Governance Rules 2003 clause 2 schedule J2

Clause 2: substituted, on 29 August 2013, by clause 24 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

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**.

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) **Volume information** created using **estimated readings** must be replaced at the earliest opportunity by the relevant **reconciliation participant** with **volume information** that has been created using **validated meter readings** or **permanent estimates** by no later than the month 14 revision cycle.
- (3) A **permanent estimate** may be used in place of a **validated meter reading** only if a **reconciliation participant**, despite having used reasonable endeavours, has been unable to obtain a **validated meter reading**.

Compare: Electricity Governance Rules 2003 clause 4 schedule J2

Meter interrogation for non half hour metering

5 Non half-hour metering information

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.

Compare: Electricity Governance Rules 2003 clause 5.1 schedule J2

Clause 5: substituted, on 29 August 2013, by clause 25 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

6 Non half hour meter readings apply from end of day

Non **half hour meter readings** are deemed to apply 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

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 **market administrator**, 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 **market administrator** 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 **market administrator'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

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 **market administrator** 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 **market administrator** 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 **market administrator** 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

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 Arrangements) Code Amendment 2011

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 Arrangements) Code Amendment 2011

13 **Trading period**

The **trading period** duration, which is normally 30 minutes, must be within $\pm 0.1\%$ (± 2 seconds).

Compare: Electricity Governance Rules 2003 clause 6.3 schedule J2

14 **Quantification error**

The design of the **interrogation** system must ensure that the requirements of clause 38(1) of Schedule 10.7 are complied with.

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 Amendments) Code Amendment 2012.

Clause 14: amended, on 29 August 2013, by clause 28 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

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**.

Compare: Electricity Governance Rules 2003 clause 6.5 schedule J2

Clause 15(1): amended, on 29 August 2013, by clause 29 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

Clause 15(1): amended, on 15 May 2014, by clause 102 of the Electricity Industry Participation (Modified Dispatchable Demand) Code Amendment 2013

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 Heading: amended, on 29 August 2013, by clause 15 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2013.

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

Clause 17(4): amended, on 29 August 2013, by clause 9 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011, Amendment 2013 (No 2)

Clause 17(4)(f): amended, on 15 May 2014, by clause 65 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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.

Compare: Electricity Governance Rules 2003 clause 8 schedule J2

Clause 18(1): substituted, on 29 August 2013, by clause 31 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

19 Correction of meter readings

- (1) If errors are detected during the validation of non **half hour meter readings**, 1 of the following must be undertaken:
 - (a) confirmation of the original **meter reading** by carrying out another **meter reading**;
 - (b) replacement of the original **meter reading** by another **meter reading** (even if the replacement **meter reading** may be at a different date);
 - (c) if the original **meter reading** cannot be confirmed or replaced by a **meter reading** from another **interrogation**, an **estimated reading** may be substituted if the **estimated reading** is marked as an estimate and it is subsequently replaced in accordance with clause 4(2).
- (2) If errors are detected during the validation of **half-hour meter readings**, the **meter readings** must be corrected as follows:
 - (a) if a check **meter** or **data storage device** is installed at the **metering installation**, data from the check **meter** or **data storage device** may be substituted;
 - (b) in the absence of any check **meter** or **data storage device**, data may be substituted from another period if the total of all substituted intervals matches the total consumption recorded on a **meter**, if available, and the pattern of consumption is considered to be materially similar to the period in error.
- (3) **Error compensation** and **loss compensation** may be carried out as part of the process of determining accurate data. Whatever methodology is used, the compensation process must be documented and must comply with audit trail requirements.

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

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**;
 - (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:
 - (b) the date and time of the activity:
 - (c) the operator identifier.
- (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

Clause 21(5): amended, on 29 August 2013, by clause 33(b) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

22 Correction of meter readings

- (1) In correcting a **meter reading** in accordance with clause 19, the **raw meter data** must not be overwritten. If the **raw meter data** and the **meter readings** are the same, an automatic secure backup of the affected data must be made and archived by the processing or data correction application.
- (2) If data is corrected or altered, the **reconciliation participant** correcting or altering the data must generate and archive a journal that contains the following information:
 - (a) the date of the correction or alteration:
 - (b) the time of the correction or alteration:
 - (c) the operator identifier of the **reconciliation participant**:
 - (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:
 - (e) the technique used to arrive at the corrected data:
 - (f) the reason for the correction or alteration.

Compare: Electricity Governance Rules 2003 clause 11.4 schedule J2

Schedule 15.3

Calculation and provision of submission information

cl 15.4

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** must comprise the following:
 - (a) **half hour volume information** for each **ICP** provided under clause 11.7(2) for which there is a category 3 or higher **metering installation**;
 - (b) for each **ICP** about which information is provided under clause 11.7(2) for which there is a **category 1 metering installation** or **category 2 metering installation**,—
 - (i) **half hour volume information** for the **ICP**; or
 - (ii) non **half hour volume information** calculated under clauses 4 to 6 (as applicable) for the **ICP**;
 - (c) **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.
- (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) A **reconciliation participant** must, to create **submission information** for a **point of connection** for which it is responsible, apply 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

Clause 2(1)(c): amended, on 15 May 2014, by clause 66 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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:

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

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:

$$HE_{ICP} = kWh_{p1} \times A_1 / B_1 + kWh_{p2} \times A_2 / B_2$$

where

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

kWh_{p1} is the difference in kWh between the last **validated meter reading** before the **consumption period** and the **validated meter reading** during the **consumption period**

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

B_1 is the sum of the **seasonal adjustment shape** values for the same time period as is covered by kWh_{p1}

kWh_{p2} is the difference in kWh between the first **validated meter reading** during the **consumption period** and the 1st **validated meter reading** after the **consumption period**

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

B_2 is the sum of the **seasonal adjustment shape** values for the same time period as is covered by kWh_{p2} .

Compare: Electricity Governance Rules 2003 clauses 2.2.1 schedule J3

5 Historical estimates without seasonal adjustment

If a **seasonal adjustment shape** is not available, either due to timing (for the provision of **submission information** by the 4th **business day** of each **reconciliation period**) or for any other reason, 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} .

Compare: Electricity Governance Rules 2003 clause 2.2.2 schedule J3

6 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 clause 2.2.3 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**.

Compare: Electricity Governance Rules 2003 clause 2.2.4 schedule J3

8 Provision of submission information to reconciliation manager

Each **reconciliation participant** must provide **submission information** to the **reconciliation manager** aggregated to the following level:

- (a) **NSP code**:
- (b) **reconciliation type**:
- (c) **profile**:
- (d) **loss category code**:
- (e) **flow direction**:
- (f) **dedicated NSP**:
- (g) **trading period** for **half hour** metered **ICPs** and **consumption period** or day for all other **ICPs**.

Compare: Electricity Governance Rules 2003 clause 3 schedule J3

9 Rounding of submission information

A **reconciliation participant** must round **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 **distributed 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) the **ICP identifier** associated with the distributed **unmetered load**; and
 - (b) the location of each item of load; and
 - (c) a description of load type for each item of load including any assumptions made in the assessment of its capacity; and
 - (d) the capacity of each item of load in kW.
- (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) The annual **audit** of a **reconciliation participant** who is a **retailer** in accordance with Schedule 15.1 must include an **audit** of the databases of **distributed unmetered load** to verify that the **volume information** is being calculated accurately and that **profiles** have been correctly applied.

Compare: Electricity Governance Rules 2003 clause 5 schedule J3

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:

<i>Timing</i>	<i>Reconciliation process</i>	<i>Revisions cycles</i>
Commencement of the 1 st day of the reconciliation period	Beginning of reconciliation period .	Beginning of reconciliation period .
By 1600 hours on the 4th business day of the reconciliation period	The registry 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	

<i>Timing</i>	<i>Reconciliation process</i>	<i>Revisions cycles</i>
	NSP information, in accordance with clauses 15.4 to 15.12.	
By 1600 hours on the 7th business day of the reconciliation period	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.	
From the 8th business day of the reconciliation period	Each reconciliation participant must seek to resolve all inaccuracies and disputes concerning the reconciliation information .	
By 1600 hours on the 13 th business day of the reconciliation period		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 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.

<i>Timing</i>	<i>Reconciliation process</i>	<i>Revisions cycles</i>
By 1200 hours on the last business day of the reconciliation period		The reconciliation manager must distribute revised reconciliation information to the entitled reconciliation participants and the clearing manager , in accordance with clause 28 of this Schedule.

Compare: Electricity Governance Rules 2003 clause 2 schedule J4

3 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).

Compare: Electricity Governance Rules 2003 clause 3 schedule J4

4 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 notification 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 on 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** 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:

$$ICP_{SF} = ICPD_{REG} / ICPD_{RTLRL}$$

where

ICP_{SF} is the **ICP** scaling factor

$ICPD_{REG}$ is the number of **ICP days** for that **retailer** per **balancing area** as reported by the **registry**

$ICPD_{RTLRL}$ 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** is not 0, the **reconciliation manager** must add to that **retailer's submission information** for that **consumption period** an amount (designated $SI_{ICPD-ADD}$) 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**.
- (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

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:

$$SI_{ICPD-ADJ} = (SI \times ICP_{SF}) + SI_{ICPD-ADD}$$

where

$SI_{ICPD-ADJ}$ is **submission information** adjusted for **ICP days**

SI is the amount of **electricity** reported as part of that **retailer's** or **direct purchaser's submission information**

ICP_{SF} is the **ICP** scaling factor determined in accordance with clause 7

$SI_{ICPD-ADD}$ 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 **market administrator** in accordance with Schedule 15.5; and
- (b) the **profile owner** has notified 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

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 **market administrator** in accordance with Schedule 15.5; and

- (b) the **profile owner** has notified 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

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 **market administrator** for use as a **balancing area** derived **profile** in accordance with Schedule 15.5; and
- (b) the **profile owner** has notified 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 **profile** code had not been approved by the **market administrator**, or notified to the **reconciliation manager**, the **reconciliation manager** must use the final residual **profile**.

Compare: Electricity Governance Rules 2003 clause 6.4 schedule J4

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** 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.
- (3) The **reconciliation manager** must apply **loss factors** to **submission information** in respect of each **embedded network** and **interconnection point**, and **submission information** in respect of parent **networks** for the appropriate **reconciliation period**.

Compare: Electricity Governance Rules 2003 clause 7 schedule J4

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**:

$$UFE_{BA} = TOT_{BA} - Q_{BA-EN}$$

where

UFE_{BA} is the **unaccounted for electricity** for each **balancing area** for the relevant **trading period**

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** connected to the **balancing area**

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:

$$UFE\ Factor_{BA} = TOT_{BA} / Q_{ICPD-LA}$$

where

$UFE\ Factor_{BA}$ 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).

Compare: Electricity Governance Rules 2003 clause 8 schedule J4

Clause 16(1) definition of Q_{BA-EN} : amended, on 15 May 2014, by clause 67(a) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

Clause 16(2) definition of $Q_{ICPD-LA}$: amended, on 15 May 2014, by clause 67(b) of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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.

Compare: Electricity Governance Rules 2003 clause 9.1 schedule J4

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):

$$SC_{Ri} = AES_{Ri} / (ACI_{Ri} \times SC_{Thres})$$

where

SC_{Ri} SC is the **scorecard rating** and the subscript “Ri” is a **retailer**, for each **consumption period** and each **balancing area**

AES_{Ri} 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} 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} 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) in all cases, the latest **electricity supplied** and **submission information** quantities submitted to the **reconciliation manager** by the **retailer** must be used.

- (2) 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) Despite subclauses (1) and (2), the **scorecard rating** for **direct consumers** and **direct purchasers** must be 1.
- (4) Despite anything else in this Code, the **scorecard rating** must be set to 1 until such time as the **Authority** notifies **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:

$$UFE_{Ri} = UFE_{BA} \times AF_{Ri}$$

$$AF_{Ri} = \frac{(SC_{Ri} \times MS_{Ri})}{\text{sum}(SC_{R1} \times MS_{R1}, \dots, SC_{Rn} \times MS_{Rn})}$$

$$MS_{Ri} = Q_{ICPD-LA Ri} / \text{sum}(Q_{ICPD-LA 1}, \dots, Q_{ICPD-LA n})$$

where, for each **trading period**

UFE_{Ri} is the quantity of **unaccounted for electricity** to be allocated to each **retailer** or **direct purchaser**

UFE_{BA} is the quantity of **unaccounted for electricity** for each **balancing area** calculated by the **reconciliation manager** in accordance with clause 16(1)

$Q_{ICPD-LA Ri}$ 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_{Ri} 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_{Ri} 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_{Ri} 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.

Compare: Electricity Governance Rules 2003 clause 10.1 schedule J4

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:

$$Q_{ILU\ Ri} = Q_{ICPD-LA\ Ri} + UFE_{Ri}$$

where, for each **trading period**

$Q_{ILU\ Ri}$ 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

$Q_{ICPD-LA\ Ri}$ and UFE_{Ri} have the meaning given to them in clause 19.

Compare: Electricity Governance Rules 2003 clause 10.2 schedule J4

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 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:

$$Q_{BAL\ NSP_x\ Ri} = \frac{Q_{ILUN\ NSP_x\ Ri} \times TOT_{ND\ NSP_x}}{\text{sum}(Q_{ILUN\ NSP_x\ R1}, \dots, Q_{ILUN\ NSP_x\ Rn})}$$

where

$Q_{BAL\ NSP_x\ Ri}$ 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

$Q_{ILUN\ NSP_x\ Ri}$ 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

$TOT_{ND\ NSP_x}$ 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:

$$Q_{OVER\ Ri} = \text{sum}(Q_{ILUN\ NSP1\ Ri} - Q_{BAL\ NSP1\ Ri}, \dots, Q_{ILUN\ NSPn\ Ri} - Q_{BAL\ NSPn\ Ri})$$

where

$Q_{OVER\ Ri}$ 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

$Q_{ILUN\ NSP1\ Ri}$ and $Q_{BAL\ NSP1\ Ri}$ 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:

$$PR_{NSP\ x} = (TOT_{ND\ NSP\ x} - \text{sum}(Q_{ILUN\ NSP\ x\ R1} \dots Q_{ILUN\ NSP\ x\ Rn})) / Q_{OVER\ BA}$$

where

$PR_{NSP\ x}$ is the proportion by which the over-allocated quantity must be allocated to the under-allocated **NSPs**, per **retailer** and **direct purchaser**

$Q_{OVER\ BA}$ is the sum of all over-allocated quantities for all **retailers** and **direct purchasers** for all over-allocated **NSPs** in the relevant **balancing area**

$TOT_{ND\ NSP\ x}$ and $Q_{ILUN\ NSP\ x\ R1}$ 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:

$$Q_{BAL\ NSP\ x\ Ri} = \frac{Q_{OVER\ Ri} \times PR_{NSP\ Rx}}{+ Q_{ILUN\ NSP\ x\ Ri}}$$

where

$Q_{BAL\ NSP\ x\ Ri}$ is the over-allocated quantities of **electricity** attributed to each **retailer** and **direct purchaser** at each under-allocated **NSP**;

$Q_{OVER\ Ri}$ has the meaning given to it in subparagraph (i)

$Q_{ILUN\ NSP\ x\ Ri}$ has the meaning given to it in paragraph (b); and

$PR_{NSP\ Rx}$ has the meaning given to it in subparagraph (ii).

Compare: Electricity Governance Rules 2003 clause 12 schedule J4

Clause 22: amended, on 15 May 2014, by clause 68 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

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:

$$Q_{TOT\ Ri} = Q_{BAL\ NSP\ x\ Ri} + Q_{DED\ Ri}$$

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

$Q_{BAL\ NSP\ x\ Ri}$ has the meaning given to it in clause 22(c)(iii)

$Q_{\text{DED Ri}}$ are the quantities of **electricity** to be purchased by each **reconciliation participant** for dedicated quantities.

Compare: Electricity Governance Rules 2003 clause 13 schedule J4

24 Reconciliation manager reporting requirements

- (1) 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**.

Compare: Electricity Governance Rules 2003 clause 14 schedule J4

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**:
- (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

28 Provision of reconciliation information

The **reconciliation manager** must provide the following information to the **clearing manager** and those **reconciliation 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 **payee** or **payer** to enable the **clearing manager** to calculate the amounts

- payable by the **clearing manager** to each **payee** and by each **payer** 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.

Schedule 15.5 Profile administration

cl 15.19

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 **market administrator** 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

Clause 4: amended, on 29 August 2013, by clause 35 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

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

Clause 6(2): amended, on 29 August 2013, by clause 36 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

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 **market administrator** 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 **market administrator** must not approve an application unless the **market administrator** 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 **market administrator** 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

Sum of energy flow entering the balancing area	Sum of energy flow leaving the balancing area	Sum of generation injection entering the balancing area
--	---	---

where

TOT_{BA} 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 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** 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:

$$NHH_{Tot} = \underbrace{TOT_{BA}}_{\text{Sum of HHR metered consumption internal to the network area}} - HHR_M$$

where

NHH_{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

TOT_{BA} is the total quantity of **electricity** consumed within the **balancing area**, determined in accordance with clause 15

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_{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:

$$GXP_{Init} = NHH_{Tot} - \underbrace{(Pr_{ENG} + Pr_{STAT})}_{\text{Sum of independently shaped, non half hour profiled consumption internal to the network area}}$$

where

GXP_{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_{Tot} is as determined in clause 16

Pr_{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_{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_{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

Clause 17(2): amended, on 15 May 2014, by clause 69 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

18 Calculate final residual profile shape

- (1) Using the resultant GXP_{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:

$$GXP_{Res} = GXP_{Init} - (PrSh_1 + \dots + PrSh_n)$$


Sum of non half hour
dependently shaped
profiles internal to network
area

where

GXP_{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_{Init} is as determined in clause 17

$PrSh_x$ 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_{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

Clause 18(2): amended, on 15 May 2014, by clause 70 of the Electricity Industry Participation (Minor Code Amendments) Code Amendment 2014.

New NSP derived profiles

19 Applications

- (1) An application to introduce a new **NSP** derived **profile** must be submitted to the **market administrator**, 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 **market administrator** 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 **market administrator** must advise all **participants**.

Compare: Electricity Governance Rules 2003 clause 7.4 schedule J5

23 Rejected applications

If an application is rejected, the **market administrator** 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 **market administrator** in accordance with clauses 19 and 20. The use of a **profile** must be effective from a date decided by the **market administrator**, 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 **market administrator**, 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 **market administrator**.

Compare: Electricity Governance Rules 2003 clauses 8.2 and 8.2A schedule J5

27 Assessment

The **market administrator** 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.

Compare: Electricity Governance Rules 2003 clause 8.3 schedule J5

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 **market administrator** 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 **market administrator** must require a minimum sampling period of 60 calendar days, and not more than 12 months. The **market administrator** 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 **market administrator** 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 **market administrator** can reject the application, or can require the **profile applicant** to supply additional information until the **market administrator** 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 **market administrator** 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**.

Compare: Electricity Governance Rules 2003 clause 8.4 schedule J5

Clause 28(1): amended, on 29 August 2013, by clause 37 of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

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**.

Compare: Electricity Governance Rules 2003 clause 8.5 schedule J5

30 Withdrawal of applications

If an application is withdrawn by a **profile applicant** at any time following the **declaration date**, but before approval, the **market administrator** must advise all **participants**.

Compare: Electricity Governance Rules 2003 clause 8.6 schedule J5

31 Rejected applications

- (1) If an application is rejected, the **market administrator** 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 re-used 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 **market administrator** must determine if additional **ICP identifiers** are required to make up the refined **preliminary sample**.

Compare: Electricity Governance Rules 2003 clause 8.7 schedule J5

32 Use of approved profiles

- (1) A **profile** must not be used for reconciliation until the **market administrator** approves it. The use of a **profile** must be effective from a date decided by the **market administrator**, 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 8.8 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 **market administrator** when an update is necessary (refer subclause (3)). The **profile population** list is subject to random **audit** by the **market administrator** 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, notify the **market administrator** of the changes in the **profile population** list. The **market administrator** must determine, and notify the **profile owner** of, any required modifications to the **profile sample**. The **profile owner** has 1 month from the date of notification by the **market administrator** 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 **market administrator** a list of **ICP identifiers** in the current **profile sample** who have been lost or removed from the **profile population** list. The **market administrator** 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 **market administrator** 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.

Compare: Electricity Governance Rules 2003 clauses 8.9.1 and 8.9.2 schedule J5

34 Exceptions to sampling methodology

The **market administrator** may allow different sampling methodologies that are not described in this Schedule, only if—

- (a) the methodology can, in the **market administrator's** assessment, produce sample data that meets the precision standards specified under Appendix 2; and
- (b) the **market administrator** 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**.

Compare: Electricity Governance Rules 2003 clause 8.9.3 schedule J5

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 application of all **profiles** must be **audited** by the **market administrator** or its agent in a random order at least once every 2 years by application of a selection process maintained by the **market administrator** and monitored by the **Authority**.
- (3) As a minimum, a **profile audit** must cover the following:
 - (a) the documents detailing the methodology of the **profile**;
 - (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 **market administrator** 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 **market administrator** must immediately remove a **profile** that fails an **audit** from the list of approved **profiles** held by the **market administrator**.
- (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) A **profile** may be removed at the request of the **profile owner** who introduced it, or for such other reasons as may be decided by the **market administrator**.
- (4) A request for the removal of a **profile** must be notified to the **market administrator**, and must be effective from the following settlement period.
- (5) If a **profile** is removed, the **market administrator** must decide on the actions to be taken with respect to the **ICP identifiers** to which the removed **profile** applied.

Compare: Electricity Governance Rules 2003 clause 11 schedule J5

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): amended, on 29 August 2013, by clause 38(a) of the Electricity Industry Participation (Metering Arrangements) Code Amendment 2011

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) There are 2 types of non **half hour embedded generator profile** as set out in subclause (2). Details of the operation and application of those **profiles** must be determined by the **market administrator**. The **profiles** must be submitted by the **market administrator** 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 **market administrator**, the size of the **preliminary sample** must be determined by the following **preliminary sample size** formula:

$$n_1 = (z_{\alpha}^2 \times C_A^2) / r^2$$

- (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—

$$n_1' = n_1 / (1 + n_1/N)$$

- (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**

α is the confidence level

z_{α} is the value of the standard normal distribution which gives α probability outside the tails

C_A is the **assumed 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:

Assumed co-efficient of variation (C_A): 0.1

Relative standard error (r): 0.05

Confidence level (α): 0.99

- (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 calendar days. The data, in its processed form, must be submitted

to the **market administrator** 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:

$$n = (S_0^2/Y_0^2) \times (z_\alpha^2/r^2) \times \{1 + 8 \times (r^2/z_\alpha^2) \times [S_0^2/(n_1 \times Y_0^2)] + 2/n_1\}$$

- (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—

$$n' = n/(1+n/N)$$

- (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

α is the confidence level

z_α is the value of the standard normal distribution which gives α 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 (α) 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 **market administrator** and reviewed when the **market administrator** 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 **market administrator** 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 **market administrator** 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 17 Transitional provisions

Contents

Transitional provisions relating to Part 1

- 17.1 Transitional provisions for definitions
- 17.2 Special definition of purchaser and payer

Transitional provisions relating to Part 2

- 17.3 Requests for rulebook information

Transitional provisions relating to Part 3

- 17.4 Appointment of market operation service providers
- 17.5 Insurance cover
- 17.6 Notification of a force majeure event by a service provider
- 17.7 Disclosure to the Authority
- 17.8 Performance standards
- 17.9 Market operation service providers must report to Authority
- 17.10 Review of market operation service providers
- 17.11 Software specifications

Transitional provisions relating to Part 4

- 17.12 Notification of a force majeure event by an ancillary service agent

Transitional provisions relating to Part 5

- 17.13 Undesirable trading situations

Transitional provisions relating to Part 6

- 17.14 Approval to connect
- 17.15 Connection of distributed generation outside regulated terms
- 17.16 Connection of distributed generation on regulated terms
- 17.17 Obtaining approval to connect distributed generation under 10kW
- 17.18 Obtaining approval to connect distributed generation over 10kW
- 17.19 Confidentiality of information provided before connection
- 17.20 Annual reporting and record keeping
- 17.21 Confidential information for regulated terms for
- 17.22 Breach of regulated terms
- 17.23 Default dispute resolution process

Transitional provisions relating to Part 7

- 17.24 Security of supply forecasting and information policy
- 17.25 Emergency management policy
- 17.26 Review of system operator
- 17.27 Review of the system operator

Transitional provisions relating to Part 8

- 17.28 Policy statements
- 17.29 Existing contracts for higher levels of common quality
- 17.30 System security forecast
- 17.31 Load shedding obligations to support voltage

- 17.32 Information provisions
- 17.33 Commissioning plan or testing plan
- 17.34 Equivalence arrangement or dispensation
- 17.35 Excluded generating stations
- 17.36 Procurement plan
- 17.37 Alternative ancillary service arrangement
- 17.38 Allocating ancillary services costs
- 17.39 Requirements for asset capability statement
- 17.40 Connection of local networks in parallel with the grid
- 17.41 Modification and changes to assets
- 17.42 Records, tests and inspections
- 17.43 Information provided
- 17.44 Retention of records
- 17.45 Redistribution of automatic under-frequency load shedding
- 17.46 Notice
- 17.47 Specific requirements for document transmission communication
- 17.48 Outage

Transitional provisions relating to Part 9

- 17.49 System operator rolling outage plan
- 17.50 Participant rolling outage plans
- 17.51 Supply shortage declaration
- 17.52 Security of supply direction
- 17.53 Provision of information

Transitional provisions relating to Part 10

- 17.54 Meter installations
- 17.55 Quantification at points of connection
- 17.56 Electricity recorded
- 17.57 Metering installation tests
- 17.58 Approved test house
- 17.59 Certification of metering installations of Practice 10.3.
- 17.60 Inspection requirements
- 17.61 Variation of requirements

Transitional provisions relating to Part 11

- 17.62 Requirement to provide complete and accurate information
- 17.63 ICP identifiers for ICPs
- 17.64 Participants may request that distributors create ICP
- 17.65 Provision of ICP information
- 17.66 Provision of and changes to ICP and NSP information
- 17.67 Network owner notifications
- 17.68 Audits
- 17.69 Process for maintaining shared unmetered load
- 17.70 Timeframes and formats of information
- 17.71 Confirmation of receipt of data
- 17.72 Registry must maintain a database of information
- 17.73 Reports from the registry
- 17.74 Registry reports to specific participants
- 17.75 Access to the registry

- 17.76 Registry notifications
- 17.77 Customer and embedded generator queries
- 17.78 Dispensations
- 17.79 Distributors to provide ICP information to registry
- 17.80 Traders to provide ICP information to registry
- 17.81 Correction of errors in the registry
- 17.82 Management of ICP status by distributors and traders
- 17.83 Updating table of loss category codes
- 17.84 Updating loss factors for loss category codes
- 17.85 Updating table of price category codes
- 17.86 Balancing area information
- 17.87 Creation and decommissioning of NSPs and transfer of ICPs
- 17.88 Information to be provided if NSPs are created or ICPs
- 17.89 Information to be provided if ICPs become NSPs
- 17.90 Reconciliation manager to allocate new identifiers
- 17.91 Obligations concerning change in network owner
- 17.92 Reconciliation manager to advise registry
- 17.93 Transfer of ICPs between distributors' networks
- 17.94 Standard switching process for ICPs with non half-hour metering and unmetered ICPs
- 17.95 Switch move process for ICPs with non half-hour metering and unmetered ICPs
- 17.96 Half-hour switching process
- 17.97 Withdrawal of switch requests
- 17.98 Participants to use file formats
- 17.99 Method of exchanging files
- 17.100 Costs of interrogation or estimation
- 17.101 Registry notifications

Transitional provisions relating to Part 12

- 17.102 Discretion to waive requirements
- 17.103 Benchmark agreements to be default transmission agreements
- 17.104 Changes to the connection assets under default transmission agreements
- 17.105 Expiry or termination of transmission agreements
- 17.106 Transmission agreement to be provided and published
- 17.107 Review of Connection Code
- 17.108 Increased services and reliability
- 17.109 Approval of decreased services and reliability
- 17.110 Approval of other variations to terms of benchmark agreement
- 17.111 Customer specific value of unserved energy
- 17.112 Replacement and enhancement of shared connection assets
- 17.113 Resolution of disputes relating to transmission agreements
- 17.114 Review of benchmark agreement
- 17.115 Existing agreements
- 17.116 Transpower to publish grid reliability report
- 17.117 Issues paper
- 17.118 Development of transmission pricing methodology
- 17.119 Development of transmission prices
- 17.120 Audit of transmission prices
- 17.121 Review of approved transmission pricing methodology

- 17.122 Transpower to identify interconnection branches, and propose service measures and levels
- 17.123 Transpower to propose reliability investments
- 17.124 Transpower to propose economic investments
- 17.125 Information on capacities of individual interconnection assets
- 17.126 Transpower to provide and publish annual report on interconnection asset capacity and grid configuration
- 17.127 Transpower to report on availability and reliability

Transitional provisions relating to Part 13

- 17.128 Requests for rulebook information
- 17.129 Approval process for industrial co-generating stations
- 17.130 Offer preparation by generators
- 17.131 Generators' notice of initial offer
- 17.132 Bids by purchasers
- 17.133 Purchasers' notice of initial bids
- 17.134 Bids and offers are valid until cancelled
- 17.135 Offers made by unit of plant
- 17.136 New, revised or cancelled bid or offer inside the 2 hour period
- 17.137 Backup procedures if the information system is unavailable
- 17.138 Backup procedures
- 17.139 Plant with special circumstance
- 17.140 Retention of bids and offers
- 17.141 Special treatment of some grid exit points
- 17.142 Standing data to be provided to the system operator
- 17.143 Transmission grid capability information to be updated
- 17.144 Grid owners must submit revised information to the system operator
- 17.145 Changes may be made within 2 hours prior to the trading period
- 17.146 System operator to approve ancillary service agents wishing to make reserve offers
- 17.147 Ancillary service agents to submit reserve offers to the system operator
- 17.148 Revised reserve offer inside the 2 hour period
- 17.149 Availability of final bids and final offers
- 17.150 Process for preparing a pre-dispatch schedule
- 17.151 Block dispatch may occur
- 17.152 System operator to notify block security constraints
- 17.153 Station dispatch may occur
- 17.154 System operator to notify security constraints
- 17.155 Generator notifies change from station to unit dispatch
- 17.156 Dispatch instructions
- 17.157 Market administrator to appointment person to monitor and assess demands side participation
- 17.158 Grid emergency
- 17.159 The effect of a grid emergency in total quantities bid
- 17.160 Reporting requirements in respect of grid emergencies
- 17.161 Reporting obligation of the system operator
- 17.162 System operator to publish information
- 17.163 Run dispatch options
- 17.164 Clearing manager must conduct auctions
- 17.165 Deadline for auction bids

- 17.166 Authorisation to successful bidders
- 17.167 High spring washer price situation
- 17.168 Preparation of provisional and final prices
- 17.169 Half-hour metering information
- 17.170 Input information
- 17.171 Pricing manager to publish interim prices
- 17.172 SCADA situation
- 17.173 Metering situation
- 17.174 High spring washer price situation
- 17.175 Requirements if provisional price situation exists
- 17.176 Provisional prices and provisional reserve prices
- 17.177 Final prices and provisional prices and provisional reserve prices
- 17.178 Publish final prices or notice that a high spring washer price situation exists
- 17.179 System operator to apply high spring washer price relaxation factor and give notice
- 17.180 Revised data
- 17.181 If a provisional price situation (other than a high spring washer price situation)
continues
- 17.182 Interim pricing period
- 17.183 Authority may order delay of publication of final prices
- 17.184 System operator to give pricing manager a list of model variable failures
- 17.185 Calculate constrained off amounts
- 17.186 Rights to constrained off information
- 17.187 Constrained on amounts
- 17.188 Payment of constrained on compensation
- 17.189 Market administrator to publish pricing manager reports
- 17.190 Right to information concerning pricing manager's action
- 17.191 Information that must be submitted
- 17.192 Calculation of contract price
- 17.193 Information submitted
- 17.194 Timeframes for submitting that information

Transitional provisions relating to Part 14

- 17.195 Acceptable forms of security
- 17.196 Cash deposits
- 17.197 Change in form of security
- 17.198 Reductions and releases
- 17.199 Hedge settlement agreements
- 17.200 Release of security
- 17.201 Level of security
- 17.202 Information, monitoring and reporting
- 17.203 Disputes
- 17.204 Invoices to and payments by payers
- 17.205 Operating account
- 17.206 Payments to and from payees
- 17.207 Defaults
- 17.208 Disputed invoices
- 17.209 Washups
- 17.210 Reporting obligations

Transitional provisions relating to Part 15

- 17.211 Requirement to provide complete and accurate information
- 17.212 Provision of trading information at point of connection to network
- 17.213 Submission information to be delivered for reconciliation
- 17.214 Retailer and direct purchaser ICP days information
- 17.215 Retailer electricity supplied information
- 17.216 Retailer and direct purchaser half-hourly metered ICPs monthly kWh information
- 17.217 Grid owner volume information
- 17.218 Local network and embedded network submission information
- 17.219 Grid connected generator
- 17.220 Accuracy of submitted information
- 17.221 Notification by embedded generators
- 17.222 Notification of changes to the grid
- 17.223 System operator notifies reconciliation manager of points of connection to the grid subject to outages or alternative supply
- 17.224 Balancing area NSP grouping changes
- 17.225 Submission information to be reviewed in the case of an outage constraint
- 17.226 Reconciliation manager may request additional information
- 17.227 Providing information specific to reconciliation participants
- 17.228 Providing information to reconciliation participants
- 17.229 Reconciliation information checked
- 17.230 Reconciliation manager must assess information not supplied
- 17.231 Reconciliation manager to correct information
- 17.232 Transitional provisions concerning revision
- 17.233 Volume information disputes
- 17.234 Alleged breaches reported by the reconciliation manager
- 17.235 Right to information concerning reconciliation manager's actions
- 17.236 Reconciliation reports
- 17.237 The publication of reports
- 17.238 Provision of information
- 17.239 New Zealand daylight time adjustment techniques
- 17.240 Audit
- 17.241 Functions requiring certification
- 17.242 Participant must use participant identifiers
- 17.243 Requirement for certification
- 17.244 Obtaining certification
- 17.245 Granting certification
- 17.246 Lists of certified reconciliation participants and agents
- 17.247 Renewed certification
- 17.248 Changes that affect certification
- 17.249 Auditors
- 17.250 Audits
- 17.251 Audit reports
- 17.252 Participant requested audits
- 17.253 Scope of audits
- 17.254 Information requests
- 17.255 Participants provide access and information
- 17.256 Production of audit report

- 17.257 Determination
- 17.258 Summary of audit report
- 17.259 Meter interrogation for non half-hour metering
- 17.260 Non half-hour meter reading every 4 months
- 17.261 Interrogation logs
- 17.262 Meter interrogation for half-hour metering
- 17.263 Audit trails
- 17.264 Correction of meter readings
- 17.265 Creation of submission information
- 17.266 Provision of submission information to reconciliation manager
- 17.267 Reporting requirements
- 17.268 Distributed unmetered load database
- 17.269 Calculation by difference for embedded networks
- 17.270 Calculation by difference for local networks
- 17.271 ICP days information
- 17.272 Calculation of residual non half-hour profile shape
- 17.273 Convert non half-hour quantities using profiles
- 17.274 Invalid submission information
- 17.275 Loss factors
- 17.276 Scorecard rating
- 17.277 Calculation of scorecard rating
- 17.278 Application of scorecard rating
- 17.279 Reconciliation manager reporting requirements
- 17.280 Provision of reconciliation information
- 17.281 Departure from requirements for profile administration
- 17.282 Profile population list
- 17.283 Profiles approved for use
- 17.284 Change of profile
- 17.285 Profile codes
- 17.286 New NSP derived profiles
- 17.287 New statistically sampled/engineered profiles
- 17.288 MARIA profiles
- 17.289 Audits
- 17.290 Removal of profiles
- 17.291 Reviews

Transitional provisions relating to Part 16 [Revoked]

- 17.292 Summary of Rio Tinto agreements *[Revoked]*
- 17.293 Variations of Rio Tinto agreements *[Revoked]*
- 17.294 Notifications of Acts and omissions *[Revoked]*
- 17.295 Right of appeal *[Revoked]*

Transitional provisions relating to exemptions

- 17.296 Exemptions
- 17.280 Provision of reconciliation information
- 17.281 Departure from requirements for profile administration
- 17.282 Profile population list
- 17.283 Profiles approved for use
- 17.284 Change of profile

-
- 17.285 Profile codes
 - 17.286 New NSP derived profiles
 - 17.287 New statistically sampled/engineered profiles
 - 17.288 MARIA profiles
 - 17.289 Audits
 - 17.290 Removal of profiles
 - 17.291 Reviews

Transitional provisions relating to Part 16 [Revoked]

- 17.292 Summary of Rio Tinto agreements [Revoked]
- 17.293 Variations of Rio Tinto agreements [Revoked]
- 17.294 Notifications of Acts and omissions [Revoked]
- 17.295 Right of appeal [Revoked]

Transitional provisions relating to exemptions

- 17.296 Exemptions
-

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 kvar reference node** approved by the **system operator** in accordance with the definition of **distributor kvar reference node** in clause 1.1(1).
- (4) Expected interruption costs estimated by the Board under the definition of expected interruption 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 **expected interruption costs** approved by the **Authority** in accordance with the definition of **expected interruption costs** in clause 1.1(1).
- (5) A grid exit point approved by the system operator under the definition of interruptible load group GXP in rule 1 of part A of the **rules** immediately before this Code came into force, is deemed to be a **grid exit point** approved by the **system operator** in accordance with the definition of **interruptible load group GXP** in clause 1.1(1).
- (6) A system operator register kept, maintained, or made available by the system operator in accordance with the definition of system operator register in rule 1 of part A of the **rules** immediately before this Code came into force, is deemed to be a **system operator**

register kept, maintained, or made available, as the case may be, by the **system operator** in accordance with definition of **system operator register** in clause 1.1(1).

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.

Transitional provisions relating to Part 6

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.

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 of intention to proceed under clause 5 of Schedule 6.1.

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.

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).

Clause 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

An agreement to redistribute automatic under-frequency load shedding quantities between grid exit points under clause 6.4 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 an agreement under clause 7(8) of **Technical Code B** of Schedule 8.3.

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.

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 the trader 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 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.
- (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(c) 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 E 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.

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.

17.130 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 force, is deemed to be notice of an initial **offer** under clause 13.6(4).

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 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 came 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 13.156(1)(a).

Clause 17.177(4): amended, on 21 September 2012, by clause 41(1) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

Clause 17.177(5): amended, on 21 September 2012, by clause 41(2) of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.

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 manger 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 manger 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 manger 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** 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.

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 kWh_p 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, under clause 18 of Schedule 15.4.

- (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 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.

Transitional provisions relating to Part 16 cross-heading: revoked on 16 December 2013, by clause 11(1) of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.

17.292 [Revoked]

Clause 17.292: revoked on 16 December 2013, by clause 11(2) of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.

17.293 [Revoked]

Clause 17.293: revoked on 16 December 2013, by clause 11(3) of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.

17.294 [Revoked]

Clause 17.294: revoked on 16 December 2013, by clause 11(2) of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.

17.295 [Revoked]

Clause 17.295: revoked on 16 December 2013, by clause 11(2) of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.

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**.