Electricity Industry Participation Code 2010

Part 12
Transport

Contents

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 advise **registered participants** of the date by which submissions on the proposed structure are to be received by the **Authority**. The date must be no earlier than 15 **business days** from the date of **publication** of the proposed structure.

(4) Each submission on the proposed structure must be made in writing to the **Authority** and received on or before the **submission expiry date**. In addition to receiving written submissions, the **Authority** may elect to hear 1 or more oral submissions.

(5) Within 20 **business days** after the **submission expiry date** (or such longer period as the **Authority** may allow), the **Authority** must complete its consideration of all submissions it receives and determine an appropriate **transmission agreement** structure.

(6) The **transmission agreement** structure determined by the **Authority** under this clause must be the structure of the **benchmark agreements** to be developed and approved by the **Authority** under clauses 12.27 to 12.34.

Compare: Electricity Governance Rules 2003 rules 2.1.3 to 2.1.5 section II part F
Clause 12.6(3): amended, on 1 November 2018, by clause 73 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

12.7 Categories of participants required to enter into transmission agreements

(1) The categories of **designated transmission customers** required to enter into **transmission agreements** with **Transpower** under clause 12.8 are as specified in Schedule 12.1.

(2) The **Authority** must record in the **register** whether a **registered participant** is a **designated transmission customer**.

(3) Registration has no effect on a **participant's** status as a **designated transmission customer**.

Compare: Electricity Governance Rules 2003 rule 2.2 section II part F

Transpower and designated transmission customers must enter transmission agreements

12.8 Obligation to enter transmission agreements

Transpower and **designated transmission customers** must enter into **transmission agreements**.

Compare: Electricity Governance Rules 2003 rule 3.1.1 section II part F

12.9 When designated transmission customer must enter into transmission agreement

A **participant** who becomes a **designated transmission customer** must enter into a **transmission agreement** with **Transpower** within 2 months after the **participant** becomes a **designated transmission customer**.

Compare: Electricity Governance Rules 2003 rule 3.1.2.3 section II part F

12.10 Benchmark agreements to be default transmission agreements

(1) Subject to clauses 12.49 and 12.50, if, at the expiry of 2 months after a **participant** becomes a **designated transmission customer**, the **designated transmission customer** and **Transpower** have not entered into a **transmission agreement** in accordance with clause 12.9, the **benchmark agreement** applies as a binding contract between the **designated transmission customer** and **Transpower**, and the **designated transmission customer** and **Transpower** must comply with the process specified in this clause.

(2) If this clause applies:

- (a) within 10 **business days** of the date that is 2 months after the **participant** became a **designated transmission customer**, the **designated transmission customer** must provide **Transpower**, at the address for service for **Transpower** registered at the New Zealand Companies Office, with—
  - (i) the **designated transmission customer's** full name; and
  - (ii) the **designated transmission customer's** physical address, postal address and electronic address to which notices under the default **transmission agreement** are to be sent; and
  - (iii) the name of the contact person of the **designated transmission customer** to whom such notices should be addressed:
- (b) by the date 20 **business days** after the receipt of the **designated transmission customer's** details under paragraph (a), **Transpower** must provide the **designated transmission customer** with a draft default **transmission agreement** completed in accordance with the **benchmark agreement**, which must include the following:
  - (i) the **designated transmission customer's** details as provided under paragraph (a):
  - (ii) **Transpower's** physical address, postal address and electronic address to which notices under the default **transmission agreement** are to be sent:
  - (iii) the contact person to whom notices under the default **transmission agreement** should be addressed:
  - (iv) **Transpower's** designated bank account for the purposes of receiving payments under the default **transmission agreement**:
  - (v) a draft Schedule 1, which sets out the **connection locations**, **points of**

service and **points of connection** of the **assets** owned or operated by the **designated transmission customer** to the **grid**:

(vi) a draft Schedule 4 setting out, in the same form as the diagram in Schedule 4 of the **benchmark agreement**, the configuration of the **connection assets** in relation to each **connection location** listed in Schedule 1:

(vii) a draft Schedule 5 setting out proposed service levels for each **connection location** listed in Schedule 1 determined in accordance with subclause (3):

(viii) if applicable, a draft Schedule 6, including identifying the facilities, facilities area, and land that are to be subject to the access and occupation terms set out in the schedule and the licence charges under the schedule:

(c) the **designated transmission customer** and **Transpower** may discuss the schedules proposed under paragraph (b)(v) to (viii), as a result of which **Transpower** may amend any of the schedules:

(d) the **designated transmission customer** must advise **Transpower** in writing no later than 20 **business days** after receiving the draft default **transmission agreement** under paragraph (b) whether—

(i) it accepts the schedules as proposed by **Transpower** under paragraph (b)(v) to (viii); or

(ii) if **Transpower** has amended any of those schedules under paragraph (c), it accepts the schedules as amended.

(3) The service levels set out in Schedule 5 of a default **transmission agreement** must be determined on the following basis:

(a) the capacity service levels for each **branch** must be consistent with—

(i) the capacities of the **branch** or component **assets** in the most recent **asset capability statement** provided by **Transpower** under clause 2(5) of **Technical Code** A of Schedule 8.3; or

(ii) if the relevant information is not contained in the **asset capability statement**, the **manufacturer's specification** for the component **assets**:

(b) the service levels for the voltage range specified in the capacity service measures for each **branch** must be consistent with,—

(i) for **assets** of voltages of 50kV or above,—

(A) the voltage ranges for the component **assets** specified in the **AOPOs**, if any; or

(B) the voltage range specified in any **equivalence arrangement** approved or any **dispensation** granted under clauses 8.29 to 8.31 in respect of any **asset** that does not comply with the voltage range specified in the **AOPOs**; or

(ii) for assets of voltages less than 50kV, the normal operating voltage of the component **assets**:

(c) **Transpower** must ensure that each **connection asset** is included in a **branch**:

(d) the availability and reliability service levels must—

(i) be set at a level equivalent to the average annual availability and reliability at each **point of service** subject to the default **transmission agreement** over the 5 year period (being years ending 30 June) immediately before the date that is 2 months after the **participant** became a **designated transmission customer**; or

(ii) if a **point of service** subject to the default **transmission agreement** has not been in existence for 5 years (being years ending 30 June) before the date referred to in subparagraph (i), reflect a reasonable estimate of the expected availability and reliability at the **point of service** having regard to the performance data available for the **point of service** and average annual availability and reliability of **assets** similar to the **connection assets** at the **connection location** at which the **point of service** is located:

(e) the reporting and response service levels must be consistent with **Transpower's** practices existing on the date that is 2 months after the **participant** became a **designated transmission customer**, including **Transpower's** documented policies and procedures, and must not result in changes to the management or operation of the **grid** that could materially affect **Transpower** or any other **participant** or end use customer, or require **Transpower** to materially alter the level of its normal on-going **grid** expenditure.

(4) If the **designated transmission customer** accepts the schedules as proposed by **Transpower** under subclause (2)(b)(v) to (viii), or as amended by **Transpower** under subclause (2)(c), the default **transmission agreement** applies as a binding contract between **Transpower** and the **designated transmission customer** from the date that is 2 months after the **participant** became a **designated transmission customer**.

(5) If **Transpower** and a **designated transmission customer** are unable to agree on the terms of any of the schedules to a default **transmission agreement** proposed by **Transpower** under subclause (2)(b)(v) to (viii), or as amended by **Transpower** under subclause (2)(c), either party may refer the matter to the **Rulings Panel** for determination under clauses 12.45 to 12.48.

(6) If a dispute is referred to the **Rulings Panel**, under subclause (5)—

(a) the default **transmission agreement** as determined by the **Rulings Panel** in accordance with clauses 12.45 to 12.48 applies as a binding agreement between **Transpower** and the **designated transmission customer** from the date that is 2 months after the **participant** became a **designated transmission customer** or the date on which the **Rulings Panel** makes its determination or its determination is expressed to come into effect, whichever is later; and

(b) if the **Rulings Panel** has not made a determination by the date that is 2 months after the **participant** became a **designated transmission customer**, the draft default **transmission agreement** provided under subclause (2)(b) applies as a binding agreement between **Transpower** and the **designated transmission customer** until the date on which the **Rulings Panel** makes its determination or the determination comes into effect.

Compare: Electricity Governance Rules 2003 rule 3.1.3 section II part F

Clause 12.10(1): amended, on 16 December 2013, by clause 5 of the Electricity Industry Participation (Revocation of Part 16) Code Amendment 2013.

Clause 12.10(2)(a)(ii) and (b)(ii): amended, on 5 October 2017, by clause 287 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

12.11 Subsequent transmission agreements

If a **benchmark agreement** applies as a default **transmission agreement**, the **benchmark agreement** may be superseded by a subsequent **transmission agreement** entered into by **Transpower** and the **designated transmission customer**.

Compare: Electricity Governance Rules 2003 rule 3.1.4 section II part F

12.12 Changes to connection assets under default transmission agreements

(1) If **Transpower** reconfigures, replaces, enhances, or permanently removes a **connection asset** from service in accordance with the provisions of a default **transmission agreement** that applies under clauses 12.10 or 12.13,—

- (a) within 20 **business days**, to the extent necessary, **Transpower** must provide the **designated transmission customer** who is a party to that agreement with a revised Schedule 1, a revised Schedule 4, and a revised Schedule 5 for that agreement, reflecting any changes to the description of the **connection locations**, **points of service**, or **points of connection** in Schedule 1, the diagram in Schedule 4, or to the service levels specified in Schedule 5 resulting from the replacement or enhancement of the **connection asset**; and
- (b) the **designated transmission customer** and **Transpower** may discuss the revised schedules, as a result of which **Transpower** may amend any of the revised schedules; and
- (c) the **designated transmission customer** must advise **Transpower** within 20 **business days** of receiving the revised schedules under paragraph (a) whether—
  - (i) it accepts the revised schedules as proposed by **Transpower** under paragraph (a); or
  - (ii) if **Transpower** has amended any of those revised schedules under paragraph (b), it accepts the revised schedules as amended; and
- (d) the revised schedules apply under the default **transmission agreement** from the date that acceptance is received by **Transpower** under paragraph (c).

(2) If the **designated transmission customer** does not accept the revised schedules under subclause (1)(c), either party may refer the matter to the **Rulings Panel** for determination under clauses 12.45 to 12.48.

(3) If a dispute is referred to the **Rulings Panel** in accordance with subclause (2)—

- (a) the revised schedules proposed by **Transpower** under subclause (1)(a) apply from the date on which **Transpower** provides the **designated transmission customer** with the revised schedules under subclause (1)(a) until the date on which the **Rulings Panel** makes its determination or the determination comes into effect; and
- (b) the revised schedules as determined by the **Rulings Panel** under clauses 12.45 to 12.48 apply under the default **transmission agreement** from the date determined by the **Rulings Panel**.

Compare: Electricity Governance Rules 2003 rule 3.1.5 section II part F

12.13 Expiry or termination of transmission agreements

If a **transmission agreement**, or an existing written agreement to which clause 12.49 applies, expires or terminates on or after the date that is 2 months after the **participant** became a **designated transmission customer** and **Transpower** and the **designated transmission customer** do not enter into a new **transmission agreement** within 2 months of that date, the following procedure applies:

(a) within 10 **business days**, the **designated transmission customer** must provide **Transpower**, at the address for service for **Transpower** registered at the New Zealand Companies Office, with—
   (i) the **designated transmission customer's** full name; and
   (ii) the **designated transmission customer's** physical address, postal address and electronic address to which notices under the default **transmission agreement** are to be sent; and
   (iii) the name of the contact person of the **designated transmission customer** to whom such notices should be addressed:

(b) within 20 **business days** of receipt of the **designated transmission customer's** details under paragraph (a), **Transpower** must provide the **designated transmission customer** with a draft default **transmission agreement** completed in accordance with the **benchmark agreement**, which must include—
   (i) the **designated transmission customer's** details as provided under paragraph (a); and
   (ii) **Transpower's** physical address, postal address and electronic address to which notices under the default **transmission agreement** are to be sent; and
   (iii) the contact person to whom notices under the default **transmission agreement** should be addressed; and
   (iv) **Transpower's** designated bank account for the purposes of receiving payments under the default **transmission agreement**; and
   (v) a draft Schedule 1, which sets out the **connection locations**, **points of service** and **points of connection** of the **assets** owned or operated by the **designated transmission customer** to the **grid**; and
   (vi) a draft Schedule 4 setting out, in the same form as the diagram in Schedule 4 of the **benchmark agreement**, the configuration of the **connection assets** in relation to each **connection location** listed in Schedule 1; and
   (vii) a draft Schedule 5 setting out proposed service levels for each **connection location** listed in Schedule 1 determined in accordance with clause 12.10(3); and
   (viii) if applicable, a draft Schedule 6, including identifying the facilities, facilities area, and land that are to be subject to the access and occupation terms set out in that schedule 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

Clause 12.13(a)(ii) and (b)(ii): amended, on 5 October 2017, by clause 288 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

Content of transmission agreements

12.14 Transmission agreements to be consistent with benchmark agreements and grid reliability standards

Subject to clauses 12.35 to 12.38, a **transmission agreement** entered into between **Transpower** and a **designated transmission customer** under clause 12.8 must be consistent in all material respects with—

(a) the **benchmark agreement**; and

(b) the **grid reliability standards**,—

as at the date the **transmission agreement** is entered into.

Compare: Electricity Governance Rules 2003 rule 3.2.1 section II part F

12.15 Transpower to publish information about transmission agreements and provide them on request

(1) **Transpower** must **publish** and update annually a list of all **transmission agreements** it has with **designated transmission customers** that includes, in respect of each **transmission agreement** contained in the list, the following information:

(a) the full name of the **designated transmission customer** that is a party to the **transmission agreement**; and

(b) the date on which the **transmission agreement** was executed; and

(c) whether the **transmission agreement** includes any material variations from the **benchmark agreement**; and

(d) if the **transmission agreement** includes any material variations from the **benchmark agreement**, a description of the variations; and

(e) if any schedule to the **transmission agreement** has been revised in accordance with clause 12.12, the date from which the revised schedule began to apply.

(2) A person may request from **Transpower** a copy of a **transmission agreement** that **Transpower** has with a **designated transmission customer**, and **Transpower** must provide a copy to the person as soon as practicable after receiving the request.

(3) Despite subclause (2), **Transpower** may refuse to provide information from a **transmission agreement** if it considers that there would be grounds for withholding the information under the Official Information Act 1982.

Compare: Electricity Governance Rules 2003 rule 3.2.2 section II part F
Clause 12.15: substituted, on 1 February 2016, by clause 46 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

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
Clause 12.17: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 12.17: amended, on 5 October 2017, by clause 289 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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 relation to the conveyance of **electricity**, and that is situated on land owned by **Transpower**:

(d) information requirements to be met by **designated transmission customers** before equipment is connected to the **grid** and before changes are made to the equipment:

(e) an obligation on **Transpower** to provide a 10 year forecast of the expected maximum fault level of each point of service to **designated transmission customers** set out in the **transmission agreement** between **Transpower** and each **designated transmission customer**.

Compare: Electricity Governance Rules 2003 rule 3.3.3 section II part F
Clause 20.20: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 12.20(a): amended, on 5 October 2017, by clause 290(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 12.20(b) and (d): amended, on 5 October 2017, by clause 290(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 12.20(c): amended, on 5 October 2017, by clause 290(3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 12.20(e): amended, on 5 October 2017, by clause 290(4) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

12.21 Principles for developing Connection Code

The **Connection Code** must give effect to the following principles:

(a) the principles of the **benchmark agreement** in clause 12.30:

(b) the desirability of the **Connection Code** and Part 8 operating in an integrated and consistent manner, if possible:

(c) the need to ensure that the **grid owner** can meet all obligations placed on it by the **system operator** for the purpose of meeting common security and power quality requirements under Part 8:

(d) the need to ensure that the safety of all personnel is maintained:

(e) the need to ensure that the safety and integrity of equipment is maintained.

Compare: Electricity Governance Rules 2003 rule 3.3.4 section II part F

12.22 Authority may initially approve proposed Connection Code or refer back to Transpower

(1) After consideration of **Transpower's** proposed **Connection Code**, and accompanying explanation and **statement of proposal**, the **Authority** may—

(a) provisionally approve the proposed **Connection Code** having regard to the matters set out in clause 12.20 and the principles in clause 12.21; or

(b) refer the proposed **Connection Code** and accompanying explanation and **statement of proposal** back to **Transpower** if, in the **Authority's** view,—

(i) the proposed **Connection Code** does not contain the matters set out in clause 12.20; or

(ii) the proposed **Connection Code** does not adequately provide for the principles in clause 12.21; or

(iii) the explanation or **statement of proposal** provided with the proposed **Connection Code** in accordance with clause 12.19(2) is inadequate.

(2) **Transpower** may, no later than 20 **business days** (or such longer period as the **Authority** may allow) after the **Authority** advises **Transpower** of its decision under subclause (1), consider the **Authority's** concerns and resubmit its proposed **Connection Code** and accompanying explanation and **statement of proposal** for consideration by the **Authority**.

Compare: Electricity Governance Rules 2003 rule 3.3.5 section II part F
Clause 12.22(2): amended, on 1 November 2018, by clause 74 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

12.23 Amendment of proposed Connection Code by Authority

If the **Authority** considers that the **Connection Code** resubmitted by **Transpower** under clause 12.22(b) does not adequately provide for the matters set out in clause 12.20 or adequately give effect to the principles in clause 12.21, the **Authority** may make any amendments to the proposed **Connection Code** it considers necessary.

Compare: Electricity Governance Rules 2003 rule 3.3.6 section II part F

12.24 Authority must consult on proposed Connection Code

(1) The **Authority** must **publish** the proposed **Connection Code**, either as provisionally approved by the **Authority** or as amended by the **Authority**, as soon as practicable, for consultation with any person that the **Authority** thinks is likely to be materially affected by the proposed **Connection Code**.

(2) As well as the consultation required under subclause (1), the **Authority** may undertake any other consultation it considers necessary.

Compare: Electricity Governance Rules 2003 rules 3.3.7 and 3.3.8 section II part F

12.25 Decision on Connection Code

(1) When the **Authority** has completed its consultation on the proposed **Connection Code** it must consider whether to incorporate the **Connection Code** by reference in this Code.

(2) If the **Authority** decides to incorporate the **Connection Code** by reference in this Code, the Authority must determine a date on which the incorporation by reference takes effect and comply with Schedule 1 of the **Act** in relation to it.

Compare: Electricity Governance Rules 2003 rule 3.3.9 section II part F

12.26 Incorporation of Connection Code by reference

(1) The **Connection Code** is incorporated by reference in this Code in accordance with section 32 of the **Act**.

(2) Subclause (1) is subject to Schedule 1 of the **Act**, which includes a requirement that the **Authority** must give notice in the *Gazette* before an amended or substituted **Connection Code** becomes incorporated by reference in this Code.

Clause 12.26(1): amended, on 5 October 2017, by clause 291 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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**.

Clause 12.27(1)(e): amended, on 1 February 2016, by clause 47 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

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
Clause 12.30(f): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 12.30(f): amended, on 5 October 2017, by clause 292 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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
Clause 12.31(1)(b): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 12.31(1)(b): amended, on 5 October 2017, by clause 293 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

12.32 Authority must consult on draft benchmark agreement

(1) The **Authority** must **publish** draft **benchmark agreements**.

(2) When the **Authority publishes** a draft **benchmark agreement**, the **Authority** must advise **registered participants** of the date (which must not be earlier than 15 **business days** after the date of publication of the draft **benchmark agreement**) by which submissions on the draft **benchmark agreement** must be received by the **Authority**.

(3) Each submission on a draft **benchmark agreement** must be made in writing to the **Authority** and received on or before the **submission expiry date**. In addition to

receiving written submissions, the **Authority** may elect to hear 1 or more oral submissions.

Compare: Electricity Governance Rules 2003 rules 4.4 and 4.5 section II part F

Clause 12.32(2): amended, on 1 November 2018, by clause 75 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

12.33 Decision on benchmark agreement

(1) Within 20 **business days** after the **submission expiry date** (or such longer period as the **Authority** may allow), the **Authority** must complete its consideration of all submissions it receives on the draft **benchmark agreement** and consider whether to **incorporate** the draft **benchmark agreement** by reference as the **benchmark agreement**.

(2) If the **Authority** decides to incorporate the **benchmark agreement** by reference in this Code, the **Authority** must determine a date on which the incorporation by reference takes effect and comply with Schedule 1 of the **Act** in relation to it.

Compare: Electricity Governance Rules 2003 rule 4.6 section II part F

12.34 Incorporation of benchmark agreement by reference

(1) The **benchmark agreement** is incorporated by reference in this Code in accordance with section 32 of the **Act**.

(2) Subclause (1) is subject to Schedule 1 of the **Act**, which includes a requirement that the **Authority** must give notice in the *Gazette* before an amended or substituted **benchmark agreement** becomes incorporated by reference in this Code.

Clause 12.34(1): amended, on 5 October 2017, by clause 294 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

Variations from benchmark agreements and grid reliability standards and enhancement and removal of connection assets

12.35 Increased service levels and reliability

(1) This clause applies if—

(a) a proposed **transmission agreement** is not consistent in all material respects with the **benchmark agreement** because it increases the service levels above those that would apply if the **benchmark agreement** applied in accordance with clauses 12.10 or 12.13; or

(b) subject to clause 12.39, a proposed **transmission agreement** or other agreement between **Transpower** and a **designated transmission customer** increases the level of reliability above the **grid reliability standards** for a particular **grid injection point** or **grid exit point.**

(2) If this clause applies, the parties to the proposed **transmission agreement** must confirm in writing to the **Authority** that—

(a) they have consulted with affected end use customers in relation to—

(i) the proposed service levels or the proposed increase in reliability; and

(ii) any resulting price implications; and

(b) there are no material unresolved issues affecting the interests of those end use customers.

Compare: Electricity Governance Rules 2003 rule 5.1 section II part F

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.
Clause 12.35(2): replaced, on 5 October 2017, by clause 295 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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 expected unserved energy

(1) *[Revoked]*

(2) **Transpower** or a **designated transmission customer** may apply to the **Authority**—

- (a) if permitted under a **transmission agreement**, for provisional approval to use a different **value of expected unserved energy** than the value specified in clause 4 of Schedule 12.2 for the purposes of determining whether to replace or enhance **connection assets** as provided for under that **transmission agreement**; or
- (b) for approval to use a different **value of expected unserved energy** than the value specified in clause 4 of Schedule 12.2 for the purposes of applying the **grid reliability standards** under clauses 12.35 to 12.37 for a **grid injection point** or **grid exit point**, regardless of whether **Transpower** or the **designated transmission customer** has applied for the **Authority's** provisional approval under subclause (4).

(3) An application under subclause (2) must be made in writing to the **Authority**—

- (a) in the case of an application under subclause (2)(a), within 20 **business days** of the **designated transmission customer** proposing that different value to **Transpower** under the **transmission agreement**; and
- (b) in the case of an application under subclause (2)(b), within 20 **business days** of the **designated transmission customer** reaching an agreement with **Transpower** to which clauses 12.35 to 12.37 apply.

(4) If **Transpower** or a **designated transmission customer** applies for approval of a different **value of expected unserved energy** under subclause (2)(a), the **Authority** may provisionally approve that value if the **Authority** considers that the value is a reasonable estimate of the **value of expected unserved energy** in respect of the **grid injection point** or **grid exit point** for the **designated transmission customer** concerned.

(5) If **Transpower** or a **designated transmission customer** applies for approval of a different **value of expected unserved energy** under subclause (2)(b) the **Authority**—

- (a) may approve that value if the **Authority** considers that the value is a reasonable estimate of the **value of expected unserved energy** in respect of the **grid injection point** or **grid exit point** for the **designated transmission customer** concerned; and
- (b) may decline to approve that value despite having provisionally approved that value under subclause (4).

(6) If the **Authority** approves the **value of expected unserved energy** proposed by **Transpower** or the **designated transmission customer** under subclause (2)(b), that

value of expected unserved energy applies for the purposes of applying the **grid reliability standards** under clauses 12.35 to 12.37 for the **grid injection point** or **grid exit point** instead of the **value of expected unserved energy** specified under clause 4 of Schedule 12.2.

(7) If the **Authority** does not approve the **value of expected unserved energy** proposed by **Transpower** or the **designated transmission customer** under subclause (2)(b), the **value of expected unserved energy** under clause 4 of Schedule 12.2 applies for the purposes of applying the **grid reliability standards** under clauses 12.35 to 12.37 for the **grid injection point** or **grid exit point**.

Compare: Electricity Governance Rules 2003 rule 5.5 section II part F
Clause 12.39 Heading: amended, on 1 February 2016, by clause 48(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.
Clause 12.39: amended, on 1 February 2016, by clause 48(3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.
Clause 12.39(1): revoked, on 1 February 2016, by clause 48(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.
Clause 12.39(2)(b): amended, on 1 February 2016, by clause 48(4) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.
Clause 12.39(4): amended, on 1 February 2016, by clause 48(5) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.
Clause 12.39(6): amended, on 1 February 2016, by clause 48(6) and (7) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.
Clause 12.39(7): amended, on 1 February 2016, by clause 48(8) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

12.40 Replacement and enhancement of shared connection assets

(1) If 2 or more **designated transmission customers** are connected to a **point of connection** and **Transpower** has advised those **designated transmission customers**, in accordance with the provisions of a **transmission agreement** between **Transpower** and each of the **designated transmission customers**, that a **grid reliability report published** by **Transpower** in accordance with clause 12.76 sets out that the power system is not reasonably expected to meet the **N-1 criterion** at all times over the next 5 years because of a **connection asset** related to that **point of connection**, **Transpower** must—

- (a) as soon as practicable after advising the **designated transmission customers**, investigate whether the **connection asset** meets the **grid reliability standards**; and
- (b) if it finds that the **connection asset** does not meet the **grid reliability standards**, develop proposals for investment in the **grid** to ensure that the **connection asset** meets the **grid reliability standards** and propose them to the **designated transmission customers** as soon as reasonably possible after **publication** of the **grid reliability report**.

(2) **Transpower** and the **designated transmission customers** advised under subclause (1) must attempt in good faith, within 6 months of the date on which **Transpower** makes its proposals to the **designated transmission customers** under subclause (1)(b), or such longer period as the **Authority** may allow, to reach an agreement for an investment or other solution that will have the effect of—

- (a) maintaining the level of reliability for the **connection asset** at the level of reliability in the **grid reliability standards**; or

(b) increasing or decreasing the level of reliability for the **connection asset** above or below the **grid reliability standards**, so long as **Transpower** and the **designated transmission customers** have complied with clauses 12.35 to 12.37 and 12.39.

(3) **Transpower** may undertake an investment proposed under subclause (2) only—

(a) if the **designated transmission customers** unanimously agree with the proposal in accordance with subclause (2); or

(b) if the **designated transmission customers** do not unanimously agree or none of the **designated transmission customers** agree with the proposed investment, if—

(i) the proposal has been approved under a grid upgrade plan requested by the Electricity Commission in accordance with rule 5.10 of section II of part F of the **rules** before this Code came into force; or

(ii) the proposal is approved by the Commerce Commission under an investment proposal requested by the Commerce Commission in accordance with clause 12.44(1); or

(iii) the proposal is permitted under an input methodology determined by the Commerce Commission under section 54S of the Commerce Act 1986.

Compare: Electricity Governance Rules 2003 rule 5.6 section II part F
Clause 12.40(1): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 12.40(1): amended, on 5 October 2017, by clause 296 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 12.40(1) and (2): amended, on 1 November 2018, by clause 76(a) and (b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

12.41 Removal of shared connection assets from service

(1) If 2 or more **designated transmission customers** are connected to a **point of connection**, and **Transpower** is required by a **transmission agreement** between **Transpower** and each of those **designated transmission customers** to provide the **connection assets** at the **point of connection**, **Transpower** may **decommission** a **connection asset** at that **point of connection** from service only—

(a) if the **designated transmission customers** unanimously agree with the **decommissioning** and clauses 12.35 to 12.37 (if applicable) are complied with; or

(b) if the **designated transmission customers** do not unanimously agree, or none of the **designated transmission customers** agree, with the **decommissioning**, if the **decommissioning** results in a net benefit, as calculated under the test set out in clause 12.43.

(2) To avoid doubt, this clause applies only if **Transpower** proposes to remove a **connection asset** from service and not replace the **asset** with another **connection asset**.

Compare: Electricity Governance Rules 2003 rule 5.7 section II part F
Clause 12.41(1): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 12.41(1): amended, on 5 October 2017, by clause 297 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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

Clause 12.42: amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 12.42: amended, on 5 October 2017, by clause 298 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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** in clause 4 of Schedule 12.2 and

Transpower's estimate of the **expected unserved energy** in respect of each affected **designated transmission customer** and end use customer.

Compare: Electricity Governance Rules 2003 rule 5.9 section II part F

Clause 12.43: substituted, on 16 December 2013, by clause 5 of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.

Clause 12.43(8)(b): amended, on 1 February 2016, by clause 49 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

Clause 12.43(8)(b): amended, on 1 November 2018, by clause 77 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

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

Clause 12.49(1): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 12.49(1): amended, on 5 October 2017, by clause 299 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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
Clause 12.50(1): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 12.50(1): amended, on 5 October 2017, by clause 300 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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) *[Revoked]*
- (d) grid reliability reporting.

Compare: Electricity Governance Rules 2003 rule 1 section III part F
Clause 12.52(c): revoked, on 1 February 2016, by clause 50 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

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 **publish** the date by which submissions on the draft **grid reliability standards** are to be received by the **Authority**. The date must be no earlier than 15 **business days** from the date of **publication** of the draft **grid reliability standards**.

(4) Each submission on the draft **grid reliability standards** must be made in writing to the **Authority** and be received on or before the **submission expiry date**. In addition to receiving written submissions, the **Authority** may elect to hear 1 or more oral submissions.

Compare: Electricity Governance Rules 2003 rules 4.5 and 4.6 section III part F

Clause 12.61(3): amended, on 5 October 2017, by clause 301 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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 **publish** the date by which submissions on the draft **core grid determination** are to be received by the **Authority**. The date must be no earlier than 15 **business days** from the date of publication of the draft **core grid determination**.

(4) Each submission on the draft **core grid determination** must be made in writing to the **Authority** and be received on or before the **submission expiry date**. In addition to receiving written submissions, the **Authority** may elect to hear 1 or more oral submissions.

Compare: Electricity Governance Rules 2003 rules 5A.4 and 5A.5 section III part F
Clause 12.68(3): amended, on 5 October 2017, by clause 302 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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** advises the **Authority** of the proposed **investment contract**.

Compare: Electricity Governance Rules 2003 rule 8.2 section III part F
Clause 12.71(b): amended, on 1 November 2018, by clause 78 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

[Revoked]

Cross Heading: revoked, on 1 February 2016, by clause 51(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

12.72 *[Revoked]*

Compare: Electricity Governance Rules 2003 rule 11.1 section III part F
Clause 12.72: revoked, on 1 February 2016, by clause 51(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

12.73 *[Revoked]*

Compare: Electricity Governance Rules 2003 rule 11.2 section III part F
Clause 12.73: revoked, on 1 February 2016, by clause 51(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

12.74 *[Revoked]*

Compare: Electricity Governance Rules 2003 rule 11.3 section III part F
Clause 12.74: revoked, on 1 February 2016, by clause 51(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

12.75 *[Revoked]*

Compare: Electricity Governance Rules 2003 rule 11.4 section III part F
Clause 12.75: revoked, on 1 February 2016, by clause 51(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

Grid reliability reporting

12.76 Transpower to publish grid reliability report

(1) **Transpower** must **publish** a **grid reliability report** setting out—

(a) a forecast of **demand** at each **grid exit point** over the next 10 years; and

(b) a forecast of **supply** at each **grid injection point** over the next 10 years; and
(c) whether the power system is reasonably expected to meet the **N-1 criterion**, including in particular whether the power system would be in a **secure state** at each **grid exit point**, at all times over the next 10 years; and
(d) proposals for addressing any matters identified in accordance with paragraph (c).

(2) **Transpower** must **publish** a **grid reliability report** no later than 2 years after the date on which it **published** the previous **grid reliability report**, or such other date as determined by the **Authority** (having consulted with **Transpower**).

(3) If there is a material change in the forecast **demand** at a **grid exit point** or in the forecast **supply** at a **grid injection point** in the period to which the most recent **grid reliability report** relates, **Transpower** must **publish** a revised **grid reliability report** as soon as reasonably practicable after the material change.

Compare: Electricity Governance Rules 2003 rule 12A section III part F
Clause 12.76(2): amended, on 21 September 2012, by clause 17 of the Electricity Industry Participation (Minor Amendments) Code Amendment 2012.
Clause 12.76(1): amended, on 5 October 2017, by clause 303 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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 **publish** of the date by which submissions are to be received by the **Authority**. The date must be no earlier than 15 **business days** from the date of **publication** of the issues paper.

(2) Each submission on the issues paper must be made in writing to the **Authority** and received on or before the **submission expiry date**. In addition to receiving written submissions, the **Authority** may elect to hear one or more oral submissions.

(3) Within 20 **business days** of the **submission expiry date** (or such longer period as the **Authority** may allow), the **Authority** must complete its consideration of all submissions it receives on the issues paper.

Compare: Electricity Governance Rules 2003 rule 5 section IV part F
Clause 12.82(1): amended, on 5 October 2017, by clause 304 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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 Transmission pricing methodology

The **transmission pricing methodology** that applies at the commencement of this Code is the **transmission pricing methodology** in Schedule 12.4.

Clause 12.83(b): amended, on 1 June 2011, by clause 8(2) of the Electricity Industry Participation (Transmission Pricing) Code Amendment 2011.
Clause 12.84 heading: amended, on 20 December 2021, by clause 49 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2019.

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 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
Clause 12.86 heading: amended, on 20 December 2021, by clause 50 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2019.

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 **publish** the date by which submissions are to be received by the **Authority**. The date must be no earlier than 15 **business days** from the date of **publication** of the proposed **transmission pricing methodology**.

(3) Each submission on the proposed **transmission pricing methodology** must be made in writing to the **Authority** and received on or before the **submission expiry date**. In addition to receiving written submissions, the **Authority** may elect to hear 1 or more oral submissions.

Compare: Electricity Governance Rules 2003 rules 8.2 and 8.3 section IV part F
Clause 12.92(2): amended, on 5 October 2017, by clause 305 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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

Amending the transmission pricing methodology

Cross Heading: inserted, on 25 July 2022, by clause 4 of the Electricity Industry Participation Code Amendment (Transmission Pricing Methodology Related Amendments) 2022.

12.94A Amending the transmission pricing methodology

Despite anything else in this Code, the **Authority** may amend the **transmission pricing methodology** under section 38 of the **Act** if—

(a) the **Authority** is satisfied on reasonable grounds regarding any of the matters in section 39(3)(a), (b) or (c) of the **Act** (in which case sections 39(1)(b) and (c) of the **Act** will not apply to the amendment); or

(b) section 40 of the **Act** applies (in which case section 39(1) of the **Act** will not apply to the amendment).

Clause 12.94A: inserted, on 25 July 2022, by clause 4 of the Electricity Industry Participation Code Amendment (Transmission Pricing Methodology Related Amendments) 2022.

Application of approved transmission pricing methodology

12.95 Charges to comply with transmission pricing methodology

Transpower must charge for those transmission services affected only in accordance with the **transmission pricing methodology**.

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.
Clause 12.95: replaced, on 1 April 2023, by clause 5 of the Electricity Industry Participation Code Amendment (Transmission Pricing Methodology Related Amendments) (No 2) 2022.

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
Clause 12.96(a): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.
Clause 12.96(a): amended, on 5 October 2017, by clause 306 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

Audit of transmission prices

12.97 Audit of transmission prices

(1) The **Authority** may appoint an **auditor** to confirm whether **Transpower's** transmission prices have been calculated in accordance with the **transmission pricing methodology**.
(2) **Transpower** must ensure that the **auditor's** report includes the **auditor's** view on whether the application of the **transmission pricing methodology** by **Transpower** contains errors or inconsistencies that may have a material impact on the prices of any individual **designated transmission customers**, or **designated transmission customers** in general.
(3) **Transpower** must provide the **auditor** with all relevant information required by the **auditor** to complete its review.

Compare: Electricity Governance Rules 2003 rule 9.3 section IV part F
Clause 12.97(2): amended, on 1 February 2016, by clause 52 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

12.98 Transpower may respond to auditor's report

Transpower must ensure that the **auditor's** report includes any comments that **Transpower** provided to the **auditor** within 15 **business days** of **Transpower** receiving a draft of the report.

Compare: Electricity Governance Rules 2003 rule 9.4 section IV part F
Clause 12.98: substituted, on 1 February 2016, by clause 53 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

12.99 Final auditor report to the Authority

(1) **Transpower** must ensure that, within 10 **business days** after the **auditor** receives **Transpower's** response under clause 12.98, the **auditor** provides a report to the **Authority** certifying that either—
(a) **Transpower** had applied correctly the approved **transmission pricing methodology**; or
(b) material errors remained in **Transpower's** application of the **transmission pricing methodology**.
(2) Within 5 **business days** of receiving the report, the **Authority** must **publish** the **auditor's** report.

Compare: Electricity Governance Rules 2003 rules 9.5 and 9.6 section IV part F
Clause 12.99(1): amended, on 1 February 2016, by clause 54 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

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

Information for calculating transmission charges

Cross Heading: inserted, on 25 July 2022, by clause 5 of the Electricity Industry Participation Code Amendment (Transmission Pricing Methodology Related Amendments) 2022.

12.102A Information held by system operator may be used to calculate charges

(1) The **system operator** may provide to **Transpower** any information the **system operator** holds that the **system operator** or **Transpower** considers **Transpower** reasonably needs to calculate charges under the **transmission pricing methodology**.

(2) **Transpower** may use any information provided to it by the **system operator** under this clause to calculate charges under the **transmission pricing methodology**. **Transpower** must not use the information for any other purpose except—

- (a) as provided for in this Code; or
- (b) as required by law; or
- (c) if the information is or becomes publicly available; or
- (d) if the information is or has been provided to **Transpower** other than under this clause and without restriction as to **Transpower's** use of it for the other purpose; or
- (e) otherwise as may be agreed with the **participant** or other person who is the subject of the information.

Clause 12.102A: inserted, on 25 July 2022, by clause 5 of the Electricity Industry Participation Code Amendment (Transmission Pricing Methodology Related Amendments) 2022.

12.102B Information about embedded electricity

(1) In this clause, "AMDR", "capacity", "consuming plant", "difference cap", "embedded electricity", and "generating plant" have the meanings given to those terms in the **transmission pricing methodology**.

(2) This clause applies where the **Authority** or **Transpower** reasonably considers a **participant** owns generating plant with a total capacity of 10 **MW** or more directly or indirectly connected to the same **point of connection** in respect of which **Transpower** holds insufficient information to calculate embedded electricity under the **transmission pricing methodology**.

(3) If subclause (2) applies, the **Authority** or **Transpower** may request that the **participant** provide the information specified in subclause (5) to **Transpower** in a format reasonably requested by the **Authority** or **Transpower**.

(4) The **Authority** or **Transpower** (as applicable) must withdraw a request made under subclause (3) if the **participant** satisfies the **Authority** or **Transpower** (as applicable) within 10 **business days** (or such longer period as provided for by the **Authority** or **Transpower**) of the request that—

(a) the **participant** does not own the generating plant referred to in subclause (2); or

(b) the generating plant does not have a total capacity of 10 **MW** or more directly or indirectly connected to the same **point of connection**; or

(c) the total capacity of any consuming plant supplied or potentially supplied by the generating plant, without that **electricity** first flowing through a **point of connection**, is 1 **MW** or less.

(5) The information referred to in subclause (3) is any information about the **electricity** generated by the **participant's** generating plant referred to in subclause (2) (whether **metered** or estimated) for any **trading period** or **trading periods** specified by the **Authority** or **Transpower** from (and including) **trading period** 1 on 1 July 2014 to (and including) **trading period** 48 on the day immediately before the date of the request under subclause (3).

(6) **Transpower** may use any information provided to it by a **participant** under this clause to calculate charges under the **transmission pricing methodology**. **Transpower** must not use the information for any other purpose except—

(a) as provided for in this Code; or

(b) as required by law; or

(c) if the information is or becomes publicly available; or

(d) if the information is or has been provided to **Transpower** other than under this clause and without restriction as to **Transpower's** use of it for the other purpose; or

(e) otherwise as may be agreed with the **participant**.

(7) Subject to subclause (9), if—

(a) a **participant** does not provide to **Transpower** any or all of the information requested by the **Authority** or **Transpower** under subclause (5) within 20 **business days** (or such longer period as provided for by the **Authority** or **Transpower**) of the date of the request under subclause (3); or

(b) any or all of the information provided is not provided in the requested format or another format **Transpower** can reasonably use for calculating charges under the **transmission pricing methodology**; or

(c) **Transpower** reasonably considers any or all of the information provided is not sufficiently reliable for calculating charges under the **transmission pricing methodology**,

Transpower must use the values specified in subclause (8) to calculate charges under the **transmission pricing methodology** in place of the information that is not provided, is not in the requested format or another format **Transpower** can reasonably use, or is not sufficiently reliable.

(8) The values referred to in subclause (7) are, for calculating the relevant **designated transmission customer's** AMDR and difference cap under the **transmission pricing methodology**, a value or values of **electricity** generated by the generating plant calculated as if it were operating at its capacity.

(9) Subclause (7) is subject to any requirement on **Transpower** in this Code to use information from a specific source to calculate charges under the **transmission pricing methodology**.

Clause 12.102B: inserted, on 25 July 2022, by clause 5 of the Electricity Industry Participation Code Amendment (Transmission Pricing Methodology Related Amendments) 2022.

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) **Transpower** must provide the information and diagram referred to in subclause (1) to the **Authority** in the form specified by the **Authority**.

(3) The interconnection asset capacity and grid configuration referred to in subclause (1) must be provided within 3 months of the date on which the **Authority**, in accordance with subclause (2), sets the form in which the interconnection asset capacity and grid configuration must be provided.

(4) The information required under subclause (1) is—

(a) for each **interconnection circuit branch**, the following service measures and service levels:

(i) the overall continuous capacity rating of the **interconnection circuit branch**, for both summer and winter periods in MVA and amperes:

(ii) the level of impedance of the interconnection **circuit branch** both **resistive** and **reactive** and for **assets** arranged in both **shunt** and **series** in PU, using a base of 100 MVA, provided the impedance of the **interconnection circuit branch** is equal to or more than 0.0001 PU, using 100 MVA as the base:

(iii) the nominal high voltage rating of each interconnection **circuit branch** in kV:

(iv) the high voltage range that each **interconnection circuit branch** can be operated over in kV, specified as a maximum and a minimum; and

(b) for each **interconnection transformer branch**, the following information:

(i) the overall 24 hour post contingency capacity rating of the **interconnection**

transformer branch, for both the summer and winter period, in amperes and MVA as follows:

(A) for 2 Winding **interconnection transformer branches**, the overall 24 hour post contingency capacity rating:

(B) for 3 Winding **interconnection transformer branches**, the overall 24 hour post contingency capacity rating, at HV, MV, and LV:

(ii) the continuous capacity rating of the **interconnection transformer branch** in amperes and MVA as follows:

(A) for 2 Winding **interconnection transformer branches**, the continuous capacity rating:

(B) for 3 Winding **interconnection transformer branches**, the continuous capacity rating, at HV, MV, and LV:

(iii) the level of impedance of the **interconnection transformer branch**, both **resistive** and **reactive** and for **assets** arranged in both **shunt** and in **series** in PU, using a base of 100 MVA, as follows:

(A) for 2 Winding **interconnection transformer branches**, the level of impedance **of** the **interconnection transformer branch**:

(B) for 3 Winding **interconnection transformer branches**, the level of impedance of the **interconnection transformer branch**, at HV, MV, and LV:

(iv) the nominal high voltage rating of the interconnection **transformer branch** in kV:

(v) the high voltage range that the interconnection **transformer branch** can be operated over in kV, specified as a maximum, and a minimum:

(vi) in respect of the tapping steps and ranges of the **interconnection transformer branch**:

(A) the tap voltage range in volts, specified as a maximum and a minimum:

(B) the **number** of tapping steps:

(C) the size of each tapping step as a percentage of the operational voltage range:

(D) whether the tapping step is on-load or off-load:

(E) whether on-load tapping capacity is automatic or manual;

(F) if on-load tapping capacity is automatic, whether it is auto-selected:

(G) if on-load tapping capacity is manual, the tap step it is normally set to, which for the purposes of this clause is the actual or expected position at winter peak demand; and

(c) the transfer capacity in the North and South transfer for each **configuration** of the **HVDC link** expressed as follows:

(i) DC sent in **MW**:

(ii) AC received in **MW**; and

(d) for each **shunt asset**, the following service measures and service levels:

(i) the overall capacity rating, in MVAr, in terms of both absorption or provision:

(ii) the nominal voltage rating of the **shunt asset** in kV:

(iii) the maximum and minimum voltage range in kV that the **shunt asset** can operate over; and

(e) in addition to the information required under paragraph (d) in relation to **shunt assets**:

(i) whether each **shunt asset** is dynamic or static:

(ii) if the **shunt asset** is dynamic, whether it is an SVC or synchronous compensator:

(iii) any **shunt assets** that may directly affect the capacity of the **HVDC link** as set out in paragraph (c) and the likely magnitude of such effect; and

(f) the dates for the summer and winter periods or other such defined periods as may apply for the purposes of paragraphs (a) and (b).

(5) The information provided under subclause (4) must,—

(a) in the case of information provided under subclause (4)(a), (c) and (d), be consistent with the information disclosed by **Transpower** in the most recent **asset capability statement** provided by **Transpower** under clause 2(5) of **Technical Code** A of Schedule 8.3; and

(b) in the case of information provided under subclause (4)(b), be consistent with the **manufacturer's specification** for the component **assets** and the information disclosed by **Transpower** in the most recent **asset capability statement** provided under clause 2(5) of **Technical Code** A of Schedule 8.3, if this differs from the **manufacturer's specifications**;

(c) in the case of information provided under subclause (4)(a), be consistent with the thermal design rating of each **interconnection branch**; and

(d) cover every **interconnection asset**, either as part of an **interconnection circuit branch**, **interconnection transformer branch**, the **HVDC link** or as a **shunt asset**.

(6) After reviewing the interconnection asset capacity and grid configuration provided under subclause (1), the **Authority** may request **Transpower** to reconsider whether any of the interconnection asset capacity and grid configuration, is accurate, and require **Transpower** to resubmit the interconnection asset capacity and grid configuration to the **Authority** for reconsideration.

Compare: Electricity Governance Rules 2003 rules 2.1 to 2.6 section VI part F
Clause 12.107(2): replaced, on 5 October 2017, by clause 307(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 12.107(4): amended, on 5 October 2017, by clause 307(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 12.107(4)(c): amended, on 20 December 2021, by clause 51 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2019.Clause 12.107(5): amended, on 5 October 2017, by clause 307(3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

12.108 Consultation on proposed interconnection asset capacity and grid configuration

(1) If the **Authority** is provisionally satisfied that the interconnection asset capacity and grid configuration provided under clause 12.107(1) or resubmitted under clause 12.107(6) are correct, the **Authority** must **publish** the proposed interconnection asset capacity and grid configuration as soon as practicable for consultation with any person that the **Authority** thinks is likely to be materially affected by the incorporation

of the proposed interconnection asset capacity and grid configuration by reference in this Code.

(2) As well as the consultation required under subclause (1), the **Authority** may undertake any other consultation it considers necessary.

Compare: Electricity Governance Rules 2003 rules 2.7 and 2.8 section VI part F

12.109 Decision on interconnection asset capacity and grid configuration

(1) When the **Authority** has completed its consultation on the proposed interconnection asset capacity and grid configuration, it must consider whether to incorporate the proposed interconnection asset capacity and grid configuration by reference in this Code.

(2) If the **Authority** decides to incorporate the interconnection asset capacity and grid configuration by reference in this Code, the **Authority** must determine a date on which the incorporation by reference takes effect and comply with Schedule 1 of the **Act** in relation to it.

Compare: Electricity Governance Rules 2003 rule 2.9 section VI part F

12.110 Incorporation of interconnection asset capacity and grid configuration by reference

(1) The interconnection asset capacity and grid configuration is incorporated by reference in this Code in accordance with section 32 of the **Act**.

(2) Subclause (1) is subject to Schedule 1 of the **Act**, which includes a requirement that the **Authority** must give notice in the *Gazette* before an amended or substituted interconnection asset capacity and grid configuration becomes incorporated by reference in this Code.

Clause 12.110(1): amended, on 5 October 2017, by clause 308 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

12.111 Transpower to make interconnection branches and other assets available and keep grid configuration

(1) **Transpower** must make each **interconnection circuit branch**, **interconnection transformer branch**, the **HVDC link**, and each **shunt asset** identified in the interconnection asset capacity and grid configuration available for use by the **system operator** for the conveyance of **electricity—**

  (a) at least at the service levels specified in the interconnection asset capacity and grid configuration in accordance with clause 12.107(4); and

  (b) in accordance with **good electricity industry practice** and relevant health and safety standards.

(2) **Transpower** must keep the **grid** in the configuration set out in the interconnection asset capacity and grid configuration.

(3) **Transpower** is not required to comply with subclauses (1)(a) or (2) if clause 12.112(1) applies.

Compare: Electricity Governance Rules 2003 rule 3 section VI part F

12.112 Exceptions to clause 12.111

(1) **Transpower** is not required to comply with clause 12.111(1)(a) or (2) if—
  (a) permitted under the **Outage Protocol** made under subpart 7; or
  (b) an **interconnection asset** that forms part of an interconnection **branch** or the **HVDC link**, or a **shunt asset**—
    (i) is permanently removed from service, the **grid** is permanently reconfigured, or the transmission capacity of such an **asset** is reduced, and the decision to remove the **asset** from service or reconfigure the **grid** or reduce the transmission capacity of the **asset** takes into account the effect of the removal of the **asset**, reconfiguration of the **grid**, or the reduction in transmission capacity of the **asset**, on other materially affected parties, and is undertaken—
      (A) in order to maintain the health and safety of any person; or
      (B) in order to maintain the safety and integrity of equipment; or
      (C) in accordance with demonstrably prudent economic criteria; or
    (iaa) has been temporarily removed from service, or the **grid** has been temporarily reconfigured, in accordance with clause 12.116AA; or
    (ia) *[Expired]*
    (ii) has been permanently removed from service, or the **grid** has been permanently reconfigured, in accordance with clause 12.117; or
  (c) a modification to an **interconnection branch**, the **HVDC link**, a **shunt asset** or to the configuration of the **grid**, has been made as a result of an investment in the **grid**; or
  (d) a modification to an **interconnection branch**, the **HVDC link**, a **shunt asset** or to the configuration of the **grid** has been made as a result of an investment made under an **investment contract** entered into in accordance with clauses 12.70 and 12.71; or
  (e) the voltage range specified in the **AOPOs** for an **interconnection asset** that forms part of an **interconnection branch** is modified, or any **equivalence arrangement** is approved or **dispensation** is granted under clauses 8.29 to 8.31 in respect of the **asset**; or
  (ea) in relation to the **HVDC link**—
    (i) the **HVDC owner** is operating the **HVDC link** in accordance with—
      (A) a **commissioning** plan agreed with the **system operator** under clause 2(6) to (9) of **Technical Code** A of Schedule 8.3; or
      (B) a test plan provided to the **system operator** under clause 2(6) to (9) of **Technical Code** A of Schedule 8.3; and
    (ii) the **configuration** of the **HVDC link** is—
      (A) Pole 3 and Pole 2 bipole **round power**; or
    (B) Pole 3 and Pole 2 bipole not **round power**; or
  (f) **Transpower** and a **designated transmission customer** have agreed otherwise in accordance with clause 12.128.

(2) If subclause (1)(c) to (e) applies, or the **grid** is reconfigured under subclause (1)(b)(i) or (ii), **Transpower** must—

(a) make the **interconnection branch**, the **HVDC link** or the **shunt asset** available to the **system operator** at least at its modified capacity rating, and at its modified service levels; and
(b) keep the **grid** in its modified configuration.

(2AA) Subclause (2AB) applies—
(a) if subclause (1)(b)(iaa) applies; and
(b) while—
(i) an **interconnection asset** that forms part of an **interconnection branch** or the **HVDC link**, or a **shunt asset**, has been temporarily removed; or
(ii) the **grid** has been temporarily reconfigured.

(2AB) **Transpower** must make the **interconnection branch**, the **HVDC link** or the **shunt asset** available to the **system operator** at least at its modified capacity rating, and at its modified service levels.

(2A) *[Expired]*

(2B) *[Expired]*

(3) If a decision to remove an **asset**, or reconfigure the **grid**, or reduce the transmission capacity of an **asset** has been made under subclause (1)(b)(i) or (ii), **Transpower** must as soon as reasonably possible **publish** the analysis it undertook in accordance with subclause (1)(b)(i) or (ii), or a summary of that analysis.

Compare: Electricity Governance Rules 2003 rule 4 section VI part F
Clause 12.112(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(1)(ea)(i)(A): amended, on 5 October 2017, by clause 309(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
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(2): amended, on 5 October 2017, by clause 309(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
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.

Clause 12.112(3): amended, on 5 October 2017, by clause 309(3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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
Clause 12.113: amended, on 20 December 2021, by clause 52 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2019.

Transpower to propose investments

12.114 Investments to meet the grid reliability standards

(1) If a **grid reliability report** identifies, in accordance with clause 12.76(1)(c), that the power system is not reasonably expected to meet the **N-1 criterion** at a **grid exit point** at all times over the 5 years following the date on which the report is **published** and that this is due to an **interconnection asset**, **Transpower** must—
   (a) as soon as practicable, investigate whether the **interconnection asset** meets the **grid reliability standards**; and
   (b) if the **interconnection asset** does not **meet** the **grid reliability standards**, consider reasonably practicable options for ensuring that the **grid reliability standards** can be met in respect of that asset; and
   (c) if **Transpower** considers that 1 or more investments are required in respect of that **interconnection asset** in order to meet the **grid reliability standards**, submit an investment proposal to the Commerce Commission—
      (i) in sufficient time to avoid a breach of the **grid reliability standards**; or
      (ii) if the **grid reliability standards** have already been breached, within 6 months, or such longer period as the **Authority** may allow, after the publication of the **grid reliability report** that sets out the investment or investments that - **Transpower** proposes to make; and
   (d) if it considers that an investment is not necessary, **publish** the reasons for this and any alternative measures that **Transpower** proposes to undertake.

(2) If an investment proposal submitted under this clause is approved by the Commerce Commission under section 54R of the Commerce Act 1986 or permitted under an input methodology determined under section 54S of that Act, **Transpower** must undertake the investment—
   (a) before the **grid** falls below the **grid reliability standards** for the reason referred to in subclause (1); or
   (b) if the **grid** had already fallen below the **grid reliability standards**, or if it is not reasonably practicable to undertake the investment as provided in paragraph (a), as soon as reasonably practicable.

(3) **Transpower** does not need to submit an investment proposal under subclause (1)(c) if the investment to which the proposal relates has previously been included in an investment proposal submitted to, and considered—
   (a) before this Code came into force, by the Electricity Commission under section III of part F of the **rules**; or

(b) after this Code came into force, by the Commerce Commission under section 54R or section 54S of the Commerce Act 1986.

Compare: Electricity Governance Rules 2003 rule 6.1 section VI part F

12.115 Other investments

(1) **Transpower** must publish a **grid economic investment report** on whether there are investments that it considers, other than the investments identified under clause 12.114, could be made in respect of the **interconnection assets**.

(2) **Transpower** must publish a **grid economic investment report** no later than 2 years after the date on which it published the previous **grid economic investment report**, or such other date as determined by the **Authority**.

(3) If a **grid economic investment report** identifies that there are investments that could be made, **Transpower** must **publish** within 6 months a report setting out a proposed timetable for **Transpower** to consider whether to submit 1 or more investment proposals to the Commerce Commission in respect of those possible investments.

(4) The **grid economic investment report** does not need to report on possible investments that have been previously included in an investment proposal submitted to, and considered,—

(a) before this Code came into force, by the Electricity Commission under section III of part F of the **rules**; or

(b) after this Code came into force, by the Commerce Commission under section 54R or section 54S of Part 4 of the Commerce Act 1986.

Compare: Electricity Governance Rules 2003 rule 6.2 section VI part F

12.116 Information on capacities of individual interconnection assets

(1) **Transpower** must **publish** the following information in respect of each **interconnection asset**:

(a) for each transformer that is an **interconnection asset**, the overall 24 hour post contingency capacity rating of the **asset** in amperes and MVA, for both the summer and winter periods:

(b) for all other **interconnection assets**, the overall capacity rating of the **asset** in amperes and MVA and, if the **interconnection assets** are circuits, for both the summer and winter periods.

(2) The information required under subclause (1)—

(a) must be consistent with the **manufacturer's specification** for the **asset** or with the most recent **asset capability statement** provided by **Transpower** under clause 2(5) of **Technical Code** A of Schedule 8.3, if this differs from the **manufacturer's specification**; and

(b) must be in a form that allows the **branch** to which each **asset** belongs to be easily identified; and

(c) must be **published** in the form determined by the **Authority** as soon as reasonably practicable after the **Authority** has determined the form.

Compare: Electricity Governance Rules 2003 rule 7 section VI part F

Clause 12.116(1): amended, on 5 October 2017, by clause 310(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

Clause 12.116(2)(b): amended, on 5 October 2017, by clause 310(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

Clause 12.116(2)(c): substituted, on 1 February 2016, by clause 55 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

12.116AA Temporary removal of interconnection assets from service or temporary grid reconfiguration

(1) **Transpower** must temporarily remove 1 or more **interconnection assets** from service, or temporarily reconfigure the **grid** as permitted under clause 12.112(1)(b)(iaa), if—
  (a) the removal or reconfiguration is requested by the **system operator** in accordance with clause 9.13B; and
  (b) the removal or reconfiguration will result in a net benefit, as calculated under the test set out in clause 12.117.

(2) If **Transpower** temporarily removes **interconnection assets** from service or temporarily reconfigures the **grid** in response to a notice given under clause 9.13B, **Transpower** must, as soon as is reasonably practicable after the circumstances specified in that notice cease to exist—
  (a) restore the **interconnection assets** to service; or
  (b) restore the **grid** to its original configuration.

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.
Clause 12.116AA(1): amended, on 5 October 2017, by clause 311 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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 published

If **Transpower** receives a notice given in accordance with clause 9.13B, **Transpower** must **publish**,—
(a) as soon as practical, a copy of the notice; and
(b) by no later than 5 **business days** after receiving the notice, a summary of **Transpower's** application of the net benefit test that relates to the exceptional circumstances stated in the notice.

Clause 12.116AC Heading: amended, on 5 October 2017, by clause 312(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
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.
Clause 12.116AC: amended, on 5 October 2017, by clause 312(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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 or permanent grid reconfiguration

(1) **Transpower** may permanently remove **interconnection assets** from service or permanently reconfigure the **grid** as permitted under clause 12.112(1)(b) only if removal of the **asset** or reconfiguration of the **grid** results in a net benefit, as calculated under the test set out in subclause (2).

(2) When **Transpower** is required to apply a net benefit test, **Transpower** must—

(a) estimate the following costs:

(i) any additional fuel costs incurred by a **generator** in respect of any **generating units** that will be **dispatched** or are likely to be **dispatched** during or after the removal of the **interconnection asset** or the reconfiguration of the **grid**, arising as a result of the removal or reconfiguration:

(ii) any direct labour and material costs that will be incurred by **Transpower** and the **designated transmission customers** undertaking the removal of the **interconnection asset** or the reconfiguration of the **grid**:

(iii) any increase in the estimate of **expected unserved energy** in MWh multiplied by the value per MWh of that **expected unserved energy**, arising as a result of the removal of the **interconnection asset** or the reconfiguration of the **grid**:

(iv) any relevant cost specified in clause 12.43(1)(a)(iv):

(v) any other relevant cost to a person that produces, transmits, retails or consumes **electricity** in New Zealand; and

(b) estimate the following benefits:

(i) any reduction in maintenance costs arising as a result of the removal of the **interconnection asset** or the reconfiguration of the **grid** (including **Transpower's** and any **designated transmission customer's** costs):

(ii) any reduction in fuel costs incurred by a **generator** in respect of any **generating units**, arising or likely to arise during or after the removal of the **interconnection asset** or the reconfiguration of the **grid**, as a result of the removal or reconfiguration:

(iii) any decrease in the estimate of **expected unserved energy** in MWh multiplied by the value per MWh of that **expected unserved energy**, arising as a result of the removal of the **interconnection asset** or the reconfiguration of the **grid**:

(iv) any relevant benefit specified in clause 12.43(1)(b)(iv):

(v) any other relevant benefit to a person that produces, transmits, retails or consumes **electricity** in New Zealand; and

(c) deduct the costs estimated under paragraph (a) from the benefits estimated under paragraph (b) to determine the net benefit of the proposed removal of the **interconnection asset** or the reconfiguration of the **grid**.

(3) **Transpower** may apply the test under this clause at differing levels of rigour in different circumstances, which may include taking into account the number of **assets** to be removed or reconfigured, the value of the **assets** involved, and the size of the load served by the **assets**.

(4) **Transpower** is only required to—

(a) make a reasonable estimate of the costs and benefits identified in subclause (2), based on information reasonably available to it at the time it undertakes the test, and taking into account the proposed number of **assets** to be removed or reconfigured, the value of the **assets** involved, and the size of the load served by the **assets**; and

(b) take account of events that can be reasonably foreseen.

(5) **Transpower's** estimate of fuel costs under subclause (2) must—

(a) in relation to thermal **generating stations**, be a reasonable estimate of the fuel costs, based on the economic value of the fuel required for the relevant thermal **generating station**, and justified by **Transpower** with reference to opinions on the economic value of the fuel, provided by 1 or more independent and suitably qualified persons; and

(b) in relation to hydroelectric **generating stations**—

(i) be a reasonable estimate of the fuel costs, based on the economic value of the water stored at a hydroelectric **generating station**, provided by a suitably qualified person other than—

(A) **Transpower**; or

(B) an employee of **Transpower**; and

(ii) be **published**, as provided for in the **Outage Protocol**.

(6) The direct labour costs of **Transpower** and **designated transmission customers** under subclause (2)(a) may include any amounts paid to contractors, but must not include any apportionment of the overheads or office costs of **Transpower** or **designated transmission customers**.

(7) The material costs of **Transpower** and **designated transmission customers** under subclause (2)(a) are the costs of the materials used in carrying out the work during the removal of the **interconnection asset** or the reconfiguration of the **grid**.

(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** in clause 4 of Schedule 12.2 and

Transpower's estimate of the **expected unserved energy** in respect of each affected **designated transmission customer** and end use customer.

(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 Heading: amended, on 5 October 2017, by clause 313(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 12.117: substituted, on 16 December 2013, by clause 9 of the Electricity Industry Participation (Urgent Temporary Grid Reconfiguration) Code Amendment 2013.
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(1): amended, on 5 October 2017, by clause 313(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 12.117(9): amended, on 1 February 2016, by clause 56 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.
Clause 12.117(9): amended, on 1 November 2018, by clause 79 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

12.118 Transpower to provide and publish annual report on interconnection asset capacity and grid configuration

(1) **Transpower** must provide the **Authority** with and **publish** an annual report including—

(a) any matter required to be reported on for the purposes of this clause by the **Outage Protocol**; and

(b) the extent to which, in the preceding year ending 30 June, it has complied with the requirements of clause 12.111(1)(a) and (2); and

(c) any specific instances in which **Transpower** has not complied with clause 12.111(1)(a) and (2); and

(d) to the extent practicable, the circumstances that have given rise to any failure to comply with clause 12.111(1)(a) and (2); and

(e) to the extent practicable, any steps that it intends to take or other options to reduce the likelihood of failing to comply with clause 12.111(1)(a) and (2) in the future; and

(f) any modifications made to **interconnection circuit branches**, the **HVDC link**, and each **shunt asset** under clause 12.112(c) to (e) in the preceding year ending 30 June and the extent to which it has complied with clause 12.112(2) in respect of those modifications, including any specific instances in which **Transpower** has not complied; and

(g) any **interconnection assets** that have been removed from service, or any reconfigurations to the **grid** made, in accordance with clause 12.116AA or clause 12.117; and

(h) copies of any agreements made under clause 12.128 or, in respect of **interconnection assets** only, clause 12.151 in the preceding year ending 30 June; and

(i) an update of the interconnection asset capacity and grid configuration required under clause 12.107(1), as at the end of the preceding year ending 30 June.

(2) **Transpower** must provide to the **Authority** and **publish**, the report referred to in subclause (1) by 30 November each year.

(3) The **Authority** may incorporate by reference in this Code the updated interconnection asset capacity and grid configuration referred to in subclause (1)(i) in accordance with clause 12.110. The **Authority** may consult with any person the **Authority** considers is likely to be materially affected by the proposed amendments to the interconnection asset capacity and grid configuration, as it sees fit. **Transpower** must comply with the interconnection asset capacity and grid configuration incorporated by reference in this Code in accordance with clause 12.110.

Compare: Electricity Governance Rules 2003 rule 9 section VI part F
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.
Clause 12.118(1): amended, on 5 October 2017, by clause 314(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 12.118(2): amended, on 5 October 2017, by clause 314(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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 (1), **Transpower** must categorise **interconnection branches** and **shunt assets** into groups of **interconnection branches** and **shunt assets** comprising similar **assets**.

(3) The index measures to be provided under subclause (1) are—

(a) annual unavailability of each **interconnection branch**, **shunt asset** and the **HVDC link** due to **planned outages** of 1 minute or longer in hours per year ending 30 June, expressed as a percentage; and

(b) annual unavailability of each **interconnection branch**, **shunt asset** and the **HVDC link** due to **unplanned outages** of 1 minute or longer in hours per year ending 30 June, expressed as a percentage; and

(c) annual number of **planned interruptions** of 1 minute or longer caused by **planned outages** of 1 minute or longer of each **interconnection branch**, **shunt asset** and the **HVDC link**; and

(d) annual number of **unplanned interruptions** of 1 minute or longer caused by **unplanned outages** of 1 minute or longer of each **interconnection branch**, **shunt asset** and the **HVDC link**;

(e) total unserved energy per year ending 30 June in **MWh** resulting from **planned interruptions** of 1 minute or longer caused by **planned outages** of 1 minute or longer of each **interconnection branch**, **shunt asset** and the **HVDC link**; and

(f) total unserved energy per year ending 30 June in **MWh** resulting from **unplanned interruptions** of 1 minute or longer caused by **unplanned outages** of 1 minute or longer of each **interconnection branch**, **shunt asset** and the **HVDC link**.

(4) At the same time, **Transpower** must propose availability and reliability index measures for aggregated **interconnection branches** and **shunt assets**, such as by **asset** class or for all of the **grid**.

Compare: Electricity Governance Rules 2003 rule 10.1 section VI part F
Clause 12.121(2): amended, on 5 October 2017, by clause 315(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 12.121(3): amended, on 5 October 2017, by clause 315(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

12.122 Requirements for index measures

(1) The proposed availability and reliability index measures under clause 12.121(3) must be based on the average annual availability and reliability of each category of **interconnection branch**, or **shunt asset** and of the **HVDC link** over the 5 year period (ending 30 June) immediately before this clause came into force.

(2) The proposed index measures under clause 12.121(3) must be accompanied by an explanation showing how the requirements of subclause (1) were applied.

(3) The index measure for unserved energy under clause 12.121(3)(e) and (f) must be determined in accordance with the methodology for determining **expected unserved energy** 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
Clause 12.122(1): amended, on 5 October 2017, by clause 316 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

12.123 Authority may initially approve proposed index measures or refer back to Transpower

After considering **Transpower's** proposed availability and reliability index measures and accompanying reasons the **Authority** may either—

(a) provisionally approve the proposed availability and reliability index measures; or

(b) refer the proposed availability and reliability index measures and accompanying explanation back to **Transpower** if in the **Authority's** view—

  (i) the proposed availability and reliability index measures under clause 12.121 are not consistent with the requirements of clause 12.122(1) or the methodology referred to in clause 12.122(3); or

  (ii) the proposed availability and reliability index measures under clause 12.121 do not provide sufficient information to meet the reasonable needs of **grid** users; or

  (iii) the reasons provided with the availability and reliability targets in accordance with clause 12.122 are inadequate—

and **Transpower** must within 20 **business days** (or such longer period as the **Authority** may allow) consider the **Authority's** concerns and resubmit the proposed availability and reliability index measures and accompanying explanations for consideration by the **Authority**.

Compare: Electricity Governance Rules 2003 rule 10.3 section VI part F

12.124 Amendment of proposed index measures by the Authority

If the **Authority** considers that the availability and reliability index measures resubmitted by **Transpower** under clause 12.123(b) are not consistent with the requirements of clause 12.122(1) or the methodology referred to in clause 12.122(3), or do not provide relevant information to **grid** users, the **Authority** may make any amendments to the index measures it considers necessary.

Compare: Electricity Governance Rules 2003 rule 10.4 section VI part F

12.125 Authority must consult on proposed index measures

(1) The **Authority** must **publish** the proposed availability and reliability index measures, either as provisionally approved by the **Authority** or as amended by the **Authority**, as soon as is practicable, for consultation with any person that the **Authority** thinks is likely to be materially affected by the proposed index measures.

(2) As well as the consultation required under subclause (1), the **Authority** may undertake any other consultation it considers necessary.

Compare: Electricity Governance Rules 2003 rules 10.5 and 10.6 section VI part F

12.126 Decision on index measures

When the **Authority** has completed its consultation on the proposed availability and reliability measures it must consider whether to include the index measures as a schedule to this Part.

Compare: Electricity Governance Rules 2003 rule 10.7 section VI part F

12.127 Transpower to report on availability and reliability

(1) By 30 November in each year, **Transpower** must **publish** and provide to the **Authority** information on availability and reliability of **interconnection assets** including—

(a) annual unavailability of each **interconnection branch**, **shunt asset** and the **HVDC link** due to **planned outages** of 1 minute or longer in the preceding year ending 30 June in hours per year expressed as a percentage; and

(b) annual unavailability of each **interconnection branch**, **shunt asset** and the **HVDC link** due to **unplanned outages** of 1 minute or longer in the preceding year ending 30 June in hours per year, expressed as a percentage; and

(c) annual number of **planned interruptions** of 1 minute or longer caused by **planned outages** of one minute or longer of each **interconnection branch**, **shunt asset** and the **HVDC link** in the preceding year ending 30 June; and

(d) annual number of **unplanned interruptions** of 1 minute or longer caused by **unplanned outages** of 1 minute or longer of each **interconnection branch**, **shunt asset** and the **HVDC link** in the preceding year ending 30 June; and

(e) total unserved energy in the preceding year ending 30 June resulting from **planned interruptions** of 1 minute or longer caused by **planned outages** of 1 minute or longer of **interconnection branches**, **shunt assets** and the **HVDC link**; and

(f) total unserved energy in the preceding year ending 30 June resulting from **unplanned interruptions** of 1 minute or longer caused by **unplanned outages** of 1 minute or longer of **interconnection branches**, **shunt assets** and the **HVDC link**; and

(g) annual number of **outages** of each **interconnection branch**, **shunt asset** and the **HVDC link** that are shorter than 1 minute in the preceding year ending 30 June; and

(h) the annual number of **interruptions** shorter than 1 minute caused by **outages** that are shorter than 1 minute of each **interconnection branch**, **shunt asset** and the **HVDC link**, in the preceding year ending 30 June; and

(i) a comparison of the information required by paragraphs (a) to (f) against the availability and reliability index measures for **interconnection branches**, **shunt assets** and the **HVDC link** included in a schedule to this Part under clause 12.126;

(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
Clause 12.127(1): amended, on 5 October 2017, by clause 317 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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 must not exclude the application of subclause (3)(b) and must be conditional in all respects on—

(a) obtaining agreement from all other potentially affected **designated transmission customers** that this Part does not apply to the specified **interconnection circuit branches**, the **HVDC link**, **shunt assets** or **interconnection assets**, or the **designated transmission customer**; and

(b) **Transpower** and the **designated transmission customer** confirming in writing to the **Authority** that they have consulted with all potentially affected end use customers on this Part not applying to the specified **interconnection branches**, **circuit branches**, the **HVDC link**, **shunt assets** or **interconnection assets** or the **designated transmission customer**, and that there are no material unresolved issues affecting the interests of those end use customers.

(3) **Transpower** must—

(a) give written notice to the **Authority** as soon as practicable if **Transpower** enters into an agreement with a **designated transmission customer** under this clause; and

(b) **publish** the agreement no later than 20 **business days** after entering into the agreement.

Compare: Electricity Governance Rules 2003 rule 11 section VI part F
Clause 12.128(2): amended, on 5 October 2017, by clause 318(a) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 12.128(3): replaced, on 5 October 2017, by clause 318(b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

Subpart 7—Preparation of Outage Protocol

12.129 Purpose of this subpart

The purpose of this subpart is to provide for the making of an **Outage Protocol**, with input from **Transpower** and in consultation with other interested parties, that—

(a) specifies the circumstances in which **Transpower** may temporarily remove any **assets** forming part of the **grid** from service or reduce the capacity of assets to efficiently manage the operation of the **grid**; and

(b) specifies procedures and policies for **Transpower** to plan for **outages** and for carrying out such **outages** to—

(i) ensure **Transpower** involves **designated transmission customers** in making decisions on **planned outages** as much as possible; and
(ii) ensure coordination between **Transpower** and **designated transmission customers**; and
(iii) enable **Transpower** to efficiently manage the operation of the **grid**; and
(c) specifies procedures and policies for dealing with **unplanned outages** of the **grid**.

Compare: Electricity Governance Rules 2003 rule 1 section VII part F

12.130 Definition of outage

(1) An **outage** exists when **interconnection assets** or **connection assets** are temporarily not provided in accordance with—
(a) the requirements of a **transmission agreement**; or
(b) the requirements of subpart 6.
(2) Without limiting subclause (1), an **outage** includes any situation in which—
(a) **Transpower** removes **assets** from service temporarily; or
(b) **assets** are not able to be provided due to **grid emergencies**, in order to deal with health and safety issues, or due to circumstances beyond **Transpower's** reasonable control; or
(c) **Transpower** reduces the capacity of **branches** below the capacity required by a **transmission agreement** or clause 12.111; or
(d) **Transpower** changes the configuration of the **grid**; or
(e) **Transpower** is required by law to carry out an **outage**.

Compare: Electricity Governance Rules 2003 rule 2 section VII part F

12.131 Outage Protocol

(1) The **Outage Protocol** set out in schedule F7 of section VII of part F of the **rules** immediately before this Code came into force, continues in force and is deemed to be the **Outage Protocol** that applies at the commencement of this Code, with the following amendments:
(a) every reference to the Board must be read as a reference to the **Authority**:
(b) every reference to the **rules** must be read as a reference to the Code:
(c) every reference to a provision of the **rules** must be read as a reference to the corresponding provision of the Code:
(d) the reference in clause 3.1.2(d), clause 3.3.5(c), and clause 3.3.8(a) to a reliability investment or an economic investment approved by the Board must be read as a reference to an **approved investment**:
(e) the reference in clause 10.2.1(a) and (b) to the **benchmark agreement** in schedule F2 must be read as a reference to the **benchmark agreement** incorporated by reference into this Code under clause 12.34:
(f) the reference in clauses A1.1(a)(ii), A7.2(a)(ii), and A7.2(b)(i) to the value of unserved energy in clause 8.3.4 of schedule F4 of section III must be read as a reference to the **value of expected unserved energy** in clause 4 of Schedule 12.2:

(g) the reference in clauses A6.1(f) and A6.2(e) to the matters specified in clauses 27.1 to 27.9 of schedule F4 of section III must be read as the matters specified in clause 12.43(1)(a)(iv) and (b)(iv):

(h) the reference in clause A8.1(a)(i) to fuel costs specified in the statement of opportunities must be read as a reference to fuel costs calculated in accordance with clause 12.141(3)(a)(i).

(2) The **Authority** must as soon as practicable after this Code comes into force, publish a version of the **Outage Protocol** in which the provisions of this Code that correspond to the provisions of the **rules** referred to in the **Outage Protocol** are shown.

(3) Clause 12.150 applies to the **Outage Protocol**.

Review of Outage Protocol

12.132 Review of Outage Protocol

The **Authority** may review the **Outage Protocol** at any time, in accordance with the requirements of clauses 12.133 and 12.145 to 12.149.

Compare: Electricity Governance Rules 2003 rule 14 section VII part F

12.133 Transpower to submit proposed Outage Protocol

(1) **Transpower** must submit a proposed **Outage Protocol** to the **Authority** within 3 months (or such longer period as the **Authority** may allow) of receipt of a written request from the **Authority**. The **Authority** may issue such a request at any time.

(2) The proposed **Outage Protocol** must give effect to or promote the principles set out in clause 12.134 and provide for the matters set out in clauses 12.135 to 12.144.

(3) With its proposed **Outage Protocol**, **Transpower** must submit to the **Authority** an explanation of the proposed **Outage Protocol** and a **statement of proposal** for the proposed **Outage Protocol**.

Compare: Electricity Governance Rules 2003 rule 8 section VII part F

Principles and required content of Outage Protocol

12.134 Principles for developing Outage Protocol

The **Outage Protocol** must give effect to the following principles:

(a) the matters in clause 12.129;

(b) the need for a fair and reasonable balance of interests between the **grid owner** and **designated transmission customers**:

(c) the need to ensure that the **grid owner** can meet all obligations placed on it by the **system operator** for the purpose of meeting common security and power quality requirements under Part 8 of this Code;

(d) the need to ensure that the safety of all personnel is maintained:

(e) the need to ensure that the safety and integrity of equipment is maintained:

(f) the desirability of the **Outage Protocol** and Part 8 operating in an integrated and consistent manner, if possible.

Compare: Electricity Governance Rules 2003 rule 3 section VII part F

12.135 Required content of Outage Protocol

(1) The **Outage Protocol** must—
   (a) require **Transpower** to plan for **outages**, other than **outages** that are not reasonably foreseeable, in accordance with clause 12.136; and
   (b) require **Transpower** and **designated transmission customers** to act reasonably and in good faith in planning for **outages**, in accordance with clause 12.137; and
   (c) set out the situations and times at which **Transpower** must reconsider the timing of proposed **planned outages**, as specified in clause 12.138; and
   (d) permit **Transpower** to vary a proposed **planned outage**, as specified in clause 12.139;
   (e) set out the requirements for **Transpower** to consider when planning for **outages**, in order to give effect to the net benefit principle, as specified in clause 12.140; and
   (f) permit **Transpower** to undertake **outages** in order to give effect to an **approved investment**, and to undertake **outages** that are required by the Electricity Act 1992, as specified in clause 12.142; and
   (g) permit **Transpower** to undertake **outages**, or take such other steps, as the **system operator** may reasonably require.

(2) The **Outage Protocol** must require **Transpower** to set out the procedures and policies for dealing with **unplanned outages**, as specified in clause 12.143.

(3) The **Outage Protocol** must require **Transpower** to report on compliance with the **Outage Protocol**, in accordance with clause 12.144.

(4) The **Outage Protocol** must set out—
   (a) processes for **Transpower** to consult with **designated transmission customers** and to determine an **outage plan** setting out **planned outages** for each year ending 30 June, and processes for the **outage plan** to be updated; and
   (b) requirements on **Transpower** to keep **designated transmission customers** informed about **planned outages**, including minimum notice periods for **Transpower** to advise affected **designated transmission customers** of **planned outages** not set out in the **outage plan**; and
   (c) procedures for **outage** co-ordination by **Transpower** and between **Transpower** and **designated transmission customers**; and
   (d) requirements on **Transpower** to provide information to **designated transmission customers** about **unplanned outages**.

(5) The **Outage Protocol** is not limited to the matters referred to in this clause, and may provide for any other matters related to **outages**.

Compare: Electricity Governance Rules 2003 rule 4 section VII part F
Clause 12.135(4)(a): amended, on 5 October 2017, by clause 319 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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 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 subsubparagraph (A), the **value of expected unserved energy** in clause 4 of Schedule 12.2 and **Transpower's** estimate of the

expected unserved energy in respect of each affected **designated transmission customer** and end use customer; and

(ii) in the case of **interconnection assets**, be based on—

(A) the **value of expected unserved energy** in clause 4 of Schedule 12.2; and

(B) **Transpower's** estimate of the **expected unserved energy** in respect of each affected **designated transmission customer** and end use customer.

(4) In addition to the requirements in subclause (3), the **Outage Protocol** must require **Transpower**, in planning for **outages**, to consider any reasonably expected operating conditions, forecasts in the **system security forecast**, likely fuel costs, and any other reasonable assumptions.

(5) The **Outage Protocol** must include a methodology for determining **expected unserved energy** for the purposes of subclause (2)(a) to (c) that complies with subclauses (3)(d) and (4).

(6) The **Outage Protocol** may permit **Transpower** to—

(a) make only a reasonable estimate of the matters specified in subclauses (2) to (4) based on information reasonably available to it at the time **Transpower** considers whether to carry out a **planned outage**, and taking into account the number of **assets** to which the proposed **outage** applies, the value of the **assets** involved, the size of the load served by the **assets**, the proposed duration of the **outage**; and

(b) apply differing levels of rigour in different circumstances, which may include taking into account the number of **assets** to which a proposed **outage** applies, the value of the **assets** involved, the size of the load served by the **assets**, the proposed duration of the **outage**, and any other relevant matters.

Compare: Electricity Governance Rules 2003 rule 5.6 section VII part F

Clause 12.141 heading: amended, on 20 December 2021, by clause 53 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2019.

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.

Clause 12.141(3)(d)(i)(B): amended, on 1 February 2016, by clause 57(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

Clause 12.141(3)(d)(i)(B): amended, on 1 November 2018, by clause 80 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

Clause 12.141(3)(d)(ii)(A): amended, on 1 February 2016, by clause 57(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

Clause 12.141(3)(d)(ii)(B): amended, on 1 November 2018, by clause 80 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2018.

12.142 Planned outages required in order to give effect to an investment or required by the Act

(1) The **Outage Protocol** must set out requirements for **Transpower** to consider when determining the timing of **planned outages** that are required in order to give effect to an **approved investment** or that are required by the Electricity Act 1992.

(2) The requirements specified under subclause (1) must require **Transpower** to give effect to the net benefit principle in clause 12.140(2) in determining the timing and duration of **outages** subject to this clause, and may require **Transpower** to consider some or all of the costs and benefits specified in clause 12.141.

Compare: Electricity Governance Rules 2003 rule 5.7 section VII part F

12.143 Required content of Outage Protocol in relation to unplanned outages

(1) The **Outage Protocol** must—
  (a) set out procedures and policies for dealing with **unplanned outages**, so as to minimise the costs and, if relevant, maximise the benefits arising from an **unplanned outage**; and
  (b) set out the reasonable steps and measures that **Transpower** must take in order to be prepared for **unplanned outages**, so as to ensure that it is readily able to deal with **unplanned outages** in a way that minimises the costs and, if relevant, maximises the benefits arising from an **unplanned outage**; and
  (c) require **Transpower** to deal with **unplanned outages** as quickly as reasonably possible, in accordance with the procedures specified in the **Outage Protocol**.

(2) The costs and benefits under subclause (1) are the costs and benefits of the **outage** to persons who produce, transmit, distribute, retail, or consume **electricity**.

Compare: Electricity Governance Rules 2003 rule 6 section VII part F

12.144 Reporting on compliance with Outage Protocol

The **Outage Protocol** must require **Transpower** to publish and report to **designated transmission customers** and the **Authority**, whether in the report provided under clause 12.118 or otherwise, on its compliance with the requirements of the **Outage Protocol**, including the requirements specified in clause 12.140(1) for giving effect to the net benefit principle specified in clause 12.140(2) and the requirements of the **Outage Protocol** relating to **unplanned outages** specified in clause 12.143.

Compare: Electricity Governance Rules 2003 rule 7 section VII part F

Decisions on Outage Protocol

12.145 Authority may initially approve the proposed Outage Protocol or refer back to Transpower

After consideration of **Transpower's** proposed **Outage Protocol** and accompanying explanation and **statement of proposal**, the **Authority** may—
  (a) provisionally approve the proposed **Outage Protocol** having regard to the principles in clause 12.134 and the matters set out in clauses 12.135 to 12.144; or
  (b) refer the proposed **Outage Protocol** and accompanying explanation and regulatory statement back to **Transpower**, if in the **Authority's** view—
    (i) the proposed **Outage Protocol** does not adequately give effect to or promote the principles in clause 12.134; or
    (ii) the proposed **Outage Protocol** does not adequately provide for the matters set out in clauses 12.135 to 12.144; or
    (iii) the explanation or **statement of proposal** provided with the **Outage Protocol** in accordance with clause 12.133(3) is not adequate—

and **Transpower** must, within 20 **business days** (or such longer period as the **Authority** may allow), consider the **Authority's** concerns and resubmit its proposed

Outage Protocol and accompanying explanation and **statement of proposal** for reconsideration by the **Authority**.

Compare: Electricity Governance Rules 2003 rule 9 section VII part F

12.146 Reconsideration of revised Outage Protocol by the Authority

After reconsideration of **Transpower's** proposed **Outage Protocol**, and accompanying explanation and **statement of proposal**, as revised under clause 12.145(b), the **Authority** may either—

(a) provisionally approve the proposed **Outage Protocol**, as revised, having regard to the principles in clause 12.134 and the matters set out in clauses 12.135 to 12.144; or

(b) if the **Authority** considers that the **Outage Protocol** resubmitted by **Transpower** under clause 12.145(b) does not adequately give effect to or promote the principles in clause 12.134, or adequately provide for the matters set out in clauses 12.135 to 12.144, the **Authority** may make any amendments to the proposed **Outage Protocol**, as revised, that it considers necessary.

Compare: Electricity Governance Rules 2003 rule 10 section VII part F

12.147 Authority must consult on the proposed Outage Protocol

The **Authority** must **publish** the proposed **Outage Protocol**, either as provisionally approved by the **Authority** or as amended by the **Authority**, as soon as is practicable, for consultation with any person that the **Authority** thinks is likely to be materially affected by the proposed **Outage Protocol**.

Compare: Electricity Governance Rules 2003 rule 11 section VII part F

12.148 Authority may undertake additional consultation

As well as the consultation required under clause 12.147, the **Authority** may undertake any other consultation it considers necessary.

Compare: Electricity Governance Rules 2003 rule 12 section VII part F

12.149 Decision on Outage Protocol

(1) When the **Authority** has completed its consultation on the proposed **Outage Protocol**, it must consider whether to incorporate the proposed **Outage Protocol** by reference as the **Outage Protocol**.

(2) If the **Authority** decides to incorporate the **Outage Protocol** by reference in this Code, the Authority must determine a date on which the incorporation by reference takes effect and comply with Schedule 1 of the Act in relation to it.

Compare: Electricity Governance Rules 2003 rule 13 section VII part F

12.150 Incorporation of Outage Protocol by reference

(1) The **Outage Protocol** is incorporated by reference in this Code in accordance with section 32 of the **Act**.

(2) Subclause (1) is subject to Schedule 1 of the **Act**, which includes a requirement that the **Authority** must give notice in the *Gazette* before an amendment or substituted **Outage Protocol** becomes incorporated by reference in this Code.

Clause 12.150(1): amended, on 5 October 2017, by clause 320(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 12.150(2): amended, on 5 October 2017, by clause 320(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

Complying with Outage Protocol

12.151 Compliance with Outage Protocol

(1) **Transpower** and each **designated transmission customer** must comply with the **Outage Protocol**, unless agreed otherwise by **Transpower** and a **designated transmission customer** in respect of specified **assets** or the **designated transmission customer** in accordance with subclause (2).

(2) An agreement between **Transpower** and a **designated transmission customer** to which the **Outage Protocol** does not apply in respect of specified **assets** must not exclude the application of subclause (3)(b) and must be conditional in all respects on—
  (a) obtaining agreement from all other potentially affected **designated transmission customers** that the **Outage Protocol** does not apply in respect of the specified **assets** or the **designated transmission customer**; and
  (b) **Transpower** and the **designated transmission customer** satisfying the **Authority** that they have consulted with all potentially affected end use customers on the **Outage Protocol** not applying in respect of the specified **assets** or the **designated transmission customer** and that there are no material unresolved issues affecting the interests of those end use customers.

(3) **Transpower** must—
  (a) give written notice to the **Authority** as soon as practicable if **Transpower** enters into an agreement with a **designated transmission customer** under this clause; and
  (b) **publish** the agreement no later than 20 **business days** after entering into the agreement.

Compare: Electricity Governance Rules 2003 rule 15 section VII part F
Clause 12.151(2): amended, on 5 October 2017, by clause 321(a) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.
Clause 12.151(3): replaced, on 5 October 2017, by clause 321(b) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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) **connected asset owners**; and

(b) *[Revoked]*

(c) **generators** that are directly connected to the **grid**.

(2) *[Revoked]*

(3) *[Revoked]*

(4) *[Revoked]*

(5) *[Revoked]*

Compare: Electricity Governance Rules 2003 schedule F1 part F

Schedule 12.1, clause 1(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(1)(a): amended, on 1 February 2016, by clause 58(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

Schedule 12.1, clause 1(1)(b): revoked, on 1 February 2016, by clause 58(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

Schedule 12.1, clause 1(1)(c): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Schedule 12.1, clause 1(1)(c): amended, on 5 October 2017, by clause 322 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

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 any **expected unserved energy** is—

(a) $20,000 per **MWh**; or

(b) such other value as the **Authority** may determine.

(2) The **Authority** may determine different **values of expected unserved energy** under this clause for different purposes and for different times.

(3) If the **Authority** determines a **value of expected unserved energy** under this clause, the **Authority** must **publish** its determination.

Schedule 12.2, clause 4(1): amended, on 1 February 2016, by clause 59(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.
Schedule 12.2, clause 4(2): amended, on 1 February 2016, by clause 59(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.
Schedule 12.2, clause 4(3): amended, on 1 February 2016, by clause 59(3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2015.

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	
220/110kV interconnection Tarukenga	

North Island core grid links	South Island core grid links
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

cl 12.93

Schedule 12.4
Transmission Pricing Methodology

Schedule 12.4: replaced, on 20 December 2022, by clause 4 of the Electricity Industry Participation Code Amendment (Transmission Pricing Methodology) 2022.

Part A Preliminary

Introduction

1. Purpose

The **transmission pricing methodology** is used to recover the cost of **transmission services** provided by **Transpower**, other than costs recovered under **investment agreements**, but not more than **recoverable revenue** for each **pricing year**. This **transmission pricing methodology** allocates that cost to **customers** through **transmission charges**.

2. Overview of Transmission Charges

The **transmission charges** are—

(a) **connection charges**, which recover part of **recoverable revenue** by reference to the cost of **connection investments**. 0 specifies how **connection charges** are calculated; and
(b) **benefit-based charges**, which recover part of **recoverable revenue** by reference to the **covered cost** of **benefit-based investments**. 0 specifies how **benefit-based charges** are calculated; and
(c) **cap recovery charges**, which are a redistribution of **transmission charges** that would otherwise be payable by **capped customers** who are receiving **cap reductions**; and
(d) **prudent discount recovery charges**, which are a redistribution of **transmission charges** that would otherwise be payable by **prudent discount recipients**; and
(e) **residual charges**, which recover the remainder of **recoverable revenue**. 0 specifies how **residual charges** are calculated.

Interpretation

3 General Definitions

In this **transmission pricing methodology**, unless the context otherwise requires—

2020 guidelines means the guidelines the **Authority** published under paragraph 12.83(b) of this Code on 10 June 2020

AC assets means **grid assets** other than **HVDC assets**

AC switch means a switch that is an **AC asset**

accelerated depreciation means **depreciation** or tax depreciation (as the context requires) of an asset exclusively due to damage to, or destruction, stranding, decommissioning or disposal of, the asset

adjustment event means a **connection charge adjustment event**, **benefit-based charge adjustment event** or **residual charge adjustment event**

alleviated price means, for a **regional customer group**, **factual** and **counterfactual**, a price at a **market node** in the **regional customer group's modelled region** that, due to a **modelled constraint** is—

(a) higher in the **counterfactual** than the **factual**; or
(b) higher in the **counterfactual** than a price at another **market node** in the **counterfactual** that is in a **modelled region** for a different **regional customer group** of the same type (**regional demand group** or **regional supply group**)

allocation data means any data about **supply**, **demand**, **injection**, **offtake** or **gross energy** that affects a **customer's** allocation of **transmission charges**

allowance means, for a cost or charge over a period, the forecast MAR building block under the **Transpower IPP** over the period for the cost or charge

alternative project means—

(a) for an **inefficient bypass prudent discount**, an investment by the **customer** in a **transmission alternative** that, if implemented, would bypass existing **grid assets**; or

(b) for a **stand-alone cost prudent discount**, an investment in the **grid** or 1 or more **transmission alternatives** by an efficient **transmission services** provider that, if implemented, would provide **transmission services** in substitution for all **transmission services** the **customer** currently receives

alternative project costs has the meaning in clause 117

ancillary service BBI means a **post-2019 BBI** that is expected to have a material impact on prices or quantities in the **wholesale market** for a **specified ancillary service** relative to the **post-2019 BBI's counterfactual**. An **ancillary service BBI** may also be a **market BBI** or **reliability BBI**, but cannot be a **resiliency BBI**

ancillary service regional customer group means a **regional customer group** defined in subclause 53(3)

ancillary service regional NPB means **regional NPB** arising from changes in prices or quantities in the **wholesale market** for a **specified ancillary service**. **Ancillary service regional NPB** may be calculated for **ancillary service BBIs**

annual benefit-based charge has the meaning in subclause 35(2)

annual cap recovery charge has the meaning in subclause 112(1)

annual charges means the following **transmission charges** for a **customer** and **pricing year**:
(a) **annual connection charges**:
(b) **annual benefit-based charges**:
(c) **annual cap recovery charge**:
(d) **annual prudent discount recovery charge**:
(e) **annual residual charge**

annual connection charge has the meaning in subclause 24(2) or 24(3)

annual prudent discount recovery charge has the meaning in subclause 138(5)

annual residual charge has the meaning in subclause 68(2)

anticipatory BBI has the meaning in subclause 27(2)

anticipatory connection asset has the meaning given in subclause 26(3)

anytime maximum demand (connection) or **AMDC** means, for a **customer**, **connection location** and **pricing year**, the average of the 12 highest **offtake** quantities for the **customer** at the **connection location** during **CMP A** for the **pricing year**, multiplied by 2 to convert to average **demand**

anytime maximum demand (residual) or **AMDR** means the amount calculated under clause 69 for a **load customer** and **pricing year**

anytime maximum injection (connection) or **AMIC** means, for a **customer**, **connection location** and **pricing year**, the average of the 12 highest **injection** quantities for the **customer** at the **connection location** during **CMP A** for the **pricing year**, multiplied by 2 to convert to average **supply**

Appendix A allocation means, for an **Appendix A customer** and **Appendix A BBI** and subject to clause 10(8), the **Appendix A customer's BBI customer allocation** for the **Appendix A BBI** specified in Appendix A to 2 decimal places

Appendix A BBI means the following **interconnection investments**:

Bunnythorpe Haywards	the **interconnection investment** approved by the **Commission** on 9 May 2014 as the Bunnythorpe-Haywards A and B Lines Conductor Replacement Project, including all amendments to that approved project subsequently approved by the **Commission**
HVDC	all **interconnection investments** in the **HVDC link commissioned** on or before 23 July 2019
LSI Reliability	the **interconnection investment** approved by the Electricity Commission on 6 September 2010 as the Lower South Island Reliability Transmission Investment, including all amendments to that approved project subsequently approved by the Electricity Commission or **Commission**
LSI Renewables	the **interconnection investment** approved by the Electricity Commission on 9 August 2010 as the Lower South Island Renewables Investment, including all amendments to that approved project subsequently approved by the Electricity Commission or **Commission**, but excluding the **post-2019 CUWLP investment**
NIGU	the **interconnection investment** approved by the Electricity Commission on 5 July 2007 as the North Island Grid Upgrade, including all amendments to that approved project subsequently approved by the Electricity Commission or **Commission**
UNIDRS	the **interconnection investment** approved by the Electricity Commission on 5 July 2010 as the Upper North Island Dynamic Reactive Support Investment, including all amendments to that approved project subsequently approved by the Electricity Commission or **Commission**
Wairakei Ring	the **interconnection investment** approved by the Electricity Commission on 20 February 2009 as the Wairakei Ring Investment, including all amendments to that approved project subsequently approved by the Electricity Commission or **Commission**

Appendix A beneficiary means, for an **Appendix A BBI**, an **Appendix A customer** who has a positive **Appendix A allocation** for the **Appendix A BBI**

Appendix A customer means a person specified in Appendix A, even if not a current **customer** at the time this definition is applied

application means an application to **Transpower** under this **transmission pricing methodology**, including an application for a **prudent discount** or **reassignment**

application fee means a fee for a type of **application published** by **Transpower**, if any

application requirements means, for an **application**, the content requirements for the **application published** by **Transpower**

assumptions book means a document **published** by **Transpower** containing assumptions and detailed methodologies that **Transpower**—
(a) intends to apply for allocating and adjusting **benefit-based charges**; and
(b) does not expect to vary between **BBIs** except according to the method (**standard method**, **simple method** or Appendix A) used to calculate their **BBI customer allocations**

avoided transmission charges means—
(a) for an **inefficient bypass prudent discount**, the **transmission charges** the relevant **customer** would avoid paying if the relevant **alternative project** were implemented—
  (i) assessed relative to the **transmission charges** the **customer** would pay if the **alternative project** were not implemented; and
  (ii) assuming none of the **alternative project costs** for the **alternative project** would be recovered through **transmission charges**; and
(b) for a **stand-alone cost prudent discount**, the relevant **customer's connection charges**, **benefit–based charges** and **residual charge**

back-dated prudent discount means a **prudent discount** for which the **application**—
(a) is received by **Transpower** within 6 months of the date on which **Transpower** first publishes the **application requirements** and the **application fee**, if any, for the relevant type of **prudent discount** (**inefficient bypass prudent discount** or **stand-alone cost prudent discount**); and
(b) is not rejected by **Transpower** under subclause 14(1), 115(1) or 115(2)

battery storage means equipment functioning together as a single entity that is able to both—
(a) take **electricity** and store the energy in another form; and
(b) inject that energy as **electricity** into the **grid**, a **local network**, a **non-grid network** or **consuming plant**

BBI customer allocation means a **customer's** allocation of the **benefit-based charge** for a **BBI**—
(a) specified in or calculated under this **transmission pricing methodology**; and
(b) as adjusted under this **transmission pricing methodology**

BBI prudent discount recovery charge means a charge calculated under subclause 138(1) for a **prudent discount**, **customer** and **pricing year**

BBI reassignment factor has the meaning in subclause 102(4)

beneficiary means, for a **BBI**, a **customer** who has a positive **BBI customer allocation** for the **BBI**

benefit factor has the meaning in subclause 83(7)

benefit-based charge means a charge described in subclause 2(b) and calculated under clause 35 for a **BBI**, **beneficiary** and **pricing year**

benefit-based charge adjustment event has the meaning in subclause 81(1)

benefit-based investment or **BBI** means**—**
(a) an **Appendix A BBI**; or
(b) a **post-2019 BBI**

benefitting customer means, for an **application** for an **inefficient bypass prudent discount**, any **customer** named in the **application** whose **transmission charges** would be reduced if the **alternative project** for the **application** were implemented

cap condition means the condition specified in subclause 110(2)

cap recovery charge means a charge described in subclause 2(c) and calculated under clause 112 for a **customer** and **pricing year**

cap recovery-relevant charges means, for a **customer** and **pricing year**, the **customer's—**
(a) **annual benefit-based charges** for the **Appendix A BBIs** and **pricing year**; and
(b) **annual residual charge** for the **pricing year**,
net of any **prudent discount** of those **transmission charges** for the **customer** and **pricing year**

cap reduction means the total reduction in a **capped customer's transmission charges** for a **pricing year** under subclause 110(1)

capacity means the rated capacity of an asset to (as the case may be)—
(a) consume or generate **electricity**; or
(b) take **electricity** from or inject **electricity** into a **network**; or
(c) transmit or **distribute electricity**,
in each case measured in units appropriate for the context

capacity measurement period or **CMP** means a period over which a calculation under this **transmission pricing methodology** is made, being either:

CMP A for **pricing year** n, **capacity year** n-2. **CMP A** is relevant to calculating **connection charges**

CMP B for a **BBI**, the period ending on the last **trading period** of the most recent complete **capacity year** before the **final investment decision date** for the **BBI** (**capacity year** n) and starting on the first **trading period** of **capacity year** n-4. **CMP B** is relevant to calculating **benefit-based charges** for **BBIs** under a **standard method**

CMP C for the first **simple method period**, the period ending on the last **trading period** of the second most recent complete **capacity year** before the **first pricing year** (**capacity year** n) and starting on the first **trading period** of **capacity year** n-4

for a subsequent **simple method period**, the period ending on the last **trading period** of the second most recent complete **capacity year** before the first **pricing year** of the **simple method period** (**capacity year** n) and starting on the first **trading period** of **capacity year** n-4.

CMP C is relevant to calculating **benefit-based charges** for **BBIs** under the **simple method**

CMP D the period from the first **trading period** of **financial year** 2014 to the last **trading period** of **financial year** 2017. **CMP D** is relevant to calculating **benefit factors** and **residual charges**

CMP E for **pricing year** n, the period from the first **trading period** of **financial year** n-8 to the last **trading period** of **financial year** n-5. **CMP E** is relevant to calculating **residual charges**

CMP F for a **SSCGU**, the period ending on the last **trading period** of the most recent complete **capacity year** before the **SSCGU** occurred (**capacity year** n) and starting on the first **trading period** of **capacity year** n-4. **CMP F** is relevant to adjusting **benefit-based charges** for **high-value BBIs**

CMP G the period from the first **trading period** of **pricing year** 2015 to the last **trading period** of **pricing year** 2019. **CMP G** is relevant to calculating **difference caps**

capacity year means a period of 12 months starting on 1 September and ending on 31 August. **Capacity year** n means the **capacity year** starting in year n

capital charge means **Transpower's** return on its investment in an asset

capped charges means, for a **capped customer** and **pricing year**, the **capped customer's**:
(a) **annual benefit-based charges** for the **Appendix A BBIs** and **pricing year**; and
(b) **annual residual charge** for the **pricing** year; and
(c) **annual cap recovery charge** for the **pricing year**

capped customer means—
(a) for the **first pricing year**, a **customer**, other than in its capacity as a **generator**, who was a **customer** during **pricing year** 2019 and at least 2 **pricing years** preceding **pricing year** 2019; and
(b) for each subsequent **pricing year**, any such **customer** who had a **cap reduction** for the previous **pricing year**

closing RAB value has the meaning in the **Transpower IMs**

coincident peak offtake has the meaning in subclause 65(8)

Commission means the Commerce Commission established by section 8 of the Commerce Act 1986

commissioned has the meaning in clause 5

commissioning date means the date an asset, **connection investment** or **interconnection investment** (including a **BBI**) is **commissioned**

compliance investment means an investment by **Transpower** in an existing **grid asset** or **transmission alternative** to ensure the **grid asset** or **transmission alternative** is maintained, and can be operated, in accordance with **good electricity industry practice**. A **compliance investment** may also be an **enhancement investment**, **refurbishment investment** or **replacement investment**

connection asset has the meaning in subclause 21(1), and includes "deep" **connection assets** as described in paragraph 22(5)(b)

connection charge means a charge described in subclause 2(a) and calculated under clause 24 for a **customer** and **pricing year** and—
(a) a **connection asset** and **connection location**; or
(b) a **connection transmission alternative**

connection charge adjustment event has the meaning in clause 76

connection customer allocation means a **customer's** allocation of the **connection charge** for a **connection asset** and **connection location** calculated under clause 32

connection investment means a **transmission investment** or group of related **transmission investments** exclusively in 1 or more **connection assets** or **connection transmission alternatives**

connection link has the meaning in paragraph 20(1)(e)

connection node has the meaning in paragraph 20(1)(d)

connection region means a region determined by **Transpower** under subclause 62(4)

connection transmission alternative means a **transmission alternative** to the extent it is an alternative to an investment in a **connection asset**, as determined by **Transpower**

consuming plant means—
(a) equipment that consumes **electricity**, regardless of size, including electrical appliances as defined in the Electricity Act 1992; and
(b) **battery storage** when charging

continuing BBI has the meaning in subclause 84(5) or 85(4)

contributing customer means, for a **funded asset—**
(a) a **customer** who funded, or is funding, all or part of the capital cost of the **funded asset** under an **investment agreement**; or
(b) a **customer** who funded, or is funding, all or part of the capital cost of the **funded asset** through **connection charges**

counterfactual means, for a **BBI**, the expected future **grid** state assuming the **BBI** is not **commissioned**

covered cost means the amount of **recoverable revenue** allocated to a **BBI** for a **pricing year** calculated under subclause 39(1)

CPI means the consumers price index (all groups) published by Stats NZ

curtailed energy means **unserved energy** or **unsupplied energy**

customer means a **designated transmission customer**

demand factor means the scaling factor for **regional NPB** for **regional demand groups** under the **simple method** calculated under clause 64(4)

depreciation means depreciation of an asset calculated in accordance with the **Transpower IMs**

de-rate means, for an asset or **plant**, to alter the asset or **plant** physically so that the asset's or **plant's capacity** is permanently reduced

difference cap has the meaning in clause 111(1)

direct supplied load customer means, for a **connection location** and **trading period**, a **connected asset owner** who—
(a) owns or controls a **local network** or **consuming plant** connected to the **grid** at the **connection location**; and
(b) has **embedded electricity** at the **connection location** of the type defined in paragraph 4(1)(b) for the **trading period**

discounted BBI means—
(a) for an **inefficient bypass prudent discount**, a **BBI** that would be bypassed by the relevant **alternative project**; or
(b) for a **stand-alone cost prudent discount**, a **BBI** of which the **prudent discount recipient** is a **beneficiary**

economic life means, for an asset, the asset's physical asset life as defined in the **Transpower IMs**

EDB ID determination means the *Electricity Distribution Information Disclosure Determination 2012* [2012] NZCC 22

EDB IMs means the *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26

efficient stand-alone investment has the meaning in clause 135

eligible BBI means a **BBI**, including a **BBI** that is currently **reassigned** or was previously **reassigned**, for which both of the following conditions are satisfied (as applicable):
(a) the total **closing RAB value** of all assets comprised in the **BBI** for the most recent complete **financial year**, adjusted by the **BBI reassignment factor** for any current **reassignment** the **BBI** is subject to, is at least the **reassignment threshold**:
(b) if the **BBI** is a **post-2019 BBI**, either—
  (i) at least 10 years have passed since the **BBI's commissioning date**; or
  (ii) since the **BBI's commissioning date—**
    (A) a **customer** permanently disconnected from the **grid** at a **connection location** at which the **customer** was a **beneficiary** of the **BBI** when it disconnected; and
    (B) that disconnection, by itself and without taking into account other events, caused the **BBI's BBI reassignment factor** to decrease by at least 0.2; or
  (iii) since the **BBI's commissioning date—**
    (A) a **customer** who is a **beneficiary** of the **BBI** permanently disconnected **plant** from the **grid**; and
    (B) that disconnection, by itself and without taking into account other events, caused the **BBI's BBI reassignment factor** to decrease by at least 0.2

eligible person means, for an **application** for r**eassignment** or a proposal to reverse a **reassignment—**
(a) a **beneficiary** of the **BBI** to which the **application** or proposal relates; or
(b) a person who owns or controls **embedded plant** connected to the **local network** or **grid**-connected **plant** of a **beneficiary** of the **BBI**

embedded means, for **plant**, that the **plant** is connected to a **local network** or to **grid**-connected **plant**. If the **plant** is also connected to the **grid**, **Transpower** may treat the **plant** as part **embedded** and part **grid**-connected

embedded electricity has the meaning in paragraph 4(1)(b), 4(1)(c) or 4(1)(d) for a **customer** and **trading period**

enhancement investment means a **transmission investment** that is not a **refurbishment investment** or **replacement investment**. An **enhancement investment** may also be a **compliance investment**

event pricing year means the **pricing year** during which an **adjustment event** occurs

exacerbated price means, for a **regional customer group**, **factual** and **counterfactual**, a price at a **market node** in the **regional customer group's modelled region** that, due to a **modelled constraint** is—
(a) higher in the **factual** than the **counterfactual**; or
(b) lower in the **counterfactual** than a price at another **market node** in the **counterfactual** that is in a **modelled region** for a different **regional customer group** of the same type (**regional demand group** or **regional supply group**)

exempt post-2019 investment means an **interconnection investment**, other than the **post-2019 CUWLP investment**, that is—
(a) **commissioned** after 23 July 2019 and before the start of **financial year** 2021; and
(b) a **refurbishment investment**, **replacement investment** or **enhancement investment** in respect of an **Appendix A BBI** or another **interconnection investment commissioned** on or before 23 July 2019

exempt pricing year means, for an **adjustment event** and **customer**—
(a) the **event pricing year**; and
(b) the **pricing year** after the **event pricing year** if the **adjustment event** occurred less than 1 month before the deadline for **Transpower** notifying the **customer** of its **transmission charges** for the **pricing year** under the relevant **transmission agreement**

expected effective full commissioning date means, for a **BBI**, a date determined by **Transpower**, which must fall within the period from (and including) the **BBI's** expected **commissioning date** to (and including) the **BBI's** expected **full commissioning date**, by which sufficient **grid assets** and **transmission alternatives** comprised in the **BBI** are expected to have been **commissioned** such that all of the **BBI's** principal benefits will have been released

factual means, for a **BBI**, the expected future **grid** state assuming the **BBI** is **fully commissioned**

final investment decision date means, for a **BBI**, the date **Transpower** makes its final decision to proceed with its investment in the **BBI**

financial year means a period of 12 months starting on 1 July and ending on 30 June. **Financial year** n means the **financial year** starting in year n

first pricing year means the first **pricing year** to which this **transmission pricing methodology** applies

forecast loading period has the meaning in subclause 102(1)

forecast peak loading has the meaning in subclause 102(2)

full commissioning date means the date a **connection investment** or **interconnection investment** (including a **BBI**) is **fully commissioned**

fully commissioned has the meaning in clause 5

funded asset means a **connection asset**—
(a) **commissioned** after the start of the **first pricing year**; and
(b) (all or part of the capital cost of which was funded, or is being funded, by a **customer** under an **investment agreement**

future regional customer group means a **regional customer group**—
(a) that is expected to have no members when the relevant **post-2019 BBI** is **commissioned**; and
(b) the future members of which (if any) will be new **customers** and **customers** who connect new **plant** to the **grid**

GAAP means generally accepted accounting practice in New Zealand

GEIP (standing for good electricity industry practice) means, for an **alternative project**, the exercise of that degree of skill, diligence, prudence, foresight and economic management that would reasonably be expected from a skilled and experienced asset owner engaged in the management of the **alternative project**, under conditions comparable to those applicable to the **alternative project**, consistent with applicable law, safety and environmental protection

generating plant has the meaning in Part 1 of this Code and includes **battery storage** when discharging

grid assets has the meaning in subclause 17(1)

grid point of connection means a **point of connection** to the **grid**

gross energy has the meaning in subclause 4(5)

GXP tie means a situation in which a **connected asset owner's assets** are simultaneously connected to the **grid** at more than 1 **point of connection**

high-value means, for a **BBI**, that the sum of—
(a) the depreciated value of the assets comprised in the **BBI**; and
(b) expected future **TA opex** for the **interconnection transmission alternatives** comprised in the **BBI**,
is, at the relevant time, more than the base capex threshold as defined in the **Transpower Capex IM**

high-value intervening BBI means a **post-2019 BBI**—
(a) with a **final investment decision date** before the start of the **first pricing year**; and
(b) **commissioned** on or before the last day of the **financial year** that precedes the **pricing year** after the **first pricing year**; and
(c) expected to be **high-value** when **fully commissioned**

high-voltage grid means the part of the **grid** with a nominal voltage of 220 kV or more

HILP event means a low probability event or group of events that, if it or they occurred, would have a high impact on **unserved energy** other than by way of cascade failure, as determined by **Transpower**

host customer means, for **embedded plant**, the **customer** who owns or controls the **local network** or **grid**-connected **plant** the **embedded plant** is connected to

HVDC asset means a **grid asset** that is part of the **HVDC link**

HVDC opex means—
(a) **availability costs** allocated to the **HVDC owner**; and
(b) insurance premiums for the **HVDC link**

ID WACC means, for **Transpower** or a **distributor**, the post-tax or pre-tax (as the context requires) **WACC** determined by the **Commission** under the **Transpower IMs** or **EDB IMs** for the purposes of **Transpower's** or the **distributor's** information disclosure regulation under Part 4 of the Commerce Act 1986

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 1 of them be appointed. Failing agreement between the parties, the **independent expert** will be appointed by the **Authority**

independent verification means, for an **application**, a written report on the accuracy and sufficiency of the information and analysis contained in the **application** prepared by 1 or more persons who are—
(a) recognised technical experts on the subject matter of the **application**; and
(b) independent of the **customer** making the **application**; and
(c) approved by **Transpower**

indirect supplied load customer means, for a **connection location** and **trading period**, an **asset owner** who—
(a) owns or controls a **local network**, **consuming plant** or **generating plant** connected to the **grid** at the **connection location**; and
(b) has **embedded electricity** at the **connection location** of the type defined in paragraph 4(1)(c) for the **trading period**

individual NPB means **NPB** for a **customer** calculated under clause 47 or 57 or subclause 61(1)

inefficient bypass prudent discount means a discount of a **customer's transmission charges** provided under this **transmission pricing methodology** for the purpose in clause 127

injection means—
(a) for a **trading period** and a **customer's grid point of connection**, the positive net quantity of **electricity** flow into the **grid** at the **grid point of injection** from the **customer's assets** during the **trading period** (if any); and
(b) for a **trading period** and a **customer's connection location**, the positive net quantity of **electricity** flow into the **grid** at all of the **customer's grid points of connection** at the **connection location** during the **trading period** (if any)

injection customer means, for a **connection location** and **trading period**, a **customer** at the **connection location** who has **injection** at the **connection location** for the **trading period**

interconnection asset has the meaning in subclause 21(2)

interconnection investment means a **transmission investment** or group of related **transmission investments** exclusively in 1 or more **interconnection assets** or **interconnection transmission alternatives**

interconnection link has the meaning in paragraph 20(1)(f)

interconnection node has the meaning in paragraph 20(1)(a)

interconnection transmission alternative means a **transmission alternative** to the extent it is not a **connection transmission alternative**

intra-regional allocator has the meaning in subclause 65(1), 65(2), 65(3) or 65(4) for the relevant **regional customer group**

investment agreement means—
(a) a contract entered into at any time between **Transpower** and another person (who may or may not be a **customer**) under which—
    (i) **Transpower** agrees to provide any new, **upgraded** or modified **transmission investment**; or
    (ii) the other person agrees to make a contribution to the capital, maintenance, operating or other cost of a **transmission investment**,

    including—
    (iii) a **new investment agreement contract**; and
    (iv) a contract to move or remove **grid assets**; or
(b) an agreement deemed to be an **investment agreement** under paragraph 28(5)(b)

investment agreement asset means a **grid asset** provided under an **investment agreement**

investment grid means a simplified model of the **grid** for a **market BBI's factual** or **counterfactual** that models—
(a) all existing **branches** and **market nodes**, as those **branches** and **market nodes** may be added to or removed in the **market BBI's factual** or **counterfactual** (as the case may be); and
(b) the **constraints** of the **HVDC link**, as those **constraints** would be in the **market BBI's factual** or **counterfactual** (as the case may be); and
(c) the **market BBI's modelled constraints**, as those **constraints** would be in the **market BBI's factual** or **counterfactual** (as the case may be)

investment reassignment factor has the meaning in subclause 102(3)

investment region means a **modelled region** under the **simple method** where a **BBI** or part of a **BBI** is located

investment test means the investment test applied to a **tested investment** under section III of Part F of the **rules** or the **Transpower Capex IM**

land and buildings has the meaning in subclause 17(3)

large means, subject to clause 7—
(a) for **plant**, that the **plant**—
  (i) is connected to the **grid**; or
  (ii) has **capacity** of at least 10 **MW**; and
(b) for an **upgrade** of **plant**, that the **plant's capacity** has increased by at least 10 **MW** compared to the **plant's capacity** before the **upgrade**; and
(c) for a **de-rating** of **plant**, that the **plant's capacity** has reduced by at least 10 **MW** compared to the **plant's capacity** before the **de-rating**

link has the meaning in subclause 19(3)

load customer means a **customer** who, at a **connection location** during a **trading period**, is or was (as the context requires) 1 or more of the following:
(a) an **offtake customer**:
(b) a **direct supplied load customer**:
(c) an **indirect supplied load customer**:
(d) a **supplying load customer**

loop has the meaning in paragraph 20(1)(b)

low-value means, for a **BBI**, that the sum of—
(a) the depreciated value of the assets comprised in the **BBI**; and
(b) expected future **TA opex** for the **interconnection transmission alternatives** comprised in the **BBI**,
is, at the relevant time, not more than the base capex threshold as defined in the **Transpower Capex IM**

low-voltage grid means the part of the **grid** with a nominal voltage of less than 220 kV

market BBI means a **post-2019 BBI** that is expected to have a material impact on prices or quantities in the **wholesale market** for **electricity** relative to the **post-2019 BBI's counterfactual**. A **market BBI** may also be an **ancillary service BBI** or a **reliability BBI**, but cannot be a **resiliency BBI**

market node means a **GXP** or **GIP**

market regional NPB means **regional NPB** arising from changes in prices or quantities in the **wholesale market** for **electricity**. **Market regional NPB** is calculated for **market BBIs**

market scenario means, for a **BBI**, a future state for factors that influence **NPB** for the **BBI**

material damage means destruction of, or substantial damage to, a **BBI**, as determined by **Transpower**

maximum gross demand has the meaning in subclause 4(6)

maximum revenue means, for a **pricing year**, the maximum revenue **Transpower** is permitted to recover for the **pricing year**, as determined by the **Commission** under Part 4 of the Commerce Act 1986. At the date of this **transmission pricing methodology**, this is the most recently updated forecast SMAR for the **pricing year** under the **Transpower IPP**

MCP opex means operating costs of the type described in clause 3.1.3(1)(d) of the **Transpower IMs**, being operating costs relating to major capex projects

mixed connection asset means a **connection asset** that, as well as connecting a **customer**, is used for **grid** operation generally

modelled constraint means, for a **market BBI**—
(a) a **constraint** affecting a new **grid asset** comprised in the **market BBI**; or
(b) a **constraint** that would be alleviated materially if the **market BBI** were **fully commissioned**, as determined by **Transpower**

modelled region means a region defined in, or determined by **Transpower** under—
(a) for a **BBI** under the **price-quantity method**, subclause 50(1), 54(3), 55(4) or 56(3) depending on the type of **regional NPB** being calculated; and
(b) for a **BBI** under the **resiliency method**, clause 58; and
(c) for a **BBI** under the **simple method**, subclause 62(1)

monthly benefit-based charge has the meaning in subclause 35(3)

monthly cap recovery charge has the meaning in subclause 112(2)

monthly charges means the following **transmission charges** for a **customer** and **pricing year**:
(a) **monthly connection charges**:
(b) **monthly benefit-based charges**:
(c) **monthly cap recovery charge**:
(d) **monthly prudent discount recovery charge**:
(e) **monthly residual charge**

monthly connection charge has the meaning in subclause 24(4)

monthly prudent discount recovery charge has the meaning in subclause 138(6)

monthly residual charge has the meaning in subclause 68(3)

net private benefit or **NPB** (which may be negative, zero or positive)**—**
(a) means, for a **regional customer group** or **customer**, the sum of the quantified benefits (positive values) and disbenefits (negative values) the **regional customer group** or **customer** is expected to receive from the relevant **BBI**; and
(b) for a **host customer**, includes the sum of the quantified benefits (positive values) and disbenefits (negative values) the **embedded plant** owners connected to the **host customer's local network** or **grid**-connected **plant** are expected to receive from the relevant **BBI**

node has the meaning in subclause 19(1)

nominated peak kVar means, for a **connected asset owner**, **zone** and **capacity year**, the quantity $\sum_j Q_{xjz}$ in subclause 8.67(2) of this Code calculated using the **connected asset owner's** nomination for the **zone** applying from the most recent 1 March before the start of the **capacity year**

non-contributing customer means, for a **funded asset**, a **customer** who—
(a) is connected by the **funded asset** at a **connection location**; and
(b) was not a **contributing customer** for the **funded asset** before connecting to it

non-grid network means a system of **lines**, substations and other **works**, used primarily for the conveyance of **electricity**, that is not part of the **grid** or connected to the **grid**, including an **embedded network**

notional IRA value has the meaning in clause 67

offtake means—
(a) for a **trading period** and a **customer's grid point of connection**, the positive net quantity of **electricity** flow out of the **grid** at the **grid point of connection** into the **customer's assets** during the **trading period** (if any); and

(b) for a **trading period** and a **customer's connection location**, the positive net quantity of electricity flow out of the grid at all of the **customer's grid points of connection** at the **connection location** during the **trading period** (if any)

offtake customer means, for a **connection location** and **trading period**, a **customer** at the **connection location** who has **offtake** at the **connection location** for the **trading period**

opening RAB value has the meaning in the **Transpower IMs**

optimised replacement cost means, for any **grid asset** or group of **grid assets**, the optimised replacement cost of the **grid asset** or group of **grid assets** as at 1 July 2006, as determined by **Transpower**

other regional NPB means **regional NPB** that is not **market regional NPB**, **ancillary service regional NPB** or **reliability regional NPB**. **Other regional NPB** may be calculated for **market BBIs**, **ancillary service BBIs** or **reliability BBIs**

outage scenario means, for a **reliability BBI**, an **outage** or other event or group of events affecting access to **transmission services** in respect of which the **reliability BBI** is expected to have a material impact on **curtailed energy**

peak BBI means a **post-2019 BBI** for which the investment need is primarily attributable to meeting peak **demand**

peak offtake trading period has the meaning in paragraph 65(8)

periods of benefit has the meaning in paragraph 51(3)(b)

plant means **consuming plant** or **generating plant**

post-2019 BBI means an **interconnection investment commissioned** after 23 July 2019 excluding any **exempt post-2019 investment**. To avoid doubt—
(a) the **post-2019 CUWLP investment** is a **post-2019 BBI**; and
(b) an **interconnection investment** that is an **Appendix A BBI** is not a **post-2019 BBI**; and
(c) an **interconnection investment** carried out or approved as a single project or programme may comprise more than 1 **post-2019 BBI**; and
(d) a **post-2019 BBI** may comprise more than 1 **interconnection investment**, each of which is carried out or approved as a single project or programme

post-2019 CUWLP investment means the **interconnection investment** comprising the following **transmission investments** approved by the Electricity Commission on 9 August 2010 as part of the Lower South Island Renewables Investment:
(a) thermal upgrade of the circuits between Cromwell and Twizel:
(b) re-conductoring of the circuits between Roxburgh and Livingstone

PQ WACC means, for **Transpower** or a price-quality regulated **distributor**, the vanilla or pre-tax (as the context requires) **WACC** determined by the **Commission** under the **Transpower IMs** or **EDB IMs** for the purposes of **Transpower's** or the **distributor's** price-quality regulation under Part 4 of the Commerce Act 1986

pre-commencement adjustment event means an event that occurred before the start of the **first pricing year** and—
(a) would have been an **adjustment event** had it occurred at or after the start of the **first pricing year**; or
(b) **Transpower** determines is analogous to an **adjustment event**

pre-existing customer means a **customer** who has been a member of a **regional customer group** for (as the case may be)—

(a) at least 2 full **capacity years** during **CMP B** for the relevant **BBI**; or
(b) at least 2 full **capacity years** during **CMP C** for the relevant **simple method period**

pre-existing load customer means a **load customer** who was a **customer** for the whole of **CMP D**

pre-start adjustment event means, for a **post-2019 BBI**, an event that occurred before the start of the **post-2019 BBI's start pricing year** and would have been a **benefit-based charge adjustment event** for the **post-2019 BBI** had it occurred at or after the start of the **post-2019 BBI's start pricing year**. To avoid doubt, a **pre-start adjustment event** may be a **pre-commencement adjustment event**

previous discount means—
(a) a prudent discount provided under the **previous transmission pricing methodology**; or
(b) a discount provided under a **notional embedding contract**; or
(c) any other discount or effective discount of transmission charges provided under an agreement between **Transpower** and a **customer** entered into before the start of the **first pricing year**

previous transmission pricing methodology means, as applicable, the transmission pricing methodology comprised in this Code when it came into force, as subsequently amended up to the date this **transmission pricing methodology** came into force

price-quantity method means the method for calculating **NPB** for a **post-2019 BBI** specified in clauses 44 to 55

pricing year has the meaning given to that term in the **Transpower IMs**. At the date of this **transmission pricing methodology**, a **pricing year** is a period of 12 months starting on 1 April and ending on 31 March. **Pricing year** n means the **pricing year** starting in year n

prior contributing customer means, for a **funded asset** and in respect of a **non-contributing customer** for the **funded asset**, a **contributing customer** who was connected to the **funded asset** before the **non-contributing customer** became connected to the **funded asset**

prudent discount means an **inefficient bypass prudent discount** or **stand-alone cost prudent discount**. The amount of a **prudent discount** for a **pricing year** is—
(a) the absolute value of the reduction in the **prudent discount recipient's transmission charges** for the **pricing year** under the **prudent discount** agreement; less
(b) the annuity payable by the **prudent discount recipient** under the **prudent discount** agreement

prudent discount calculation period means, for a **prudent discount**, the period—
(a) starting at the start of the **prudent discount's start pricing year**, or estimated **start pricing year** assuming the **prudent discount** is approved; and
(b) ending—
    (i) for an **inefficient bypass prudent discount**, at the end of the remaining **economic life** of the **grid assets** the relevant **alternative project** would bypass, up to a maximum of 15 years after the start of the **prudent discount calculation period**; or
    (ii) for a **stand-alone cost prudent discount**, 15 years after the start of the **prudent discount calculation period**

prudent discount confirmation date means, for a **prudent discount** decision, the date the following conditions are satisfied:
(a) either—
    (i) the relevant **customer** has confirmed to **Transpower** in writing that it does not intend to refer any aspect of **Transpower's** decision to an **independent expert**; or

(ii) the **customer** did not refer any aspect of **Transpower's** decision to an **independent expert** before time to do so expired under subclause 120(3); or
(iii) an **independent expert** has made final binding decisions on all aspects of **Transpower's** decision referred to the **independent expert**:
(b) for an approved **prudent discount**, **Transpower** and the **customer** have entered into a **prudent discount** agreement for the **prudent discount**

prudent discount practice manual means a document **published** by **Transpower** containing assumptions and detailed methodologies that **Transpower—**
(a) intends to apply for assessing **applications** for **prudent discounts**; and
(b) does not expect to vary between **prudent discount applications** except according to whether the **application** is for an **inefficient bypass prudent discount** or **stand-alone cost prudent discount**

prudent discount rate means—
(a) subject to paragraph 128(c), for an **inefficient bypass prudent discount—**
(i) if the applicant **customer** is a **distributor**, the **distributor's ID WACC** at the time of the **application** for the **prudent discount**; or
(ii) if the applicant **customer** is not a **distributor** but is subject to another regulated **WACC**, that **WACC**; or
(iii) otherwise, a **WACC** for the applicant **customer** determined by **Transpower** by applying the methodology for estimating **ID WACC** for **distributors** in the **EDB IMs**; or
(b) for a **stand-alone cost prudent discount**, **Transpower's ID WACC** at the time of the **application** for the **prudent discount**

prudent discount recipient means a **customer** receiving a **prudent discount**

prudent discount recovery charge means a charge described in subclause 2(d), being a **BBI prudent discount recovery charge** or **residual prudent discount recovery charge**

reassignment means a reassignment of all or part of the **covered cost** of a **BBI** to **residual revenue**, and **reassigned** has a corresponding meaning

reassignment amount has the meaning in clause 97

reassignment confirmation date means, for a **reassignment** decision, the date any of the following conditions is satisfied:
(a) the relevant **eligible person** has confirmed to **Transpower** in writing that it does not intend to refer any aspect of **Transpower's** decision to an **independent expert**:
(b) **expert** the **eligible person** did not refer any aspect of **Transpower's** decision to an **independent** before time to do so expired under subclause 104(3) or paragraph 107(2)(c):
(c) an **independent expert** has made final binding decisions on all aspects of **Transpower's** decision referred to the **independent expert**

reassignment practice manual means a document **published** by **Transpower** containing assumptions and detailed methodologies that **Transpower—**
(a) intends to apply for assessing **applications** for **reassignment**; and
(b) does not expect to vary between **reassignment applications**

reassignment threshold has the meaning in subclause 98(2)

recent customer means a **customer** who has been a member of a **regional customer group** for (as the case may be)—
(a) less than 2 full **capacity years** during **CMP B** for the relevant **BBI**; or
(b) less than 2 full **capacity years** during **CMP C** for the relevant **simple method period**

recent load customer means a **load customer** who is not a **pre-existing load customer**

recoverable revenue means, for a **pricing year**—
(a) **maximum revenue** for the **pricing year**; less
(b) any part of **maximum revenue** for the **pricing year** **Transpower** is able or required to recover other than through **transmission charges**, including by way of annuities paid by **prudent discount recipients**

reduction event means, for a **pre-existing load customer**, a reduction in the **pre-existing load customer's** expected **maximum gross demand** compared to the **pre-existing load customer's AMDR** baseline calculated under clause 70(1)—
(a) of at least 10 **MW**; and
(b) due to an event or series of directly related events that—
  (i) occurred, or **Transpower** determines will occur, after the start of **CMP D** and before the start of the **first pricing year**; and
  (ii) **Transpower** determines was, were or will be beyond the **pre-existing load customer's** reasonable control, not being—
    (A) a change in the basis for calculating future transmission charges; or
    (B) a change in the market for the **pre-existing load customer's** products or services, other than the services the **pre-existing load customer** supplies to an **embedded plant** owner connected to the **pre-existing load customer's local network** or **grid**-connected **plant** who is not a **related entity** of the **pre-existing load customer**; or
    (C) any of the events specified in paragraph (d) of the definition of **force majeure event** in clause 1.1(1) of this Code occurring in respect of the **pre-existing load customer** or a **related entity** of the **pre-existing load customer**; or
    (D) 1 or more events that could have been prevented by the **customer** by the exercise of a reasonable standard of care; and
(c) that **Transpower** determines is reasonably likely to persist for at least 5 years after the event or series of directly related events occurred or will occur

refurbishment investment means a **transmission investment** that—
(a) is asset refurbishment as defined in the **Transpower Capex IM**; or
(b) would be asset refurbishment as defined in the **Transpower Capex IM** if an investment in a **transmission alternative** were an investment in the **grid**.

A **refurbishment investment** may also be a **compliance investment**

regional customer group means a **regional demand group** or **regional supply group**

regional demand group means a group of **customers** in a **modelled region** defined in, or determined by **Transpower** under—
(a) for a **BBI** under the **price-quantity method**, subclause 50(2), 53(3), 55(4) or 55(3) depending on the type of **regional NPB** being calculated; and
(b) for a **BBI** under the **resiliency method**, clause58; and
(c) for a **BBI** under the **simple method**, clause 63

regional NPB means **NPB** for a **regional customer group** calculated in accordance with, or assumed under, a **standard method** or the **simple method**

regional supply group means a group of **customers** in a **modelled region** defined in, or determined by **Transpower** under —
(a) for a **BBI** under the **price-quantity method**, subclause 50(2), 54(3), 55(4) or 56(3) depending on the type of **regional NPB** being calculated; and
(b) for a **BBI** under the **simple method**, clause 63

regulatory asset base or **RAB** means **Transpower's** record of **commissioned** assets and their depreciated values used to calculate **maximum revenue** under the **Transpower IMs**

regulatory control period or **RCP** means a regulatory period as defined in the **Transpower IPP**

related entity of a person means another person that controls, is controlled by, or is under common control with the first person, including a person that—
(a) is a related company of the first person as defined in section 2(3) of the Companies Act 1993; or
(b) would be a related company of the first person under that section if both the first person and the other person were companies registered under that Act

reliability BBI means a **post-2019 BBI** that is expected to reduce materially **curtailed energy** relative to the **post-2019 BBI's counterfactual** if there is an **outage** or other event or group of events affecting access to **transmission services**. A **reliability BBI** may also be a **market BBI** or **ancillary service BBI**, but cannot be a **resiliency BBI**

reliability regional NPB means **regional NPB** arising from changes in **curtailed energy**. **Reliability regional NPB** is calculated for **reliability BBIs**

replacement cost means, for a **grid asset** and subject to subclause 34(5), the cost of replacing the **grid asset**, either separately or as part of a group of **grid assets**, with a modern equivalent **grid asset** with the same service potential

replacement cost adjustment factor means, for a **grid asset** or group of **grid assets**, the **optimised replacement cost** for the **grid asset** or group of **grid assets** divided by the cost, as at (or about) 1 July 2006, of replacing the **grid asset** or group of **grid assets** with the then modern equivalent **grid asset** with the same service potential, as determined by **Transpower**

replacement investment means a **transmission investment** that—
(a) is asset replacement as defined in the **Transpower Capex IM**; or
(b) would be asset replacement as defined in the **Transpower Capex IM** if an investment in a **transmission alternative** were an investment in the **grid**.
A **replacement investment** may also be a **compliance investment**

residual charge means a charge described in subclause 2(e) and calculated under clause 68 for a **load customer** and **pricing year**

residual charge adjustment event has the meaning in subclause 92(1)

residual charge adjustment factor or **RCAF** means the factor calculated under clause 71 for a **load customer** and **pricing year**

residual prudent discount recovery charge means a charge calculated under subclause 138(3) for a **prudent discount**, **customer** and **pricing year**

residual revenue means, for a **pricing year**, **recoverable revenue** for the **pricing year** less all **transmission charges** for the **pricing year** other than **residual charges**. The minimum value of **residual revenue** for a **pricing year** is 0

resiliency BBI means a **post-2019 BBI** for which the investment need is primarily attributable to mitigating a risk of cascade failure or a **HILP event**. A **resiliency BBI** cannot also be a **market BBI**, **ancillary service BBI** or **reliability BBI**

resiliency method means the method for calculating **NPB** for a **resiliency BBI** specified in clauses 56 to 58

reverse flow means **electricity** exiting the **grid** at a **GXP** and entering the **grid** at another **GXP** as a result of a **GXP tie**

scenario means a **market scenario** or **outage scenario**

Schedule 1 allocation means, for a **Schedule 1 customer** and **Appendix A BBI**, the **Schedule 1 customer's** allocation for the **Appendix A BBI** specified in Schedule 1 of the **2020 guidelines** to 2 decimal places

Schedule 1 beneficiary means, for an **Appendix A BBI**, a **Schedule 1 customer** who has a positive **Schedule 1 allocation** for the **Appendix A BBI**

Schedule 1 customer means a person specified in Schedule 1 of the **2020 guidelines**, even if not a current **customer** at the time this definition is applied

simple method means the method for calculating **NPB** for a **low-value post-2019 BBI** specified in clauses 59 to 64

simple method contribution has the meaning in clause 64(7)

simple method factor has the meaning in subclause 61(2)

simple method period has the meaning in clause 60

small regional loop has the meaning in paragraph 20(1)(c)

specified ancillary service means **instantaneous reserve**, **frequency keeping** or **voltage support**

specified pre-start adjustment event means, for a **post-2019 BBI** and **pre-existing customer**, a **pre-start adjustment event** for the **post-2019 BBI** that would have been a **benefit-based charge adjustment event** in any of paragraphs 81(1)(d) to 81(1)(h) in respect of the **pre-existing customer**

stand-alone cost prudent discount means a discount of a **customer's transmission charges** provided under this **transmission pricing methodology** for the purpose in clause 133

standard method means the **price-quantity method** or **resiliency method**

standard method calculation period means, for a **BBI**, the period—
(a) starting on the first 1 January after the **BBI's expected effective full commissioning date**; and
(b) ending on the earlier of—
  (i) 20 years after that 1 January; and
  (ii) the end of the useful life of the **BBI**, as determined by **Transpower**

standard method rate means, for a **BBI**—
(a) if the **BBI** is a **tested investment**, the pre-tax, real discount rate used when the **BBI** was assessed under the **investment test**, excluding discount rates used only for sensitivity analysis; or
(b) otherwise—
  (i) the applicable rate **published** in the **assumptions book**; or
  (ii) if there is no applicable rate **published** in the **assumptions book**, the rate in clause D6(3)(a) of the **Transpower Capex IM**

start pricing year means—
(a) for a **connection investment**, the first **pricing year** that starts after the end of the **financial year** during which the **connection investment** was **commissioned**; or
(b) for a **BBI**, the first **pricing year** that starts after the end of the **financial year** during which the **BBI** was **commissioned** (which, for an **Appendix A BBI**, is the **first pricing year**); or
(c) for a **SSCGU**, the first **pricing year** that starts at least 6 months (or such shorter period as **Transpower** may determine is practicable) after the date of the **SSCGU**; or

(d) for a **reassignment**, the first **pricing year** that starts at least 6 months (or such shorter period as **Transpower** may determine is practicable) after the **reassignment confirmation date**; or
(e) for an **inefficient bypass prudent discount** and subject to paragraph 122(2), the first **pricing year** that starts—
  (i) at least 6 months (or such shorter period as **Transpower** may determine is practicable) after the **prudent discount confirmation date**; and
  (ii) on or after a date determined by **Transpower** based on the time that would be required for the **prudent discount recipient** to implement the relevant **alternative project** if the project to implement the **alternative project** had started on the date **Transpower** received the **application** for the **inefficient bypass prudent discount**; or
(f) for a **stand-alone cost prudent discount** and subject to paragraph 122(2), the first **pricing year** that starts at least 6 months (or such shorter period as **Transpower** may determine is practicable) after the **prudent discount confirmation date**

station means a substation or switching station

substantial sustained increase means, for **large plant**, an increase in the **large plant's** expected annual **electricity** consumption or generation (as the case may be)—
(a) of at least 25% since the last time the relevant **customer's BBI customer allocations** for 1 or more **BBIs** were calculated, as assessed under subclause 81(4); and
(b) that is not attributable to a **large upgrade** of the **large plant**; and
(c) that **Transpower** determines is reasonably likely to persist for at least 5 years after the start of the relevant **event pricing year**

substantial sustained change in grid use or **SSCGU** means an event or series of directly related events that result in a change in expected total annual **injection** or **offtake**—
(a) of at least 5% of average total annual **injection** or **offtake** (as the case may be) over **CMP F**; and
(b) that **Transpower** determines is reasonably likely to persist for at least 5 years after the event or series of directly related events occurred

supplying load customer means, for a **connection location** and **trading period**, a **generator** who—
(a) owns or controls **generating plant** connected to the **grid** at the **connection location**; and
(b) has **embedded electricity** at the **connection location** of the type defined in paragraph 4(1)(d) for the **trading period**

system limit means a level of **supply**, **demand** or **electricity** flow at which the power system would not remain in a **satisfactory state** during and following an **outage scenario**, potentially requiring involuntary post-contingency generation or **demand** reduction

system limit model means a simplified model of the **grid** that—
(a) models a **reliability BBI's factual, counterfactual, system limits** and **market scenarios**; and
(b) applies the **reliability BBI's outage scenarios** to the **factual, counterfactual, system limits and market scenarios** to model the change in **curtailed energy** between the **reliability BBI's factual** and **counterfactual**

TA opex means operating costs for **transmission alternatives**

tested investment means a **connection investment** or **interconnection investment** that—
(a) was approved by the Electricity Commission under section III of Part F of the **rules**; or
(b) was individually approved by the **Commission** as a major capex project or listed project under the **Transpower Capex IM**; or

(c) is a base capex project to which **Transpower** was required to apply a cost-benefit analysis under the **Transpower Capex IM**

total gross energy has the meaning in subclause 4(7)

transmission charges means the charges specified in clause 2

transmission investment means an investment by **Transpower** in the **grid** or a **transmission alternative**, including such an investment for which another person contributes to the capital, maintenance, operating or other cost under an **investment agreement**

transmission services means the following services provided by a **grid owner**:
(a) electricity lines services, as defined in section 54C of the Commerce Act 1986, but excluding **system operator** services:
(b) the provision of **transmission alternatives**

Transpower Capex IM means the *Transpower Capital Expenditure Input Methodology Determination 2012* [2012] NZCC 2

Transpower IMs means the *Commerce Act (Transpower Input Methodologies) Determination 2010* [2012] NZCC 17

Transpower IPP means the *Transpower Individual Price-Quality Path Determination 2020* [2019] NZCC 19

Transpower operations facility means a facility that is used by **Transpower** only to operate the **grid** and is not a **station**

upgrade means, for an asset or **plant**, to alter the asset or **plant** physically so that the asset's or **plant's capacity** is permanently increased

unserved energy (measured in kWh or **MWh**) means an amount by which **offtake** at 1 or more **GXPs** is curtailed

unsupplied energy (measured in kWh or **MWh**) means an amount by which **injection** at 1 or more **GIPs** is curtailed

value of commissioned asset has the meaning in the **Transpower IMs**

value of lost load or **VOLL** means, for a **reliability BBI**—
(a) if the **reliability BBI** is a **tested investment**, the value of **unserved energy** used when the **reliability BBI** was assessed under the **investment test**, excluding values of **unserved energy** used only for sensitivity analysis; or
(b) otherwise—
    (i) the applicable value of **unserved energy published** in the **assumptions book**; or
    (ii) if there is no applicable value of **unserved energy published** in the **assumptions book**, the value of **unserved energy** referred to in subclause 4(1) of Schedule 12.2 of this Code

WACC means weighted average cost of capital

wholesale market model means a simplified model of prices and quantities in the **wholesale market** for **electricity** (and only in that **wholesale market**) that—
(a) models a **market BBI's factual**, **counterfactual** and **market scenarios**; and
(b) assumes suppliers offer prices based on their marginal variable costs of supply; and
(c) assumes perfectly inelastic demand up to 1 or more estimated costs of self-supply that are the same for all demand types; and
(d) applies least-cost dispatch to the **market BBI's factual**, **counterfactual** and **market scenarios**, under the assumptions in paragraphs, (b) and (c) to model the change in prices

and quantities in the **wholesale market** for **electricity** between the **market BBI's factual** and **counterfactual**

write-down means a reduction in an asset's **RAB** value or **value of commissioned asset** exclusively due to damage to, or destruction, stranding, decommissioning or disposal of, the asset, which may be a partial impairment or write-off

zero RNPB investment region has the meaning in subclause 83(12).

4. Load Customers, Gross Energy and Maximum Gross Demand

(1) The different types of **load customer** are shown in figures 1, 2, 3 and 4 below. In figures 1, 2, 3 and 4, "LN" means **local network**, "CP" means **consuming plant**, "GP" means **generating plant**, "NGN" means **non-grid network** and "POC" means a **grid point of connection**. This subclause (1) is subject to subclause (2):

(a) In figure 1, a **customer** owning or controlling LN, CP or GP is an **offtake customer** to the extent of the **offtake** for the relevant **trading period**:

(b) In figure 2, a **customer** owning or controlling LN or CP is a **direct supplied load customer** to the extent of the generated **electricity** net of any coincident **injection** through LN or CP for the relevant **trading period** (**embedded electricity**). The **embedded electricity** is referred to as the **direct supplied load customer's embedded electricity** "at" POC and the relevant **connection location** for the **trading period**:

(c) In figure 3, a **customer** owning or controlling LN, **grid**-connected CP or **grid**-connected GP is an **indirect supplied load customer** to the extent of the generated **electricity** net of any coincident **injection** through LN or **grid**-connected CP for the relevant **trading period** (**embedded electricity**). The **embedded electricity** is referred to as the **indirect supplied load customer's embedded electricity** "at" POC and the relevant **connection location** for the **trading period**:

(d) In figure 4, a **customer** owning or controlling GP is a **supplying load customer** to the extent of the **embedded electricity** for the relevant **trading period**. The **embedded electricity** is referred to as the **supplying load customer's embedded electricity** "at" POC and the relevant **connection location** for the **trading period**.

Figure 1

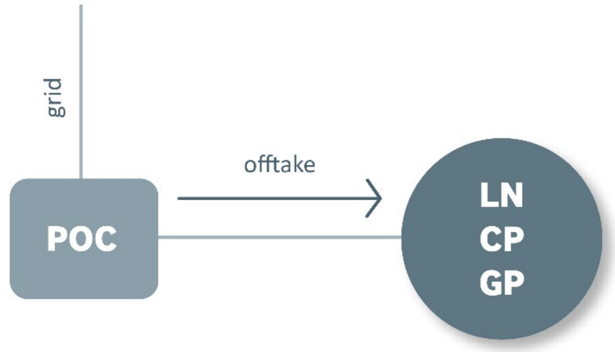


Figure 2

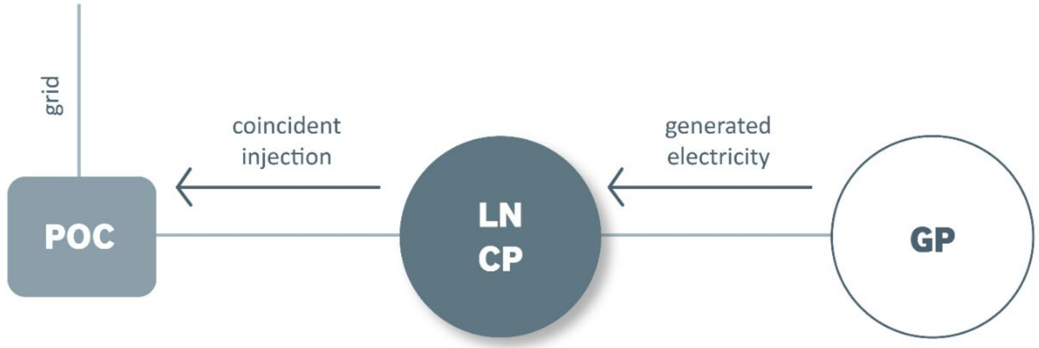
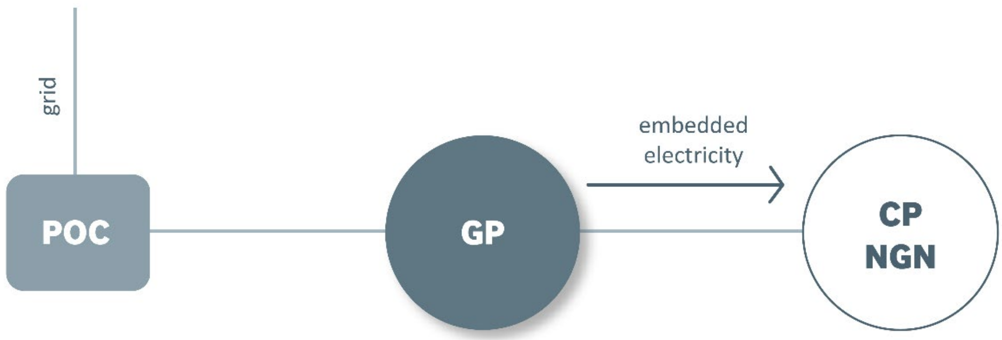


Figure 3

Figure 4



(2) If—
 (a) GP in figure 2 above is **battery storage**, the generated **electricity** referred to in paragraph (1)(b) is deemed to be 0; or
 (b) **embedded** GP in figure 3 above is **battery storage**, the generated **electricity** referred to in paragraph (1)(c) is deemed to be 0; or
 (c) GP in figure 4 above is **battery storage**, the **embedded electricity** referred to in paragraph (1)(d) is deemed to be 0.

(3) If **Transpower** determines it has insufficient information to determine whether, or the extent to which, an amount of **electricity** was generated by **battery storage**, **Transpower** must assume none of that amount of **electricity** was generated by **battery storage**.

(4) If a configuration of **consuming plant** and **generating plant** connected to the **grid** is such that the **customer** may be treated as either a **direct supplied load customer** or **supplying load customer**, the **customer's** status as a **direct supplied load customer** or **supplying load customer** must be determined by **Transpower**.

(5) **Gross energy** (measured in kWh or **MWh**) means, for a **load customer**, **connection location** or **grid point of connection**, and **trading period—**
 (a) the **load customer's offtake** at the **connection location** or **grid point of connection** for the **trading period**; plus
 (b) the **load customer's embedded electricity** at the **connection location** or **grid point of connection** for the **trading period**.

(6) **Maximum gross demand** (measured in kW or **MW**) means, for a **load customer**, **connection location** or **grid point of connection**, and period, the **load customer's** maximum per-**trading period gross energy** at the **connection location** or **grid point of connection** during the period multiplied by 2.

(7) **Total gross energy** (measured in kWh or **MWh**) for a **load customer** and period (TGE) is calculated as follows:

$$TGE = \left(\sum_{l}\sum_{t} GE_{tl}\right) - E_{battery}$$

where

GE_{tl} is the **load customer's gross energy** for **trading period** t at **connection location** l during the period

$E_{battery}$ is total **injection** from all of the **load customer's grid**-connected **battery storage** over the period, if any.

5 Commissioning

(1) An asset is **commissioned** when it is first commissioned as defined in the **Transpower IMs**.

(2) A **connection investment** or **interconnection investment** (including a **BBI**) is **commissioned** when the first **grid asset** or **transmission alternative** comprised in it is **commissioned** or started (as the case may be).

(3) A **connection investment** or **interconnection investment** (including a **BBI**) is **fully commissioned** when all **grid assets** and **transmission alternatives** comprised in it are **commissioned** or started (as the case may be).

(4) Subject to subclauses (1) to (3), the time an asset, **connection investment** or **interconnection investment** (including a **BBI**) is **commissioned** or **fully commissioned** is to be determined by **Transpower**.

6 Connection and Disconnection

In this **transmission pricing methodology**, unless the context otherwise requires—

(a) an asset becomes connected to a **network** at a **point of connection** at the time the **point of connection** is **commissioned**; and

(b) an asset becomes disconnected from a **network** at a **point of connection** at the time the **point of connection** is **decommissioned**; and

(c) subject to paragraphs (a) and (b), the time an asset becomes connected to or disconnected from a **network** or **plant** is to be determined by **Transpower**; and

(d) **plant** is **grid**-connected only if it is directly connected to the **grid**; and

(e) **embedded plant** is connected to a **local network** or **grid**-connected **plant** if the **embedded plant** is—

  (i) directly connected to the **local network** or **grid**-connected **plant**; or

  (ii) indirectly connected to the **local network** or **grid**-connected **plant** through other **plant** or a **non-grid network**.

7 Large Plant

Where **Transpower** is required under this **transmission pricing methodology** to assess whether **plant**, or an **upgrade** or **de-rating** of **plant**, is **large**, **Transpower** may make that assessment by combining 2 or more units of **plant** that are—

  (a) of the same type (**consuming plant** or **generating plant**); and

  (b) owned by the same person or **related parties**,

if **Transpower** determines it is reasonable in all the circumstances to do so.

8 Interpretation

In this **transmission pricing methodology**, unless the context otherwise requires—

(a) all defined terms are shown in bold text; and

(b) a term in bold text not defined in this **transmission pricing methodology** has the meaning given to it in Part 1 of this Code; and

(c) any other grammatical form of a defined 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 formula, the formula takes precedence; and

(e) if there is any inconsistency between an illustrative figure, table or associated commentary and the provisions of this **transmission pricing methodology** being illustrated by the figure, table or associated commentary, the provisions being illustrated take precedence; and

(f) a reference to **Transpower** means **Transpower** in its capacity as a **grid owner**; and

(g) a reference—

  (i) to the singular includes the plural and vice versa; and

  (ii) to a person includes an individual, company, other body corporate, association, partnership, firm, joint venture, trust or Crown entity; and

  (iii) to a clause, subclause, paragraph, subparagraph, Part or figure is to a clause, subclause, paragraph, subparagraph or Part of, or figure in, this **transmission pricing methodology**; and

(iv) to any legislation, including this Code, the **Transpower IPP**, the **Transpower IMs** and the **Transpower Capex IM**, includes that legislation as amended or replaced from time to time; and

(h) 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

(i) a reference to a preceding **financial year** is a reference to the most recent complete **financial year** that precedes the start of the **pricing year** in respect of which the relevant calculation is undertaken or assessment is made; and

(j) a reference to a **plant** owner is a reference to the person who owns or controls the **plant**; and

(k) a reference to a **customer's offtake**, **embedded electricity** or **injection** at a **connection location** is a reference to the **customer's offtake**, **embedded electricity** or **injection** at all **grid points of connection** at the **connection location** where the **customer offtakes electricity**, has **embedded electricity** or **injects electricity** (as the case may be); and

(l) a reference to a **load customer's** (including an **offtake customer's**) or **injection customer's connection location**:

(i) is a reference to all **grid points of connection** at the **connection location** where the **load customer offtakes electricity** or has **embedded electricity** or where the **injection customer injects electricity** (as the case may be); and

(ii) does not include any **connection location** where the **load customer** does not **offtake electricity** or have **embedded electricity** or where the **injection customer** does not **inject electricity** (as the case may be).

Calculation of Transmission Charges

9 Transmission Charges Calculated Separately

A **customer** may be both a **load customer** and an **injection customer** at a **connection location** (but cannot be both an **offtake customer** and **injection customer** at the **connection location** for the same **trading period**). If a **customer** is both a **load customer** and an **injection customer** at a **connection location**, the **customer's transmission charges** are calculated separately for the **customer** as a **load customer** and an **injection customer**, except as otherwise stated in this **transmission pricing methodology**.

10 Calculations and Estimations

(1) Except as otherwise stated in this **transmission pricing methodology**—

(a) any calculation or estimation of a value under this **transmission pricing methodology** (including any **transmission charge**) is to be carried out by **Transpower**; and

(b) any input to a calculation or estimation of a value under this **transmission pricing methodology** is to be determined by **Transpower**; and

(c) to the extent a calculation or estimation of a value under this **transmission pricing methodology** requires modelling, **Transpower** may use the modelling tools it uses in its business from time to time, which may change over time.

(2) To avoid doubt, **Transpower** is not required to maintain its access to a modelling tool it no longer uses in its business merely for the purpose of verifying previous calculations or estimations of values under this **transmission pricing methodology** that were made using the modelling tool.

(3) If this **transmission pricing methodology** specifies a source for an input to a calculation or estimation of a value under this **transmission pricing methodology** but the source is not

available or the input is not included in or provided by the source, the input is to be determined by **Transpower**.

(4) Except as otherwise stated in this Code, **Transpower** may use the following information to calculate **allocation data** and is not required to (but may) use any other information:
(a) **metering information**:
(b) information required to be provided by the **reconciliation manager** to **Transpower** under this Code, including under clause 28(b) of Schedule 15.4 of this Code:
(c) other **reconciled quantities** published or made available to **Transpower**:
(d) **half-hour metering information** required to be provided by **generators** to **Transpower** under this Code, including under clauses 13.136, 13.137 and 13.137A of this Code:
(e) indications and measurements required to be provided by a **participant** to the **system operator** under this Code, including under Technical Code C of Schedule 8.3 of this Code, that are published or made available to **Transpower**.

(5) Except as otherwise stated in this **transmission pricing methodology**, **connection customer allocations**, **BBI customer allocations** and any other **transmission charge** allocators, and adjustments to those allocators, are calculated without regard to the impact of any **prudent discount** or **previous discount**.

(6) **Transpower** must calculate or estimate all values under this **transmission pricing methodology**—
(a) that are **connection customer allocations**, **BBI customer allocations** or other **transmission charge** allocators intended to sum to 1 or 100%, to at least 4 decimal places (if expressed as a decimal) or 2 decimal places (if expressed as a percentage), and **Transpower** is not obliged to calculate or estimate the values any more precisely than that; and
(b) that are in units of dollars, to 2 decimal places; and
(c) that are **supply** or **demand**, in whole kW; and
(d) that are **electricity**, in whole kWh.

(7) If, after any methodology in this **transmission pricing methodology** is applied—
(a) the **connection customer allocations** for a **connection asset**; or
(b) the **BBI customer allocations** for a **BBI**; or
(c) any other **transmission charge** allocators that are intended to sum to 1 or 100%,
do not sum to 1 or 100%, **Transpower** must adjust all of the relevant **transmission charge** allocators on a pro rata basis to achieve a sum of 1 or 100% or as close to 1 or 100% as practicable given the precision of the **transmission charge** allocators.

(8) The **BBI customer allocations** specified in Appendix A do not sum to 100% for every **Appendix A BBI** because they have been rounded to 2 decimal places. However, **Transpower** has calculated those **BBI customer allocations** to a greater number of decimal places and must use those more precise **BBI customer allocations**, as adjusted under this **transmission pricing methodology**, to calculate **benefit-based charges** and the **benefit factors** for the **Appendix A BBIs**. References in this **transmission pricing methodology** to an **Appendix A allocation** are to be interpreted accordingly.

(9) If an **ID WACC**, **PQ WACC** or other regulated **WACC** is determined by the relevant regulator on a post-tax and not pre-tax basis, and a pre-tax **WACC** based on the post-tax **WACC** is required for a calculation under this **transmission pricing methodology**, the pre-tax **WACC** ($W_{pre\text{-}tax}$) must be calculated as follows:

$$W_{pre-tax} = W_{post-tax} \times \frac{1}{1-r}$$

where

$W_{post\text{-}tax}$ is the post-tax **WACC**

r is the corporate tax rate, as defined in the **Transpower IMs**, at the relevant time.

(10) Subclause (9) also applies to calculating a post-tax **WACC** from a regulated pre-tax **WACC**, with a corresponding change to the formula.

11 Determinations

(1) Matters under this **transmission pricing methodology** determined by **Transpower** are determined in **Transpower's** sole discretion while acting—
(a) reasonably; and
(b) subject to subclause (2), in accordance with **GAAP**; and
(c) subject to subclause (3), with reference to—
(i) information made available to **Transpower** by or on behalf of **participants** and other persons with an interest in the determination; and
(ii) **Transpower's** and (where published) other persons' financial and regulatory records, registers and disclosures, including the **RAB**; and
(iii) other information relevant to the determination **Transpower** is reasonably able to obtain.

(2) If there is any inconsistency between the requirements of **GAAP** and the requirements of this **transmission pricing methodology**, this **transmission pricing methodology** takes precedence.

(3) **Transpower** is not required to give equal weight to the information referred to in paragraph (1)(c).

12 Reverse Flow

(1) This clause 12 applies if all of the following conditions are satisfied:
(a) a **customer** has an agreement with the **system operator** under clause 6 of Technical Code A of Schedule 8.3 of this Code:
(b) the **customer** has notified **Transpower** in writing that there is **reverse flow** at a **connection location** as a result of a **GXP tie** authorised under the agreement referred to in paragraph (a):
(c) the **customer** notified **Transpower** under paragraph 0 within 20 **business days** of the **reverse flow** starting:
(d) **Transpower** is reasonably satisfied there is **reverse flow** at the **connection location** as a result of a **GXP tie** authorised under the agreement referred to in paragraph (a).

(2) Subject to subclause (3), **Transpower** must, despite anything else in this **transmission pricing methodology**—
(a) adjust the **customer's allocation data** for the **connection location** to mitigate or eliminate the impact of the **reverse flow**, as determined by **Transpower**; and
(b) use the adjusted **allocation data** to calculate future **transmission charges**.

(3) Subclause (2) does not apply to any **allocation data** used to calculate **regional NPB** for a **regional customer group** under the **simple method**.

(4) **Transpower** must **publish** the details of any adjustment it makes under subclause (2) within 20 **business days** of making the adjustment.

13 Exceptional Operating Circumstances

(1) Subject to subclause (2), if **Transpower** determines—
  (a) a **Transpower** requirement, **system operator** requirement, or planned or unplanned **outage** has caused exceptional operating circumstances in the power system; and
  (b) those circumstances have resulted in a **customer's allocation data** not reflecting normal operating circumstances in the power system (a distortion),

Transpower may, despite anything else in this **transmission pricing methodology**—
  (c) adjust the **allocation data** to mitigate or eliminate the distortion, as determined by **Transpower**; and
  (d) use the adjusted **allocation data** to calculate future **transmission charges**.

(2) Subclause (1) does not apply to any **allocation data** used to calculate **regional NPB** for a **regional customer group** under the **simple method**.

(3) **Transpower** must **publish** the details of any adjustment it makes under subclause (1) within 20 **business days** of making the adjustment.

General

14 Applications, Application Fees and Application Requirements

(1) **Transpower—**
  (a) is not obliged to start assessing an **application**; and
  (b) may suspend its assessment of, or reject, an **application**,

if—
  (c) the **application fee**, if any, for the **application** has not been paid; or
  (d) the **application** does not comply with the relevant **application requirements**; or
  (e) the applicant otherwise does not comply, or has not complied, with this **transmission pricing methodology** in relation to the **application**.

(2) Subject to subclause (1), **Transpower** must—
  (a) prioritise assessment of **applications** in the order they are received by **Transpower**; and
  (b) complete its assessment of an **application** within a reasonable time of receiving it, having regard to the complexity of the **application** and the quality of the information provided by the applicant in support of it.

(3) Any **application fee** must be reasonable having regard to **Transpower's** expected costs of assessing **applications** of the relevant type, and may be—
  (a) fixed or based on actual costs; and
  (b) capped or uncapped; and
  (c) up-front or staged; and
  (d) refundable or non-refundable.

(4) **Application requirements** must be reasonable having regard to the matters relevant to **Transpower's** assessment of **applications** of the relevant type.

15 Consultation on Transmission Charges

(1) **Transpower** must consult on the following matters with at least the following groups before the relevant **transmission charges** or adjustments to them are finalised:

subject matter	minimum group to be consulted
Proposed **annual connection charges**	**Customers** who will pay the **connection charges**
Proposed material adjustment to **connection charges** during a **pricing year**	**Customers** who will pay the adjusted **connection charges**
Proposed starting **BBI customer allocations** for a **post-2019 BBI** expected to be **high-value** when **fully commissioned**	Public consultation
Proposed adjustment to the **BBI customer allocations** for a **post-2019 BBI** due to a **SSCGU**	Public consultation
Other proposed material adjustment to the **BBI customer allocations** for a **post-2019 BBI** expected to be **high-value** immediately before the adjustment	**Customers** who are or will be **beneficiaries** of the **post-2019 BBI**
Proposed allocation of **residual charges** for a **pricing year**	All **load customers**
Proposed material adjustment to the allocation of **residual charges** during a **pricing year**	All **load customers**

(2) **Transpower** must consult publicly on the proposed **modelled regions** and **regional NPBs** under the **simple method**, and proposed **simple method factors**, for—
- (a) the first **simple method period**, before the start of the **first pricing year**; and
- (b) each subsequent **simple method period**, before the start of the **simple method period**.

(3) Consultation—
- (a) under subclause (1) on the proposed starting **BBI customer allocations** for a **high-value post-2019 BBI** or a proposed material adjustment to the **BBI customer allocations** for a **high-value post-2019 BBI**; and
- (b) under subclause (2)

must include information about any material departures from the assumptions and methodologies **published** in the **assumptions book** and the reasons for those departures.

(4) Consultation under subclause (1) on—
- (a) the proposed starting **BBI customer allocations** for a **high-value post-2019 BBI**; or
- (b) a proposed material adjustment to the **BBI customer allocations** for a **high-value post-2019 BBI**, including due to a **SSCGU**,

must include an estimate of the **high-value post-2019 BBI's covered cost** when **fully commissioned**.

(5) Consultation under subclause (1) or (2) may occur as part of **Transpower** or **Commission** consultation required under the **Transpower Capex IM**, other parts of this Code, or **transmission agreements**, either before or after the start of the **first pricing year**.

16 Information about Transmission Charges

(1) **Transpower** must provide each **customer** with reasonable information that is sufficient for the **customer** to understand the basis on which the **customer's annual charges** and **monthly charges** have been calculated. For a **load customer**, this information must include, for the relevant **pricing year—**

(a) the amount of otherwise unallocated operating costs included in **residual revenue**; and

(b) **reassignment amounts** included in **residual revenue**.

(2) The information referred to in subclause (1) may be provided to a **customer** as part of **Transpower's** obligation under a **transmission agreement** to notify the **customer** of **annual charges**, **monthly charges** and changes to them, either before or after the start of the **first pricing year**.

Part B Grid Asset Classification

17 Grid Assets and Land and Buildings

(1) Subject to subclause (3), **grid assets** are **assets** and other works (including land, easements, leases and other interests in land, buildings, containment facilities and other structures, but excluding **Transpower's** fibre optic network) that—

(a) comprise or support the **grid**; and

(b) are—

(i) owned by or leased to **Transpower**, provided that if the **assets** or other works are leased by **Transpower** to another person then the **assets** or other works will only be **grid assets** if **Transpower** has expressly agreed in writing with that person that the **assets** or other works are to be treated as **grid assets** for the purposes of this **transmission pricing methodology**; or

(ii) owned by another person and not leased to **Transpower**, but only if **Transpower** has expressly agreed in writing with that person that the **assets** or other works are to be treated as **grid assets** for the purposes of this **transmission pricing methodology**.

(2) **Transpower's** provision of, or agreement to provide, **grid assets** that facilitate the connection of other **assets** to the **grid** does not constitute **Transpower's** agreement to treat the other **assets** as **grid assets** for the purposes of subparagraph (1)(b)(ii).

(3) An asset that was, immediately before the start of the **first pricing year**—

(a) treated as a **grid** asset under the **previous transmission pricing methodology**; and

(b) not owned by or leased to **Transpower**,

will not cease to be a **grid asset** merely because neither subparagraph (1)(b)(i) nor subparagraph (1)(b)(ii) applies to the asset.

(4) **Land and buildings** are **grid assets** that are land, easements, leases or other interests in land, buildings, oil containment facilities, or other structures that are not comprised in the **grid**.

(5) **Land and buildings** that support a part of the **grid** are referred to as being "part of" that part of the **grid**, together with the **grid assets** that comprise that part of the **grid**.

18 Partial Funding of Grid Assets

Subject to other legal requirements and **GAAP**, a **grid asset** the capital cost of which is partially funded under an **investment agreement**—

(a) may be represented in **Transpower's** financial and regulatory records, registers and disclosures, including the **RAB**, as multiple **grid assets**; and

(b) those **grid assets** may be treated as separate **grid assets** for the purposes of calculating **transmission charges**,

as necessary or convenient to ensure **Transpower** does not under-recover the total cost of the **grid asset** through this **transmission pricing methodology** and the **investment agreement**. To avoid doubt, **Transpower** must not use its discretion under this clause to over-recover the total cost of a **grid asset**.

19 Nodes and Links

(1) A **node** is any of the following:

(a) a **connection location**:

(b) a **station** that is not a **connection location**:

(c) a location in the **grid** where a circuit diverges or terminates (such as a "tee" point, or a deviation of a circuit within a **line** to connect to a **station** where the **line** does not terminate).

(2) For the purposes of paragraph (1)(c)—
(a) a circuit does not "diverge" at a location merely because it changes direction at the location, or transitions from overhead to underground or vice versa at the location; and
(b) adjacent towers, poles or other structures at which a circuit diverges may be treated as a single location.

(3) Subject to subclause (8), a **link** is either a single circuit or multiple parallel circuits (of the same voltage) that are **grid assets** and connect 2 **nodes** (and includes any **grid assets**, such as circuit breakers, that are required to connect the **link** at either **node**).

(4) To avoid doubt—
(a) a **Transpower operations facility** is not a **node**; and
(b) a circuit or multiple parallel circuits that are **grid assets** and connect—
(i) a **node**; and
(ii) a **Transpower operations facility** that is not connected to any other **node**,
is not a **link**.

(5) Figures 5 and 6 below illustrate how **nodes** and **links** are identified under subclauses (1) to (4):
(a) Figure 5 shows a physical **grid** configuration. CL1, CL2 and CL3 are **connection locations**. TOF is a **Transpower operations facility**. T1, T2, T3 and T4 are towers. The lines are circuits between the **connection locations** or **Transpower operations facility** and the towers. All of the circuits are **grid assets** except the circuit between CL2 and CL3:
(b) Figure 6 shows the same **grid** configuration as figure 5 but in the form of **nodes** and **links**. **Nodes** N2, N4 and N5 correspond to **connection locations** CL1, CL2 and CL3 respectively. **Node** N1 corresponds to the divergence at tower T1. **Node** N3 corresponds to the divergence at towers T2 and T3, which are adjacent and treated as a single location. There is no **node** corresponding to tower T4 because the change of direction of the circuits at T4 is insufficient to constitute a divergence. There is no **node** corresponding to **Transpower operations facility** TOF because a **Transpower operations facility** is not a **node**. There is no **link** between N4 and N5 because the circuit between CL2 and CL3 is not a **grid asset**. There is no **link** between T3 and TOF because TOF is not a **node**.

Figure 5

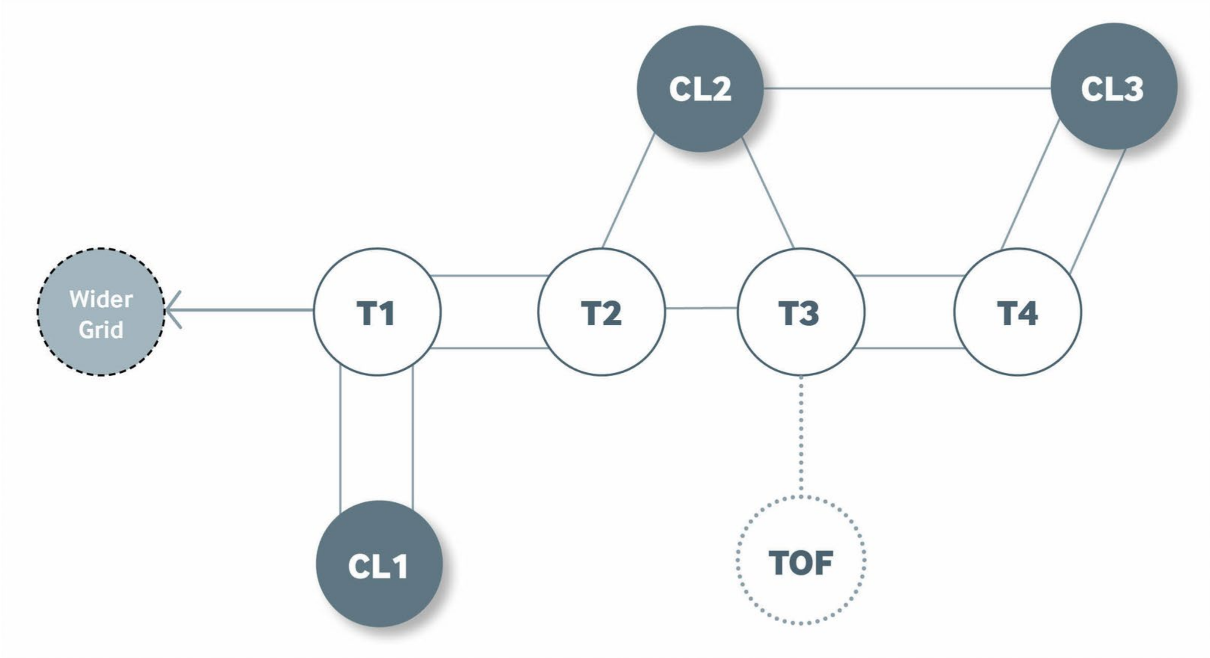
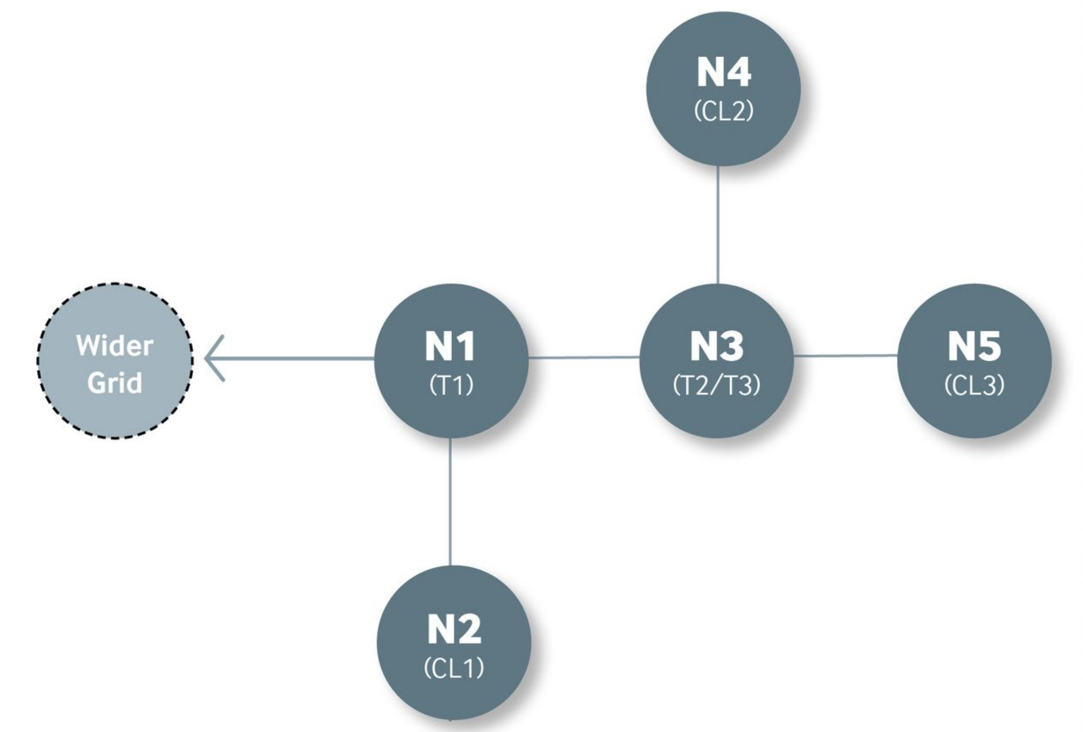


Figure 6



(6) Subclauses (1) to (3) must be applied to identify **nodes** and **links** contemporaneously and not prospectively or retrospectively. If a **grid asset** is expected to change from being a **node** or **link** to not being a **node** or **link**, or vice versa, once a future event occurs (such as the

commissioning or **decommissioning** of it or another **asset**), that does not affect the **node** or **link** status of the **grid asset** before the event occurs.

(7) Subject to subclause (8), if a **grid asset** was a **node** or **link** before this **transmission pricing methodology** came into effect or before an event occurred, that does not prevent the **grid asset** ceasing to be a **node** or **link** when this **transmission pricing methodology** came into effect or when the event occurred, or vice versa.

(8) A circuit or circuits that are not **grid assets** but, immediately before this **transmission pricing methodology** came into effect, comprised a "link" under the **previous transmission pricing methodology**—

(a) will be treated as a **link** despite not being **grid assets**; but

(b) will cease to be a **link** if the circuit or circuits otherwise cease to meet the requirements for comprising a **link** under this **transmission pricing methodology**.

20 Connection and Interconnection Nodes and Links

(1) **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**:

(b) a **loop** is a continuous path of **nodes** and **links** with the same start and end **node**:

(c) a **small regional loop** is a **loop** between any group of **nodes** (excluding the **nodes** at the Benmore and Haywards substations) with only a single **link** from the **loop** to a **node** outside the **loop** that—

(i) is part of another **loop**; or

(ii) ultimately links to another **loop**, either directly or indirectly through other **nodes**:

(d) a connection node is any node that is not an interconnection node, including all nodes in a small regional loop:

(e) a **connection link** is a **link** with a **connection node** at 1 or both of its ends:

(f) an **interconnection link** is a **link** that connects 2 **interconnection nodes**.

(2) Figures 7, 8 and 9 below illustrate how **small regional loops**, **interconnection nodes** and **links**, and **connection nodes** and **links** are identified under subclause (1):

(a) In figures 7 and 8, **nodes** N2, N3 and N4 comprise a **small regional loop** because in each case there is only 1 **link** (from N4) to another **loop**. In figure 7, the **link** from N4 to the other **loop** is direct because **interconnection node** N6 is part of the other **loop**. In figure 8, the **link** from N4 to the other **loop** is indirect through **connection node** N5. In figures 7 and 8, N2, N3 and N4 are **connection nodes** and the **links** between and to them are **connection links**. In figure 8, the **link** from N5 to N6 is also a **connection link**:

(b) In figure 9, **nodes** N2, N3 and N4 do not comprise a **small regional loop** because there is more than 1 **link** (from N3 and N4) to another **loop**. Even if the **link** from N4 to N6 did not exist, N2, N3 and N4 would still not comprise a **small regional loop** because there are 2 **links** to another **loop** from N3. In figure 9, N2, N3 and N4 are **interconnection nodes** and (apart from the **link** from **connection node** N1 to N2, which is a **connection link**) the **links** between and to them are **interconnection links**.

Figure 7

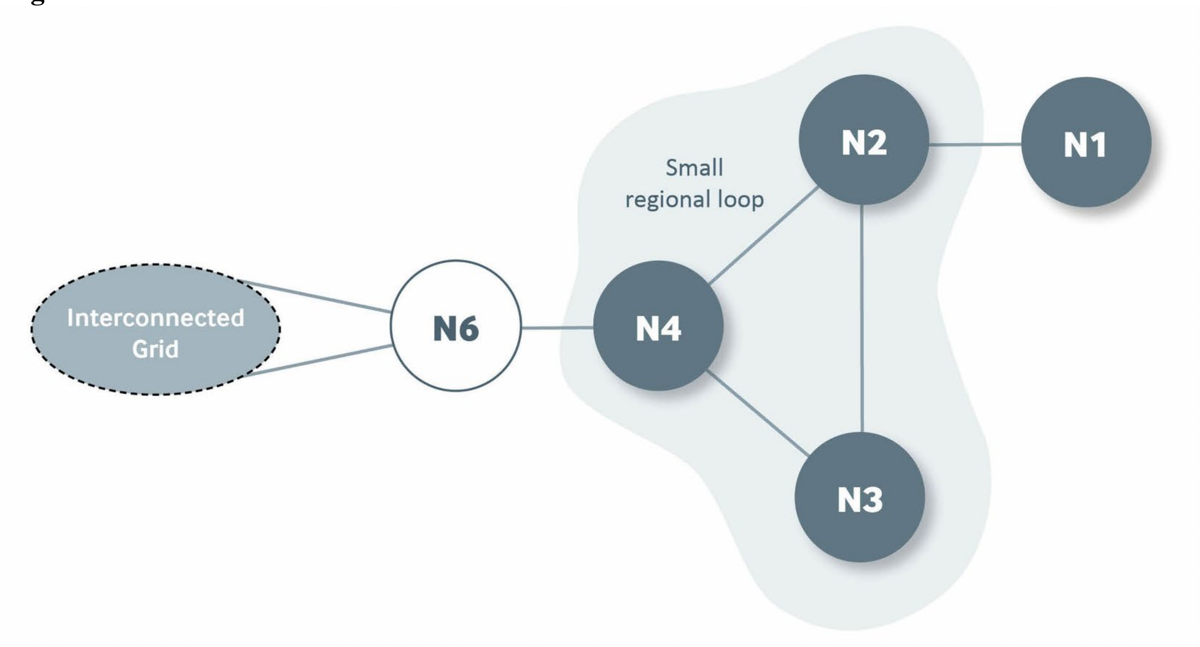


Figure 8

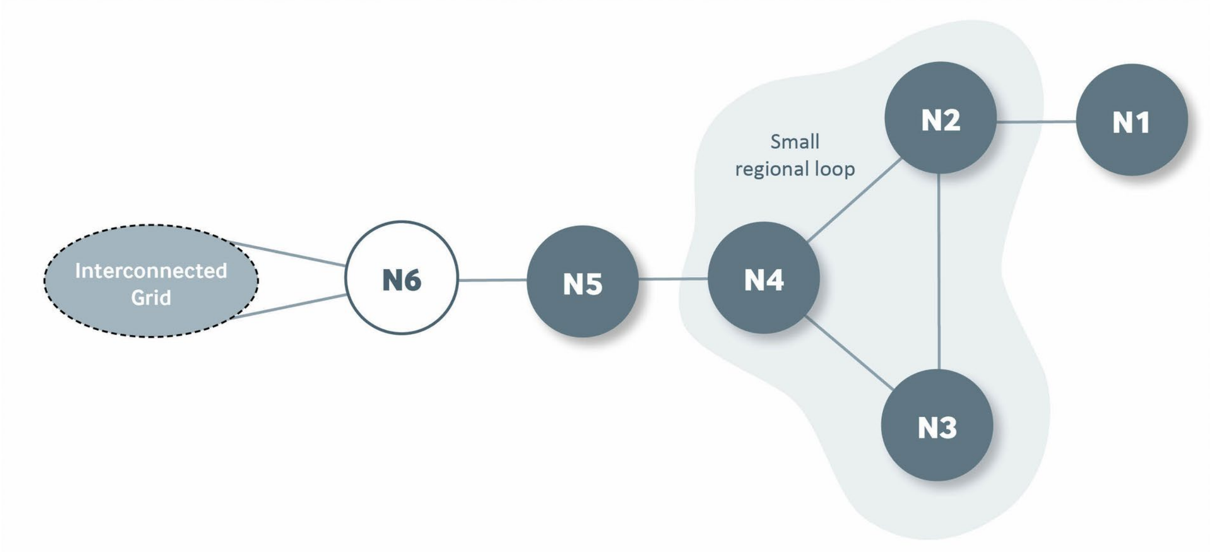
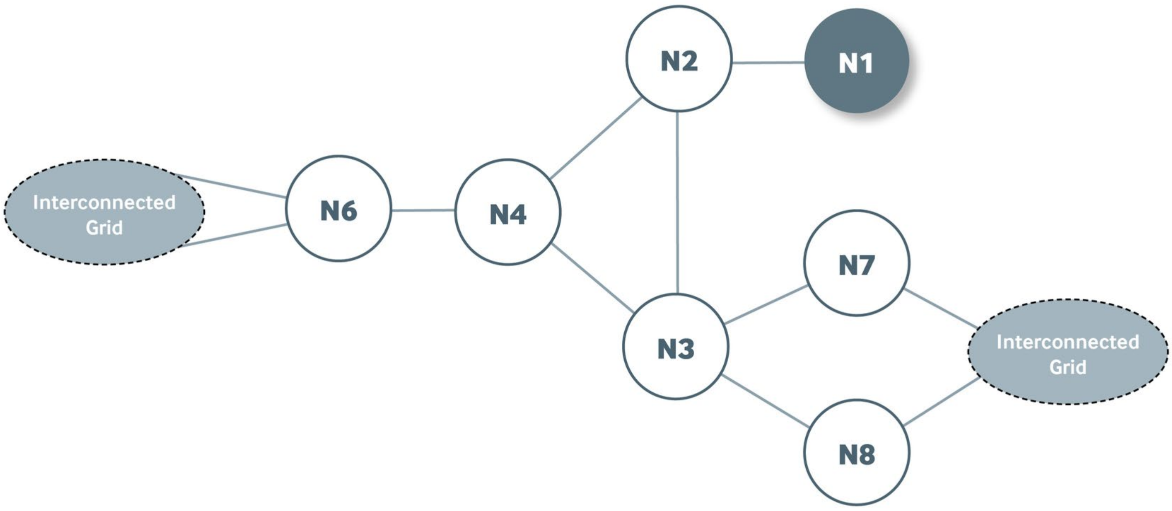


Figure 9



(3) Subject to subclause (4) , subclause (1) must be applied to classify **nodes** and **links** contemporaneously and not prospectively or retrospectively. If a **node** or **link** is expected to change from a **connection node** or **link** to an **interconnection node** or **link**, or vice versa, once a future event occurs (such as the **commissioning** or **decommissioning** of it or another **asset**), that does not affect the classification of the **node** or **link** before the event occurs.

(4) If a group of **nodes** or **links** that are to be provided as part of the same project are **commissioned** in a staged manner, the **connection** or **interconnection** status of each **node** and **link** in the group must be determined prospectively based on all **nodes** and **links** in the group being **commissioned**. However—
   (a) if all the **nodes** and **links** have not been **commissioned** by the start of the **pricing year** that is at least 9 months after the first **node** or **link** is **commissioned—**
      (i) subclause (3) will apply from the start of that **pricing year** and not this subclause (4) (so that the **nodes** and **links** will be classified contemporaneously from the start of that **pricing year**); and
      (ii) once all the **nodes** and **links** are **commissioned**, subclause (3) will apply from the start of the first **pricing year** that starts after the last **node** or **link** is **commissioned** (so that the **nodes** and **links** will be classified contemporaneously from the start of that **pricing year**); and
   (b) this subclause (4) must not be applied to classify an **interconnection node** or **interconnection link** as a **connection node** or **connection link**.

(5) If a **node** or **link** was classified as a **connection node** or **link** before this **transmission pricing methodology** came into effect or before an event occurred, that does not prevent the **node** or **link** being re-classified as an **interconnection node** or **link** when this **transmission pricing methodology** came into effect or when the event occurred, or vice versa.

21 Connection and Interconnection Assets

(1) A **connection asset** is any of the following that is not an **HVDC asset**:
   (a) a **grid asset** at a **connection node**, other than voltage support equipment that is not an **investment agreement asset**:
   (b) at an **interconnection node** that is a **connection location—**
      (i) any **grid asset** that is used to connect a **customer's assets** to the **grid**. This may include:

(A) a supply transformer, feeder bay, or supply transformer high voltage or low voltage breaker:

(B) a low voltage breaker, low voltage bus section breaker, voltage transformer, revenue meter, or other equipment that is on the same bus as a feeder; and

(ii) a proportion of the **land and buildings** at the **connection location** (LB_{conn}) calculated as follows:

$$LB_{conn} = \frac{RC_{conn\,total}}{RC_{total}}$$

where

$RC_{conn\ total}$ is the total **replacement cost** of all **grid assets** described in subparagraph (i) at the **connection location** at the end of the preceding **financial year**

RC_{total} is the total **replacement cost** of all **grid assets** (excluding **land and buildings**) at the **connection location** at the end of the preceding **financial year**:

(c) a **grid asset** that is part of a **connection link**. If a **line** is included in a **connection link** and 1 or more other **links**, the part of the **line** ascribed to the **connection link** must be determined according to the length of the **line** included in the **connection link** relative to the total length of the **line**.

(2) An **interconnection asset** is any **grid asset** that is not a **connection asset**, and includes any **HVDC asset**.

22 Associating Connection Assets with Connection Locations and Customers

(1) A **connection asset** that—

(a) is at a **connection location**; or

(b) if the **connection location** is a **connection node**, connects the **connection location** (directly or indirectly) to an **interconnection node**,

is referred to as a **connection asset** "for" the **connection location**, "that connects" (or other grammatical form of that phrase) the **customers** at the **connection location** and that those **customers** are "connected to" (or other grammatical form of that phrase).

(2) A **customer** who owns or controls **assets** connected at a **connection location** is referred to as a **customer** "at" the **connection location**.

(3) Subject to subclause (4), a **connection asset** for a **connection location** is referred to as "shared" between the **customers** at the **connection location**.

(4) A **connection asset** at a **connection location** that connects a specific **customer** only is not shared with any other **customer**.

(5) Figure 10 below is the **node** and **link** configuration in figure 7 above and illustrates how **connection assets** are associated with **connection locations** and **customers** under subclauses (1) to (3):

(a) N1, N3, N4 and N6 are **connection locations** at which **customers** A, B, C, D and E are connected. The smaller circles within N1, N3, N4 and N6 are **connection assets** at those **connection locations** that connect the specific **customers** shown only:

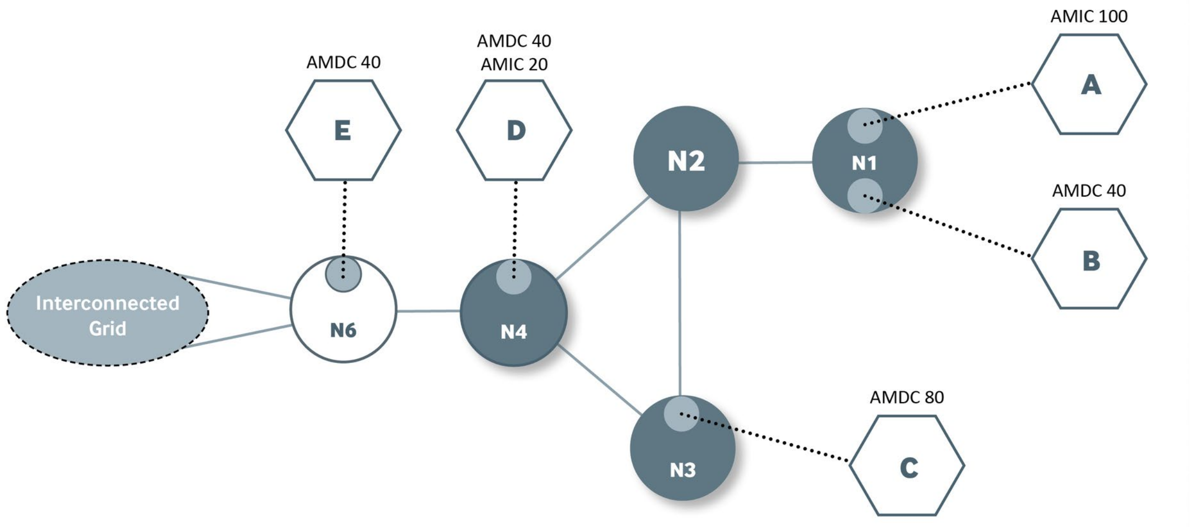
(b) The following table shows which **connection assets** are "for" the **connection locations** at N1, N3, N4 and N6. The **links** with an asterisk are "deep" **connection assets** for the relevant **connection location** because they are not located at, and do not directly connect to, the **connection location**:

connection assets	N1	N3	N4	N6
at **connection location**	Y	Y	Y	Y
in **link** N1-N2	Y	N	N	N
in **link** N2-N3	Y*	Y	N	N
in **link** N3-N4	Y*	Y	N	N
in **link** N2-N4	Y*	Y*	N	N
in **link** N4-N6	Y*	Y*	Y	N

(c) The following table shows how the **connection assets** at and between N1, N2, N3, N4 and N6 are "shared" between **customers** A, B, C, D and E:

connection assets	sharing
at N1	shared between A and B, apart from A- or B-specific **connection assets**
at N2	shared between A, B and C
at N3	shared between A, B and C, apart from C-specific **connection assets**
at N4	shared between A, B, C and D, apart from D-specific **connection assets**
at N6	shared between A, B, C, D and E, apart from E-specific **connection assets**
in **link** N1-N2	shared between A and B
in **link** N2-N3	shared between A, B and C
in **link** N3-N4	shared between A, B and C
in **link** N2-N4	shared between A, B and C
in **link** N4-N6	shared between A, B, C and D

Figure 10



23 Discretion to Classify and Reclassify as Connection Asset

(1) Despite anything else in this **transmission pricing methodology**, **Transpower** may classify or (subject to subclause (2)) reclassify any **grid asset** that would otherwise be an **interconnection asset** as a **connection asset** if **Transpower** determines—

(a) the **grid asset** provides or will provide **transmission services** to 1 or more **customers** of a type and nature typically provided by **connection assets**; and

(b) the **grid asset** does not provide or will not provide any material **transmission services** of a type and nature typically provided by **interconnection assets**; and

(c) it is reasonable in all the circumstances to classify or reclassify the **grid asset** as a **connection asset**.

(2) **Transpower** must not reclassify a **grid asset** as a **connection asset** under subclause (1) retrospectively.

(3) **Transpower** must—

(a) before classifying or reclassifying a **grid asset** as a **connection asset** under subclause (1) , consult with all **customers** who will be connected to the **grid asset**. This consultation may occur either before or after the start of the **first pricing year**; and

(b) notify those **customers** of **Transpower's** decision whether or not to classify or reclassify the **grid asset** as a **connection asset** under subclause (1).

(4) A **customer** referred to in subclause (3) may, within 20 days of **Transpower** notifying the **customer** of **Transpower's** decision, refer **Transpower's** decision under subclause (1) to an **independent expert** for review.

(5) The **independent expert's** decision will be binding on **Transpower** and the **customer,** and will have effect as if **Transpower** had made the decision itself, except that the **customer** may not refer the decision to an **independent expert** again.

(6) The costs of the **independent expert** must be met by the **customer** unless the **independent expert** decides **Transpower's** decision was unreasonable, in which case **Transpower** may be required to meet all or some of the costs of the **independent expert**, as determined by the **independent expert**.

Part C Connection Charges

24 Calculation of Connection Charges

(1) Only **customers** connected to **connection assets** pay **connection charges**.

(2) A **customer's annual connection charge** for a **connection asset**, **connection location** and **pricing year** (CC) is calculated as follows:

$$CC = \big((A + FA + M + O) \times CA\big) - RBT$$

where

A is the asset component for the **connection asset** and **pricing year** calculated under clause 26

FA is the **customer's funded asset** component for the **connection asset** and **pricing year** calculated under clause 28

M is the maintenance component for the **connection asset** and **pricing year** calculated under clause 30

O is the operating component for the **connection asset** and **pricing year** calculated under clause 31

CA is the **customer's connection customer allocation** for the **connection asset**, **connection location** and **pricing year**

RBT is the **customer's funded asset** rebate for the **connection asset**, **connection location** and **pricing year** calculated under clause 29.

(3) A **customer's annual connection charge** for a **connection location** and **pricing year** (ACC) is calculated as follows:

$$ACC = \sum_a CC_a$$

where CC_a is the **customer's annual connection charge** for **connection asset** a for the **connection location** and **pricing year**.

(4) A **customer's annual connection charge** for a **connection transmission alternative** and **pricing year** (TACC) is calculated as follows:

$$TACC = TAC \times \frac{\sum_l ACC_l}{\sum_l ACC_{l\,total}}$$

where

TAC is the **TA opex** for the **connection transmission alternative** and preceding **financial year**, less any contribution to the **TA opex** under **investment agreements**

ACC_l is the **customer's annual connection charge** for **connection location** l and the previous **pricing year**, where **connection location** l is a **connection location** that would be connected by a **connection asset** for which the **connection transmission alternative** is an alternative

$ACC_{l\ total}$ is the total of all **customers' annual connection charges** for **connection location** l and the previous **pricing year**.

(5) A **customer's monthly connection charge** for a **pricing year** (MCC) is calculated—

(a) for a **connection location**, as follows:

$$MCC = \frac{ACC}{12}$$

where ACC is the **customer's annual connection charge** for the **connection location** and **pricing year**; and

(b) for a **connection transmission alternative**, as follows:

$$MCC = \frac{TACC}{12}$$

where TACC is the **customer's annual connection charge** for the **connection transmission alternative** and **pricing year**.

(6) **Connection charges** are calculated for each **pricing year** before the start of the **pricing year**.

(7) A **connection charge** may be adjusted, including during a **pricing year**, under clauses 76 to 80 if there is a **connection charge adjustment event**.

25 Start of Connection Charges

Transpower must start the **connection charges** for a **connection investment** from the **connection investment's start pricing year**. To avoid doubt, this clause does not apply to charges under an **investment agreement**.

26 Asset Component

(1) Subject to subclause (2), **Transpower** may designate a **connection asset**, or an actual or notional part of a **connection asset**, as anticipatory for a **pricing year** if—

(a) the **connection asset** or part of the **connection asset** was **commissioned** at or after the start of the **first pricing year**; and

(b) **Transpower** determines that the **connection asset** or part of the **connection asset** is not likely to be required during the **pricing year** by the **customers** connected to the **connection asset**.

(2) Once **Transpower** has designated a notional part of a **connection asset** as anticipatory for a **pricing year** under subclause (1), **Transpower** must not designate a greater notional part of the **connection asset** or the whole **connection asset** as anticipatory for any subsequent **pricing year**.

(3) A **connection asset** or part of a **connection asset** designated as anticipatory for a **pricing year** under subclause (1) is an **anticipatory connection asset** for the **pricing year**. If the **anticipatory connection asset** is part of a larger **connection asset** then, for the purposes of

this clause 26 and clause 27, the larger **connection asset** is treated as two separate **connection assets** for the **pricing year**, being the **anticipatory connection asset** and the part of the larger **connection asset** that is not anticipatory for the **pricing year**.

(4) Whether or not a **connection asset** or part of **a connection asset** is an **anticipatory connection asset** for a **pricing year** must be determined by **Transpower** having regard to the extent to which—

(a) the **customers** connected to the **connection asset** have agreed to fund the **anticipatory connection asset** under **investment agreements**; and

(b) the **anticipatory connection asset** is likely to be required to meet the requirements of the **customers** connected to the **connection asset** and cover reasonable **grid** contingencies during the **pricing year**.

(5) Half of the capital cost of an **anticipatory connection asset** is recovered through the asset component of **connection charges**. The other half of the capital cost of the **anticipatory connection asset** is recovered through **benefit-based charges** for the relevant **anticipatory BBI** (see clause 27).

(6) The asset component of the **connection charge** for a **connection asset** and **pricing year** (A) allocates a portion of the capital cost of all **connection assets** to the **connection asset**, and is calculated as follows:

$$A = (ARR \times RC) + (DARR \times RC')$$

where

ARR is the **connection asset** return rate for the **pricing year** calculated under subclause (7)

RC is—

(a) 0 if the **connection asset** is an **investment agreement asset** or **anticipatory connection asset**; or

(b) otherwise, the **replacement cost** of the **connection asset** at the end of the preceding **financial year**

DARR is the discounted **connection asset** return rate for the **pricing year** calculated under subclause (8)

RC′ is—

(a) 0 if the **connection asset** is an **anticipatory connection asset**; or

(b) otherwise, the **replacement cost** of the **connection asset** at the end of the preceding **financial year** (even if the **connection asset** is an **investment agreement asset**).

(7) The **connection asset** return rate for a **pricing year** (ARR) is calculated as follows:

$$ARR = \frac{\left(r \times \left(V_{total} - V_{total\ anticipatory}\right)\right) + \left(D_{total} - D_{total\ anticipatory}\right)}{RC_{total}}$$

where

r is **Transpower's PQ WACC** (pre-tax) for the **pricing year**

V_{total} is the total **closing RAB value** of all **connection assets** for the preceding **financial year**

$V_{total\ anticipatory}$ is the part of V_{total} attributable to **anticipatory connection assets**, as determined by **Transpower**

D_{total} is total **depreciation** of all **connection assets** other than **investment agreement assets** during the preceding **financial year**, excluding **accelerated depreciation**

$D_{total\ anticipatory}$ is the part of D_{total} attributable to **anticipatory connection assets**, as determined by **Transpower**

RC_{total} is the total **replacement cost** of all **connection assets** other than **investment agreement assets** and **anticipatory connection assets** at the end of the preceding **financial year**.

(8) The discounted **connection asset** return rate for a **pricing year** (DARR) is calculated as follows:

$$DARR = \frac{(r \times V_{total\ anticipatory}) + D_{total\ anticipatory}}{RC'_{total}} \times 0.5$$

where

r is **Transpower's PQ WACC** (pre-tax) for the **pricing year**

$V_{total\ anticipatory}$ is the part of the total **closing RAB value** of all **connection assets** for the preceding **financial year** attributable to **anticipatory connection assets**, as determined by **Transpower**

$D_{total\ anticipatory}$ is the part of total **depreciation** of all **connection assets** other than **investment agreement assets** during the preceding **financial year**, excluding **accelerated depreciation**, attributable to **anticipatory connection assets**, as determined by **Transpower**

RC'_{total} is the total **replacement cost** of all **connection assets** (including **connection assets** that are **investment agreement assets**) other than **anticipatory connection assets** at the end of the preceding **financial year**.

27 Anticipatory BBIs

(1) The **benefit-based charges** for **anticipatory BBIs** recover the part of the capital cost of **anticipatory connection assets** that is not recovered through the asset component of **connection charges**, specifically half of that capital cost.

(2) For each **anticipatory connection asset** for a **pricing year** there is deemed to be a **commissioned BBI** (an **anticipatory BBI**) for the **pricing year** (only for the purpose of recovering half of the capital cost of the **anticipatory connection asset**)—
(a) that comprises the **anticipatory connection asset**; and
(b) that has a **covered cost** for the **pricing year** (CVC) calculated as follows:

$$CVC = \left(\left(r \times V_{anticipatory}\right) + \mathrm{D}_{anticipatory}\right) \times 0.5$$

where

r is **Transpower's PQ WACC** (pre-tax) for the **pricing year**

$V_{anticipatory}$ is the part of the total **closing RAB value** for the preceding **financial year** attributable to the **anticipatory connection asset**, as determined by **Transpower**

$D_{anticipatory}$ is the part of total **depreciation** during the preceding **financial year,** excluding **accelerated depreciation**, attributable to the **anticipatory connection asset**, as determined by **Transpower**; and

(c) for which the **start pricing year** is the **pricing year**; and
(d) for which a **customer's individual NPB** is calculated under the **simple method**, subject to the modifications in subclause (3) cand even if the **anticipatory BBI's** deemed **covered cost** for the **pricing year** under paragraph (b)is more than the base capex threshold as defined in the **Transpower Capex IM**.

(3) The modifications referred to in paragraph 2(d) are as follows:
(a) If **Transpower** determines the **anticipatory BBI** is primarily to allow for a future increase in **offtake**, the **anticipatory BBI's regional customer groups** are limited to **regional supply groups**:
(b) If **Transpower** determines the **anticipatory BBI** is primarily to allow for a future increase in **injection**, the **anticipatory BBI's regional customer groups** are limited to **regional demand groups**.

28 Funded Asset Component

(1) The **funded asset** component of the **connection charge** ensures that **non-contributing customers** pay part of the capital cost of **funded assets** through their **connection charges**.

(2) A **customer's funded asset** component for a **connection asset** is 0 unless—
(a) the **connection asset** is a **funded asset**; and
(b) the **customer** is, but for the **funded asset** component, a **non-contributing customer** for the **funded asset**.

(3) Subject to subclauses (4) and (5), a **non-contributing customer's funded asset** component for a **funded asset** and **pricing year** (FA) is calculated as follows:

$$FA = TF \times \frac{EL_{remain}}{EL_{total}} \times \frac{1}{10}$$

where

TF is the total amount paid, or expected to be paid, towards the capital cost of the **funded asset** under all **investment agreements**

EL_{remain} is the remaining **economic life** of the **funded asset** at the end of the **pricing year** during which the **non-contributing customer** connected to the **funded asset**

EL_{total} is the total **economic life** of the **funded asset**, including any part of it that has elapsed.

(4) The **non-contributing customer's funded asset** component for the **funded asset** applies for 10 consecutive **pricing years** only, starting with the **pricing year** after the **pricing year** during which the **non-contributing customer** connected to the **funded asset**.

(5) If the **non-contributing customer** agrees with 1 or more **prior contributing customers** to contribute towards the capital cost of a **funded asset**—

(a) subclause (3) applies to the **funded asset** subject to that agreement; and

(b) the agreement is deemed to be an **investment agreement** for the **funded asset** (even if **Transpower** is not a party to it).

29 Funded Asset Rebate

(1) A **non-contributing customer's funded asset** component for a **funded asset** and **pricing year** is rebated to each **prior contributing customer** for the **funded asset** in respect of the **non-contributing customer**.

(2) A **customer's funded asset** rebate for a **connection asset** and **pricing year** is 0 unless—

(a) the **connection asset** is a **funded asset**; and

(b) a **non-contributing customer** pays a **funded asset** component for the **funded asset** and **pricing year**; and

(c) the **customer** is a **prior contributing customer** for the **funded asset** in respect of the **non-contributing customer**.

(3) Subject to subclause (4), **prior contributing customer** c's **funded asset** rebate of **non-contributing customer** i's **funded asset** component for a **connection location** and **pricing year** (RBT_c) is calculated as follows:

$$RBT_c = FA_i \times CA_i \times \frac{CA_c}{CA_{prior\ total}}$$

where

FA_i	is **non-contributing customer** i's **funded asset** component for the **funded asset** and **pricing year**
CA_i	is **non-contributing customer** i's **connection customer allocation** for the **funded asset**, **connection location** and **pricing year**
CA_c	is **prior contributing customer** c's **connection customer allocation** for the **funded asset**, **connection location** and **pricing year**
$CA_{prior\ total}$	is the total of all **prior contributing customers'** (including **prior contributing customer** c's) **connection customer allocations** for the **funded asset**, **connection location** and **pricing year**.

(4) Subclause (3) applies subject to any agreement of the type referred to in subclause 28(5).

30 Maintenance Component

(1) The maintenance component of the **connection charge** for a **connection asset** and **pricing year** (M) allocates to the **connection asset** a portion of **Transpower's** total maintenance costs for all **connection assets**, and is calculated as follows:

$$M = MC \times (1 - ICR_{maint})$$

where

MC is the maintenance cost component for the **connection asset** and **pricing year** calculated under subclause (2)

ICR_{maint} is the percentage of the maintenance cost for the **connection asset** and **pricing year** expected to be recovered by **Transpower** under **investment agreements**, expressed as a decimal and no more than 1.

(2) The maintenance cost component for the **connection asset** and **pricing year** (MC) is—
(a) if the **connection asset** is located at a **station**, the **station** maintenance cost component for the **pricing year** calculated under subclause (3); or
(b) if the **connection asset** is a **line**, the **line** maintenance cost component for the **pricing year** calculated under subclause (5).

(3) The **station** maintenance cost component for the **connection asset** and **pricing year** ($MC_{station}$) is calculated as follows:

$$MC_{station} = MRR_{station} \times RC$$

where

$MRR_{station}$ is the **station** maintenance recovery rate for the **pricing year** calculated under subclause (4)

RC is the **replacement cost** of the **connection asset** at the end of the preceding **financial year**.

(4) The **station** maintenance recovery rate for a **pricing year** ($MRR_{station}$) is calculated as follows:

$$MRR_{station} = \frac{AMC_{station\ total}}{RC_{station\ total}}$$

where

$AMC_{station\ total}$ is the average over the preceding 4 **financial years** of **Transpower's** maintenance costs for all **connection assets** located at **stations**

$RC_{station\ total}$ is the total **replacement cost** of all **connection assets** located at **stations** at the end of the preceding **financial year**.

(5) The **line** maintenance cost component is calculated using a **line** maintenance recovery rate that depends on the **line** type. The different **line** types (all AC) used are—
(a) 220kV or higher voltage tower **lines**; and
(b) other tower **lines**; and
(c) pole **lines**; and
(d) underground cable **lines**.

(6) The **line** maintenance cost component for the **connection asset** and **pricing year** (MC_{line}) is calculated as follows:

$$MC_{line} = MRR_{line\ t} \times L$$

where

$MRR_{line\ t}$ is the **line** maintenance recovery rate for the **connection asset's line** type t and the **pricing year** calculated under subclause (7)

L is the **line** length (in km) of the **connection asset** at the end of the preceding **financial year**.

(7) Subject to subclause (8), the **line** maintenance recovery rate for **lines** of type t and a **pricing year** ($MRR_{line\ t}$) is calculated as follows:

$$MRR_{line\ t} = \frac{AMC_{line\ t\ total}}{L_{t\ total}}$$

where

$AMC_{line\ t\ total}$ is the average over the preceding 4 **financial years** of **Transpower's** maintenance costs for all **connection assets** that are **lines** of type t

$L_{t\ total}$ is the total **line** length (in km) of all **connection assets** that are **lines** of type t at the end of the preceding **financial year**.

(8) **Transpower** may estimate the **line** maintenance recovery rate for underground cable **lines** if **Transpower** determines it has insufficient data to carry out the calculation in subclause (7) for underground cable **lines**.

31 Operating Component

(1) The operating component of the **connection charge** for a **connection asset** and **pricing year** (O) allocates to the **connection asset** a portion of **Transpower's** total operating costs for all **AC assets**, and is calculated as follows:

$$O = OC \times (1 - ICR_{op})$$

where

OC is the operating cost component for the **connection asset** and **pricing year** calculated under subclause (2)

ICR_{op} is the percentage of the operating cost for the **connection asset** and **pricing year** expected to be recovered by **Transpower** under **investment agreements**, expressed as a decimal and no more than 1.

(2) The operating cost component for the **connection asset** and **pricing year** (OC) is calculated as follows:

$$OC = ORR \times (S - (0.1 \times S_{cust}))$$

where

ORR is the operating recovery rate for the **pricing year** calculated under subclause (3)

S is the number of switches that are part of the **connection asset** at the end of the preceding **financial year**

S_{cust} is the number of switches that are part of the **connection asset** and operated by a **customer** at the end of the preceding **financial year**.

(3) The operating recovery rate for the **pricing year** (ORR) is calculated as follows:

$$ORR = \frac{OC_{switch\ total}}{\left(S_{total} - (0.1 \times S_{cust\ total})\right)}$$

where

$OC_{switch\ total}$ is **Transpower's** total operating costs for all **AC switches** over the preceding **financial year**

S_{total} is the total number of **AC switches** at the end of the preceding **financial year**

$S_{cust\ total}$ is the total number of **AC switches** that are operated by a **customer** at the end of the preceding **financial year**.

32 Connection Customer Allocations

(1) Subject to subclause (5) and clause 33, a **customer's connection customer allocation** for a **connection asset**, **connection location** and **pricing year** (CA_1) is calculated as follows if the **connection asset** is—
(a) for 1 **connection location** only; and
(b) not a **mixed connection asset**:

$$CA_1 = \frac{AMDIC}{AMDIC_{total}}$$

where

AMDIC is the total of the **customer's AMDC** and **AMIC** at the **connection location** for the **pricing year**

$AMDIC_{total}$ is the total of all **customers' AMDCs** and **AMICs** at the **connection location** for the **pricing year**.

(2) Subject to subclause (5) and clause 33, a **customer's connection customer allocation** for a **connection asset**, **connection location** and **pricing year** (CA_{2+}) is calculated as follows if the **connection asset** is—
(a) for 2 or more **connection locations**, being the set of **connection locations** L; and
(b) not a **mixed connection asset**:

$$CA_{2+} = \frac{AMDIC}{AMDIC_{L\ total}}$$

where

AMDIC is the total of the **customer's AMDC** and **AMIC** at the **connection location** for the **pricing year**

$AMDIC_{L\ total}$ is the total of all **customers' AMDCs** and **AMICs** at all **connection locations** in the set of **connection locations** L for the **pricing year**.

(3) Subject to subclauses (4) and (5) and clause 33, a **customer's connection customer allocation** for a **connection asset**, **connection location** and **pricing year** (CA_{mixed}) is calculated as follows if the **connection asset** is a **mixed connection asset**:

$$CA_{mixed} = \frac{AMDIC}{C}$$

where

AMDIC is the total of the **customer's AMDC** and **AMIC** at the **connection location** for the **pricing year**

C is the **capacity** of the **connection asset** at the end of **CMP A** for the **pricing year**.

(4) If the sum of all **customers' connection customer allocations** for a **mixed connection asset** and **pricing year** is greater than 1, **Transpower** must scale down all of the **connection customer allocations** on a pro rata basis so that they sum to 1.

(5) If a **connection asset** is—
(a) an **investment agreement asset** provided under an **investment agreement** with a **customer**; and
(b) for more than 1 **connection location**, or for 1 **connection location** at which there is more than 1 **customer**,

then the calculation of the **connection customer allocations** for the **connection asset** and **connection locations** is subject to any provisions in the **investment agreement** that alter the **customer's connection customer allocation** for the **connection asset** and **connection locations**.

(6) The following table shows the **connection customer allocations** for the **connection assets** that are part of the **connection links** in figure 10 above (based on the **AMDC** and **AMIC** quantities shown in figure 10):

link	connection location	customer	connection customer allocation
N1-N2	N1	A	$\frac{100}{140} = 0.7143$
		B	$\frac{40}{140} = 0.2857$
N2-N3 N3-N4 N2-N4	N1	A	$\frac{100}{220} = 0.4545$
		B	$\frac{40}{220} = 0.1818$
	N3	C	$\frac{80}{220} = 0.3636$
N4-N6	N1	A	$\frac{100}{280} = 0.3571$
		B	$\frac{40}{280} = 0.1429$
	N3	C	$\frac{80}{280} = 0.2857$
	N4	D (offtake)	$\frac{40}{280} = 0.1429$
		D (injection)	$\frac{20}{280} = 0.0714$

33 De-rating

(1) This clause 33 applies if both of the following conditions are satisfied:
  (a) a **customer** (the notifying **customer**) has notified **Transpower** in writing that—
    (i) the notifying **customer's assets** at a **connection location** have been **de-rated**; or
    (ii) **embedded plant** connected to the notifying **customer's assets** at a **connection location** have been **de-rated** and the **de-rating** is **large**:
  (b) **Transpower** is reasonably satisfied the notified **de-rating** or **large de-rating** has occurred.

(2) In this clause 33, a relevant **pricing year** is—
  (a) the first **pricing year** that starts at least 6 months (or such shorter period as **Transpower** may determine is practicable) after the date the conditions in subclause (1) are first satisfied; and
  (b) a subsequent **pricing year** if the date the conditions in subclause (1) are first satisfied is within **CMP A** for the **pricing year**.

(3) **Transpower** must, for each relevant **pricing year**, calculate **connection charges** for the **connection location** by—
  (a) estimating the notifying **customer's** future **AMDC** and **AMIC** for the **connection location** taking into account—
    (i) the reduced **capacity** of the connecting **customer's assets** or the **embedded plant** (as the case may be); and
    (ii) any available historical information about the notifying **customer's offtake** and **injection** at the **connection location**; and

(b) capping the notifying **customer's AMDC** and **AMIC** for the **connection location** and relevant **pricing year** at the notifying **customer's** estimated future **AMDC** and **AMIC** for the **connection location**.

34 Replacement Costs

(1) **Transpower** must review, including update as appropriate, the **replacement costs** it uses to calculate **connection charges** no later than 5 years after the start of the **first pricing year** and, after that, at intervals of no more than 5 years.

(2) **Transpower's** first review of **replacement costs** under subclause (1) may occur before the start of the **first pricing year**.

(3) Subject to subclause (4), **Transpower** must consult with all **customers** who pay **connection charges** on any update to **replacement costs** under subclause (1) before updating the **replacement costs**.

(4) **Transpower** is not required to consult on an update to **replacement costs** under subclause (1) if **Transpower** determines—
(a) the update is technical and non-controversial; or
(b) there is widespread support for the update among **customers**; or
(c) there has been adequate prior consultation on the update so that all relevant views of **customers** have been considered.

(5) Before **Transpower's** first review of **replacement costs** under subclause (1) is completed, the **replacement cost** of a **connection asset commissioned** before 1 July 2006 is calculated by multiplying the **connection asset's** unadjusted **replacement cost** by the **replacement cost adjustment factor**.

(6) If **Transpower** does not have a **replacement cost** for a **connection asset**, **Transpower** must use the **replacement cost** available to **Transpower** for the closest equivalent of the **connection asset**, as determined by **Transpower**, for the purposes of calculating **connection charges** for the **connection asset**.

Part D Benefit-based Charges

General

35 Calculation of Benefit-based Charges

(1) Subject to subclauses 84(7) and 85(6) and clause 88, only **beneficiaries** pay **benefit-based charges**, and only for the **BBIs** of which they are **beneficiaries**.

(2) A **beneficiary's annual benefit-based charge** for a **BBI** and **pricing year** (BBC) is calculated as follows:

$$BBC = CC \times CA$$

where

CC is the **BBI's covered cost** for the **pricing year**

CA is the **beneficiary's BBI customer allocation** for the **BBI**.

(3) A **beneficiary's monthly benefit-based charge** for a **BBI** and **pricing year** (MBBC) is calculated as follows:

$$MBBC = \frac{BBC}{12}$$

where BBC is the **beneficiary's annual benefit-based charge** for the **BBI** and **pricing year**.

(4) **Benefit-based charges** are calculated for each **pricing year** before the start of the **pricing year**.

(5) A **benefit-based charge** may be—
(a) adjusted, including during a **pricing year**, under clauses 81 to 91 if there is a **benefit-based charge adjustment event**; and
(b) adjusted under clause 96 if the relevant **BBI** is subject to **reassignment**.

36 Start of Benefit-based Charges

(1) Subject to subclause (2), **Transpower** must start the **benefit-based charges** for a **BBI** from the **BBI's start pricing year**. To avoid doubt, this subclause does not apply to charges under an **investment agreement**.

(2) **Transpower** may delay the start of the **benefit-based charges** for a **low-value post-2019 BBI** under the **simple method** until the **pricing year** that starts at least 6 months (or such shorter period as **Transpower** may determine is practicable) after **Transpower's** financial and regulatory records and registers contain all the locational information **Transpower** reasonably requires to calculate the **benefit-based charges** for the **BBI**.

37 Expenditure on Existing BBIs

(1) Subject to subclause (4) and (5), **Transpower** must treat a **refurbishment investment** or **replacement investment** in respect of an existing **post-2019 BBI** as—
(a) part of the existing **post-2019 BBI**, in which case the **refurbishment investment** or **replacement investment** will increase the **covered cost** of the **post-2019 BBI** but will not change its **BBI customer allocations**; or

(b) a separate **post-2019 BBI**; or
(c) part of an existing **post-2019 BBI** referred to in paragraph (b), in which case the **refurbishment investment** or **replacement investment** will increase the **covered cost** of the **post-2019 BBI** but will not change its **BBI customer allocations**.

(2) Subject to subclause (4) and (5), **Transpower** must treat a **refurbishment investment** or **replacement investment commissioned** after 23 July 2019 in respect of an **Appendix A BBI** as—
(a) a separate **post-2019 BBI**; or
(b) part of an existing **post-2019 BBI** referred to in paragraph (a), in which case the **refurbishment investment** or **replacement investment** will increase the **covered cost** of the **post-2019 BBI** but will not change its **BBI customer allocations**.

(3) Subject to subclause (5), **Transpower** must treat an **enhancement investment commissioned** after 23 July 2019 in respect of an existing **BBI** as a separate **post-2019 BBI**.

(4) **Transpower** must not treat a **refurbishment investment** or **replacement investment** as part of an existing **post-2019 BBI** under subclause (1) or (2) if **Transpower** determines the **refurbishment investment** or **replacement investment** is likely to have—
(a) different **beneficiaries** than the existing **post-2019 BBI**; or
(b) a materially different distribution of **NPB** than the existing **post-2019 BBI**.

(5) If a **refurbishment investment**, **replacement investment** or **enhancement investment** referred to in subclause(1), (2) or (3) is an **exempt post-2019 investment**—
(a) **Transpower** must not treat the **refurbishment investment**, **replacement investment** or **enhancement investment** as, or as part of, a **post-2019 BBI**; and
(b) if the **refurbishment investment**, **replacement investment** or **enhancement investment** is in respect of an **Appendix A BBI**, **Transpower** must treat the **refurbishment investment**, **replacement investment** or **enhancement investment** as part of the **Appendix A BBI**, in which case the **refurbishment investment**, **replacement investment** or **enhancement investment** will increase the **covered cost** of the **Appendix A BBI** but will not change its **BBI customer allocations**.

38 Assumptions Book

(1) **Transpower** must **publish**, and may from time to time **publish** updates to, an **assumptions book**.

(2) The **assumptions book** must not contain any assumptions or methodologies that are inconsistent with this Code.

(3) Subject to subclause (4), **Transpower** must consult with all **customers** on the **assumptions book** or any update to it before **publishing** the **assumptions book** or update.

(4) **Transpower** is not required to consult on an update to the **assumptions book** if **Transpower** determines—
(a) the update is technical and non-controversial; or
(b) there is widespread support for the update among **customers**; or
(c) there has been adequate prior consultation on the update so that all relevant views of **customers** have been considered.

(5) Except as otherwise stated in this **transmission pricing methodology**, the **assumptions book** is not binding on **Transpower** or any **independent expert**.

(6) **Transpower** must review the content of the **assumptions book** and consider whether any of the content is appropriate for incorporation in this **transmission pricing methodology** by way of a

review under clause 12.85 of this Code no later than 7 years after its date of publication and, after that, at intervals of no more than 7 years.

(7) The **assumptions book** may be part of the same document in which the **reassignment practice manual** or **prudent discount practice manual** is contained.

Covered Cost

39 Covered Cost

(1) A **BBI's covered cost** for a **pricing year** (CC) is calculated as follows:

$$CC = \sum_{a}(D_a + C_a + T_a) + AO$$

where

D_a is, subject to paragraph (6)(e), **depreciation** of asset a for the preceding **financial year**, where asset a is an asset comprised in the **BBI**, excluding **accelerated depreciation**

C_a is the **capital charge** for asset a and the preceding **financial year** calculated under subclause (2)

T_a is the sum of—

(a) **Transpower's** depreciation tax loss (positive value) or gain (negative value) for asset a and the preceding **financial year** calculated under subclause (3); and

(b) income tax on the **capital charge** for asset a and the preceding **financial year** calculated under subclause (5)

AO is the attributed opex component for the **BBI** and **pricing year** calculated under subclause 40(1).

(2) The **capital charge** for an asset and **financial year** (C) is calculated—

(a) if the asset had an **opening RAB value** for the **financial year**, as follows:

$$C = r \times V$$

where

r is **Transpower's PQ WACC** (vanilla) at the start of the **financial year**

V is, subject to subclause 7, the **opening RAB value** for the asset and **financial year**; or

(b) if the asset was **commissioned** during the **financial year**, as follows:

$$C = V \times \frac{r \times (12.5 - m)}{12}$$

where

V is, subject to subclause (7), the asset's **value of commissioned asset** r is **Transpower's PQ WACC** (vanilla) at the start of the **financial year**

m is the month of the **financial year** during which the asset was **commissioned** (for example, m = 3 for September).

(3) **Transpower's** depreciation tax loss or gain for an asset and **financial year** (T_{dep}) is calculated as follow

$$T_{dep} = \frac{r \times (AD - TD - I)}{1 - r}$$

where

r is the corporate tax rate, as defined in the **Transpower IMs**, at the start of the **financial year**

AD is, subject to paragraph (6)(e), **depreciation** of the asset during the **financial year**, excluding **accelerated depreciation**

TD is, subject to paragraph (6)(e), tax depreciation of the asset during the **financial year**, excluding **accelerated depreciation**

I is notional interest for the asset and **financial year** calculated under subclause (4).

(4) Notional interest for an asset and **financial year** (I) is calculated as follows:

$$I = V \times L \times CD$$

where

V is, subject to subclause (7), the **opening RAB value** for the asset and **financial year**

L is leverage, as defined in the **Transpower IMs**, at the start of the **financial year**

CD is the estimated cost of debt used under the **Transpower IMs** to calculate **Transpower's PQ WACC** (vanilla) applicable at the start of the **financial year**.

(5) Income tax on the **capital charge** for an asset and **financial year** (T_{inc}) is calculated as follows:

$$T_{inc} = \frac{r \times C}{1 - r}$$

where

r is the corporate tax rate, as defined in the **Transpower IMs**, at the start of the **financial year**

C is the **capital charge** for the asset and **financial year** calculated under subclause (2).

(6) If an asset comprised in a **BBI** that is expected to be **high-value** when **fully commissioned**—
(a) was **commissioned** before or during a **pricing year's** preceding **financial year**; and
(b) does not have an asset type recorded in **Transpower's** fixed asset register at the time **Transpower** calculates the **BBI's covered cost** for the **pricing year**,

Transpower must—
(c) determine an interim asset type for the asset for **depreciation** and tax depreciation purposes; and
(d) use the interim asset type determined under paragraph (c) to calculate notional **depreciation** and notional tax depreciation for the asset and preceding **financial year**; and
(e) use the notional **depreciation** and notional tax depreciation calculated under paragraph (d) as the values for the variables D_a, AD and TD, as appropriate, in subclauses (1), (3) and 40(1) for the asset and **pricing year**; and
(f) make such adjustments to **depreciation** and depreciation tax loss or gain for the **BBI** and subsequent **financial years** as are necessary to ensure—
(i) there is no material over-recovery of **depreciation** for the asset; and
(ii) there is no material over or under-recovery of depreciation tax loss or gain for the asset.

(7) If the asset referred to in subclause (2) or (4)—
(a)has been **written-down**; and
(b)is comprised in a **BBI** that, as at the start of the relevant **financial year**, does not meet the requirements of subparagraph (b)(i), (b)(ii) or (b)(iii) of the definition of **eligible BBI** in clause 3; and
(c)the circumstances justifying the **write-down** of the asset would otherwise justify **reassignment** of the **BBI** (excluding subparagraph 104(2)(b)(ii)),

Transpower must carry out the calculation under subclause (2) or (4) for the asset as if the asset had not been **written-down**.

40 Attributed Opex Component

(1) The attributed opex component for a **BBI** and **pricing year** (AO) is calculated as follows:

$$AO = \sum_{a} (D_a \times AOR) + HVDC + TA + MCP$$

where

D_a is, subject to subclause 39(6), **depreciation** of asset a for the preceding **financial year**, where asset a is an asset comprised in the **BBI**, excluding **accelerated depreciation**

AOR is the attributed opex ratio for the **pricing year** calculated under subclause (3)

HVDC is—
(a) if the **BBI** comprises 1 or more **transmission investments** in the **HVDC link**, an allocation of **HVDC opex** for the preceding **financial year** as determined by **Transpower** subject to subclause (2); or
(b) otherwise, 0

TA is—

(a) if the **BBI** comprises 1 or more **interconnection transmission alternatives**, **TA opex** for the **interconnection transmission alternatives** and preceding **financial year**, less any contribution to the **TA opex** under **investment agreements**; or
(b) otherwise, 0

MCP is **MCP opex** for the **BBI** and preceding **financial year**.

(2) **HVDC opex** for a **financial year** must be fully allocated to 1 or more **BBIs** that comprise a **transmission investment** in the **HVDC link**, unless there are no such **BBIs**.

(3) The attributed opex ratio for a **pricing year** during an **RCP** (AOR) is calculated as follows:

$$AOR = \frac{OC + PC + RC - HVDC - TA - MCP - FD}{D}$$

where

OC is the **allowance** for operating costs, as defined in the **Transpower IMs**, for the **RCP**

PC is the **allowance** for pass-through costs, as defined in the **Transpower IMs**, for the **RCP**

RC is the **allowance** for recoverable costs, as defined in the **Transpower IMs**, for the **RCP**

HVDC is forecast **HVDC opex** for the **RCP**

TA is the **allowance** for **TA opex** for the **RCP**, to the extent it is included in any of the above **allowances**

MCP is the **allowance** for **MCP opex** for the **RCP**, to the extent it is included in any of the above **allowances**

FD is an amount of operating costs attributable to **Transpower** assets that are fully depreciated at the start of the **RCP**, as determined by **Transpower**

D is the **allowance** for **depreciation** for the **RCP**.

(4) The value of AOR in subclause (3) is—
(a) calculated for the whole of the **RCP**; and
(b) only re-calculated if any of the relevant **allowances** are reset by the **Commission** during the **RCP**.

41 Covered Cost of Anticipatory BBI

To avoid doubt, clauses 39 and 40 do not apply to an **anticipatory BBI**, the deemed **covered cost** of which is calculated under paragraph 27(2)(b).

BBI Customer Allocations

42 BBI Customer Allocations for Appendix A BBIs

(1) Subject to paragraph 75(5)(a), for each **Appendix A BBI—**

(a) the starting **beneficiaries** are the **Appendix A beneficiaries** for the **Appendix A BBI**; and

(b) the starting **BBI customer allocations** are the **Appendix A allocations** for the **Appendix A BBI**.

(2) To avoid doubt, for each **Appendix A BBI—**

(a) the **Appendix A beneficiaries** are based on the **Schedule 1 beneficiaries** of the **Appendix A BBI**; and

(b) the **Appendix A allocations** are based on the **Schedule 1 allocations** for the **Appendix A BBI**,

in each case adjusted as **Transpower** determined necessary to account for changes to and affecting **customers** before and after the **Authority** published the **2020 guidelines**.

43 BBI Customer Allocations for Post-2019 BBIs

(1) A **customer's BBI customer allocation** for a **post-2019 BBI** (CA) is calculated as follows:

$$CA = \frac{NPB}{NPB_{total}}$$

where

NPB is the **customer's individual NPB** for the **post-2019 BBI**

NPB_{total} is the total of all **customers' individual NPBs** for the **post-2019 BBI**.

(2) Subject to subclause (3), a **customer's individual NPB** for a **post-2019 BBI** is calculated under a **standard method** or the **simple method** as follows:

type	sub-type	method
post-2019 BBI expected to be **high-value** when **fully commissioned**	**resiliency BBI**	**resiliency method**
	otherwise	**price-quantity method**
post-2019 BBI expected to be **low-value** when **fully commissioned**	none	**simple method**

(3) For the purpose of calculating **customers' BBI customer allocations** for a **high-value intervening BBI** and its **start pricing year**, **Transpower** may apply the **simple method** if **Transpower** determines it is necessary to do so to ensure there is sufficient time for **Transpower** to complete a robust process for calculating the **BBI's BBI customer allocations** under the **standard method**, including consultation under clause 15.

(4) If **Transpower** applies the **simple method** under subclause (3) for a **high-value intervening BBI**, **Transpower** must carry out a wash-up of **transmission charges** in the **pricing year** after the **BBI's start pricing year** so that no **customer** is under or over-charged **benefit-based**

charges for the **BBI** and **start pricing year** as a result of **Transpower** applying the **simple method** under subclause (3). The wash-up must include time value of money adjustments using **Transpower's ID WACC** (pre-tax).

(5) If a **post-2019 BBI** is a **tested investment**, the assumptions and other inputs (including the **factual**, **counterfactual**, **modelled constraints** and **scenarios**) **Transpower** uses in applying a **standard method** to the **post-2019 BBI** must be as consistent as reasonably practicable with the assumptions and other inputs used in applying the **investment test** to the **post-2019 BBI**, except—
  (a) as otherwise stated in this **transmission pricing methodology**; or
  (b) to the extent **Transpower** determines such alignment would not produce **BBI customer allocations** that are broadly proportionate to positive **NPB** from the **post-2019 BBI**, in which case **Transpower** may use different assumptions and other inputs provided they do not contradict what **Transpower** determines were its key drivers for proceeding with its investment in the **post-2019 BBI** as at the **post-2019 BBI's final investment decision date**.

(6) To avoid doubt, the order of the provisions of this **transmission pricing methodology** specifying the **standard methods** and **simple method** do not necessarily reflect the order in which **Transpower** will carry out the steps specified in those provisions when **Transpower** applies the relevant **standard method** or **simple method**.

Standard Method: Price-quantity Method

44 Overview of Price-quantity Method

(1) Clauses 44 to 55 apply—
  (a) to the **price-quantity method** only; and
  (b) only to those **post-2019 BBIs** to which **Transpower** applies the **price-quantity method** in accordance with subclause 43(2).

(2) Under the **price-quantity method**—
  (a) **regional NPB** is calculated for a **regional customer group** as any of the following:
    (i) **market regional NPB** under clauses 49 to 52
    (ii) **ancillary service regional NPB** under clause 53:
    (iii) **reliability regional NPB** under clausec54:
    (iv) **other regional NPB** under clause 55; and
  (b) subject to subclauses (3) and 55(2), **Transpower**—
    (i) must calculate **market regional NPB** for a **market BBI**; and
    (ii) may calculate **ancillary service regional NPB** for an **ancillary service BBI**; and
    (iii) may calculate **reliability regional NPB** for a **reliability BBI**; and
    (iv) may calculate or estimate **other regional NPB** for a **market BBI**, **ancillary service BBI** or **reliability BBI**; and
  (c) **individual NPB** is calculated for each **customer** in a **regional customer group** with positive **regional NPB**.

(3) Under the **price-quantity method**, **Transpower** must—
  (a) always calculate at least 1 of **market regional NPB**, **ancillary service regional NPB** or **reliability regional NPB** for a **post-2019 BBI**; and
  (b) calculate **ancillary service regional NPB** for an **ancillary service BBI** if **Transpower** determines it is necessary to do so to produce **BBI customer allocations** for the **ancillary service BBI** that are broadly proportionate to positive **NPB** from the **ancillary service BBI**; and

(c) calculate **reliability regional NPB** for a **reliability BBI** if **Transpower** determines it is necessary to do so to produce **BBI customer allocations** for the **reliability BBI** that are broadly proportionate to positive **NPB** from the **reliability BBI**.

45 Factual and Counterfactual

(1) **Transpower** must determine a **BBI's factual** and **counterfactual**.

(2) **Transpower** must apply the following principles to determine the **BBI's counterfactual** unless **Transpower** determines applying these principles does not produce a reasonably likely future **grid** state:

(a) if a **transmission investment** comprised in the **BBI** is an **enhancement investment**, the **counterfactual** must include the **transmission investment** not being made:

(b) if a **transmission investment** comprised in the **BBI** is a **replacement investment** or **compliance investment**, the **counterfactual** must include the immediate decommissioning of the relevant **grid asset** or **transmission alternative** without replacement:

(c) if a **transmission investment** comprised in the **BBI** is a **refurbishment investment**, the **counterfactual** must include leaving the relevant **grid asset** or **transmission alternative** in operation without refurbishment until it reaches replacement state and then immediately decommissioning it without replacement.

46 Scenarios

(1) **Transpower** must determine a **BBI's scenarios** and probability weightings for the **scenarios**. A **market BBI's market scenarios** must include variations in load growth, generation expansion and hydrology.

(2) **Transpower** must apply the same **scenarios** in a **BBI's factual** and **counterfactual**, unless the **BBI** is a **market BBI** that is expected to influence materially **generating plant** investment decisions, in which case **Transpower** may apply different generation expansion **market scenarios** in the **BBI's factual** and **counterfactual**.

(3) If a **market scenario** for a **BBI** includes a **customer** ceasing to be a **customer**, the **market scenario** must not be applied in the **BBI's factual or counterfactual** in respect of the **customer**. To avoid doubt, this means the present value of **regional NPB** for a **regional customer group** for the **BBI** of which the **customer** is a member may be different for the **customer** than for all other **customers** who are members of the **regional customer group**.

47 Individual NPB

A **customer's individual NPB** for a **BBI** (NPB) is calculated as follows:

$$NPB = \sum_{g} \left(PVRNPB_g \times \frac{IRA_g}{IRA_{g\ total}} \right)$$

where

$PVRNPB_g$ is the present value of **regional NPB** for **regional customer group** g calculated under clause 48, where **regional customer group** g is a **regional customer group** for the **BBI—**

(a) that has a positive present value of **regional NPB**; and

(b) of which the **customer** is a member

IRA_g is the value of the **customer's intra-regional allocator** for **regional customer group** g

$IRA_{g\ total}$ is the total of the values of all **customers' intra-regional allocators** for **regional customer group** g.

48 Present Value of Regional NPB

(1) Subject to subclause (2), the present value of a **regional customer group's regional NPB** (PVRNPB) is calculated as follows:

$$PVRNPB = \sum_n \frac{RNPB_n}{(1+r)^n}$$

where

$RNPB_n$ is the **regional customer group's market regional NPB**, **ancillary service regional NPB**, **reliability regional NPB** or **other regional NPB** (as the case may be) for year n of the **BBI's standard method calculation period**

r is the **BBI's standard method rate**.

(2) As an alternative to the calculation under subclause (1), **Transpower** may calculate a **regional customer group's market regional NPB**, **ancillary service regional NPB**, **reliability regional NPB** or **other regional NPB** (as the case may be) for each year of the **BBI's standard method calculation period** on a present value basis, provided that the method of calculating present value is consistent with the method in subclause (1).

49 Modelling for Market Regional NPB

(1) This clause 49 applies to modelling for calculating **market regional NPB** for a **market BBI**.

(2) **Transpower** must determine the **market BBI's investment grids**.

(3) **Transpower** must use a **wholesale market model** to model the prices, quantities and changes in prices and quantities in the **wholesale market** for **electricity** between the **market BBI's factual** and **counterfactual** under its **market scenarios** and based on its **investment grids**. The modelling must cover each year of the **market BBI's standard method calculation period**.

(4) The illustrative **wholesale market models** in figures 11 and 12 below show alternative modelled prices, quantities and changes in prices and quantities for a notional **market BBI**, **market scenario** and year of the **market BBI's standard method calculation period** (assuming no adjustments under subclause (6)). The effect of the **market BBI** is modelled as a change in the supply curve from S (**counterfactual**) to S′ (**factual**). P_{max} is **consumers'** estimated cost of self-supply for **electricity** or alternative energy.

Figure 11

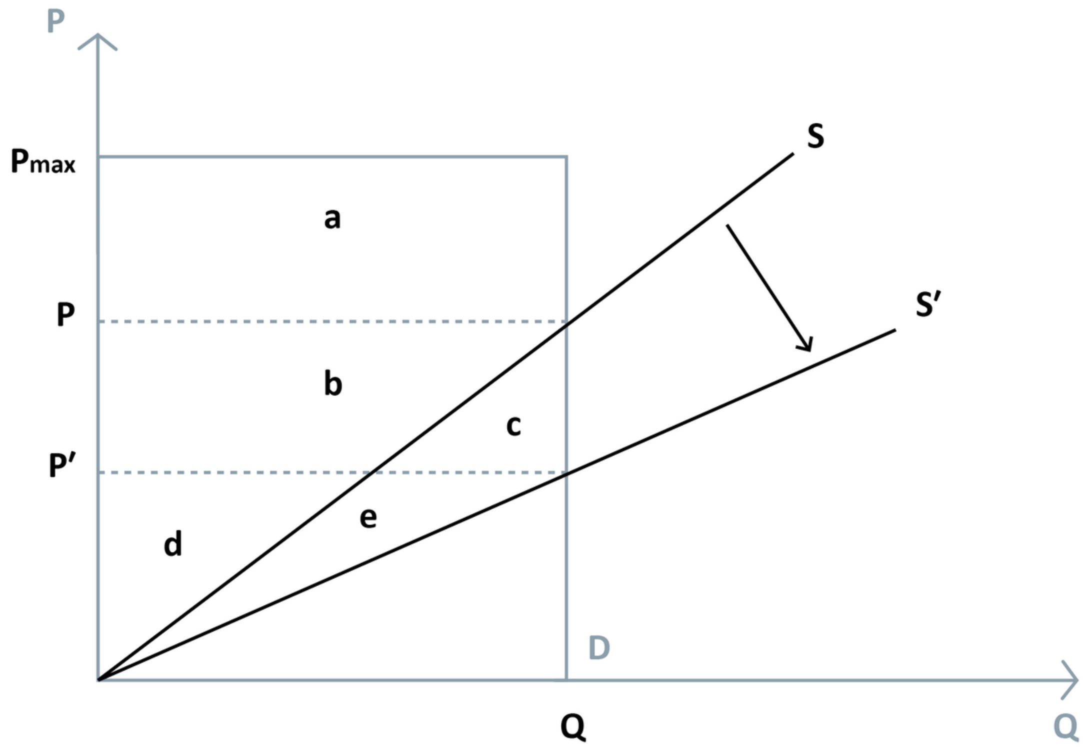
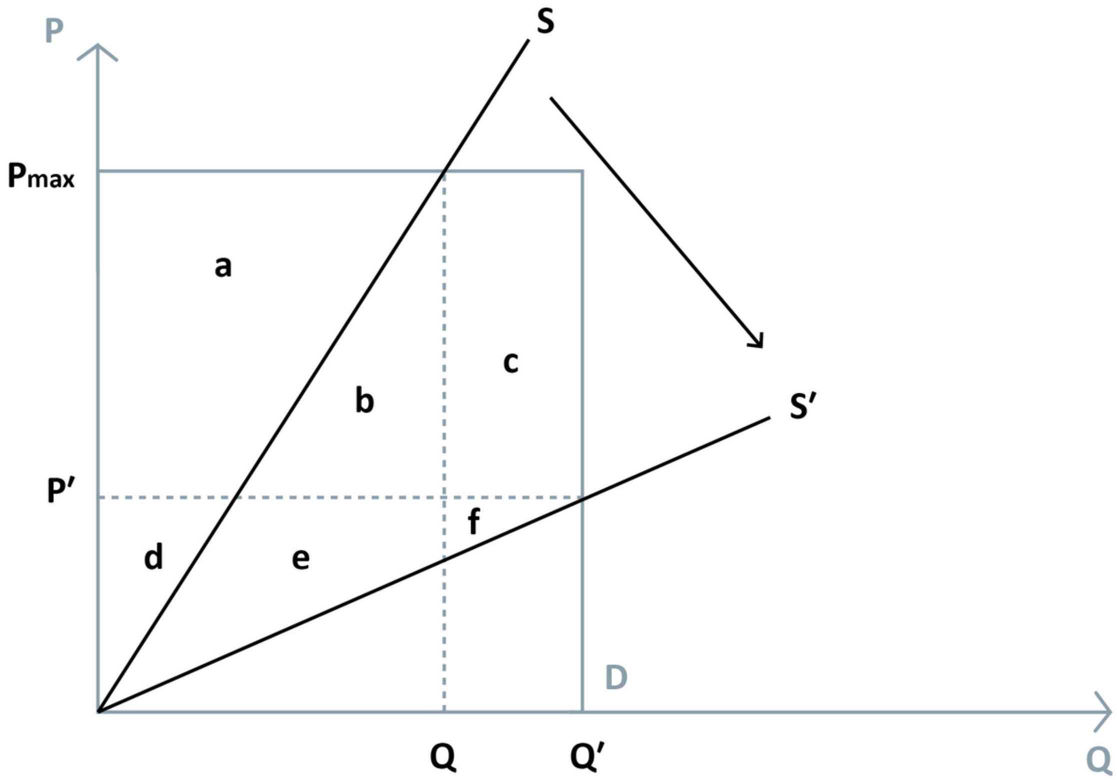


Figure 12



(5) In carrying out the modelling under this clause 49, **Transpower** may model **embedded plant** as if it were **grid**-connected. If **Transpower** does this, the modelled market benefits and

disbenefits in respect of the **plant** must be attributed to the relevant **host customer**, not the owner of the **plant**.

(6) **Transpower** may adjust prices in the modelling under this clause 49 if, and to the extent, **Transpower** determines it is appropriate to do so to moderate the sensitivity of modelled prices and changes in prices to modelling assumptions and other inputs, or otherwise with the objective of ensuring the **BBI customer allocations** for the **market BBI** are broadly proportionate to positive **NPB** from the **market BBI**.

50 Modelled Regions and Regional Customer Groups

(1) **Transpower** must determine the **market BBI's modelled regions** as follows and based on the outcomes of the modelling under clause 49:

(a) a **modelled region** must be a set of either **GXPs** or **GIPs**:

(b) the modelled price or quantity changes, if any, at all **GXPs** or **GIPs** in a **modelled region** must be in the same direction:

(c) a region meeting the requirements of paragraphs (a) and (b) may comprise more than 1 **modelled region** if the market benefits or disbenefits accruing at different **GXPs** or **GIPs** in the region—

(i) are of a materially different magnitude; or

(ii) occur at different times, or are of a materially different magnitude, depending on whether there are binding **constraints**; or

(iii) occur under different **market scenarios:**

(d) **Transpower** must determine the **market BBI's modelled regions** with the objective of ensuring the **BBI customer allocations** for the **market BBI** are broadly proportionate to positive **NPB** from the **market BBI**.

(2) **Transpower** must determine the **market BBI's regional customer groups** as follows and based on the outcomes of the modelling under clause 49:

(a) subject to paragraph (b) and subclauses 51(7) and 52(9), the **market BBI's regional customer groups** are as follows:

type of **regional customer group**	**modelled region**	**regional customer group**
regional demand group	a region defined by a set of **GXPs**	subject to subclause (4), all **offtake customers** in the **modelled region**
regional supply group	a region defined by a set of **GIPs**	all **injection customers** in the **modelled region**

(b) there may be more than 1 **regional demand group** or **regional supply group** for the same **modelled region**, each comprising different **offtake customers** or **injection customers** (as the case may be), if **Transpower** determines it is necessary to have more than 1 **regional demand group** or **regional supply group** for the **modelled region** to produce **BBI customer allocations** for the **market BBI** that are broadly proportionate to positive **NPB** from the **market BBI**, having regard to the attributes of the **offtake customers** or **injection customers** (including whether the **offtake customers** or **injection customers** currently exist in the **modelled region**).

(3) To avoid doubt—

(a) the **market BBI** may have 1 or more **future regional customer groups**, which may be **regional demand groups**, **regional supply groups** or a combination of both; and
(b) a **regional customer group** that is not a **future regional customer group** may, in future, include **offtake customers** or **injection customers** who do not currently exist in the relevant **modelled region**.

(4) An **offtake customer** is not a member of a **regional demand group** for the **market BBI** in respect of its **grid**-connected **battery storage** if the **market BBI's market regional NPB** is calculated under clause 52.

51 Calculation of Market Regional NPB based on Quantity

(1) **Transpower** must calculate **market regional NPB** for a **market BBI** under this clause 51 if—
(a) **Transpower** determines, based on the outcomes of the modelling under clause 49 and taking into account the **market BBI's market scenarios** and their probability weightings determined by **Transpower** under clause 46(1), that most of the positive **market regional NPB** for the **market BBI's regional supply groups** relates to new **large generating plant** for which, at the time **Transpower** makes its determination under this paragraph, the proponent has not made its final decision to proceed with its investment in the **plant**; or
(b) subclause 52(1) does not apply.

(2) To avoid doubt, paragraph (1)(a) does not require **Transpower** to have determined the **market BBI's regional supply groups** before making the determination under that paragraph.

(3) For each **regional customer group**, **market scenario** and year of the **market BBI's standard method calculation period**, the expected market benefit (positive value) or disbenefit (negative value) is calculated based on—
(a) the modelling under clause 49; and
(b) the period or periods during which the **market BBI** is modelled to generate its primary market benefits, as determined by **Transpower** (the **periods of benefit**),
as follows:
(c) for a **regional demand group**, quantities in the **counterfactual** are positive if there are **alleviated prices** for the **regional demand group** during the **periods of benefit** and negative if there are **exacerbated prices** for the **regional demand group** during the **periods of benefit**:
(d) for a **regional supply group**, quantities in the **counterfactual** are positive if there are **exacerbated prices** for the **regional supply group** during the **periods of benefit** and negative if there are **alleviated prices** for the **regional supply group** during the **periods of benefit**:
(e) subject to subclause (4), for a **regional demand group** or **regional supply group**, the positive or negative quantities under paragraph (c) or (d) (as appropriate) are summed with the changes in quantities between the **factual** and **counterfactual** during all periods, an increase being positive and a decrease being negative, the sum being the expected market benefit or disbenefit.

(4) In applying paragraph (3)(e), **Transpower** must adjust the changes in quantities as it determines necessary to ensure the market benefit or disbenefit attributable to modelled changes in **injection** and **offtake** for **grid**-connected **battery storage** is not double-counted.

(5) To avoid doubt, any **alleviated prices** or **exacerbated prices** outside the **periods of benefit** are ignored when applying paragraphs (3)(c) and (3)(d).

(6) Subject to subclause (7), a **regional customer group's market regional NPB** for a year of the **market BBI's standard method calculation period** (MRNPB) is calculated as follows:

$$MRNPB = \frac{1}{\sum_s W_s} \sum_s (EMBD_s \times W_s)$$

where

$EMBD_s$ is the expected market benefit (positive value) or disbenefit (negative value) for the **regional customer group** and year for **market scenario** s, where **market scenario** s is a **market scenario** for the **market BBI**, but excluding any expected market benefit or disbenefit attributable to a future **customer** or future **large plant** unless the **regional customer group** is a **future regional customer group**

W_s is the probability weighting for **market scenario** s determined by **Transpower** under clause 46(1).

(7) If a **customer** has **injection** and **offtake** at the same **connection location**, **Transpower** may, in carrying out the calculation under subclause (6), set off the **customer's** expected market disbenefit from its **injection** or **offtake** at the **connection location** against the **customer's** expected market benefit from its **offtake** or **injection** at the **connection location**. If **Transpower** does this, **Transpower** must assign the **customer** and the **customer's** net expected market benefit to either the **regional demand group** or **regional supply group** for the **modelled region** in which the **connection location** is located (but not to both) depending on the **regional customer group** for which the **customer** has the higher present value net expected market benefit over the **market BBI's standard method calculation period** (each present value calculated consistently with clause 48).

(8) To avoid doubt, subject to subclause (7), expected market benefits and disbenefits are not summed between different **regional customer groups**.

(9) If necessary for calculating the **BBI customer allocations** for the **market BBI**, **Transpower** must determine the dollar value of each **regional customer group's market regional NPB** for each year of the **market BBI's standard method calculation period**, taking into account total positive **market regional NPB** for the **market BBI** calculated under clause 52.

52 Calculation of Market Regional NPB based on Price and Quantity

(1) **Transpower** must calculate **market regional NPB** for the **market BBI** under this clause 52 if—

(a) paragraph 51(1)(a) does not apply; and

(b) **Transpower** determines, based on the outcomes of the modelling under clause 49 and taking into account the **market BBI's market scenarios** and their probability weightings determined by **Transpower** under clause 0, that—

(i) most of the positive **market regional NPB** for the **market BBI's regional customer groups** derives from **consumers** avoiding having to pay their estimated cost of self-supply for **electricity** or alternative energy during peak **demand** periods; or

(ii) calculating **market regional NPB** for the **market BBI** under clause 51 would not produce **BBI customer allocations** that are broadly proportionate to positive **NPB** from the **market BBI**.

(2) To avoid doubt, subparagraph (1)(b)(i) does not require **Transpower** to have determined the **market BBI's regional customer groups** before making the determination under that subparagraph.

(3) For a **regional demand group**, **market scenario** and year of the **market BBI's standard method calculation period**, the expected market benefit or disbenefit is equal to—
(a) the modelled change in consumer benefit for the **regional demand group** in the **wholesale market** for **electricity** (a positive change being a market benefit and a negative change being a market disbenefit); plus
(b) the modelled change in **loss and constraint excess** received by **customers** in the **regional demand group** as a result of the change in consumer benefit other than through the settlement of **FTRs** (a positive change being a market benefit and a negative change being a market disbenefit), unless—
(i) **Transpower** has adjusted modelled price outcomes under subclause 49(6); or
(ii) the **market BBI** is a **high-value intervening BBI**.

(4) For a **regional supply group**, **market scenario** and year of the **market BBI's standard method calculation period**, the expected market benefit or disbenefit arising is equal to—
(a) the modelled change in producer benefit for the **regional supply group** in the **wholesale market** for **electricity** (a positive change being a market benefit and a negative change being a market disbenefit); plus
(b) the modelled change in **loss and constraint excess** received by **customers** in the **regional supply group** as a result of the change in producer benefit other than through the settlement of **FTRs** (a positive change being a market benefit and a negative change being a market disbenefit), unless—
(i) **Transpower** has adjusted modelled price outcomes under subclause 49(6); or
(ii) the **market BBI** is a **high-value intervening BBI**.

(5) In applying paragraph (4)(a), **Transpower** must model **offtake** of **grid**-connected **battery storage** as a production cost for **injection** from the **grid**-connected **battery storage**.

(6) In the illustrative **wholesale market model** in figure 11 above—
(a) the expected market benefit or disbenefit for the **regional demand group** is equal to the modelled change in consumer benefit, being:

factual	**counterfactual**	change in consumer benefit
a + b + c	a	b + c

(b) the expected market benefit or disbenefit for the **regional supply group** is equal to the modelled change in producer benefit, being:

factual	**counterfactual**	change in producer benefit
d + e	b + d	e - b

(7) In the illustrative **wholesale market model** in figure 12 above—

(a) the expected market benefit or disbenefit for the **regional demand group** is equal to the modelled change in consumer benefit, being:

factual	**counterfactual**	change in consumer benefit
a + b + c	0	a + b + c

(b) the expected market benefit or disbenefit for the **regional supply group** is equal to the modelled change in producer benefit, being:

factual	**counterfactual**	change in producer benefit
d + e + f	a + d	e + f - a

(8) Subject to subclause (9), a **regional customer group's market regional NPB** for a year of the **market BBI's standard method calculation period** (MRNPB) is calculated as follows:

$$MRNPB = \frac{1}{\sum_s W_s} \sum_s (EMBD_s \times W_s)$$

where

$EMBD_s$ is the expected market benefit (positive value) or disbenefit (negative value) for the **regional customer group** and year for **market scenario** s, where **market scenario** s is a **market scenario** for the **market BBI**, but excluding any expected market benefit or disbenefit attributable to a future **customer** or future **large plant** unless the **regional customer group** is a **future regional customer group**

W_s is the probability weighting for **market scenario** s determined by **Transpower** under clause 46(1).

(9) If a **customer** has **injection** and **offtake** at the same **connection location**, **Transpower** may, in carrying out the calculation under subclause (8), set off the **customer's** expected market disbenefit from its **injection** or **offtake** at the **connection location** against the **customer's** expected market benefit from its **offtake** or **injection** at the **connection location**. If **Transpower** does this, **Transpower** must assign the **customer** and the **customer's** net expected market benefit to either the **regional demand group** or **regional supply group** for the **modelled region** in which the **connection location** is located (but not to both) depending on the **regional customer group** for which the **customer** has the higher present value net expected market benefit over the **market BBI's standard method calculation period** (each present value calculated consistently with clause 48).

(10) To avoid doubt, subject to subclause (9), expected market benefits and disbenefits are not summed between different **regional customer groups**.

53 Ancillary Service Regional NPB

(1) This clause 53 applies to calculating **ancillary service regional NPB** for an **ancillary service BBI** (if **Transpower** decides to calculate **ancillary service regional NPB** for the **ancillary service BBI**).

(2) **Transpower** must model changes in prices and quantities in the **wholesale market** for the relevant **specified ancillary service** between the **ancillary service BBI's factual** and **counterfactual** under its **market scenarios**. The modelling must cover each year of the **ancillary service BBI's standard method calculation period**.

(3) **Transpower** must determine the **ancillary service BBI's modelled regions** and **regional customer groups** as follows:

specified ancillary service	type of **regional customer group**	**modelled region**	**regional customer group**
instantaneous reserve (by **island**)	**regional demand group**	none	none
	regional supply group	**island**	all **grid**-connected **generators** in the **modelled region** except in respect of **generating plant** with **capacity** equal to or less than the value of INJ_D in clause 8.59 of this Code
frequency keeping	**regional demand group**	New Zealand	all **direct consumers** in the **modelled region**
	regional supply group	none	none
voltage support (by **zone**)	**regional supply group**	none	none
	regional demand group	**zone**	all **connected asset owners** in the **modelled region**

(4) To avoid doubt—

(a) the **ancillary service BBI** may have 1 or more **future regional customer groups**, which may be **regional demand groups**, **regional supply groups** or a combination of both; and

(b) a **regional customer group** that is not a **future regional customer group** may, in future, include **grid**-connected **generators**, **direct consumers** or **connected asset owners** who do not currently exist in the relevant **modelled region**.

(5) For a **regional customer group**, **market scenario** and year of the **ancillary service BBI's standard method calculation period**, the expected market benefit or disbenefit is equal to the modelled change in the **allocable cost** of the **specified ancillary service** (a negative change being a market benefit and a positive change being a market disbenefit).

(6) A **regional customer group's ancillary service regional NPB** for a year of the **ancillary service BBI's standard method calculation period** (ASRNPB) is calculated as follows:

$$ASRNPB = \frac{1}{\sum_s W_s} \sum_s (EASBD_s \times W_s)$$

where

$EASBD_s$ is the expected market benefit (positive value) or disbenefit (negative value) for the **regional customer group** and year for **market scenario** s, where **market scenario** s is a **market scenario** for the **ancillary service BBI**, but excluding any expected market benefit or disbenefit attributable to a future **customer** or future **large plant** unless the **regional customer group** is a **future regional customer group**

W_s is the probability weighting for **market scenario** s determined by **Transpower** under clause 46(1).

(7) To avoid doubt, expected market benefits and disbenefits are not summed between different **regional customer groups**.

54 Reliability Regional NPB

(1) This clause 54 applies to calculating **reliability regional NPB** for a **reliability BBI** (if **Transpower** decides to calculate **reliability regional NPB** for the **reliability BBI**).

(2) **Transpower** must use a **system limit model** to model changes in expected **curtailed energy** between the **reliability BBI's factual** and **counterfactual** under its **outage scenarios**. The modelling must cover each year of the **reliability BBI's standard method calculation period**.

(3) The illustrative **system limit model** in figure 13 below shows, for a notional **reliability BBI**, **outage scenario**, **market scenario** and year of the **reliability BBI's standard method calculation period**, the effect of the **reliability BBI**. The effect of the **reliability BBI** is modelled as a change in the **system limit** from S (**counterfactual**) to S′ (**factual**), which reduces the value of X (percentage of year t **supply**, **demand** or **active power** transfer is at or more than the **system limit**). The modelled change in expected **curtailed energy** for the year (ΔECE_z) is calculated as follows:

$$\Delta ECE_z = CE \times P_z \times \Delta P_x$$

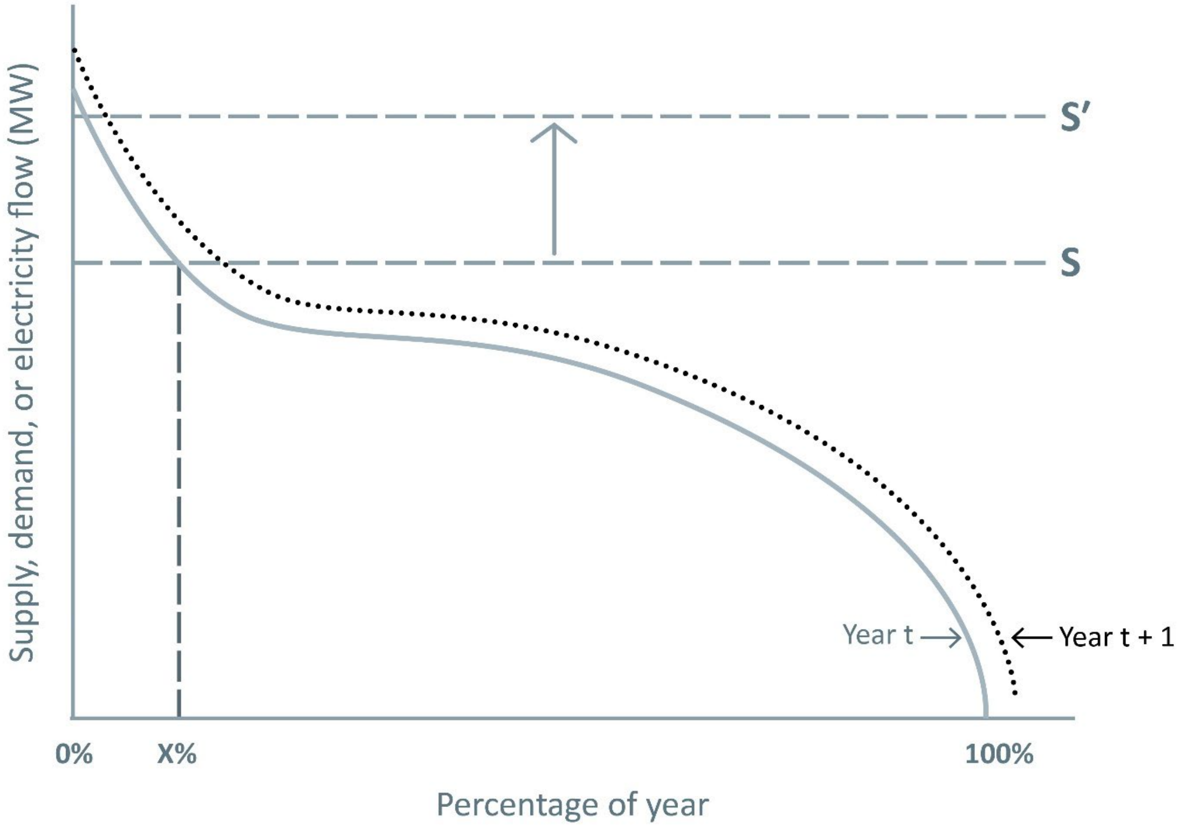
where

CE is **Transpower's** estimate of **curtailed energy** caused by the **outage scenario** occurring in the **market scenario**

P_z is **Transpower's** estimate of the probability of the **outage scenario** occurring during the year

ΔP_x is the change in the value of X in figure 13 between the **counterfactual** and **factual**.

Figure 13



(4) **Transpower** must determine the **reliability BBI's modelled regions** and **regional customer groups** as follows and based on the outcomes of the modelling under subclause (2):

(a) subject to paragraph (b), the **reliability BBI's modelled regions** and **regional customer groups** are as follows:

type of **regional customer group**	**modelled region**	**regional customer group**
regional demand group	a region defined by a set of **GXPs** at which there is expected to be a change in **unserved energy** in the same direction if an **outage scenario** for the **reliability BBI** occurs	all **offtake customers** in the **modelled region** except in respect of **grid**-connected **battery storage**
regional supply group	a region defined by a set of **GIPs** at which there is expected to be a change in **unsupplied energy** in the same direction if an **outage scenario** for the **reliability BBI** occurs	all **injection customers** in the **modelled region**

(b) there may be more than 1 **regional demand group** or **regional supply group** for the same **modelled region**, each comprising different **offtake customers** or **injection customers** (as the case may be), if **Transpower** determines it is necessary to have more than 1 **regional demand group** or **regional supply group** for the **modelled region** to produce **BBI customer allocations** for the **reliability BBI** that are broadly proportionate to positive **NPB** from the **reliability BBI**, having regard to the attributes of the **offtake customers** or **injection customers** (including whether the **offtake customers** or **injection customers** currently exist in the **modelled region**).

(5) To avoid doubt—
(a) the **reliability BBI** may have 1 or more **future regional customer groups**, which may be **regional demand groups**, **regional supply groups** or a combination of both; and
(b) a **regional customer group** that is not a **future regional customer group** may, in future, include **offtake customers** or **injection customers** who do not currently exist in the relevant **modelled region**.

(6) For each **regional customer group**, **market scenario** and year of the **reliability BBI's standard method calculation period**, the expected reliability benefit or disbenefit (ERBD) is calculated as follows:

$$ERBD = -\sum_{z}(\Delta ECE_z \times VL)$$

where

ΔECE_z is the modelled change in expected **curtailed energy** for the **regional customer group** and **outage scenario** z, where **outage scenario** z is an **outage scenario** for the **reliability BBI**, calculated under subclause (3)

VL is—

(a) if the **regional customer group** is a **regional demand group**, the **reliability BBI's VOLL**; or
(b) if the **regional customer group** is a **regional supply group**, a value of lost generation determined by **Transpower**.

(7) A **regional customer group's reliability regional NPB** for a year of the **reliability BBI's standard method calculation period** (RRNPB) is calculated as follows:

$$RRNPB = \frac{1}{\sum_s W_s} \sum_s (ERBD_s \times W_s)$$

where

$ERBD_s$ is the expected reliability benefit (positive value) or disbenefit (negative value) for the **regional customer group** and year for **market scenario** s, where **market scenario** s is a **market scenario** for the **reliability BBI**, but excluding any expected reliability benefit or disbenefit attributable to a future **customer** or future **large plant** unless the **regional customer group** is a **future regional customer group**

W_s is the probability weighting for **market scenario** s determined by **Transpower** under clause 46(1).

(8) To avoid doubt—
(a) expected reliability benefits and disbenefits are not summed between different **regional customer groups**; and
(b) all **regional demand groups**, and all members of a **regional demand group**, are assumed to have the same value of **unserved energy**, being the **reliability BBI's VOLL**; and
(c) all **regional supply groups**, and all members of a **regional supply group**, are assumed to have the same value of **unsupplied energy**, being the value of lost generation determined by **Transpower** under subclause (5).

55 Other Regional NPB

(1) This clause 55 applies to calculating or estimating **other regional NPB** for a **market BBI**, **ancillary service BBI** or **reliability BBI** (if **Transpower** decides to calculate or estimate **other regional NPB** for the **BBI**).
(2) **Transpower** must only calculate or estimate **other regional NPB** for a **BBI** if all of the following criteria are satisfied:
(a) **Transpower** reasonably expects positive **other regional NPB** for the **BBI** to be received—
(i) directly by 1 or more existing **customers**, whether in their capacities as **customers** or otherwise; or
(ii) by the majority of **embedded plant** owners connected to a **host customer's local network** or **grid**-connected **plant**, whether in their capacities as **embedded plant** owners or otherwise:
(b) **Transpower** determines the **other regional NPB** will be a material part of total positive **regional NPB** for the **BBI**:
(c) **Transpower** determines the dollar value of the **other regional NPB** can be calculated or estimated to a reasonable level of certainty without **Transpower** incurring disproportionate cost.

(3) **Transpower** must determine the **BBI's modelled regions** and **regional customer groups** as follows:

type of **regional customer group**	**modelled region**	**regional customer group**
regional demand group	a region in which **other regional NPB** is expected to arise from the **BBI**	all **offtake customers** in the **modelled region** expected to receive the **other regional NPB**
regional supply group		all **injection customers** in the **modelled region** expected to receive the **other regional NPB**

(4) To avoid doubt, the **BBI customer allocations** for a **BBI** are not adjusted merely because **other regional NPB** for the **BBI** arises or is discovered after the starting **BBI customer allocations** for the **BBI** have been calculated.

Standard Method: Resiliency Method

56 Overview of Resiliency Method

(1) Clauses 56 to 58 apply—
- (a) to the **resiliency method** only; and
- (b) only to those **post-2019 BBIs** to which **Transpower** applies the **resiliency method** in accordance with subclause 43(2).

(2) Under the **resiliency method**—
- (a) there is 1 **modelled region** and 1 **regional customer group**; and
- (b) **regional NPB** for the **regional customer group** is assumed to be positive and is not calculated; and
- (c) **individual NPB** is calculated for each **customer** in the **regional customer group**.

57 Individual NPB

A **customer's individual NPB** for the **resiliency BBI** is equal to the value of the **customer's intra-regional allocator** for the **regional customer group**.

58 Modelled Region and Regional Customer Group

Transpower must determine a **resiliency BBI's modelled region** and **regional customer group** as follows:

type of **regional customer group**	**modelled region**	**regional customer group**
regional demand group	the **island** in which the risk of cascade failure is mitigated	all **offtake customers** in the **modelled region** except in respect of **grid**-connected **battery storage**
	a region in which the risk of the **HILP event** is mitigated	
regional supply group	none	none

Simple Method

59 Overview of Simple Method

(1) Clauses 59 to 64 apply—
- (a) to the **simple method** only; and
- (b) only to—
  - (i) those **low-value post-2019 BBIs** to which **Transpower** applies the **simple method** in accordance with subclause 43(2); and
  - (ii) those **high–value intervening BBIs** to which **Transpower** applies the **simple method** in accordance with subclause 43(3); and
  - (iii) **anticipatory BBIs**.

(2) Under the **simple method**—
- (a) **regional NPB** is calculated for a **regional customer group** in respect of an **investment region** based on the extent to which the **regional customer group** is deemed to contribute to total **offtake** and **injection** in, or **electricity** flow to or from, the **investment region**, either as—
  - (i) a **regional customer group** in the **investment region**; or
  - (ii) a **regional demand group** in another **modelled region** that imports **electricity** from the **investment region** directly or indirectly; or
  - (iii) a **regional supply group** in another **modelled region** that exports **electricity** to the **investment region** directly or indirectly; and
- (b) **individual NPB** is calculated for each **customer** in a **regional customer group** with positive **regional NPB** in respect of the **investment region**.

(3) To avoid doubt, a **BBI** may have more than 1 **investment region** depending on where the **transmission investments** comprised in the **BBI** are located.

60 Simple Method Periods

(1) Subject to subclause (2), the **simple method periods** are—
- (a) the period starting on 24 July 2019 and ending at the end of the fourth **pricing year** after the **first pricing year**; and
- (b) each period of 5 **pricing years** immediately following the end of the previous **simple method period**.

(2) **Transpower** may start a new **simple method period** to coincide with the start of an **RCP**.

61 Individual NPB

(1) A **customer's individual NPB** for a **BBI** in an **investment region** (NPB) is calculated as follows:

$$NPB = \sum_{g} \left(RNPB_g \times SMF_g \right)$$

where

$RNPB_g$ is **regional NPB** for **regional customer group** g, where **regional customer group** g is a **regional customer group** for the **BBI**—
(a) that has positive **regional NPB** in respect of the **investment region**; and
(b) of which the **customer** is a member

SMF_g is the **customer's simple method factor** for **regional customer group** g.

(2) A **customer's simple method factor** for a **simple method period** and **regional customer group** of which the **customer** is a member (SMF) is calculated as follows:

$$SMF = \frac{IRA}{IRA_{total}}$$

where

IRA is the value of the **customer's intra-regional allocator** for the **simple method period** and **regional customer group**

IRA_{total} is the total of the values of all **customers' intra-regional allocators** for the **simple method period** and **regional customer group**.

(3) If a **benefit-based charge adjustment event** in any of paragraphs 81(1)(b) to 81(1)(j) occurs between the end of **CMP C** for a **simple method period** and the start of the **simple method period**, **Transpower** must apply subclause (6) to calculating all **customers' simple method factors** for the **simple method period** as if the **benefit-based charge adjustment event** occurred during the **simple method period**.

(4) The values of $RNPB_g$ and SMF_g under subclause (1) are those that apply when the **BBI** is **commissioned**. To avoid doubt, the **BBI customer allocations** for the **BBI** do not change merely because—
(a) there are different values of **regional NPB** for a subsequent **simple method period**; or
(b) there are different **simple method factors** for a subsequent **simple method period**; or
(c) new **simple method factors** for a **simple method period** are published under paragraph (6)(b).

(5) **Transpower** must—
(a) **publish** in the **assumptions book** the **simple method factors** for the first **simple method period** before the start of the **first pricing year**, which, subject to subclause (6), will apply to **BBIs commissioned** during the first **simple method period**; and
(b) **publish** in the **assumptions book** the **simple method factors** for each subsequent **simple method period** before the start of the subsequent **simple method period**, which, subject to subclause (6), will apply to **BBIs commissioned** during the subsequent **simple method period**.

(6) If a **benefit-based charge adjustment event** in any of paragraphs 81(1)(b) to 81(1)(j) occurs, **Transpower** must—
(a) calculate or re-calculate (as the case may be) all **customers' simple method factors** for the current **simple method period** using estimated values for the **customers' intra-regional allocators** to the extent necessary; and
(b) **publish** in the **assumptions book** the new **simple method factors**, which, subject to this subclause (6), will apply to **BBIs commissioned** during the **simple method period** after the new **simple method factors** are **published**.

62 Modelled Regions

(1) The **modelled regions** are the **connection regions** and **HVDC link**.

(2) **Transpower** must—
(a) **publish** in the **assumptions book** the initial **modelled regions** before the start of the **first pricing year**; and
(b) **publish** in the **assumptions book** the **modelled regions** for each subsequent **simple method period** before the start of the subsequent **simple method period**.

(3) **Transpower** must review, including update as appropriate, the **modelled regions** (other than the **HVDC link**) for each **simple method period** before the start of the **simple method period**.

(4) **Transpower** must determine the **connection regions** for a **simple method period** by—
(a) determining **high-voltage grid connection regions** on either side of the **HVDC link**; and
(b) isolating prevailing directional **electricity** flows on **interconnection branches** in the **high-voltage grid** (excluding the **HVDC link**) over **CMP C** for the **simple method period** and determining **high-voltage grid connection regions** on either side of the **interconnection branches** on which those **electricity** flows occur; and
(c) determining a **low-voltage grid connection region** on the **low-voltage grid** side of each **interconnection transformer branch** containing an **interconnecting transformer** connecting the **low-voltage grid** to a **high-voltage grid connection region**; and
(d) if a **low-voltage grid connection region** is connected to more than 1 **high-voltage grid connection region**, determining separate **low-voltage grid connection regions** on either side of the minimum transfer **interconnection branch** within the **low-voltage grid connection region**, so that each of the separate **low-voltage grid connection regions** is connected to only 1 **high-voltage grid connection region**; and
(e) for a **low-voltage connection region** connected to 1 **high-voltage connection region** by more than 1 **interconnection branch**, determining separate **low voltage grid connection regions** on either side of the minimum transfer **interconnection branch** within the **low-voltage grid connection region** if **electricity** flow on that **branch** is low relative to total **electricity** flows between **interconnecting transformers** in the **low-voltage grid connection region**; and
(f) incorporating—
(i) the **branches** referred to in paragraph (b) in both relevant **connection regions** in proportion to the **electricity** flows on those **branches** into each **connection region**; and
(ii) the **branches** referred to in paragraph (c), including the **interconnecting transformers**, in the relevant **low-voltage grid connection region**; and

(iii) the **branches** between **low-voltage connection regions** referred to in paragraphs (d) and (e) in both relevant **low-voltage connection regions** in half parts.

(5) **Transpower**—
(a) is not required to (but may) assess **electricity** flows over the entire **high-voltage grid** under paragraph (4)(b); and
(b) may amalgamate geographically adjacent **connection regions** for a **simple method period** if—
(i) the **connection regions** have the same voltage; and
(ii) 1 or more of the **connection regions** contains significantly fewer **market nodes** than the average number of **market nodes** contained in all **connection regions**.

63 Regional Customer Groups

Subject to subclause 27(3), the **regional customer groups** are as follows:

type of **regional customer group**	**modelled region**	**regional customer group**
regional demand group	a **connection region**	all **offtake customers** in the **modelled region**
regional supply group		all **injection customers** in the **modelled region**

64 Regional NPB

(1) **Transpower** must—
(a) **publish** in the **assumptions book** the **regional NPB** for each **regional customer group** in respect of each **investment region** for the first **simple method period** before the start of the **first pricing year**, which will apply to **BBIs commissioned** during the first **simple method period**; and
(b) **publish** in the **assumptions book** the **regional NPB** for each **regional customer group** in respect of each **investment region** for a subsequent **simple method period** before the start of the subsequent **simple method**, which will apply to **BBIs commissioned** during the subsequent **simple method period**.

(2) **Regional NPB** for a **regional customer group** in respect of an **investment region** for a **simple method period** (RNPB) is calculated as follows:

$$RNPB = \frac{1}{\sum_t W_t}\sum_t (SMC_t \times W_t) \times F$$

where

SMC_t is the **regional customer group's simple method contribution** in respect of the **investment region** for **trading period** t, where **trading period** t is a **trading period** during **CMP C** for the **simple method period**

W_t is a weighting for **trading period** t determined by **Transpower**

F is—

(a) if the **regional customer group** is a **regional demand group**, the **demand factor** for the **simple method period**; or
(b) if the **regional customer group** is a **regional supply group**, 1.

(3) The calculation under subclause (2) must be carried out for all **trading periods** during **CMP C** for the **simple method period** for which **Transpower** determines it has access to reliable values for the variables in subclause (7).

(4) The **demand factor** for a **simple method period** (DF) is calculated as follows:

$$DF = \frac{RNPB_{s\ total}}{RNPB_{d\ total}} \times 1.67$$

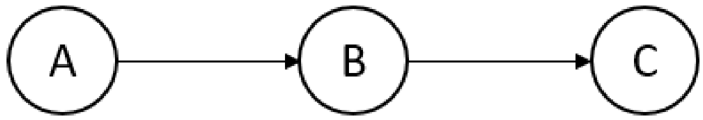
where

$RNPB_{s\ total}$ is total **regional NPB** for all **regional supply groups** in respect of all **investment regions** for the **simple method period** calculated under subclause (2)

$RNPB_{d\ total}$ is total **regional NPB** for all **regional demand groups** in respect of all **investment regions** for the **simple method period** calculated under subclause (2) but without multiplying by the **demand factor**.

(5) Figure 14 below illustrates how, given the generalised **electricity** flow state depicted (**connection region** A to B to C)—
(a) the **beneficiaries** of a **BBI** located in 1 of the **connection regions** (being the **investment region**) are identified; and
(b) a **regional customer group's simple method contribution** in respect of the **investment region** is calculated for a **trading period** during which, on average, the **electricity** flow state prevailed.

Figure 14



		connection region A	**connection region** B	**connection region** C
simple method contribution	**regional supply group** A	$\frac{G_a}{(G_a + L_a + F_{a\_b})}$	$\frac{F_{a\_b}}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	$\frac{F_{b\_c}}{(G_c + L_c + F_{b\_c})}\left(\frac{F_{a\_}}{G_b + }\right.$
	regional supply group B	0	$\frac{G_b}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	$\frac{F_{b\_c}}{(G_c + L_c + F_{b\_c})}\left(\frac{G_b}{G_b + }\right.$
	regional supply group C	0	0	$\frac{G_c}{(G_c + L_c + F_{b\_c})}$
	regional demand group A	$\frac{L_a}{(G_a + L_a + F_{a\_b})}$	0	0
	regional demand group B	$\frac{F_{a\_b}}{(G_a + L_a + F_{a\_b})}\left(\frac{L_b}{L_b + }\right.$	$\frac{L_b}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	0
	regional demand group C	$\frac{F_{a\_b}}{(G_a + L_a + F_{a\_b})}\left(\frac{F_{b\_}}{L_b + }\right.$	$\frac{F_{b\_c}}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	$\frac{L_c}{(G_c + L_c + F_{b\_c})}$

(6) In figure 14 above—

(a) the **beneficiaries** of a **BBI** in **connection region** A (being the **investment region**) are deemed to be—

(i) the **customers** in the **regional demand group** and **regional supply group** in **connection region** A; and

(ii) the **customers** in the **regional demand groups** in **connection regions** B and C, which import **electricity** from the **investment region** directly or indirectly; and

(b) the **beneficiaries** of a **BBI** in **connection region** B (being the **investment region**) are deemed to be—

(i) the **customers** in the **regional demand group** and **regional supply group** in **connection region** B; and

(ii) the **customers** in the **regional supply group** in **connection region** A, which exports **electricity** to the **investment region** directly; and

(iii) the **customers** in the **regional demand group** in **connection region** C, which imports **electricity** from the **investment region** directly; and

(c) the **beneficiaries** of a **BBI** in **connection region** C (being the **investment region**) are deemed to be—

(i) the **customers** in the **regional demand group** and **regional supply group** in **connection region** C; and

(ii) the **customers** in the **regional supply groups** in **connection regions** A and B, which export **electricity** to the **investment region** directly or indirectly.

(7) In figure 14 above, a **regional customer group's simple method contribution** in respect of the **investment region** (being either **connection region** A, B or C) for a **trading period** is calculated in accordance with the relevant formula in figure 14, where:

G_x is total **injection** at all **connection locations** in **connection region** x for the **trading period**

L_x is total **offtake** at all **connection locations** in **connection region** x for the **trading period**

F_{x_y} is **electricity** flow from **connection region** x to **connection region** y for the **trading period**.

Intra-regional Allocators

65 Intra-regional Allocators

(1) Subject to subclause (2), the **intra-regional allocator** for a **regional customer group** under the **price-quantity method** is as follows:

type of **BBI**	type of **regional customer group**	**intra-regional allocator**	subclause
peak BBI	**regional supply group**	mean historical annual **injection**	(6)
	regional demand group	mean historical **coincident peak offtake**	(7), (8)
non-**peak BBI**	**regional supply group**	mean historical annual **injection**	(6)
	regional demand group	mean historical annual **offtake**	(5)

(2) The **intra-regional allocator** for an **ancillary service regional customer group** under the **price-quantity method** is as follows:

specified ancillary service	type of **ancillary service regional customer group**	**intra-regional allocator**	subclause
instantaneous reserve	**regional supply group**	mean historical annual **injection**	(6)
frequency keeping	**regional demand group**	mean historical annual **offtake**	(5)
voltage support	**regional demand group**	mean peak kVar	(9)

(3) The **intra-regional allocator** for the **regional customer group** under the **resiliency method** is mean historical annual **offtake** (see subclause (5)).

(4) The **intra-regional allocator** for a **regional customer group** under the **simple method** is as follows:

type of **regional customer group**	**intra-regional allocator**	subclause
regional supply group	mean historical annual **injection**	(11)
regional demand group	mean historical annual **offtake**	(10)

(5) Subject to subclause (13), if a **regional customer group** for a **BBI** under a **standard method** has a mean historical annual **offtake intra-regional allocator**, the value of a **pre-existing customer's intra-regional allocator** for the **regional customer group**, where the **pre-existing customer** is a member of the **regional customer group**, (IRA) is calculated as follows:

$$IRA = \frac{1}{N}\sum_{n} TO_n$$

where

N is the number of **capacity years** (including part **capacity years** expressed as a decimal) during **CMP B** for the relevant **BBI** for which the **pre-existing customer** was a member of the **regional customer group**

TO_n is the **pre-existing customer's** total **offtake** at all **connection locations** in the **regional customer group's modelled region** during **capacity year** n of **CMP B** for the **BBI**.

(6) Subject to subclause (13), if a **regional customer group** for a **BBI** under a **standard method** has a mean historical annual **injection intra-regional allocator**, the value of a **pre-existing customer's intra-regional allocator** for the **regional customer group**, where the **pre-existing customer** is a member of the **regional customer group**, (IRA) is calculated as follows:

$$IRA = \frac{1}{N}\sum_{n} TI_n$$

where

N is the number of **capacity years** (including part **capacity years** expressed as a decimal) during **CMP B** for the relevant **BBI** for which the **pre-existing customer** was a member of the **regional customer group**

TI_n is the **pre-existing customer's** total **injection** at all **connection locations** in the **regional customer group's modelled region** during **capacity year** n of **CMP B** for the **BBI**.

(7) Subject to subclause (13), if a **regional customer group** for a **BBI** under a **standard method** has a mean historical **coincident peak offtake intra-regional allocator**, the value of a **pre-existing customer's intra-regional allocator** for the **regional customer group**, where the **pre-existing customer** is a member of the **regional customer group**, (IRA) is calculated as follows:

$$IRA = \frac{1}{N}\sum_{n}\left(\frac{1}{T_n}\sum_{t} TO_t\right)$$

where

N is the number of **capacity years** (rounded up to the nearest whole **capacity year**) during **CMP B** for the relevant **BBI** during which the **pre-existing customer** was a member of the **regional customer group**, each such **capacity year** being **capacity year** n

T_n is the number of **peak offtake trading periods** for the **regional customer group's modelled region** and **capacity year** n during which the **pre-existing customer** was a member of the **regional customer group**, each such **peak offtake trading period** being **peak offtake trading period** t

TO_t is the **pre-existing customer's** total **offtake** at all **connection locations** in the **regional customer group's modelled region** for **peak offtake trading period** t.

(8) A **modelled region's peak offtake trading periods** for a **capacity year** are the T **trading periods** during the **capacity year** that have the highest total **offtake** (across all **offtake customers**) at all **connection locations** in the **modelled region**, where T is a number of **trading periods** between 1 and 100 **published** in the **assumptions book** for the purposes of this subclause.

(9) Subject to subclause (13), if a **regional customer group** for a **BBI** under a **standard method** has a mean peak kVar **intra-regional allocator**, the value of a **pre-existing customer's intra-regional allocator** for the **regional customer group**, where the **pre-existing customer** is a member of the **regional customer group**, (IRA) is calculated as follows:

$$IRA = \frac{1}{N}\sum_{n} NPK_n$$

where

N is the number of **capacity years** (rounded up to the nearest whole **capacity year**) during **CMP B** for the relevant **BBI** for which the **pre-existing customer** was a member of the **regional customer group**

NPK_n is the **pre-existing customer's nominated peak kVar** for the **regional customer group's modelled region** and **capacity year** n of **CMP B** for the **BBI**.

(10) Subject to subclause (13), if a **regional customer group** for a **BBI** under the **simple method** has a mean historical annual **offtake intra-regional allocator**, the value of a **pre-existing customer's intra-regional allocator** for the **regional customer group**, where the **pre-existing customer** is a member of the **regional customer group**, (IRA) is calculated as follows:

$$IRA = \frac{1}{N}\sum_{n} TO_n$$

where

N is the number of **capacity years** (including part **capacity years** expressed as a decimal) during **CMP C** for the relevant **simple method period** for which the **pre-existing customer** was a member of the **regional customer group**

TO_n is the **pre-existing customer's** total **offtake** at all **connection locations** in the **regional customer group's modelled region** during **capacity year** n of **CMP C** for the **simple method period**.

(11) Subject to subclause (13), if a **regional customer group** for a **BBI** under the **simple method** has a mean historical annual **injection intra-regional allocator**, the value of a **pre-existing customer's intra-regional allocator** for the **regional customer group**, where the **pre-existing customer** is a member of the **regional customer group**, (IRA) is calculated as follows:

$$IRA = \frac{1}{N}\sum_{n} TI_n$$

where

N is the number of **capacity years** (including part **capacity years** expressed as a decimal) during **CMP C** for the relevant **simple method period** for which the **pre-existing customer** was a member of the **regional customer group**

TI_n is the **pre-existing customer's** total **injection** at all **connection locations** in the **regional customer group's modelled region** during **capacity year** n of **CMP C** for the **simple method period**.

(12) Subclause (13) applies if—
(a) one or more **specified pre-start adjustment events** for a **BBI** under a **standard method** and a **pre-existing customer** occurred during **CMP B** for the **BBI**; or
(b) one or more **specified pre-start adjustment events** for a **BBI** under the **simple method** and a **pre-existing customer** occurred during **CMP C** for the relevant **simple method period**.

(13) If this subclause applies under subclause (12), **Transpower** must estimate the value of the **pre-existing customer's intra-regional allocator** under clause 66 as if the **pre-existing customer** were a **recent customer**, but also taking into account the full impact of the **specified pre-start adjustment events**.

66 Recent Customers

The value of a **recent customer's intra-regional allocator** for a **regional customer group** is estimated under paragraph 83(3)(a) as if the **recent customer** were a new **customer** joining the **regional customer group**, but also taking into account any available historical information about the **recent customer's** mean historical annual **injection**, mean historical annual **offtake** or mean historical **coincident peak offtake** (as the case may be).

67 Notional IRA Value

If a **regional customer group** is a **future regional customer group**, **Transpower** must determine a value of the **intra-regional allocator** for a notional **pre-existing customer** who accounts for all of the **future regional customer group's market regional NPB**, being the **notional IRA value** for the **future regional customer group**.

Part E Residual Charges

68 Calculation of Residual Charges

(1) Only **load customers** pay **residual charges**.

(2) A **load customer's annual residual charge** for a **pricing year** (ARC) is calculated as follows:

$$ARC = AMDR \times RCR$$

where

AMDR is the **load customer's AMDR** for the **pricing year**

RCR is the **residual charge** rate for the **pricing year** calculated under clause 74.

(3) A **load customer's monthly residual charge** for a **pricing year** (MRC) is calculated as follows:

$$MRC = \frac{ARC}{12}$$

where ARC is the **load customer's annual residual charge** for the **pricing year**.

(4) **Residual charges** are calculated for each **pricing year** before the start of the **pricing year**.

(5) A **residual charge** may be re-calculated, including during a **pricing year**, under clauses 92 to 95 if there is a **residual charge adjustment event**.

69 Anytime Maximum Demand (Residual)

(1) A **load customer's AMDR** for **pricing year** n ($AMDR_n$) is—

(a) 0 if the **load customer** became a **customer** at or after the start of **financial year** n-4; or

(b) calculated as follows if the **load customer** became a **customer** before the start of **financial year** n-4 and at or after the start of **financial year** n-8:

$$AMDR_n = AMDR_{baseline} \times \left(\frac{n-m}{4} - 1\right)$$

where

m is the **financial year** during which the **load customer** became a **customer**

$AMDR_{baseline}$ is the **load customer's AMDR** baseline calculated or estimated under clause 70; or

(c) otherwise, calculated as follows:

$$AMDR_n = AMDR_{baseline} \times RCAF_n$$

where

$AMDR_{baseline}$ is the **load customer's AMDR** baseline calculated or estimated under clause 70

$RCAF_n$ is the **load customer's RCAF** for **pricing year** n.

70 Anytime Maximum Demand (Residual) Baseline

(1) Subject to subclause 72(1), a **pre-existing load customer's AMDR** baseline ($AMDR_{baseline}$) is calculated as follows:

$$AMDR_{baseline} = \frac{1}{4}\sum_{n=2014}^{2017}\sum_{l} MGD_{ln}$$

where MGD_{ln} is the **pre-existing load customer's maximum gross demand** for **connection location** l and **financial year** n.

(2) A **recent load customer's AMDR** baseline—

(a) is estimated by **Transpower** as if the **recent load customer's assets** were fully operational from the start of **CMP D** and taking into account—

(i) the type and **capacity** of the **recent load customer's assets**; and

(ii) the **AMDR** baselines for any other **load customers** with **assets** of the same or a similar type as the **recent load customer's assets**; and

(iii) any available information about the **recent load customer's maximum gross demand**,

but excluding any contribution to the **recent load customer's maximum gross demand** from the charging or discharging of **large battery storage** other than the **battery storage's** energy losses; and

(b) may be re-estimated by **Transpower** under clause 73.

71 Residual Charge Adjustment Factor

(1) A **load customer's RCAF** for **pricing year** n ($RCAF_n$) is calculated as follows:

$$RCAF_n = \frac{LATGE_n}{ATGE_{baseline}}$$

where

$LATGE_n$ is the **load customer's** lagged average **total gross energy** for **pricing year** n calculated under subclause (2)

$ATGE_{baseline}$ is the **load customer's** average **total gross energy** baseline calculated or estimated under subclause (4) or (5).

(2) A **load customer's** lagged average **total gross energy** for **pricing year** n ($LATGE_n$) is calculated as follows:

$$LATGE_n = \frac{1}{4}\sum_{m=n-8}^{n-5} F_m \times TGE_m$$

where

F_m is—

(a) if—

(i) the **load customer** is a **pre-existing load customer**; and

(ii) there has been one or more **reduction events** for the **load customer** that occurred after the end of **financial year** m, the **reduction event** adjustment factor for the **load customer** and **financial year** m calculated under subclause (3); or

(b) otherwise, 1

TGE_m is—

(a) if—

(i) the **load customer** is a **pre-existing load customer**; and

(ii) there has been one or more **reduction events** for the **load customer** that occurred during **financial year** m,

$ATGE_{after}$ as defined in subclause (3), immediately after the most recent such **reduction event**; or

(b) otherwise, the **load customer's total gross energy** for **financial year** m.

(3) The **reduction event** adjustment factor for a **load customer** and **financial year** m ($REAF_m$) is calculated as follows:

$$REAF_m = 1 - \frac{ATGE_{before} - ATGE_{after}}{ATGE_{before}}$$

where

$ATGE_{after}$ is the **load customer's** average **total gross energy** baseline immediately after the reduction under subclause 72(2) for the latest **reduction event** that occurred after the end of **financial year** m

$ATGE_{before}$ is the **load customer's** average **total gross energy** baseline immediately before the reduction under subclause 72(2) for the earliest **reduction event** that occurred after the end of **financial year** m.

(4) Subject to subclause 72(2), a **pre-existing load customer's** average **total gross energy** baseline ($ATGE_{baseline}$) is calculated as follows:

$$ATGE_{baseline} = \frac{1}{4} \sum_{n=2014}^{2017} TGE_n$$

where TGE_n is the **pre-existing load customer's total gross energy** for **financial year** n.

(5) A **recent load customer's** average **total gross energy** baseline—

(a) is estimated by **Transpower** as if the **recent load customer's assets** were fully operational from the start of **CMP D** and taking into account—

(i) the type and **capacity** of the **recent load customer's assets**; and

(ii) the **total gross energy** baselines for any other **load customers** with **assets** of the same or a similar type as the **recent load customer's assets**; and

(iii) any available information about the **recent load customer's total gross energy**,

but excluding any contribution to the **recent load customer's total gross energy** from the charging or discharging of **large battery storage** other than the **battery storage's** energy losses; and

(b) may be re-estimated by **Transpower** under clause 73.

(6) To avoid doubt, a **load customer's RCAF** for a **pricing year** is only calculated if the **load customer's AMDR** for the **pricing year** is calculated under clause 69(1)(c).

Clause 71(2): amended, on 22 March 2023, by clause 4 of the Electricity Industry Participation Code Amendment (Residual Charge Adjustment Factor) 2023.

Clause 71(3): amended, on 22 March 2023, by clause 4 of the Electricity Industry Participation Code Amendment (Residual Charge Adjustment Factor) 2023.

72 Reduction Events

(1) **Transpower** may reduce a **pre-existing load customer's AMDR** baseline by an amount determined by **Transpower**—

(a) if a **reduction event** for the **pre-existing load customer** has occurred or **Transpower** determines will occur; and

(b) to the extent the impact of the **reduction event** is not fully captured in the calculation of the **pre-existing load customer's AMDR** baseline under subclause 70(1).

(2) If **Transpower** reduces a **pre-existing load customer's AMDR** baseline under subclause (1), **Transpower** must also reduce the **pre-existing load customer's** average **total gross energy** baseline to the extent necessary to be consistent with the reduction in the **pre-existing customer's AMDR** baseline, as determined by **Transpower**.

(3) To avoid doubt, the time when a **reduction event** occurred or will occur is determined by **Transpower**.

73 Re-estimating for Recent Load Customers

(1) **Transpower** may re-estimate either or both of a **recent load customer's AMDR** baseline and average **total gross energy** baseline—

(a) when information is available to **Transpower** about the **recent load customer's maximum gross demand** or **total gross energy** when the **recent load customer's assets** are fully operational, but may only re-estimate each of the **recent load customer's AMDR** baseline and average **total gross energy** baseline under this paragraph once; or

(b) if **Transpower** determines information relevant to **Transpower's** estimate of the **recent load customer's AMDR** baseline or average **total gross energy** baseline provided to **Transpower** by or on behalf of the **recent load customer** was false or misleading.

(2) To avoid doubt, the purpose of a re-estimation under subclause (1) is to correct any material under- or over-estimation in **Transpower's** estimate of the **recent load customer's AMDR** baseline or average **total gross energy** baseline.

74 Residual Charge Rate

The **residual charge** rate for a **pricing year** (RCR) is calculated as follows:

$$RCR = \frac{RR}{AMDR_{total}}$$

where

RR is **residual revenue** for the **pricing year**

$AMDR_{total}$ is the total of all **customers' AMDR** for the **pricing year**.

Part F Adjustments

General

75 Adjustment Events

(1) Subject to subclauses (4) and (5), an **adjustment event** is deemed to have occurred on the date **Transpower** has actual knowledge, and is reasonably satisfied, that the **adjustment event** has occurred, regardless of when the **adjustment event** actually occurred.

(2) Except as otherwise stated in this **transmission pricing methodology**, if an **adjustment event** occurs, **Transpower** must adjust relevant **transmission charges** from the date of the **adjustment event**, if necessary on a pro rata basis for the **event pricing year** depending on when the **adjustment event** occurred during the **event pricing year**.

(3) If **adjustment events** affecting the same **transmission charge** occur simultaneously, **Transpower** must determine an order in which the **adjustment events** will be deemed to have occurred for the purpose of adjusting the **transmission charge**.

(4) Subject to subclauses (6) and (7), if a **pre-start adjustment event** for a **post-2019 BBI** has occurred, **Transpower** must treat the **pre-start adjustment event** as a **benefit-based charge adjustment event** that occurred or will occur at the start of the **post-2019 BBI's start pricing year** and—
   (a) if **Transpower** determines it is reasonably practicable to do so, factor the **pre-start adjustment event** into its calculation of relevant **transmission charges** from the start of the **post-2019 BBI's start pricing year**; or
   (b) otherwise, process the **pre-start adjustment event** as a **benefit-based charge adjustment event** during the **start pricing year**.

(5) Subject to subclauses (6) to (8), if a **pre-commencement adjustment event** has occurred, **Transpower** must treat the **pre-commencement adjustment event** as an **adjustment event** that occurred or will occur at the start of the **first pricing year** and—
   (a) if **Transpower** determines it is reasonably practicable to do so, factor the **pre-commencement adjustment event** into its calculation of relevant **transmission charges** from the start of the **first pricing year**; or
   (b) otherwise, process the **pre-commencement adjustment event** as an **adjustment event** during the **first pricing year**.

(6) Unless a **pre-start adjustment event** or **pre-commencement adjustment event** is a **SSCGU**, **Transpower** is not required to (but may) factor the **pre-start adjustment event** or **pre-commencement adjustment event** into its calculation of **regional NPB** under paragraph (4)(a) or (5)(a).

(7) Neither subclause (4) nor (5) applies to a **pre-start adjustment event** or **pre-commencement adjustment event** that is a **specified pre-start adjustment event** to which subclause 65(13) applies.

(8) Subclause (5)—
   (a) does not apply to a **pre-commencement adjustment event** for an **Appendix A BBI** that—
      (i) occurred on or before 10 June 2020 (being the date the **Authority** published the **2020 guidelines**); or
      (ii) is reflected in Appendix A through an adjustment of the type referred to in subclause 42(2); and

(b) subject to paragraph (a), applies to a **benefit-based charge** for an **Appendix A BBI** despite the starting **beneficiaries** and starting **BBI customer allocations** for the **Appendix A BBI** specified in Appendix A.

Connection Charges

76 Connection Charge Adjustment Events

(1) The following events are **connection charge adjustment events**:

(a) a **customer** (the connecting **customer**) connects at a **connection location** at which the **customer** is not already connected:

(b) a **customer** (the disconnecting **customer**) disconnects from a **connection location**:

(c) a **customer** (the vendor) sells or otherwise transfers all or part of its business that constitutes it as a **customer** at a **connection location** to another party (the purchaser):

(d) **Transpower** decides to voluntarily under-recover the **connection charges** for a **connection asset**, **connection location** or **connection transmission alternative**.

(2) **Transpower** must not voluntarily under-recover the **connection charge** for a **connection asset**, **connection location** or **connection transmission alternative** if the effect of doing so would be to increase **residual revenue** for any **pricing year**.

(3) To avoid doubt, a vendor's sale or other transfer of all or part of its business that constitutes it as a **customer** at a **connection location** to a purchaser is treated as the **connection charge adjustment event** in paragraph (1)(c) and not the **connection charge adjustment event** in paragraph (1)(a) or (1)(b).

77 Connection Charge Adjustment Event: Connecting Customer

(1) This clause 77 applies in the case of the **connection charge adjustment event** in paragraph 76(1)(a).

(2) In this clause 77, a relevant **pricing year** is the **event pricing year** and the **pricing year** after the **event pricing year**.

(3) **Transpower** must, for each relevant **pricing year**—

(a) determine whether the connecting **customer** will be treated as an **offtake customer** or **injection customer** at the **connection location**; and

(b) estimate the connecting **customer's AMDC** or **AMIC** (as applicable depending on **Transpower's** determination under paragraph (a) for the **connection location** taking into account—

(i) the type and **capacity** of the connecting **customer's assets**; and

(ii) **AMDC** or **AMIC** (as the case may be) for any other **customers** with **assets** of the same or a similar type as the new **customer's assets** connected at the **connection location**; and

(c) calculate or re-calculate (as the case may be) all **customers' connection customer allocations** for the **connection location** to account for the connecting **customer's AMDC** or **AMIC** estimated under paragraph (b); and

(d) calculate or re-calculate (as the case may be) all **customers' connection charges** for the **connection location** based on the **customers' connection customer allocations** calculated under paragraph (c); and

(e) calculate or re-calculate (as the case may be) all **customers' connection charges** for any relevant **connection transmission alternative**—

(i) to account for the connecting **customer's annual connection charge** for the **connection location** calculated under paragraph (d); and
(ii) assuming that **annual connection charge** applied for the previous **pricing year**.

(4) **Transpower** must start the connecting **customer's monthly connection charges** calculated under paragraph (3)(d) or (3)(e) as soon as reasonably practicable. The connecting **customer's monthly connection charges** may include an adjustment as necessary to ensure the connecting **customer** pays its full **connection charges** for the **connection location** or **connection transmission alternative** from the date the connecting **customer** connected at the **connection location**.

(5) **Transpower** is not required to (but may) start any other **customer's monthly connection charges** re-calculated under paragraph (3)(d) or (3)(e) during, or from the start of, an **exempt pricing year** for the **customer**. However, any over-recovery of **annual connection charges** for the **connection location** or **connection transmission alternative** and **exempt pricing year** resulting from the start of the connecting **customer's monthly connection charges** for the **connection location** or **connection transmission alternative** must be rebated, as appropriate, to the other **customers** by way of an adjustment to their **transmission charges**—
(a) if reasonably practicable, at the end of the **exempt pricing year**; or
(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

78 Connection Charge Adjustment Event: Disconnecting Customer

(1) This clause 78 applies in the case of the **connection charge adjustment event** in paragraph 76(1)(b).

(2) **Transpower**—
(a) must make the disconnecting **customer's connection customer allocations** (and the inputs to their calculation) and **connection charges** for the **connection location** and any relevant **connection transmission alternative** 0; and
(b) must not increase—
(i) any other **customer's connection charges** for the **connection location** or **connection transmission alternative** and **event pricing year**; or
(ii) any other **transmission charges** for the **event pricing year**,
as a consequence of applying paragraph (a).

79 Connection Charge Adjustment Event: Sale of Business

(1) This clause 79 applies in the case of the **connection charge adjustment event** in paragraph 76(1)(c).

(2) In this clause 79, a relevant **pricing year** is the **event pricing year** and the **pricing year** after the **event pricing year**.

(3) **Transpower** must, for a sale of part of the vendor's business and for each relevant **pricing year**—
(a) determine an apportionment between the vendor and purchaser of the vendor's **connection customer allocations** (and the inputs to their calculation) for the **connection location** taking into account the size and nature of the transferred business; and
(b) calculate or re-calculate (as the case may be) the vendor's and purchaser's **connection charges** for the **connection location** based on the apportionment of the vendor's **connection customer allocations** under paragraph (a); and
(c) calculate or re-calculate (as the case may be) the vendor's and purchaser's **connection charges** for any relevant **connection transmission alternative**—

(i) to account for the vendor's and purchaser's **annual connection charges** for the **connection location** calculated under paragraph (b); and
(ii) assuming those **annual connection charges** applied for the previous **pricing year**.

(4) **Transpower** must, for a sale of all of the vendor's business and for each relevant **pricing year**—
(a) attribute all of the vendor's **connection customer allocation** (and the inputs to its calculation) for the **connection location** to the purchaser; and
(b) calculate or re-calculate (as the case may be) the purchaser's **connection charges** for the **connection location** based on the attribution of the vendor's **connection customer allocation** under paragraph (a); and
(c) calculate or re-calculate (as the case may be) the purchaser's **connection charge** for any relevant **connection transmission alternative**—
(i) to account for the purchaser's **annual connection charges** for the **connection location** calculated under paragraph (b); and
(ii) assuming those **annual connection charges** applied for the previous **pricing year**.

(5) **Transpower** must start the purchaser's **monthly connection charges** calculated under paragraph (3)(b), (3)(c), (4)(b) or (4)(c) as soon as reasonably practicable. The purchaser's **monthly connection charges** may include an adjustment as necessary to ensure the purchaser pays its full **connection charges** for the **connection location** or **connection transmission alternative** from the date of the transfer.

(6) **Transpower** is not required to (but may) start the vendor's **monthly connection charges** calculated under paragraph (3)(b) or (3)(c) during, or from the start of, an **exempt pricing year** for the vendor. However, any over-recovery of **annual connection charges** for the **connection location** or **connection transmission alternative** and **exempt pricing year** resulting from the start of the purchaser's **monthly connection charges** for the **connection location** or **connection transmission alternative** must be rebated to the vendor by way of an adjustment to its **transmission charges**—
(a) if reasonably practicable, at the end of the **exempt pricing year**; or
(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

80 Connection Charge Adjustment Event: Voluntary Under-recovery

(1) This clause 80 applies in the case of the **connection charge adjustment event** in paragraph 76(1)(d).

(2) In this clause 80, a relevant **pricing year** is a **pricing year** for which **Transpower** decided to voluntarily under-recover the **connection charges** for the **connection asset**, **connection location** or **connection transmission alternative**.

(3) **Transpower** must, for each relevant **pricing year**, calculate or re-calculate (as the case may be) all **customers' connection charges** for the **connection asset**, **connection location** or **connection transmission alternative** to account for the amount of the voluntary under-recovery of the **connection charges**.

(4) If **Transpower** decides to voluntarily under-recover the **connection charges** for the **connection asset**, **connection location** or **connection transmission alternative** and a relevant **pricing year** during, or within 1 month of the start of, the relevant **pricing year**, **Transpower** is not required to (but may) start **customers' monthly connection charges** calculated under subclause (3) during, or from the start of, the relevant **pricing year**. However, any over-recovery of **annual connection charges** for the **connection asset**, **connection location** or **connection transmission alternative** and relevant **pricing year** (accounting for the voluntary under-recovery) must be

rebated, as appropriate, to the **customers** by way of an adjustment to their **transmission charges**—

(a) if reasonably practicable, at the end of the relevant **pricing year**; or
(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

Benefit-based Charges

81 Benefit-based Charge Adjustment Events

(1) The following events are **benefit-based charge adjustment events**:

(a) a **BBI** suffers **material damage**:
(b) a new **customer** connects to the **grid**:
(c) a **customer** (the exiting **customer**) ceases to be a **customer**:
(d) an existing **customer** (the connecting or disconnecting **customer**) connects **plant** to, or disconnects **plant** from, the **grid**:
(e) **large embedded plant** is connected to, or **large embedded plant** is disconnected from, a **host customer's** (the connecting or disconnecting **customer's**) **local network** or **grid**-connected **plant**:
(f) there is a **substantial sustained increase** by a **customer's** (the increasing **customer's**) existing **grid**-connected **plant**:
(g) there is a **substantial sustained increase** by existing **large embedded plant** connected to a **host customer's** (the increasing **customer's**) **local network** or **grid**-connected **plant**:
(h) a **distributor** (the connecting **distributor**) connects its **local network** at a **grid point of connection** (new **grid point of connection**) to which the connecting **distributor** was not connected immediately before connecting its **local network** at the new **grid point of connection**:
(i) the **point of connection** for existing **large plant** changes:
(j) a **customer** (the vendor) sells or otherwise transfers all or part of its business that constitutes it as a **beneficiary** of a **BBI** to another party (the purchaser):
(k) **Transpower** decides to voluntarily under-recover a **BBI's covered cost**:
(l) there is a **SSCGU**.

(2) **Transpower** must not voluntarily under-recover a **BBI's covered cost** if the effect of doing so would be to increase **residual revenue** for any **pricing year**.

(3) For the purposes of paragraphs (1)(d) and (1)(e)—

(a) a **large upgrade** of existing **plant** is treated as the connection of **large plant** equivalent in size to the **upgrade**; and
(b) a **large de-rating** of existing **plant** is treated as the disconnection of **large plant** equivalent in size to the **de-rating**; and
(c) a series of incremental **upgrades** or **de-ratings** of existing **plant** is treated as a **large upgrade** or **large de-rating** (as the case may be) if the incremental **upgrades** or **de-ratings** would constitute a **large upgrade** or **large de-rating** if undertaken at the same time.

(4) For the purposes of paragraphs (1)(f) and (1)(g), whether the increase in **electricity** consumed or generated by the **large plant** is a **substantial sustained increase** in respect of a **BBI** must be assessed against the average annual **electricity** consumption or generation by the **large plant** explicitly or implicitly included in the current value of the increasing **customer's intra-regional allocator** for its **regional customer group** and the **BBI**.

(5) To avoid doubt, the **benefit-based charge adjustment events** in paragraphs (1)(a) and (1)(k) do not result in any change to the relevant **BBI's BBI customer allocations**.

(6) The **benefit-based charge adjustment event** in paragraph (1)(i) is treated as the **benefit-based charge adjustment events** in 1 or both of paragraphs (1)(d) and (1)(e) (depending on the previous and new **point of connection**) occurring in respect of the same **large plant**, provided that clause 85 will not apply except as specified in clause 88.

(7) To avoid doubt, a vendor's sale or other transfer of all or part of its business that constitutes it as a **beneficiary** of a **BBI** to a purchaser is treated as the **benefit-based charge adjustment event** in paragraph (1)(j) and not the **benefit-based charge adjustment event** in paragraph (1)(b) or (1)(c).

(8) Any of the **benefit-based charge adjustment events** in paragraphs (1)(b) to (1)(j) may also be a **SSCGU**, in which case both clause 91 and clause 83, 84, 85, 86, 87 or 88 (as applicable depending on the **benefit-based charge adjustment event**) will apply. However, clause 83, 84, 85, 86, 87 or 88 will only apply to a relevant **BBI** described in paragraph 91(2)(a) in respect of **pricing years** before the **SSCGU's start pricing year**.

(9) For the purposes of subclauses 84(5), 84(6), 85(4) and 85(5) (which relate to **continuing BBIs**)—
- (a) the Bunnythorpe Haywards **Appendix A BBI** is deemed to have a **commissioning date** of 9 May 2015; and
- (b) the **post-2019 CUWLP investment** is deemed to have a **commissioning date** of 1 January 2021; and
- (c) if the **commissioning date** of any other **high-value intervening BBI** is not known to **Transpower**, the **high-value intervening BBI** is deemed to have a **commissioning date** determined by **Transpower**.

82 Benefit-based Charge Adjustment Event: Material Damage

(1) This clause 82 applies in the case of the **benefit-based charge adjustment event** in paragraph 81(1)(a).

(2) In this clause 82, a relevant **pricing year** is—
- (a) the **event pricing year**; and
- (b) each subsequent **pricing year** for which a **write-down** due to the **material damage** is not reflected in the **RAB** values or **values of commissioned asset** used to calculate the **BBI's covered cost** for the **pricing year**.

(3) Subject to subclause (4), **Transpower** must, for each relevant **pricing year**—
- (a) reduce the **BBI's covered cost** by an amount determined by **Transpower** to reflect a reasonable **write-down** of the **BBI** due to the **material damage**; and
- (b) calculate or re-calculate (as the case may be) all **beneficiaries' benefit-based charges** for the **BBI** based on the reduction of the **BBI's covered cost** under paragraph (a).

(4) If a **beneficiary** (the causing **beneficiary**) caused, or contributed to the cause of, the **material damage**, subclause (3) does not apply to the causing **beneficiary's benefit-based charge** for the **BBI**.

(5) **Transpower** is not required to (but may) start a **beneficiary's monthly benefit-based charge** calculated under paragraph (3)(b) during, or from the start of, an **exempt pricing year** for the **beneficiary**. However, any over-recovery of the **BBI's covered cost** for the **exempt pricing**

year (accounting for the **material damage**) must be rebated, as appropriate, to the **beneficiaries** (other than any causing **beneficiary**) by way of an adjustment to their **transmission charges**—
(a) if reasonably practicable, at the end of the **exempt pricing year**; or
(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

(6) **Transpower** must not increase any **transmission charges** for the **event pricing year** as a consequence of applying subclause (3).

83 Benefit-based Charge Adjustment Event: New Customer

(1) This clause 83 applies in the case of the **benefit-based charge adjustment event** in paragraph (81)(1)(b).

(2) The new **customer**—
(a) is a **beneficiary** of each **post-2019 BBI** (a relevant **post-2019 BBI**) that has positive **regional NPB** for a **regional customer group** of which the new **customer** is expected to be a member (a relevant **regional customer group** for the relevant **post-2019 BBI**); and
(b) may be a **beneficiary** of 1 or more of the **Appendix A BBIs**.

(3) **Transpower** must, for each relevant **post-2019 BBI**—
(a) estimate the value of the new **customer's intra-regional allocator** for each relevant **regional customer group** as if the new **customer's assets** were fully operational and taking into account—
(i) the type and **capacity** of the new **customer's assets**; and
(ii) the values of the **intra-regional allocators** for any other **beneficiaries** of the relevant **post-2019 BBI** with **assets** of the same or a similar type as the new **customer's assets**; and
(b) subject to subclause (4) and applying subclause (13) if required, calculate the new **customer's individual NPB** for the relevant **post-2019 BBI**—
(i) under clause 47, 57 or 61 (as applicable depending on the method used to calculate **beneficiaries' BBI customer allocations** for the relevant **post-2019 BBI**); and
(ii) based on the value of the new **customer's intra-regional allocator** for each relevant **regional customer group** estimated under paragraph (a), but excluding the value of the new **customer's intra-regional allocator** from the denominator of the formula in clause 47 or subclause 61(2) (as applicable) unless the **regional customer group** had no members immediately before the new **customer** joined it; and
(c) calculate the new **customer's BBI customer allocation** for the relevant **post-2019 BBI** based on the new **customer's individual NPB** for the relevant **post-2019 BBI** calculated under paragraph (b), but excluding the value of the new **customer's individual NPB** from the denominator of the formula in subclause 43(1); and
(d) scale down all **beneficiaries'** (including the new **customer's**) **BBI customer allocations** for the relevant **post-2019 BBI** by a factor (F) calculated as follows:

$$F = \frac{1}{1 + CA}$$

where CA is the new **customer's BBI customer allocation** for the relevant **post-2019 BBI** calculated under paragraph (c); and

(e) calculate or re-calculate (as the case may be) all **beneficiaries' benefit-based charges** for the relevant **post-2019 BBI** based on the **beneficiaries' BBI customer allocations** calculated under paragraph (d).

(4) If the new **customer** is in a **future regional customer group** for a relevant **BBI**, **Transpower** must calculate the new **customer's individual NPB** for the relevant **BBI** under paragraph (3)(b) in respect of the **future regional customer group** by using the **future regional customer group's notional IRA value** in the denominator of the formula in clause 47.

(5) The following tables illustrate the application of subclause (3) to a new **customer** (**customer** E) entering **regional customer group** Y for a **post-2019 BBI** where **regional customer group** Y is not a **future regional customer group** and the **post-2019 BBI** is not a **resiliency BBI**:

Before

regional customer group	beneficiary	regional NPB	intra-regional allocator	individual NPB	BBI customer allocation
X	A	60	1	20	18.18%
	B		2	40	36.36%
Y	C	50	3	30	27.27%
	D		2	20	18.18%

Transition (paragraphs (3)(a) to (3)(c))

regional customer group	beneficiary	regional NPB	intra-regional allocator	individual NPB	BBI customer allocation
X	A	60	1	20	18.18%
	B		2	40	36.36%
Y	C	50	3	30	27.27%
	D		2	20	18.18%
	E		1 (estimated)	1/5 × 50 = 10	10/110 = 9.09%

After (paragraph (3)(d)

regional customer group	beneficiary	regional NPB	intra-regional allocator	individual NPB	BBI customer allocation (scaled by 1/1.0909)
X	A	60	1	20	16.67%
	B		2	40	33.33%
Y	C	50	3	30	25.00%
	D		2	20	16.67%
	E		1 (estimated)	10	8.33%

(6) **Transpower** must, for each **Appendix A BBI**—

(a) calculate the new **customer's BBI customer allocation** for the **Appendix A BBI** (CA) as follows:

$$CA = E \times \frac{1}{J} \sum_{j} BF_j$$

where

E is **Transpower's** estimate of the new **customer's** average annual **offtake** or **injection** at the new **customer's connection location** when the new **customer's assets** are fully operational

J is the number of **Appendix A customers** of the same type as the new **customer** (**generator** or **connected asset owner**)—
(i) at the new **customer's connection location**; or
(ii) if there are no such **Appendix A customers** at the new **customer's connection location**, at the **connection location** electrically closest to the new **customer's connection location** at which there is 1 or more such **Appendix A customers**, as determined by **Transpower**,
each such **Appendix A customer** being **Appendix A customer** j

BF_j is **Appendix A customer** j's **benefit factor** for the **Appendix A BBI** and the new **customer's connection location** (which may be zero); and

(b) scale down all **beneficiaries'** (including the new **customer's**) **BBI customer allocations** for the **Appendix A BBI** by a factor (F) calculated as follows:

$$F = \frac{1}{1 + CA}$$

where CA is the new **customer's BBI customer allocation** for the **Appendix A BBI** calculated under paragraph (a); and

(c) calculate or re-calculate (as the case may be) all **beneficiaries' benefit-based charges** for the **Appendix A BBI** based on the **beneficiaries' BBI customer allocations** calculated under paragraph (b).

(7) An **Appendix A customer's benefit factor** for an **Appendix A BBI** and **connection location** (BF) is calculated as follows:

$$BF = \frac{CA}{E}$$

where

CA is the part of the **Appendix A customer's Appendix A allocation** for the **Appendix A BBI** attributable to the **connection location** (which may be 0)

E is—
(a) if the **Appendix A customer** is a **Schedule 1 customer**, the **Appendix A customer's** average annual **offtake** or **injection** at the **connection location** over **CMP D**, being the period the **Authority** used to calculate the **Schedule 1 allocations**, adjusted as necessary to take account of any adjustments of the type referred to in clause 42(2); or
(b) otherwise, the estimate of the **Appendix A customer's** annual **offtake** or **injection** at the **connection location Transpower** used to calculate the **Appendix A customer's Appendix A allocation** for the **Appendix A BBI**.

(8) For the purposes of the calculation under paragraph (6)(a), if the new **customer's assets** are **battery storage**—
(a) the new **customer** must be treated as a **generator** and not a **connected asset owner**; and
(b) variable E must be **Transpower's** estimate of the new **customer's** average annual **injection** at the new **customer's connection location** when the new **customer's battery storage** is fully operational.

(9) The following tables illustrate the application of subclause (6) to a new **customer** (**beneficiary** E) for an **Appendix A BBI**, where the incumbent **beneficiaries** are all **Appendix A customers** and the **benefit factors** for **beneficiaries** B and C are used in the calculation in subclause (6)(a):

Before

beneficiary	**benefit factor**	average annual **offtake/injection**	**BBI customer allocation**
A	0.1818	100	18.18%
B	0.1818	200	36.36%
C	0.0909	300	27.27%
D	0.0455	400	18.18%

Transition (paragraph (6)(a))

beneficiary	**benefit factor**	average annual **offtake/injection**	**BBI customer allocation**
A	0.1818	100	18.18%
B	0.1818	200	36.36%
C	0.0909	300	27.27%
D	0.0455	400	18.18%
E	(0.1818 + 0.0909)/2 = 0.1364	250 (estimated)	0.1364 × 250 = 34.10%

After (paragraph (6)(b))

beneficiary	**benefit factor**	annual **offtake/injection**	**BBI customer allocation** (scaled by 1/1.341)
A	0.1818	100	13.56%
B	0.1818	200	27.11%
C	0.0909	300	20.34%
D	0.0455	400	13.56%
E	0.1364	250 (estimated)	25.43%

(10) **Transpower** must start the new **customer's monthly benefit-based charges** calculated under paragraph (3)(e) or (6)(c) as soon as reasonably practicable. The new **customer's monthly benefit-based charges** may include an adjustment as necessary to ensure the new **customer** pays its full **benefit-based charge** for each **BBI** from the date the new **customer** connected to the **grid**.

(11) **Transpower** is not required to (but may) start any other **beneficiary's monthly benefit-based charges** re-calculated under paragraph (3)(e) or (6)(c) during, or from the start of, an **exempt pricing year** for the **beneficiary**. However, any over-recovery of the **benefit-based charge** for a **BBI** and **exempt pricing year** resulting from the start of the new **customer's monthly**

benefit-based charge for the **BBI** must be rebated, as appropriate, to the other **beneficiaries** by way of an adjustment to their **transmission charges**—

(a) if reasonably practicable, at the end of the **exempt pricing year**; or

(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

(12) Subclause (13) applies if the new **customer** is expected to be a member of a **regional customer group** under the **simple method** that—

(a) had no members during **CMP C** for the relevant **simple method period**; and

(b) has **regional NPB** of 0 in respect of at least one **investment region** for the relevant **simple method period** (each a **zero RNPB investment region**).

(13) If this subclause applies under subclause (12), **Transpower** must, for the purposes of the calculation under paragraph (3)(b), calculate **regional NPB** for the **regional customer group** in respect of each **zero RNPB investment region** (RNPB) as follows:

$$RNPB = \frac{RNPB_{type\ total}}{I \times IRA_{type\ total}} \times IRA \times \frac{RNPB_{inv\ total}}{RNPB_{total}}$$

where, subject to subclause (14)

$RNPB_{type\ total}$ is—

(a) if the **regional customer group** is a **regional demand group**, the total of all other **regional demand groups' regional NPB**s in respect of all **investment regions** for the **simple method period**; or

(b) if the **regional customer group** is a **regional supply group**, the total of all other **regional supply groups' regional NPBs** in respect of all **investment regions** for the **simple method period**

I is the number if **investment regions** for the **simple method period**

$IRA_{type\ total}$ is—

(a) if the **regional customer group** is a **regional demand group**, the total of all **customers' intra-regional allocator** values for all other **regional demand groups** for the **simple method period**; or

(b) if the **regional customer group** is a **regional supply group**, the total of all **customers' intra-regional allocator** values for all other **regional supply groups** for the **simple method period**

IRA is the value of the **customer's intra-regional allocator** estimated under paragraph 83(3)(a)

$RNPB_{inv\ total}$ is the total of all other **regional customer groups' regional NPBs** in respect of the **zero RNPB investment region** for which RNPB is being calculated

$RNPB_{total}$ is the total of all other **regional customer groups' regional NPBs** in respect of all **zero RNPB investment regions**.

(14) The other **regional customer groups** referred to in the definitions of variables $RNPB_{type\ total}$, $RNPB_{inv\ total}$ and $RNPB_{total}$ in subclause (13) exclude **regional customer groups** with no members.

84 Benefit-based Charge Adjustment Event: Exiting Customer

(1) This clause 84 applies in the case of the **benefit-based charge adjustment event** in paragraph 81(1)(c).

(2) The exiting **customer** ceases to be a **beneficiary** of each **BBI** (a relevant **BBI**) of which the exiting **customer** was a **beneficiary** immediately before ceasing to be a **customer**.

(3) Subject to subclause (7), **Transpower**—
(a) must, for each relevant **BBI**—
(i) make the exiting **customer's BBI customer allocation** and **benefit-based charge** for the relevant **BBI** 0; and
(ii) scale up all remaining **beneficiaries' BBI customer allocations** for the relevant **BBI** by a factor (F) calculated as follows:

$$F = \frac{1}{1 - CA}$$

where CA is the exiting **customer's BBI customer allocation** for the relevant **BBI** immediately before it was set to 0 under subparagraph (i); and
(iii) re-calculate all remaining **beneficiaries' benefit-based charges** for the relevant **BBI** based on the remaining **beneficiaries' BBI customer allocations** calculated under subparagraph (ii); and
(b) must not increase—
(i) the remaining **beneficiaries' benefit-based charges** for the relevant **BBI** and **event pricing year**; or
(ii) any other **transmission charges** for the **event pricing year**,
as a consequence of applying subparagraph (a)(i).

(4) The following tables illustrate the application of subclause (3) to a **customer** (**customer** D) exiting **regional customer group** Y for a **post-2019 BBI** that is not a **resiliency BBI**:

Before

regional customer group	beneficiary	regional NPB	intra-regional allocator	individual NPB	BBI customer allocation
X	A	60	1	20	16.67%
	B		2	40	33.33%
Y	C	50	3	30	25.00%
	D		2	20	16.67%
	E		1	10	8.33%

After (subparagraphs (3)(a)(i) and (3)(a)(ii))

regional customer group	**beneficiary**	**regional NPB**	**intra-regional allocator**	**individual NPB**	**BBI customer allocation** (scaled by 1/0.8333)
X	A	60	1	20	20.00%
	B		2	40	40.00%
Y	C	50	3	30	30.00%
	D		2	20	0%
	E		1	10	10.00%

(5) In subclauses (6) and (7), a **continuing BBI** is the Bunnythorpe Haywards **Appendix A BBI** or a **post-2019 BBI**—
  (a) of which the exiting **customer** was a **beneficiary** immediately before ceasing to be a **customer**; and
  (b) in the case of the Bunnythorpe Haywards **Appendix A BBI** or a **post-2019 BBI** under a **standard method**, **commissioned** less than 10 years before the date the exiting **customer** ceased to be a **customer**; and
  (c) in the case of a **post-2019 BBI** under the **simple method**, **commissioned** during a **simple method period** that started less than 12.5 years before the date the exiting **customer** ceased to be a **customer**.

(6) Subclause (7) applies to a **continuing BBI** until—
  (a) in the case of the Bunnythorpe Haywards **Appendix A BBI** or a **post-2019 BBI** under a **standard method**, the start of the first **pricing year** that starts at least 10 years after the **continuing BBI's commissioning date**; and
  (b) in the case of a **post-2019 BBI** under the **simple method**, the start of the **first pricing** year that starts at least 12.5 years after the start of the **simple method period** during which the **continuing BBI** was **commissioned**.

(7) If this subclause applies to a **continuing BBI** under subclause (6) and a **related entity** of the exiting **customer** is a **customer** after the exiting **customer** ceases to be a **customer—**
  (a) subparagraphs (3)(a)(ii) and (3)(a)(iii) do not apply; and
  (b) the exiting **customer's benefit-based charge** for the **continuing BBI** must be attributed (by way of increase) to the **related entity** in its capacity as a **customer**. If there is more than 1 **related entity**, this subclause applies to a **related entity** determined by **Transpower**; and
  (c) **Transpower** must start the **related entity's monthly benefit-based charges** attributed under paragraph (b) as soon as reasonably practicable. The **related entity's monthly benefit-based charges** may include an adjustment as necessary to ensure the **related entity** pays its full attributed **benefit-based charge** for the **continuing BBI** from the date the exiting **customer** ceased to be a **customer**.

85 Benefit-based Charge Adjustment Event: Large Plant Connected or Disconnected

(1) Subject to subclause 81(6), this clause 85 applies in the case of the **benefit-based charge adjustment event** in paragraph 81(1)(d) or 81(1)(e).

(2) **Transpower** must, for a connecting **customer—**
  (a) comply with clause 83 as if the **large plant** had been connected to the **grid** by a separate new **customer** (the notional new **customer**) at—

(i) if the **large plant** is connected to the **grid**, the **connection location** where the **large plant** is connected; or
(ii) if the **large plant** is connected to the connecting **customer's local network**, the **connection location** electrically closest to the **large plant's** electrically closest **point of connection** to the **local network**, as determined by **Transpower**; or
(iii) if the **large plant** is connected to the connecting **customer's grid**-connected **plant**, the **connection location** where the **grid**-connected **plant** is connected; and

(b) attribute (by way of increase) the notional new **customer's BBI customer allocation** (and the inputs to its calculation) and **benefit-based charge** for each relevant **post-2019 BBI** and **Appendix A BBI** to the connecting **customer**.

(3) Subject to subclause (6), **Transpower** must, for a disconnecting **customer**—
(a) comply with clause 84 (without regard to subclauses 0 to 0) as if the **large plant** had been disconnected from the **grid** by a separate exiting **customer** (the notional exiting **customer**) at—
(i) if the **large plant** was connected to the **grid**, the **connection location** where the **large plant** was connected; or
(ii) if the **large plant** was connected to the disconnecting **customer's local network**, the **connection location** electrically closest to the **large plant's** electrically closest **point of connection** to the **local network** before the **large plant** was disconnected, as determined by **Transpower**; or
(iii) if the **large plant** was connected to the disconnecting **customer's grid**-connected **plant**, the **connection location** where the **grid**-connected **plant** is connected; and

(b) attribute (by way of reduction) the notional exiting **customer's BBI customer allocation** (and the inputs to its calculation) and **benefit-based charge** for each relevant **BBI** to the disconnecting **customer**, provided that the minimum value of the disconnecting **customer's BBI customer allocation** (and the inputs to its calculation) and **benefit-based charge** for each relevant **BBI** is 0.

(4) In subclauses (5) and (6), a **continuing BBI** is the Bunnythorpe Haywards **Appendix A BBI** or a **post-2019 BBI**—
(a) of which the notional exiting **customer** was a **beneficiary** immediately before the disconnection of the **large plant**; and
(b) in the case of the Bunnythorpe Haywards **Appendix A BBI** or a **post-2019 BBI** under a **standard method**, **commissioned** less than 10 years before the date the **large plant** was disconnected; and
(c) in the case of a **post-2019 BBI** under the **simple method**, **commissioned** during a **simple method period** that started less than 12.5 years before the date the **large plant** was disconnected.

(5) Subclause (6) applies to a **continuing BBI** until—
(a) in the case of the Bunnythorpe Haywards **Appendix A BBI** or a **post-2019 BBI** under a **standard method**, the start of the first **pricing year** that starts at least 10 years after the **continuing BBI's commissioning date**; and
(b) in the case of a **post-2019 BBI** under the **simple method**, the start of the **first pricing** year that starts at least 12.5 years after the start of the **simple method period** during which the **continuing BBI** was **commissioned**.

(6) If this subclause applies to a **continuing BBI** under subclause (5) and the **large plant** owner or a **related entity** of the **large plant** owner (relevant person) is a **customer** after the disconnection of the **large plant**—

(a) subparagraphs 84(3)(a)(ii) and 84(3)(a)(iii) do not apply; and

(b) the notional exiting **customer's benefit-based charge** for the **continuing BBI** must be attributed (by way of increase) to the relevant person in its capacity as a **customer**. If there is more than 1 relevant person, this subclause applies to—

(i) the **large plant** owner; or

(ii) if the **large plant** owner is not a **customer** after the disconnection of the **large plant**, a **related entity** determined by **Transpower**; and

(c) **Transpower** must start the relevant person's **monthly benefit-based charges** attributed under paragraph (b) as soon as reasonably practicable. The relevant person's **monthly benefit-based charges** may include an adjustment as necessary to ensure the relevant person pays its full attributed **benefit-based charge** for the **continuing BBI** from the date the **large plant** was disconnected.

86 Benefit-based Charge Adjustment Event: Substantial Sustained Increase

(1) This clause 86 applies in the case of the **benefit-based charge adjustment event** in paragraph 81(1)(f) or 81(1)(g).

(2) **Transpower** must—

(a) comply with clause 83 as if the **substantial sustained increase** were attributable to **plant** connected to the **grid** by a separate new **customer** (the notional new **customer**) at—

(i) if the **substantial sustained increase** is in **electricity** consumed or generated by **grid**-connected **plant**, the **connection location** where the **grid**-connected **plant** is connected; or

(ii) if the **substantial sustained increase** is in **electricity** consumed or generated by **large embedded plant** connected to the increasing **customer's local network**, the **connection location** electrically closest to the **large embedded plant's** electrically closest **point of connection** to the **local network**, as determined by **Transpower**; or

(iii) if the **substantial sustained increase** is in **electricity** consumed or generated by **large embedded plant** connected to the increasing **customer's grid**-connected **plant**, the **connection location** where the **grid**-connected **plant** is connected; and

(b) attribute the notional new **customer's BBI customer allocation** (and the inputs to its calculation) and **benefit-based charge** for each relevant **post-2019 BBI** and **Appendix A BBI** to the increasing **customer**.

87 Benefit-based Charge Adjustment Event: Distributor Connection at GXP

(1) This clause 87 applies in the case of the **benefit-based charge adjustment event** in paragraph 81(1)(h).

(2) In this clause 87, a relevant **BBI** is a **BBI** that has at least 1 **regional customer group** with positive **regional NPB** that the connecting **distributor** became a member of by connecting at the new **grid point of connection** (and of which the connecting **distributor** was not a member immediately before connecting at the new **grid point of connection**).

(3) **Transpower** must for each relevant **BBI** (and no other **BBIs**)—

(a) comply with clause 83 as if a **local network** had been connected at the new **grid point of connection** by a separate new **distributor** (the notional new **distributor**), provided that the estimate of the notional new **distributor's intra-regional allocators** must take into account any expected reduction in the connecting **distributor's offtake** or **injection** at **grid points of connection** in other **modelled regions** as a result of the connection of the connecting **customer's local network** at the new **grid point of connection** (with any such reduction to be set off against the estimate of the notional new **distributor's offtake** or **injection** at the new **grid point of connection**); and

(b) attribute the notional new **distributor's BBI customer allocation** (and the inputs to its calculation) and **benefit-based charge** for each relevant **BBI** to the connecting **distributor**.

88 Benefit-based Charge Adjustment Event: Changed Point of Connection

(1) This clause 88 applies in the case of the **benefit-based charge adjustment event** in paragraph 81(1)(i).

(2) **Transpower** must—

(a) apply subclauses 85(2) and 85(3) to calculate the notional new **customer's** and notional exiting **customer's BBI customer allocations**; and

(b) identify the **BBIs** of which both the notional new **customer** and notional exiting **customer** are **beneficiaries** (the relevant **BBIs**).

(3) If the notional new **customer's BBI customer allocation** for a relevant **BBI** is equal to or more than the notional exiting **customer's BBI customer allocation** for the relevant **BBI**, **Transpower** must—

(a) apply paragraph 85(2)(b) for the connecting c**ustomer** and relevant **BBI**; and

(b) apply paragraph 85(3)(b) for the disconnecting **customer** and relevant **BBI** (without regard to subclause 85(5)).

(4) If the notional exiting **customer's BBI customer allocation** for a relevant **BBI** is more than the notional new **customer's BBI customer allocation** for the relevant **BBI**, **Transpower** must—

(a) apply paragraph 85(2)(b) for the connecting **customer** and relevant **BBI**, but by attributing to the connecting **customer** the notional exiting **customer's BBI customer allocation** (and the inputs to its calculation) and **benefit-based charge** for the relevant **BBI** instead of the notional new **customer's**; and

(b) apply paragraph 85(3)(b) for the disconnecting **customer** and relevant **BBI** (without regard to subclause 85(5)).

89 Benefit-based Charge Adjustment Event: Sale of Business

(1) This clause 89 applies in the case of the **benefit-based charge adjustment event** in paragraph 81(1)(j).

(2) **Transpower** must, for a sale of part of the vendor's business—

(a) determine an apportionment between the vendor and purchaser of the vendor's **BBI customer allocation** (and the inputs to its calculation) for the **BBI** taking into account the size and nature of the transferred business; and

(b) calculate or re-calculate (as the case may be) the vendor's and purchaser's **benefit-based charges** for the **BBI** based on the apportionment of the vendor's **BBI customer allocation** under paragraph (a); and

(c) calculate or re-calculate (as the case may be) the vendor's and purchaser's **cap recovery charge** and **prudent discount recovery charges** for the **event pricing year** to account for—

(i) the vendor's and purchaser's **annual benefit-based charges** calculated under paragraph (b); and

(ii) any **annual residual charge** for the vendor or purchaser calculated under subclause 94(2) or 94(3) in respect of the same sale of business.

(3) **Transpower** must, for a sale of all of the vendor's business—
  (a) attribute the vendor's **BBI customer allocation** (and the inputs to its calculation) for the **BBI** to the purchaser; and
  (b) calculate or re-calculate (as the case may be) the purchaser's **benefit-based charge** for the **BBI** based on the attribution of the vendor's **BBI customer allocation** under paragraph (a); and
  (c) calculate or re-calculate (as the case may be) the purchaser's **cap recovery charge** and **prudent discount recovery charges** for the **event pricing year** to account for—
    (i) the purchaser's **annual benefit-based charge** calculated under paragraph (b); and
    (ii) any **annual residual charge** for the vendor or purchaser calculated under clause 94(2) or 94(3) in respect of the same sale of business.

(4) **Transpower** must start the purchaser's **monthly benefit-based charge** calculated under paragraph (2)(b) or (3)(b) as soon as reasonably practicable. The purchaser's **monthly benefit-based charge** may include an adjustment as necessary to ensure the purchaser pays its full **benefit-based charge** for the **BBI** from the date of the transfer.

(5) **Transpower** is not required to (but may) start the vendor's **monthly benefit-based charge** calculated under paragraph (2)(b) during, or from the start of, an **exempt pricing year** for the vendor. However, any over-recovery of the **annual benefit-based charge** for the **BBI** and **exempt pricing year** resulting from the start of the purchaser's **monthly benefit-based charge** for the **BBI** must be rebated to the vendor by way of an adjustment to its **transmission charges**—
  (a) if reasonably practicable, at the end of the **exempt pricing year**; or
  (b) otherwise, as soon as reasonably practicable during the next **pricing year**.

90 Benefit-based Charge Adjustment Event: Voluntary Under-recovery

(1) This clause 90 applies in the case of the **benefit-based charge adjustment event** in paragraph 81(1)(k).

(2) In this clause 90, a relevant **pricing year** is a **pricing year** for which **Transpower** decided to voluntarily under-recover the **BBI's covered cost**.

(3) **Transpower** must, for each relevant **pricing year**, calculate or re-calculate (as the case may be) all **beneficiaries' benefit-based charges** for the **BBI** to account for the amount of the voluntary under-recovery of the **BBI's covered cost**.

(4) If **Transpower** decides to voluntarily under-recover the **BBI's covered cost** for a relevant **pricing year** during, or within 1 month of the start of, the relevant **pricing year**, **Transpower** is not required to (but may) start **beneficiaries' monthly benefit-based charges** calculated under subclause (3) during, or from the start of, the relevant **pricing year**. However, any over-recovery of the **BBI's covered cost** for the relevant **pricing year** (accounting for the voluntary under-recovery) must be rebated, as appropriate, to the **beneficiaries** by way of an adjustment to their **transmission charges**—
  (a) if reasonably practicable, at the end of the relevant **pricing year**; or
  (b) otherwise, as soon as reasonably practicable during the next **pricing year**.

91 Benefit-based Charge Adjustment Event: SSCGU

(1) This clause 91 applies in the case of the **benefit-based charge adjustment event** in paragraph 81(1)(l).

(2) **Transpower** must—
 (a) determine which **post-2019 BBIs**, if any, satisfy all of the following conditions (the relevant **BBIs**):
  (i) the **post-2019 BBI** is expected to be **high-value** at the start of the **SSCGU's start pricing year**:
  (ii) the distribution of **regional NPB** for the **post-2019 BBI** is likely to have changed materially as a result of the **SSCGU**, compared to the distribution of **regional NPB** for the **post-2019 BBI** immediately before the **SSCGU**:
  (iii) the **SSCGU** was not a **market scenario** used to calculate the existing **BBI customer allocations** for the **post-2019 BBI**; and
 (b) for each relevant **BBI**, re-calculate **beneficiaries' BBI customer allocations** as if the relevant **BBI** were a new **high-value post-2019 BBI** for which—
  (i) the **standard method calculation period** starts on the date of the **SSCGU**; and
  (ii) the **final investment decision date** is the date of the **SSCGU**.

(3) In carrying out the re-calculation under paragraph (2)(b), **Transpower** may use—
 (a) a different **standard method** than was used to calculate the existing **BBI customer allocations** for the relevant **BBI**; or
 (b) different **factual**, **counterfactual**, **investment grids**, **system limits**, **scenarios**, **modelled regions** and **regional customer groups** than were used to calculate the existing **BBI customer allocations** for the relevant **BBI**.

(4) From the **SSCGU's start pricing year**, **Transpower** must calculate **beneficiaries' benefit-based charges** for each relevant **BBI** based on the **beneficiaries' BBI customer allocations** for the relevant **BBI** re-calculated under paragraph (2)(b).

Residual Charges

92 Residual Charge Adjustment Events

(1) The following events are **residual charge adjustment events**:
 (a) a **customer** (the exiting **load customer**) ceases to be a **customer**:
 (b) a **customer** (the vendor) sells or otherwise transfers all or part of its business that constitutes it as a **load customer** to another party (the purchaser):
 (c) **Transpower** decides to voluntarily under-recover **residual revenue**.

(2) **Transpower** must not voluntarily under-recover **residual revenue** for a **pricing year** if the effect of doing so would be to increase **residual revenue** for any other **pricing year**.

(3) To avoid doubt, a vendor's sale or other transfer of all or part of its business that constitutes it as a **load customer** to a purchaser is treated as the **residual charge adjustment event** in paragraph (1)(b) and not the **residual charge adjustment event** in paragraph (1)(a), and the purchaser is not treated as a new **load customer**.

93 Residual Charge Adjustment Event: Exiting Load Customer

(1) This clause 93 applies in the case of the **residual charge adjustment event** in paragraph 92(1)(a).

(2) **Transpower—**
 (a) must make the exiting **load customer's AMDR** and **residual charge** 0; and
 (b) must not increase—
  (i) any other **load customer's residual charge** for the **event pricing year**; or
  (ii) any other **transmission charges** for the **event pricing year**,
 as a consequence of applying paragraph (a).

94 Residual Charge Adjustment Event: Sale of Business

(1) This clause 94 applies in the case of the **residual charge adjustment event** in paragraph 92(1)(b).

(2) **Transpower** must, for a sale of part of the vendor's business—
- (a) determine an apportionment between the vendor and purchaser of the vendor's **AMDR** (and the inputs to its calculation) taking into account the size and nature of the transferred business; and
- (b) calculate or re-calculate (as the case may be) the vendor's and purchaser's **residual charges** based on the apportionment of the vendor's **AMDR** under paragraph (a) (but not any change in **residual revenue** that may have occurred during the **event pricing year**); and
- (c) calculate or re-calculate (as the case may be) the vendor's and purchaser's **cap recovery charge** and **prudent discount recovery charges** for the **event pricing year** to account for—
  - (i) the vendor's and purchaser's **annual residual charges** calculated under paragraph (b); and
  - (ii) any **annual benefit-based charges** for the vendor or purchaser calculated under subclause 89(2) or 89(3) in respect of the same sale of business.

(3) **Transpower** must, for a sale of all of the vendor's business—
- (a) attribute the vendor's **AMDR** (and the inputs to its calculation) to the purchaser; and
- (b) calculate or re-calculate (as the case may be) the purchaser's **residual charge** based on the attribution of the vendor's **AMDR** under paragraph (a); and
- (c) calculate or re-calculate (as the case may be) the purchaser's **cap recovery charge** and **prudent discount recovery charges** for the **event pricing year** to account for—
  - (i) the purchaser's **annual residual charges** calculated under paragraph (b); and
  - (ii) any **annual benefit-based charges** for the vendor or purchaser calculated under subclause 89(2) or 89(3) in respect of the same sale of business.

(4) **Transpower** must start the purchaser's **monthly residual charge** calculated under paragraph (2)(b) or (3)(b) as soon as reasonably practicable. The purchaser's **monthly residual charge** may include an adjustment as necessary to ensure the purchaser pays its full **residual charge** from the date of the transfer.

(5) **Transpower** is not required to (but may) start the vendor's **monthly residual charge** calculated under paragraph (2)(b) during, or from the start of, an **exempt pricing year** for the vendor. However, any over-recovery of **residual revenue** for the **exempt pricing year** resulting from the start of the purchaser's **monthly residual charge** must be rebated to the vendor by way of an adjustment to its **transmission charges**—
- (a) if reasonably practicable, at the end of the **exempt pricing year**; or
- (b) otherwise, as soon as reasonably practicable during the next **pricing year**.

95 Residual Charge Adjustment Event: Voluntary Under-recovery

(1) This clause 95 applies in the case of the **residual charge adjustment event** in paragraph 92(1)(c).

(2) In this clause 95, a relevant **pricing year** is a **pricing year** for which **Transpower** decided to voluntarily under-recover **residual revenue**.

(3) **Transpower** must, for each relevant **pricing year**, calculate or re-calculate (as the case may be) all **load customers' residual charges** for the discounted **pricing year** to account for the amount of the voluntary under-recovery of **residual revenue**.

(4) If **Transpower** decides to voluntarily under-recover **residual revenue** for a relevant **pricing year** during, or within 1 month of the start of, the relevant **pricing year**, **Transpower** is not required to (but may) start **load customers' monthly residual charges** calculated under subclause (3) during, or from the start of, the relevant **pricing year**. However, any over-recovery of **residual revenue** for the relevant **pricing year** (accounting for the voluntary under-recovery) must be rebated, as appropriate, to **load customers** by way of an adjustment to their **transmission charges**—

(a) if reasonably practicable, at the end of the relevant **pricing year**; or

(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

Part G Reassignment

96 Effect of Reassignment

If an **eligible BBI** is **reassigned**, **Transpower** must, from the **reassignment's start pricing year**—

(a) reduce the **eligible BBI's covered cost** by the **eligible BBI's reassignment amount**; and

(b) calculate **beneficiaries' benefit-based charges** for the **eligible BBI** based on the reduction of the **eligible BBI's covered cost** under paragraph (a).

97 Reassignment Amount

The **reassignment amount** for a **reassigned eligible BBI** (RA) is calculated as follows:

$$RA = CC \times (1 - RF)$$

where

CC is the **eligible BBI's covered cost**

RF is the **eligible BBI's reassignment factor**.

98 Eligibility for Reassignment

(1) Before or as soon as reasonably practicable after the start of a **pricing year**, **Transpower** must **publish**—

(a) a list of **BBIs** that satisfy paragraph (a) of the definition of **eligible BBI** in clause 3 as at the start of the **pricing year**; and

(b) identify which of the listed **BBIs** are **post-2019 BBIs** that satisfy subparagraph (b)(i) of the definition of **eligible BBI** in clause 3 as at the start of the **pricing year**.

(2) The **reassignment threshold** (RT) for a **pricing year** is—

(a) \$5m for the **first pricing year**; and

(b) calculated as follows for each **pricing year** after the **first pricing year**:

$$RT = \$5m \times \frac{CPI}{CPI_{base}}$$

where

CPI is the average of the quarterly **CPIs** for the preceding **financial year**

CPI_{base} is the average of the quarterly **CPIs** for the most recent complete **financial year** before the start of the **first pricing year**.

(3) If there is a base adjustment to **CPI**, the calculation in paragraph (2)(b) is to include an equivalency adjustment to eliminate the impact of the base adjustment.

99 Reassignment Application

(1) If an **eligible person** wishes for a **BBI** to be **reassigned**, the **eligible person** must submit to **Transpower** a written **application** for **reassignment** that meets the requirements of subclause (2).

(2) An **application** for **reassignment** must—
   (a) contain all of the information described in the relevant **application requirements**; and
   (b) contain reasonable evidence that the conditions for **reassignment** in this **transmission pricing methodology** are met; and
   (c) be accompanied by an **independent verification** of the **application**.

(3) The **eligible person** must provide **Transpower** with any additional information **Transpower** determines is necessary to enable it to assess the **application**.

100 Application Screening and Publication

(1) **Transpower** must reject an **application** for **reassignment** without assessing the **application** further if, when **Transpower** receives the **application**—
   (a) the applicant is not an **eligible person**; or
   (b) the **BBI** to which the **application** relates is not an **eligible BBI**.

(2) **Transpower** may reject an **eligible person's application** for **reassignment** without assessing the **application** further—
   (a) under subclause 14(1); or
   (b) if an **eligible person** has previously applied for **reassignment** on substantially the same basis as the new **application** and **Transpower**—
      (i) rejected the previous **application**; and
      (ii) determines there has not been a change in circumstances since its decision on the previous **application** that materially increases the likelihood of the new **application** being approved.

(3) **Transpower** is not required to consult on any decision to reject an **application** under subclause (1), (2) or 14(1).

(4) Unless **Transpower** rejects an **application** under subclause (1), (2) or 14(1), and subject to clause 106, **Transpower** must **publish** the **application** and any information the **eligible person** provides to **Transpower** under subclause 99(3).

101 Assessment

(1) In assessing an **eligible person's application** for **reassignment**, **Transpower**—
   (a) is not obliged to use the information the **eligible person** provided in or in support of the **application**; and
   (b) may use any other information relevant to the **application**.

(2) **Transpower** must approve the **application** if **Transpower** determines that—
   (a) the **eligible BBI** to which the **application** relates has a **BBI reassignment factor** of less than 0.8; and
   (b) the circumstances causing the **BBI reassignment factor** to be less than 0.8—
      (i) are reasonably likely to persist for at least 5 years after they occurred; and
      (ii) have not resulted, and are not reasonably likely to result, in a **write-down** of assets comprised in the **BBI**.

(3) Otherwise, **Transpower** must reject the **application**.

102 Forecast Peak Loading and Reassignment Factors

(1) The **forecast loading period** for an **eligible BBI** the subject of a **reassignment** application is the period starting on the date **Transpower** receives the application and ending on the later of—
   (a) 10 years after the date **Transpower** receives the application; and

(b) if the **eligible BBI** is a **post-2019 BBI** to which subparagraph (b)(i) of the definition of **eligible BBI** in clause 3 does not apply, 20 years after the **eligible BBI's commissioning date**.

(2) **Forecast peak loading** for a **transmission investment** comprised in the **eligible BBI** is the expected future peak electrical loading of the **transmission investment** over the **eligible BBI's forecast loading period**, as determined by **Transpower**.

(3) The **investment reassignment factor** for a **transmission investment** comprised in the **eligible BBI** is the proportion of the **transmission investment's** total **replacement cost** (adjusted proportionately for any previous **write-down** of assets comprised in the **transmission investment**) **Transpower** determines it would incur to replace the **transmission investment** with a **transmission investment**—

(a) of the same type; and

(b) with a service potential sufficient to meet the **forecast peak loading** and reasonable **grid** contingencies, but no more.

(4) The **BBI reassignment factor** for the **eligible BBI** (BRF) is calculated as follows:

$$BRF = \frac{1}{CC_{total}} \sum_{i} (CC_i \times IRF_i)$$

where

CC_{total} is the **eligible BBI's covered cost** for the **pricing year** during which the application for **reassignment** was received

CC_i is the part of the **eligible BBI's covered cost** for the **pricing year** during which the application for **reassignment** was received attributable to **transmission investment** i, where **transmission investment** i is a **transmission investment** comprised in the **eligible BBI**

IRF_i is **transmission investment** i's **investment reassignment factor**.

(5) **Transpower** may **publish** in the **reassignment practice manual**, for 1 or more types of **transmission investment** in, or in relation to, **interconnection assets**, information about the relationship between the **transmission investment's forecast peak loading** and its **investment reassignment factor**, which may include 1 or more methods of calculating the **investment reassignment factor** as a function of **forecast peak loading**.

103 Consultation on Draft Decision

(1) Subject to subclause 100(3), **Transpower** must consult with all **customers** on its draft decision to approve or reject an **eligible person's application** for **reassignment**.

(2) Subject to clause106, **Transpower's** consultation under subclause (1) must include the information specified in paragraphs 105(a), 105(b) and 105(c) for the draft decision.

104 Decision and Independent Review

(1) If **Transpower** decides to approve an **eligible person's application** for **reassignment**, **Transpower** may approve a different **BBI reassignment factor** than sought in the **application**.

(2) **Transpower** must notify the **eligible person** whether **Transpower** approves or rejects the **application**. **Transpower's** notice must include the information specified in paragraphs 105(a), 105(b) and 105(c).

(3) The **eligible person** may, within 60 days of **Transpower** notifying the **eligible person** of **Transpower's** decision on the **application**, refer any aspect of **Transpower's** decision to an **independent expert** for review.

(4) The **independent expert's** decision will be binding on **Transpower** and the **eligible person**, and will have effect as if **Transpower** had made the decision itself, except that the **eligible person** may not refer the decision to an **independent expert** again.

(5) The costs of the **independent expert** must be met by the **eligible person** unless the **independent expert** decides an aspect of **Transpower's** decision under review was unreasonable, in which case **Transpower** may be required to meet all or some of the costs of the **independent expert**, as determined by the **independent expert**.

105 Decision to be Published

Subject to clause 106, as soon as reasonably practicable after the **reassignment confirmation date**, **Transpower** must **publish**—

(a) its decision to approve or reject the **eligible person's application** for **reassignment**; and
(b) if **Transpower** approves the **application**, the **eligible BBI** and its **BBI reassignment factor**; and
(c) **Transpower's** analysis supporting its decision, including any material departures from the assumptions and methodologies in the **reassignment practice manual** and the reasons for those departures; and
(d) any report prepared by an **independent expert** relating to the **reassignment**.

106 Commercially Sensitive Information

(1) Subject to subclause (2), **Transpower** is not obliged to **publish** or otherwise disclose any information under subclause 100(4) or 103(2) or clause 105 if—
(a) the **eligible person** identifies the information as commercially sensitive; and
(b) **Transpower** determines the disclosure of the information would be likely to commercially disadvantage the **eligible person** or any other person, in a material manner.

(2) **Transpower** must always **publish** under subclause 103(2) and clause 105 at least—
(a) its draft decision or decision (as the case may be) to approve or reject the **eligible person's application** for **reassignment**; and
(b) if the **application** is approved, the **eligible BBI** and its **BBI reassignment factor**.

107 Reversal for Increased Forecast Peak Loading

(1) **Transpower** must fully or partially reverse a **reassignment** if—
(a) **Transpower** determines that the **forecast peak loading** of 1 or more of the **transmission investments** comprised in the relevant **BBI** have increased such that the **BBI's BBI reassignment factor** has increased; and
(b) **Transpower** determines that the circumstances causing the **BBI reassignment factor** to have increased are reasonably likely to persist for at least 5 years after they occurred; and
(c) at the time of the reversal, the total **closing RAB value** of all assets comprised in the **BBI** for the most recent complete **financial year** is at least the **reassignment threshold**.

(2) If **Transpower** proposes to fully or partially reverse the **reassignment**—
(a) clause 103 applies as if that clause applied to **Transpower's** draft decision to reverse the **reassignment**;
(b) **Transpower** must **publish** its decision on the reversal, including—

(i) the **BBI's** new **BBI adjustment factor**; and
(ii) **Transpower's** analysis supporting its decision, including any material departures from the assumptions and methodologies in the **reassignment practice manual** and the reasons for those departures; and

(c) an **eligible person** for the **BBI** may, within 60 days of **Transpower** publishing its decision on the reversal, refer any aspect of **Transpower's** decision to an **independent expert** for review, in which cases subclauses 104(4) and 104(5) will apply; and
(d) clauses 105 and 106 apply as if those clauses applied to Transpower's decision on the reversal and the **eligible person** referred to in paragraph 106(1)(a) were any **eligible person** who referred **Transpower's** decision to an **independent expert** under paragraph (c).

(3) If **Transpower** determines that the **BBI's BBI reassignment factor** is 0.8 or more, **Transpower** must fully reverse the **reassignment**.

(4) To avoid doubt, all references to the **BBI's BBI reassignment factor** in this clause 107 refer to the **BBI reassignment factor** calculated by reference to the **replacement costs** of the **transmission investments** comprised in the **BBI** without any adjustment for their **investment reassignment factors** for the current **reassignment** of the **BBI**.

(5) A full or partial reversal of **reassignment** under this clause 107 will have effect from the first **pricing year** that starts at least 6 months (or such shorter period as **Transpower** may determine is practicable) after the **reassignment confirmation date**.

108 Reversal for Subsequent Write-Down

(1) **Transpower** must fully reverse a **reassignment** if the circumstances causing the relevant **BBI reassignment factor** to be less than 0.8 result in a **write-down** of assets comprised in the relevant **BBI**.

(2) A reversal of **reassignment** under subclause (1) will have effect from the first **pricing year** that starts after the end of the **financial year** during which the **write-down** occurred.

109 Application Fees, Application Requirements and Reassignment Practice Manual

(1) **Transpower** must **publish** the **application requirements** and the **application fees**, if any, for **reassignment applications** by the start of the **first pricing year**. **Transpower** may **publish** updates to the **application requirements** and **application fees** from time to time.

(2) **Transpower** may from time to time **publish**, and **publish** updates to, a **reassignment practice manual**.

(3) The **reassignment practice manual** must not contain any assumptions or methodologies that are inconsistent with this Code.

(4) Subject to subclause (5), **Transpower** must consult with all **customers** on the **reassignment practice manual** or any update to it before **publishing** the **reassignment practice manual** or update.

(5) **Transpower** is not required to consult on an update to the **reassignment practice manual** if **Transpower** determines—
(a) the update is technical and non-controversial; or
(b) there is widespread support for the update among **customers**; or
(c) there has been adequate prior consultation on the update so that all relevant views of **customers** have been considered.

(6) The **reassignment practice manual** is not binding on **Transpower** or any **independent expert**.

(7) **Transpower** must review the content of the **reassignment practice manual** and consider whether any of the content is appropriate for incorporation in this **transmission pricing methodology** by way of a review under clause 12.85 of this Code no later than 7 years after its date of **publication** and, after that, at intervals of no more than 7 years.

(8) The **reassignment practice manual** may be part of the same document in which the **assumptions book** or **prudent discount practice manual** is contained.

Part H Transitional Price Cap

110 Cap and Cap Condition

(1) Despite anything else in this **transmission pricing methodology**, a **capped customer's transmission charges** for each **pricing year** preceding **pricing year** 2038 must be reduced by the minimum amount necessary (if any) to ensure the **cap condition** is satisfied for the **capped customer** and **pricing year**.

(2) The **cap condition** for a **pricing year** is:

$$CC - IC_{19} - HVDC_{19} \leq DC$$

where

CC	is a **capped customer's capped charges** for the **pricing year**
IC_{19}	is the **capped customer's** annual interconnection charge for **pricing year** 2019 under the **previous transmission pricing methodology**
$HVDC_{19}$	is the **capped customer's** annual HVDC charge for **pricing year** 2019 under the **previous transmission pricing methodology**
DC	is the **capped customer's difference cap** for the **pricing year**.

(3) The **cap condition** is applied, and the **difference cap** is calculated, subject to any applicable **prudent discount** or **previous discount** that applies or applied at the relevant time.

(4) A **capped customer's capped charges** include the **capped customer's annual cap recovery charge**. It is therefore possible the **cap condition** will not be satisfied for the **capped customer** when a **cap recovery charge** is allocated to the **capped customer**. Accordingly, for each **pricing year**, subclause (1) is applied iteratively until the **cap condition** does not result in a reduction in any **capped customer's capped charges** for the **pricing year**. The **annual cap recovery charge** component of **capped charges** is 0 for the first iteration.

(5) The **cap condition** applies at the start of a **pricing year** only. The **cap condition** is not applied again, and **difference caps** are not re-calculated, if there is an adjustment to **transmission charges** during the **pricing year**.

(6) Despite anything else in this clause 110, the **cap condition** must not result in **Transpower** recovering less than **recoverable revenue** for a **pricing year**. If **Transpower** determines it is necessary to do so, **Transpower** may reduce all **capped customers' cap reductions** for a **pricing year** on a pro rata basis to ensure **Transpower** recovers **recoverable revenue** for the **pricing year** (but not more than **recoverable revenue** for the **pricing year**).

111 Difference Cap

(1) A **capped customer's difference cap** for **pricing year** n (DC_n) is calculated as follows:

$$DC_n = NEB_{19} \times (0.035 + (0.02 \times N) + \Delta CPI_n + \Delta TGE_n)$$

where

NEB_{19} is the **capped customer's** notional **electricity** bill for **pricing year** 2019 calculated under subclause (2)

N is—
0 if the **capped customer** is a **distributor**; or
the greater of 0 and n-2024 if the **capped customer** is a **direct consumer**

ΔCPI_n is the proportionate change in **CPI** for **pricing year** n calculated under subclause (3)

ΔTGE_n is the proportionate increase (if any) in the **capped customer's total gross energy** for **pricing year** n calculated under subclause (5).

(2) A **capped customer's** notional **electricity** bill for **pricing year** 2019 (NEB_{19}) is calculated as follows:

$$NEB_{19} = LC_{19} + (P_{19} \times TGE_{19})$$

where

LC_{19} is—
(a) if the **capped customer** is a **distributor**, the **capped customer's** "total line charge revenue" for **pricing year** 2019, as disclosed in the **capped customer's** Report on Billed Quantities and Line Charge Revenues (Schedule 8) under the **EDB ID determination** for its disclosure year ended 31 March 2020; or
(b) if the **capped customer** is a **direct consumer**, the **capped customer's** total annual transmission charges for **pricing year** 2019 under the **previous transmission pricing methodology**

P_{19} is the volume weighted average of **final prices** at the **capped customer's connection locations** during **CMP G**, using **gross energy** per **trading period** for weighting

TGE_{19} is the **capped customer's total gross energy** for **pricing year** 2019, being—
(a) if the **capped customer** is a **distributor**, the **capped customer's** "electricity entering system for supply to consumers' connection points" for **pricing year** 2019, as disclosed in the **capped customer's** Report on Network Demand (Schedule 9e) under the **EDB ID determination** for its disclosure year ended 31 March 2020; or
(b) if the **capped customer** is a **direct consumer**, as determined by **Transpower**.

(3) Subject to subclause (4), the proportionate change in **CPI** for **pricing year** n (ΔCPI_n) is calculated as follows:

$$\Delta CPI_n = \frac{CPI_{n-2}}{CPI_{19}} - 1$$

where

CPI_{n-2} is the average of the quarterly **CPIs** for **pricing year** n-2

CPI_{19} is 1041.75, being the average of the quarterly **CPIs** for **pricing year** 2019.

(4) If there is a base adjustment to CPI, the calculation in subclause (3) is to include an equivalency adjustment to eliminate the impact of the base adjustment.

(5) The proportionate increase (if any) in a capped customer's total gross energy for pricing year n (ΔTGE_n) is calculated as follows:

$$\Delta TGE_n = \frac{TGE_{n-2}}{TGE_{19}} - 1$$

where

TGE_{n-2} is the **capped customer's total gross energy** for **pricing year** n-2, being—

(a) if the **capped customer** is a **distributor**, the **capped customer's** "electricity entering system for supply to consumers' connection points" for **pricing year** n-2, as disclosed in the **capped customer's** Report on Network Demand (Schedule 9e) under the **EDB ID determination** for its disclosure year ended 31 March of year n-1; or

(b) if the **capped customer** is a **direct consumer**, as determined by **Transpower**.

TGE_{19} is as defined in subclause (2) for the **capped customer**.

112 Cap Recovery Charge

(1) A **customer's annual cap recovery charge** for a **pricing year** (ACRC) is calculated as follows:

$$ACRC = CR_{total} \times \frac{CRRC}{CRRC_{total}}$$

where

CR_{total} is the total of all **customers' cap reductions** for the **pricing year**

CRRC is the **customer's cap recovery-relevant charges** for the **pricing year**

$CRRC_{total}$ is the total of all **customers' cap recovery-relevant charges** for the **pricing year**.

(2) A **customer's monthly cap recovery charge** for a **pricing year** (MCRC) is calculated as follows:

$$MCRC = \frac{ACRC}{12}$$

where ACRC is the **customer's annual cap recovery charge** for the **pricing year**.

(3) Except as otherwise stated in this **transmission pricing methodology**, **cap recovery charges**—

(a) are calculated at the start of a **pricing year** only; and

(b) are not re-calculated during a **pricing year** if there is an adjustment to other **transmission charges** during the **pricing year**.

Part I Prudent Discount Policy

General

113 Effect of Prudent Discount Agreements

Despite anything else in this **transmission pricing methodology**, a **prudent discount recipient's transmission charges** are subject to its **prudent discount** agreement.

114 Prudent Discount Applications

(1) If a **customer** wishes to receive a **prudent discount**, the **customer** must submit to **Transpower** a written **application** for the **prudent discount** that meets the requirements of subclause (2).

(2) The **application** must—
- (a) contain all of the information described in the relevant **application requirements**; and
- (b) contain reasonable evidence that the conditions for obtaining the **prudent discount** in this **transmission pricing methodology** are met; and
- (c) include at least the level of detail a prudent board of directors of a company would reasonably expect when assessing an investment proposal for the **alternative project** proposed in the **application**; and
- (d) be accompanied by an **independent verification** of the **application**.

(3) The **customer** must provide **Transpower** with any additional information **Transpower** determines is necessary to enable it to assess the **application**.

115 Application Screening and Publication

(1) **Transpower** must reject an **application** for a **prudent discount** without assessing the **application** further if the applicant is not a **customer**.

(2) **Transpower** may reject a **customer's application** for a **prudent discount** without assessing the **application** further—
- (a) under subclause 14(1); or
- (b) if a **customer** has previously applied for a **prudent discount** on substantially the same basis as the new **application** and **Transpower**—
  - (i) rejected the previous **application**; and
  - (ii) determines there has not been a change in circumstances since its decision on the previous **application** that materially increases the likelihood of the new **application** being approved.

(3) **Transpower** is not required to consult on any decision to reject an **application** under subclause (1), (2) or 14(1).

(4) Unless **Transpower** rejects an **application** under subclause (1), (2) or 14(1), and subject to clause 125, **Transpower** must **publish** the **application** and any information the **customer** provides to **Transpower** under subclause 114(3).

116 Assessment

(1) In assessing a **customer's application** for a **prudent discount**, **Transpower**—
- (a) is not obliged to use the information the **customer** provided in or in support of the **application**, but must not assess an **alternative project** that is not the **alternative project** proposed in the **application**; and
- (b) may use any other information relevant to the **application**.

(2) In assessing whether the **alternative project** would provide the same or a substantially similar level of service to the **customer** as the **transmission services** it currently receives, **Transpower** must consider—
(a) access to **electricity**, including access to security of supply; and
(b) **electricity** quality, reliability and security; and
(c) any other service measures for **transmission services Transpower** determines are relevant.

117 Calculation of Alternative Project Costs

(1) The **alternative project costs** for an **alternative project** are the capital, operating, maintenance and overhead costs of the **alternative project**, as would be incurred by:
(a) the **customer**, in the case of an **inefficient bypass prudent discount**; or
(b) an efficient **transmission services** provider, in the case of a **stand-alone cost prudent discount**.

(2) For the purposes of calculating the **alternative project costs**—
(a) the value of any increase or decrease in **electrical** losses that would result from the **alternative project** must be included as an operating cost of the **alternative project** (with a decrease being treated as a negative cost); and
(b) an efficient **transmission services** provider is assumed not to have any of **Transpower's** historic statutory rights in respect of **works** or activities.

118 Assessment of Commercial Viability

(1) The **alternative project** proposed in a **customer's application** for a **prudent discount** is only commercially viable if it is reasonably likely that:

$$\frac{PVATC - PVAPC}{PVAPC} > 0.1$$

where

PVAPC is the present value of the **alternative project costs** for the **alternative project** calculated under subclause (2)

PVATC is the present value of the **customer's avoided transmission charges** calculated under subclause (2)

(2) In calculating the present values under subclause (1) (PV), **Transpower** must use the formula:

$$PV = \sum_{n} \frac{A_n}{(1+r)^n}$$

where

A_n are the **alternative project costs** or **avoided transmission charges** (as the case may be) for year n of the relevant **prudent discount calculation period**

r is the relevant **prudent discount rate**, which must be pre-tax if the cash flows being discounted are pre-tax and post-tax if the cash flows being discounted are post-tax.

(3) To avoid doubt—
  (a) the calculation under subclause (2) does not assume the **alternative project** is fully amortised over the **prudent discount calculation period**; and
  (b) any residual value of the **alternative project** at the end of the **prudent discount calculation period** is ignored in the calculation under subclause (2).

119 Consultation on Draft Decision

(1) Subject to subclause 115(3), **Transpower** must consult with all **customers** on its draft decision to approve or reject a **customer's application** for a **prudent discount**.

(2) Subject to clause 125, **Transpower's** consultation under subclause (1) must include—
  (a) the information specified in paragraphs 124(a) and 124(c) and subparagraph 124(b)(i) for the draft decision; and
  (b) if **Transpower** proposes to approve the **application**, the terms of the proposed **prudent discount** agreement specified in subparagraphs 125(2)(b)(ii), 125(2)(b)(iii) and 125(2)(b)(iv).

120 Decision and Independent Review

(1) If **Transpower** decides to approve a **customer's application** for a **prudent discount**, **Transpower** may—
  (a) approve different terms of the **prudent discount** than sought in the **application**, including a different amount of the **prudent discount**; and
  (b) approve the **application** subject to reasonable conditions.

(2) **Transpower** must notify the **customer** whether **Transpower** approves or rejects the **application**. **Transpower's** notice must include—
  (a) the information specified in paragraphs 124(a) and 124(c) and subparagraph 124(b)(i); and
  (b) if **Transpower** approves the **application**, the terms of the proposed **prudent discount** agreement specified in subparagraphs 125(2)(b)(ii), 125(2)(b)(iii) and 125(2)(b)(iv).

(3) The **customer** may, within 60 days of **Transpower** notifying the **customer** of **Transpower's** decision on the **application**, refer any aspect of **Transpower's** decision to an **independent expert** for review.

(4) The **independent expert's** decision will be binding on **Transpower** and the **customer**, and will have effect as if **Transpower** had made the decision itself, except that the **customer** may not refer the decision to an **independent expert** again.

(5) The costs of the **independent expert** must be met by the **customer** unless the **independent expert** decides an aspect of **Transpower's** decision under review was unreasonable, in which case **Transpower** may be required to meet all or some of the costs of the **independent expert**, as determined by the **independent expert**.

121 Prudent Discount Agreement

(1) If **Transpower** approves a **customer's application** for a **prudent discount**, **Transpower** must promptly offer a **prudent discount** agreement to the **customer**.

(2) The **prudent discount** agreement must provide for—
  (a) the **prudent discount** agreement to be of no effect unless and until all of the conditions precedent of **Transpower's** approval (if any) are satisfied; and

(b) the **customer** to pay **Transpower** an annuity, calculated under clause 123, in monthly instalments; and
(c) **Transpower** to calculate the **customer's transmission charges** in accordance with clause 132 or 137, as applicable; and
(d) **Transpower** to have the right to terminate the **prudent discount** agreement immediately if any condition subsequent of **Transpower's** approval is not, or ceases to be, satisfied; and
(e) the **customer** to have the right to terminate the **prudent discount** agreement at the start of a **pricing year** by notifying **Transpower** at least 6 months before the start of the **pricing year**.

(3) The term of the **prudent discount** agreement must be the same as the relevant **prudent discount calculation period**, subject to—
(a) satisfaction of all conditions precedent of **Transpower's** approval (if any); and
(b) earlier termination in accordance with the terms of the **prudent discount** agreement.
To avoid doubt, the term of the **prudent discount** agreement must start on the **prudent discount's start pricing year**, subject to satisfaction of all conditions precedent of **Transpower's** approval (if any).

(4) The annuity payable to **Transpower** by a **customer** under a **prudent discount** agreement is deemed to be a charge payable to **Transpower** under this **transmission pricing methodology** for **transmission services** provided to the **customer**.

122 Back-dated Prudent Discounts
(1) This clause 122 back-dates the **start pricing year** for a **back-dated prudent discount** and provides for a wash-up of the **prudent discount recipient's transmission charges** as necessary to give effect to that back-dating.

(2) The **start pricing year** for a **back-dated prudent discount** is the **first pricing year**.

(3) If a **back-dated prudent discount** is not reflected in the **transmission charges** for the **back-dated prudent discount's start pricing year** or any later **pricing year** during the term of the relevant **prudent discount agreement** (a relevant **pricing year**), **Transpower** must carry out a wash-up of the **prudent discount recipient's transmission charges** for each relevant **pricing year** so that the **prudent discount recipient** is not over-charged **transmission charges** for the relevant **pricing years**. The wash-up—
(a) must be carried out in the earliest practicable **pricing year**; and
(b) must include a time value of money adjustment using **Transpower's ID WACC** (pre-tax); and
(c) must not include a wash-up of **transmission charges** for any **customer** who is not the **prudent discount recipient**.

(4) To avoid doubt, there is no wash-up under subclause (3) for a relevant **pricing year** if all conditions precedent of **Transpower's** approval of the **back-dated prudent discount** (if any) are not satisfied before or during the relevant **pricing year**.

123 Calculation of Annuity
The annuity under a **prudent discount** agreement (AN) is levelised and calculated as follows:

$$AN = \frac{PVAPC}{\sum_{n=1}^{N} \frac{1}{(1+r)^n}}$$

where

N is the number of years in the relevant **prudent discount calculation period**, with each such year being year n

PVAPC is the present value of the **alternative project costs** for the relevant **alternative project** calculated under subclause 118(2)

r is the relevant **prudent discount rate**, which must be pre-tax if the present value of the **alternative project costs** for the **alternative project** is pre-tax and post-tax if the present value of the **alternative project costs** for the **alternative project** is post-tax.

124 Decision to be Published

Subject to clause 125, as soon as reasonably practicable after the **prudent discount confirmation date**, **Transpower** must **publish**—

(a) its decision to approve or reject the **customer's application** for the **prudent discount**; and

(b) if **Transpower** approves the **application**—

  (i) any conditions of its approval; and

  (ii) a copy of the relevant **prudent discount** agreement; and

(c) its analysis supporting its decision, including any material departures from the assumptions and methodologies in the **prudent discount practice manual** and the reasons for those departures; and

(d) any report prepared by an **independent expert** relating to the **prudent discount**.

125 Commercially Sensitive Information

(1) Subject to subclause (2), **Transpower** is not obliged to **publish** any information under subclause 115(4) or 119(2) or clause 124 if—

(a) the **customer** identifies the information as commercially sensitive; and

(b) **Transpower** determines the disclosure of the information would be likely to commercially disadvantage the **customer** or any other person, in a material manner.

(2) **Transpower** must always **publish** under subclause 119(2) and clause 124 at least—

(a) its draft decision or decision (as the case may be) to approve or reject the **customer's application** for the **prudent discount**; and

(b) if **Transpower** approves the application—

  (i) reasonable details of the **alternative project** and **alternative project costs**; and

  (ii) the annuity under the **prudent discount** agreement and details of how it was calculated; and

  (iii) details of how the **prudent discount recipient's transmission charges** will be calculated under the **prudent discount** agreement; and

  (iv) the term of the **prudent discount** agreement.

126 Application Fees, Application Requirements and Prudent Discount Practice Manual

(1) **Transpower** must **publish** the **application requirements** and the **application fees**, if any, for **prudent discount applications** by the start of the **first pricing year**. **Transpower** may **publish** updates to the **application requirements** and **application fees** from time to time.

(2) **Transpower** must **publish**, and may from time to time **publish** updates to, a **prudent discount practice manual**.

(3) The **prudent discount practice manual** must not contain any assumptions or methodologies that are inconsistent with this Code.

(4) Subject to subclause (5), **Transpower** must consult with all **customers** on the **prudent discount practice manual** or any update to it before **publishing** the **prudent discount practice manual** or update.

(5) **Transpower** is not required to consult on an update to the **prudent discount practice manual** if **Transpower** determines—
- (a) the update is technical and non-controversial; or
- (b) there is widespread support for the update among **customers**; or
- (c) there has been adequate prior consultation on the update so that all relevant views of **customers** have been considered.

(6) The **prudent discount practice manual** is not binding on **Transpower** or any **independent expert**.

(7) **Transpower** must review the content of the **prudent discount practice manual** and consider whether any of the content is appropriate for incorporation in this **transmission pricing methodology** by way of a review under clause 12.85 of this Code no later than 7 years after its date of **publication** and, after that, at intervals of no more than 7 years.

(8) The **prudent discount practice manual** may be part of the same document in which the **assumptions book** or **reassignment practice manual** is contained.

Inefficient Bypass Prudent Discount

127 Purpose of Inefficient Bypass Prudent Discount

The purpose of an **inefficient bypass prudent discount** is to help ensure this **transmission pricing methodology** does not provide incentives for a **customer** to invest in an **alternative project** that would allow a **customer** to reduce its own **transmission charges**, by bypassing existing **grid assets**, while increasing total economic costs.

128 Multiple Benefitting Customers

If there is more than 1 **benefitting customer** for an **application** for an **inefficient bypass prudent discount**—
- (a) all references to the applicant **customer** or **prudent discount recipient** in clauses 113 to 132 and 138 are deemed to include every **benefitting customer**; and
- (b) without limiting paragraph (a)—
  - (i) the commercial viability test in clause 118 must be applied using the total **avoided transmission charges** of all **benefitting customers**; and
  - (ii) the inefficiency test in subclause 130(2) must be applied using **Transpower's** costs of providing **transmission services** to all **benefitting customers**; and
- (c) the highest **prudent discount rate** across the **benefitting customers** applies to the **application**.

129 Assessment of Equivalence, Feasibility and Commercial Viability

Transpower must assess whether the **alternative project** for an **inefficient bypass prudent discount**—
- (a) would provide the **customer** with the same or a substantially similar level of service as the **transmission services** the **customer** currently receives from the **grid assets** the **alternative project** would bypass; and

(b) is technically feasible using present day technology and construction methods, including that it is feasible for the **customer** to obtain the necessary resource consents and property rights for the **alternative project**; and
(c) is operationally feasible, including that the **alternative project** is compliant with applicable **asset owner performance obligations**, **technical codes** and any other requirements in Part 8 of this Code; and
(d) is otherwise consistent with **GEIP**; and
(e) is commercially viable under subclause 118(1).

130 Assessment whether the Alternative Project is Inefficient

(1) If **Transpower** determines the **alternative project** for an **inefficient bypass prudent discount** satisfies all of the criteria in clause 129, **Transpower** must assess whether the **alternative project** is inefficient under subclause (2)

(2) The **alternative project** is only inefficient if it is reasonably likely that—

$$PVAPC > \left(PVTC_{no\ ap} - PVTC_{ap}\right)$$

where

PVAPC is the present value of the capital, operating, maintenance and overhead costs of the **alternative project**, including, but not limited to, the **alternative project costs**

$PVTC_{no\ ap}$ is the present value of **Transpower's** capital, operating, maintenance and overhead costs of providing **transmission services** to the **customer** at the required service levels, including the cost of future **transmission investments**, without the **alternative project** calculated under subclause (3)

$PVTC_{ap}$ is the present value of **Transpower's** capital, operating, maintenance and overhead costs of providing **transmission services** to the **customer** at the required service levels, including the cost of future **transmission investments**, with the **alternative project** calculated under subclause (3).

(3) In calculating the present values under subclause (2) (PV), **Transpower** must use the formula:

$$PV = \sum_{n} \frac{C_n}{(1+r)^n}$$

where

C_n is the relevant costs for year n of the relevant **prudent discount calculation period**

r is the relevant **prudent discount rate**, which must be pre-tax if the cash flows being discounted are pre-tax and post-tax if the cash flows being discounted are post-tax.

131 Approval or Rejection of Inefficient Bypass Prudent Discount Application

(1) **Transpower** must approve a **customer's application** for an **inefficient bypass prudent discount** if **Transpower** determines—
(a)the **alternative project** for the **application** satisfies all of the criteria in clause 129; and
(b)the **alternative project** is inefficient under subclause 130(2).

(2) Otherwise, **Transpower** must reject the **application**.

132 Impact on Transmission Charges

A **prudent discount** agreement for an **inefficient bypass prudent discount** must provide for **Transpower** to calculate the **prudent discount recipient's transmission charges** during the term of the **prudent discount** agreement as if the relevant **alternative project** had been implemented, assuming none of its **alternative project costs** would be recovered through **transmission charges**.

Stand-alone Cost Prudent Discount

133 Purpose of Stand-alone Cost Prudent Discount

The purpose of a **stand-alone cost prudent discount** is to help ensure this **transmission pricing methodology** does not result in a **customer** paying **transmission charges** that exceed the efficient stand-alone cost of the **transmission services** the **customer** currently receives. A **stand-alone cost prudent discount** achieves this by replacing the **prudent discount recipient's connection charges**, **benefit-based charges** and **residual charge** with an annuity under a **prudent discount agreement** equal to the **alternative project costs** of an **efficient stand-alone investment**.

134 Assessment of Equivalence, Feasibility and Commercial Viability

(1) **Transpower** must assess whether the **alternative project** for a **stand-alone cost prudent discount**—
- (a) is an **efficient stand-alone investment** that would provide the **customer** with the same or a substantially similar level of service as the **transmission services** the **customer** currently receives; and
- (b) subject to subclause (2), is technically feasible using present day technology and construction methods; and
- (c) is operationally feasible, including that the **alternative project** is compliant with applicable **asset owner performance obligations**, **technical codes** and any other requirements in Part 8 of this Code; and
- (d) is otherwise consistent with **GEIP**; and
- (e) is commercially viable under clause 118.

(2) The **alternative project** is technically feasible even if it is not feasible to obtain any or all of the necessary resource consents and property rights for the **alternative project**, provided that the **alternative project** is technically feasible in all other respects. In calculating the **alternative project costs**, **Transpower** must use estimates of the likely cost of obtaining any resource consents and property rights that are not feasible to obtain based on the cost of obtaining broadly equivalent resource consents and property rights for feasible activities in feasible locations.

(3) In calculating the **alternative project costs**, **Transpower** must value any optimised **grid** that forms part of the **alternative project** in a way that accounts for **depreciation** according to the age of the part of the existing **grid** that is optimised.

(4) To avoid doubt, **Transpower** must carry out the assessment under subclause (1) on a single **customer** basis.

135 Assessment of Efficient Stand-alone Investment

(1) An **efficient stand-alone investment** is an investment in the **grid**, 1 or more **transmission alternatives**, or a combination of both that an efficient **transmission services** provider would make to supply **transmission services** solely to the **customer** who has applied for a **stand-alone cost prudent discount**, assessed by—

- (a) using the existing **grid**, existing **transmission alternatives** and the **customer's** existing **grid points of connection** as a starting point; and
- (b) applying optimisation tests to the **grid** and **transmission alternatives** to identify, in the single-**customer** hypothetical, stranded **grid assets** and **transmission alternatives**, excess **capacity** in **grid assets** and **transmission alternatives**, and other **grid** and **transmission alternative** over-engineering.

(2) The **efficient stand-alone investment** does not need to be in the same location or follow the same route as the existing **grid** or existing **transmission alternatives**.

136 Approval or Rejection of Stand-alone Cost Prudent Discount Application

(1) **Transpower** must approve a **customer's application** for a **stand-alone cost prudent discount** if **Transpower** determines the **alternative project** for the **application** satisfies all of the criteria in subclause 134(1).

(2) Otherwise, **Transpower** must reject the **application**.

137 Impact on Transmission Charges

A **prudent discount** agreement for a **stand-alone cost prudent discount**—

- (a) must provide for the **prudent discount recipient's connection charges**, **benefit-based charges** and **residual charge** to be 0 during the term of the **prudent discount** agreement; and
- (b) must not provide for a change to any other **transmission charge**.

Prudent Discount Recovery

138 Prudent Discount Recovery Charges

(1) The amount of a **prudent discount** is recovered by **Transpower** through—

- (a) **BBI prudent discount recovery charges**, which—
  - (i) recover the part of the amount of the **prudent discount** deemed to relate to **discounted BBIs**; and
  - (ii) are paid by the **beneficiaries** of the **discounted BBIs** other than the **prudent discount recipient**; and
- (b) **residual prudent discount recovery charges**, which
  - (i) recover the part of the amount of the **prudent discount** not recovered by **BBI prudent discount recovery charges** (if any); and
  - (ii) are paid by the **load customers** other than the **prudent discount recipient**.

(2) Subject to subclause (4), **customer** c's **BBI prudent discount recovery charge** for **discounted BBI** b and a **pricing year** ($BPDS_{cb}$), where **customer** c is a **beneficiary** of **discounted BBI** b and not the **prudent discount recipient**, is calculated as follows:

$$BPDS_{cb} = PD \times \frac{BBC_{recipient\ b}}{\sum_k BBC_{recipient\ k} + RC_{recipient}} \times \frac{BBC_{cb}}{\sum_j BBC_{jb}}$$

where

PD is the amount of the relevant **prudent discount** for the **pricing year**

$BBC_{recipient\ b}$ is the **prudent discount recipient's annual benefit-based charge** for **discounted BBI** b and the **pricing year** without the **prudent discount**

$BBC_{recipient\ k}$ is the **prudent discount recipient's annual benefit-based charge** for **discounted BBI** k for the **pricing year** without the **prudent discount**, where **discounted BBI** k is a **discounted BBI** for the **prudent discount** (including **discounted BBI** b)

$RC_{recipient}$ is—

(a) if the **prudent discount** includes any discount to the **prudent discount recipient's residual charge** or **connection charges**, the **prudent discount recipient's annual residual charge** for the **pricing year** without the **prudent discount**; or

(b) otherwise, 0

BBC_{cb} is **customer** c's **annual benefit-based charge** for **discounted BBI** b and the **pricing year**

BBC_{jb} is **customer** j's **annual benefit-based charge** for **discounted BBI** b and the **pricing year**, where **customer** j is a **beneficiary** of **discounted BBI** b and not the **prudent discount recipient** (including **customer** c).

(3) Subject to subclause (4), **customer** c's **residual prudent discount recovery charge** for a **prudent discount** and **pricing year** ($RPDS_c$), where **customer** c is a **load customer** and not the **prudent discount recipient**, is calculated as follows:

$$RPDS_c = (PD - BPDS) \times \frac{RC_c}{\sum_j RC_j}$$

where

PD is the amount of the **prudent discount** for the **pricing year**

$BPDS$ is the part of the amount of the **prudent discount** to be recovered through **BBI prudent discount recovery charges** for the **pricing year**

RC_c is **customer** c's **annual residual charge** for the **pricing year**

RC_j is **customer** j's **annual residual charge** for the **pricing year**, where **customer** j is not the **prudent discount recipient** (including **customer** c).

(4) The minimum value of a **BBI prudent discount recovery charge** or **residual prudent discount recovery charge** is 0.

(5) A **customer's annual prudent discount recovery charge** for a **pricing year** (APDRC) is the sum of the **customer's BBI prudent discount recovery charges** and **residual prudent discount recovery charges** for the **pricing year**.

(6) A **customer's monthly prudent discount recovery charge** for a **pricing year** (MPDRC) is calculated as follows:

$$MPDRC = \frac{APDRC}{12}$$

where APDRC is the **customer's annual prudent discount recovery charge** for the **pricing year**.

(7) Except as otherwise stated in this **transmission pricing methodology**, **prudent discount recovery charges**—
(a) are calculated at the start of a **pricing year** only; and
(b) are not re-calculated during a **pricing year** if there is an adjustment to other **transmission charges** during the **pricing year**.

Appendix A – BBIs and Starting BBI Customer Allocations

Customer	Bunnythorpe Haywards	HVDC	LSI Reliability	LSI Renewables	NIGU	UNIDRS	Wairakei Ring
Alpine Energy Ltd	3.09%	0.86%	1.50%	2.99%	0.30%	0.30%	0.24%
Aurora Energy Ltd	5.67%	1.57%	0.91%	4.50%	0.30%	0.30%	0.27%
Beach Energy Resources NZ (Holdings) Ltd	0.03%	0.07%	0.10%	0.08%	0.03%	0.03%	0.04%
Buller Electricity Ltd	0.26%	0.08%	0.08%	0.19%	0.01%	0.01%	0.01%
Centralines Ltd	0.07%	0.21%	0.24%	0.17%	0.05%	0.05%	0.01%
Contact Energy Ltd	2.09%	12.58%	24.11%	0.09%	5.92%	5.92%	21.38%
Counties Energy Ltd	0.31%	1.06%	1.09%	0.85%	2.62%	2.62%	1.42%
Daiken Southland Ltd	0.27%	0.09%	1.39%	0.28%	0.02%	0.02%	0.02%
EA Networks Ltd	1.69%	0.51%	0.76%	1.72%	0.26%	0.26%	0.15%
Eastland Network Ltd	0.17%	0.35%	0.57%	0.41%	0.05%	0.05%	0.00%
Electra Ltd	2.60%	0.55%	0.65%	0.45%	0.11%	0.11%	0.09%
Genesis Energy Ltd	1.21%	3.24%	0.00%	0.03%	3.65%	3.65%	7.69%
GTL Energy (New Zealand) Pty Ltd	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%

Customer	Bunnythorpe Haywards	HVDC	LSI Reliability	LSI Renewables	NIGU	UNIDRS	Wairakei Ring
Horizon Energy Distribution Ltd	0.23%	0.24%	0.37%	0.43%	0.04%	0.04%	0.00%
KiwiRail Holdings Ltd	0.03%	0.07%	0.11%	0.08%	0.20%	0.20%	0.12%
Mainpower New Zealand Ltd	3.19%	0.88%	1.29%	2.96%	0.24%	0.24%	0.20%
Manawa Energy Ltd	0.00%	0.65%	0.00%	0.01%	0.16%	0.16%	1.15%
Marlborough Lines Ltd	2.02%	0.45%	0.87%	1.88%	0.15%	0.15%	0.13%
Mercury NZ Ltd	0.70%	0.06%	0.09%	0.07%	6.80%	6.80%	10.73%
Mercury SPV Ltd	0.38%	0.02%	0.00%	0.00%	0.25%	0.25%	0.00%
Meridian Energy Ltd	0.23%	33.80%	1.11%	0.05%	7.32%	7.32%	0.00%
Methanex New Zealand Ltd	0.03%	0.06%	0.09%	0.07%	0.03%	0.03%	0.04%
Nelson Electricity Ltd	0.28%	0.06%	0.12%	0.23%	0.02%	0.02%	0.02%
Network Tasman Ltd	3.04%	0.71%	1.35%	2.58%	0.20%	0.20%	0.17%
Network Waitaki Ltd	1.12%	0.36%	0.53%	2.17%	0.13%	0.13%	0.08%
New Zealand Aluminium Smelters Ltd	21.91%	7.27%	2.14%	23.72%	1.60%	1.60%	1.62%
New Zealand Steel Ltd	0.30%	0.51%	0.97%	0.85%	2.46%	2.46%	1.34%

Customer	Bunnythorpe Haywards	HVDC	LSI Reliability	LSI Renewables	NIGU	UNIDRS	Wairakei Ring
Nga Awa Purua Joint Venture	0.00%	0.00%	0.00%	0.00%	0.97%	0.97%	8.06%
Ngatamariki Geothermal Ltd	0.01%	0.00%	0.00%	0.00%	0.59%	0.59%	4.89%
Norske Skog Tasman Ltd	0.00%	0.00%	0.00%	0.00%	0.18%	0.18%	2.48%
Northpower Ltd	0.66%	1.13%	2.17%	1.79%	5.96%	5.96%	2.92%
Nova Energy Ltd	0.04%	0.00%	0.00%	0.00%	0.03%	0.03%	0.00%
OMV NZ Production Ltd	0.04%	0.10%	0.14%	0.12%	0.04%	0.04%	0.06%
Orion New Zealand Ltd	18.12%	4.90%	7.20%	14.77%	1.14%	1.14%	1.00%
Pan Pac Forest Product Ltd	0.34%	0.47%	0.77%	0.70%	0.10%	0.10%	0.00%
Powerco Ltd	4.00%	6.27%	8.60%	6.73%	1.90%	1.90%	3.61%
Powernet Ltd	5.35%	1.38%	10.60%	6.36%	0.38%	0.38%	0.35%
Scanpower Ltd	0.05%	0.15%	0.17%	0.12%	0.03%	0.03%	0.03%
Southern Generation GP Ltd	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Southpark Utilities Ltd	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tararua Wind Power Ltd	0.26%	0.01%	0.00%	0.00%	0.16%	0.16%	0.00%

Customer	Bunnythorpe Haywards	HVDC	LSI Reliability	LSI Renewables	NIGU	UNIDRS	Wairakei Ring
The Lines Company Ltd	0.16%	0.36%	0.47%	0.37%	0.18%	0.18%	0.49%
Todd Generation Taranaki Ltd	0.49%	0.18%	0.00%	0.03%	0.52%	0.52%	0.00%
Top Energy Ltd	0.00%	0.24%	0.00%	0.00%	1.08%	1.08%	0.52%
Unison Networks Ltd	0.63%	1.34%	2.20%	1.61%	0.16%	0.16%	0.00%
Vector Ltd	5.48%	10.79%	19.06%	14.45%	51.10%	51.10%	24.57%
Waipa Networks Ltd	0.25%	0.59%	0.82%	0.64%	0.33%	0.33%	1.02%
Waverley Wind Farm Ltd	0.23%	0.01%	0.00%	0.00%	0.15%	0.15%	0.00%
WEL Networks Ltd	0.51%	1.13%	1.82%	1.41%	1.13%	1.13%	2.38%
Wellington Electricity Lines Ltd	11.76%	4.25%	4.93%	3.23%	0.83%	0.83%	0.66%
Westpower Ltd	0.40%	0.09%	0.18%	0.46%	0.04%	0.04%	0.03%
Whareroa Co-generation Ltd	0.10%	0.03%	0.00%	0.00%	0.02%	0.02%	0.00%
Winstone Pulp International Ltd	0.16%	0.29%	0.43%	0.36%	0.07%	0.07%	0.00%

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

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