Contents

CHAPTER 2

Important note: This is a modified version of version 124 of Chapter 2 of the Rules. It incorporates changes made by the following Rules:

1 Schedule 2 of the National Electricity Amendment (Minor changes) Rule 2019 No 9
2 Schedule 1 of the National Electricity Amendment (Transparency of new projects) Rule 2019 No 9

This version does not include changes made by the following Rules:

1 Any changes made by Rules made after 27 November 2019

2 Changes to come into effect on 6 February 2022 for global settlement (the National Electricity Amendment (Global settlement and market reconciliation) Rule 2018 and the National Electricity Amendment (Five minute settlement and global settlement implementation amendments) Rule 2019)

2. Registered Participants and Registration

2.3.4 Market Customer

(a) If electricity, *supplied* through the *national grid* to any person *connected* at a *connection point*, is purchased other than from the *Local Retailer* that *load* at the *connection point* may be classified by that person or, with the consent of that person, by some other person as a *market load*.

(b) A *Customer* is taken to be a *Market Customer* only in so far as its activities relate to any *market load* and only while it is also registered with *AEMO* as a *Market Customer*.

(c) A *Market Customer* must purchase all electricity *supplied* at that *connection point* from the ~~*spot*~~ *market* and make payments to *AEMO* for electricity supplied at the *connection point* as determined for each *trading interval* in accordance with the provisions of Chapter 3.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(d) A *Market Customer* may request *AEMO* to classify any of its *market loads* as a *scheduled load* (other than a *market load* at a *connection point* in a *regulated SAPS*).

(e) *AEMO* must classify a *market load* as a *scheduled load* if it is satisfied that the *Market Customer*:

(1) has submitted data in accordance with schedule 3.1;

(2) has adequate communications and/or telemetry to support the issuing of *dispatch instructions* and the audit of responses; and

(3) has requested that the *load* be so classified and has not withdrawn that request.

(f) A *Market Customer* may submit *dispatch bids* in respect of *scheduled loads* in accordance with the provisions of Chapter 3.

(g) A *Market Customer* who submits *dispatch bids* for *scheduled loads* and makes its *scheduled loads* available for *central dispatch* must comply with the *dispatch instructions* from *AEMO* in accordance with the *Rules*.

(h) A *Customer* who is also a *Local Retailer* must classify any *connection point* which *connects* its *local area* to another part of the *power system* as a *market load*.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

2.3A Small Generation Aggregator

2.3A.1 Registration and classification

(a) A person who intends to supply electricity from one or more *small generating units* or *large SAPS generating units* to a *transmission or distribution system* may, upon application for registration by that person in accordance with rule 2.9, be registered by *AEMO* as a *Small Generation Aggregator*.

(b) To be eligible for registration as a *Small Generation Aggregator*, a person must satisfy *AEMO* that the person intends to classify, within a reasonable amount of time, one or more *small generating units* or *large SAPS generating units* each as a *market generating unit*, with each *market generating unit* having a separate *connection point*.

(c) A person must not engage in the activity of selling electricity directly to the *market* at any *connection point*~~,~~ unless that person is registered by *AEMO* as a *Market Participant* and that *connection point* is classified as one of that person's *market connection points*.

(d) A person must not classify a *small generating unit* or a *large SAPS generating unit* as a *market generating unit* for electricity supplied from any *connection point* unless the person satisfies the requirements of the *participating jurisdiction* in which the *connection point* is situated so that (subject to compliance with the *Rules*) the person is permitted to supply electricity in the ~~*spot*~~ *market* in relation to that *connection point*.

(e) A *Market Small Generation Aggregator* must classify each *small generating unit* or *large SAPS generating unit* from which it proposes to supply electricity as a *market generating unit*, with each *market generating unit* having a separate *connection point*.

2.3A.2 Market Small Generation Aggregator

(a)~~(f)~~ A *Market Small Generation Aggregator's* activities only relate to *small generating units* or *large SAPS generating units* it has classified as *market generating units*, and only while it is also registered with *AEMO* as a *Small Generation Aggregator*.

(b)~~(g)~~ A *Market Small Generation Aggregator* must sell all *sent out generation* through the ~~*spot*~~ *market* and accept payments from *AEMO* for all *sent out generation* at the price ~~*spot price*~~ applicable at the *connection point* for which it is *financially responsible* as determined for each *trading interval* in accordance with the provisions of Chapter 3.

(c)~~(h)~~ A *Market Small Generation Aggregator* must purchase all electricity *supplied* through the *national grid* to the *Market Small Generation Aggregator* at ~~that~~ a *connection point* for which it is *financially responsible* from the ~~*spot*~~ *market* and make payments to *AEMO* for such electricity *supplied* at the *connection point* ~~for which it is *financially responsible*~~ as determined for each *trading interval* in accordance with the provisions of Chapter 3.

2.10 Ceasing to be a Registered Participant

2.10.1 Notification of intention

(a) A person:

(1) may notify *AEMO* in writing that it wishes to cease to be registered in any category of *Registered Participant* or that it wishes to terminate any of its classifications of *loads*, *generating units* (other than a *generating unit* specified in subparagraph (2)) or *network services*; and

(2) who is a *Scheduled Generator* or *Semi-Scheduled Generator*, must notify *AEMO* in writing if it wishes to terminate any of its classifications of *generating units*.

(b) A person is not entitled to notify *AEMO* that it wishes to cease to be registered in relation to any category for which that person is required to be registered under the *National Electricity Law* or under the *Rules*.

(c) In any notice given under subparagraph (a)(1), the *Registered Participant* must specify a date upon which it wishes to cease to be so registered or for an existing classification to be terminated and, in the case of a *Market Participant*, the date upon which it will cease to *supply* or acquire electricity or trade directly in the *market* and whether entirely or in relation to one or more *connection points* or *market network services*.

(c1) In any notice given under subparagraph (a)(2), the *Registered Participant*:

(1) must specify a date (the *closure date*):

(i) for a *Non-Market Generator*, by which the classification of the *generating unit* will be terminated; and

(ii) for a *Market Generator*, by which:

(A) the classification of the *generating unit* will be terminated; and

(B) it will cease to supply electricity or trade directly in the *market* whether entirely or in relation to one or more *connection points*; and

(2) must provide an updated notice to *AEMO* under subparagraph (a)(2) of any amendments to the *closure date*.

(c2) A *Scheduled Generator* or *Semi-Scheduled Generator's* first notified *closure date* for a *generating unit* must be no earlier than 42 months from the date of the notice given under subparagraph (a)(2), except where the relevant *Generator* has applied for, and is granted an exemption by the *AER* under paragraph (c4).

(c3) A *Scheduled Generator* or *Semi-Scheduled Generator's* amended *closure date* for a *generating unit* provided in a notice to *AEMO* under subparagraph (c1)(2) (**amended notice**):

(1) may be a date that is later than the most recent *closure date* provided to *AEMO* under paragraph (a)(2); and

(2) must not be a date that is earlier than the most recent *closure date* provided to *AEMO* under paragraph (a)(2) except where:

(i) the amended *closure date* is no earlier than 42 months from the date the amended notice is provided to *AEMO*; or

(ii) the *Generator* has applied for, and is granted, an exemption by the *AER* under paragraph (c4).

(c4) The *AER* may, in accordance with guidelines issued from time to time by the *AER*, exempt any *Scheduled Generator* or *Semi-Scheduled Generator* from the requirement to provide the *closure date* in accordance with paragraph (c2) and (c3).

(c5) The *AER*, in accordance with the *Rules consultation procedures*:

(1) must develop and *publish* guidelines referred to in paragraph (c4) that include:

(i) the information to be provided by a *Generator* to the *AER* when requesting an exemption; and

(ii) procedures for handling requests for exemption received from *Generators*; and

(2) may amend these guidelines from time to time.

(c6) The *AER* may make minor and administrative amendments to the guidelines under clause (c5) without complying with the *Rules consultation procedures*.

(d) *AEMO* may reject a notice from a *Market Customer* that it wishes to terminate its classification of a *connection point* as one of its *market loads* or otherwise cease to be a *Market Customer* in relation to any of its *market loads* unless *AEMO* is satisfied that:

(1) another person has classified the *connection point* as one of its *market loads* and is registered as a *Market Customer*;

(2) the relevant *Local Retailer* has agreed or is otherwise required by laws of the relevant *participating jurisdiction* to assume responsibility for payments to *AEMO* for electricity *supplied* to that *connection point*; or

(3) the *load* at that *connection point* will be *disconnected* on and from the date specified and, taking into consideration any relevant guidelines and procedures specified by the relevant *participating jurisdiction* to *AEMO*, that *disconnection* is not inappropriate.

(d1) *AEMO* may reject a notice from a *Market Small Generation Aggregator* which states that it wishes to terminate its classification of a *small generating unit* or a *large SAPS generating unit* as a *market generating unit*, or otherwise cease to be a *Market Small Generation Aggregator* in relation to any of its *market generating units* or *large SAPS generating units*, unless *AEMO* is satisfied that:

(1) another person has classified the relevant ~~*small*~~ *generating unit* as one of its *market generating units* and that person is registered as a *Small Generation Aggregator* and a *Market Small Generation Aggregator*;

(2) the relevant *Local Retailer* has agreed or is otherwise required by laws of the relevant *participating jurisdiction* to assume responsibility for payments with *AEMO* for electricity *supplied* to the *connection points* of the relevant~~*market*~~ *generating unit*~~*units*~~; or

(3) the relevant~~*small*~~ *generating unit* at that *connection point* will be *disconnected* on and from the date specified in the notice, and, after having regard to any relevant guidelines and procedures specified by the relevant *participating jurisdictions* to *AEMO*, *disconnection* is appropriate.

(e) Upon receiving a notice which complies with clause 2.10.1 from a person who wishes to cease to be registered in any category of *Market Participant*, or to terminate the classification of any of its *market loads*, *market generating units*, or *market network services*, *AEMO* must deliver a notice to the *AER* and the *AEMC* and notify all *Registered Participants* stating that:

(1) *AEMO* has received a notice under clause 2.10.1(a); and

(2) the person who gave the notice has stated that, from the date specified in the notice, the person intends to cease *supplying* or acquiring electricity or trading directly in the *market* and whether entirely or in relation to certain *connection points* or *market network services*.

(f) If a *Market Customer* that is a *retailer* gives a notice under this clause, *AEMO* must, before deciding whether to reject the notice under paragraph (d), consult with the *AER*.

CHAPTER 3

Important note:

This document shows changes proposed to Chapter 3 of the National Electricity Rules for distributor-led SAPS. The changes are shown in a modified version of Chapter 3 that incorporates changes made by the Rules listed below. This modified version of Chapter 3 is provided to assist in responding to the draft report and should not be used for any other purpose.

1 Schedule 1 of the National Electricity Amendment (Retailer Reliability Obligation) Rule 2019 which came into effect on 1 July 2019

2 Schedule 1 of the National Electricity Amendment (Five minute settlement and global settlement implementation amendments) Rule 2019 No.7 which came into effect on 12 August 2019

3 Schedule 2 of the National Electricity Amendment (Enhancement to the Reliability and Emergency Reserve Trader) Rule 2019 which came into effect on 31 October 2019

4 Schedule 1 of the National Electricity Amendment (Minor changes) Rule 2019 No. 9 which came into effect on 21 November 219

5 Schedule 1 of the National Electricity Amendment (Register of distributed energy resources) Rule 2018 which came into effect on 1 December 2019

6 Schedule 2 of the National Electricity Amendment (Transparency of new projects) Rule 2019 which came into effect on 1 December 2019

7 Schedule 1 of the National Electricity Amendment (Transparency of new projects) Rule 2019 which will come into effect on 19 December 2019

8 Schedule 1 of the National Electricity Amendment (Enhancement to the Reliability and Emergency Reserve Trader) Rule 2019 which will come into effect on 26 March 2020

9 Schedule 2 of the National Electricity Amendment (Retailer Reliability Obligation) Rule 2019 which will come into effect on 26 March 2020

10 Schedule 1 of the National Electricity Amendment (Five minute settlement) Rule 2017 which will come into effect on 1 July 2021

11 Schedule 2 of the National Electricity Amendment (Five minute settlement and global settlement implementation amendments) Rule 2019 No.7 will come into effect on 1 July 2021

12 Schedule 2 of the National Electricity Amendment (Participant compensation following market suspension) Rule 2018 which will come into effect on1 July 2021

13 Schedule 2 of the National Electricity Amendment (Intervention compensation and settlement processes) Rule 2019 which will come into effect on 1 July 2021

14 Schedule 1 of the National Electricity Amendment (Global settlement and market reconciliation) Rule 2018 which will come into effect on 6 February 2022

3. Market Rules

3.15 Settlements

3.15.1 Settlements management by AEMO

(a) *AEMO* must facilitate the billing and *settlement* of payments due in respect of *transactions* under this Chapter 3, including:

(1) *spot market transactions*;

(2) *reallocation transactions*;

(3) negative *settlements residue* under clause 3.6.5; ~~and~~

(4) under clause 3.15.6A~~.~~; and

(5) under clause 3.21.3.

(b) *AEMO* must determine the *Participant fees* and the *Market Participants* must pay them to *AEMO* in accordance with the provisions of rule 2.11.

3.15.4 Adjusted gross energy amounts – connection points

(a) For each *market connection point* that is a *transmission network connection point*, the *adjusted gross energy amount* for a *trading interval* is the *metered energy*, being the amount of electrical *energy*, expressed in MWh, flowing at the *connection point* in the *trading interval*, as recorded in the *metering data* in respect of that *connection point* and that *trading interval* (expressed as a positive value where the flow is towards the *transmission network connection point* to which the *connection point* is assigned and a negative value where the flow is in the other direction).

(b) Where a *connection point* is not a *transmission network connection point* or a *connection point* in a *regulated SAPS*, the *adjusted gross energy* amount for that *connection point* for a *trading interval* is calculated by *AEMO* by applying the following formula:

AGE = (ME × DLF) + UFEA

where:

AGE is the *adjusted gross energy* amount to be determined;

ME is the amount of electrical *energy*, expressed in MWh, flowing at the *connection point* in the *trading interval*, as recorded in the *metering data* in respect of that *connection point* and that *trading interval* (expressed as a positive value where the flow is towards the *transmission network connection point* to which the *connection point* is assigned and a negative value where the flow is in the other direction);

DLF is the *distribution loss factor* applicable at that *connection point*; and

UFEA is the share of unaccounted for *energy* allocated to that *connection point* under clause 3.15.5.

(c) The *adjusted gross energy* amount for a *connection point* in a *regulated SAPS* for a *trading interval* is calculated by the following formula:

AGE = (ME × DLF) + UFEA

where:

AGE is the *adjusted gross energy* amount to be determined;

ME is the amount of electrical *energy*, expressed in MWh, flowing at the *connection point* in the *trading interval*, as recorded in the *metering data* in respect of that *connection point* and that *trading interval* (expressed as a positive value where the flow is towards the regulated SAPS and a negative value where the flow is in the other direction);

DLF is the *distribution loss factor* applicable at that *connection point* which is equal to 1; and

UFEA is the share of unaccounted for *energy* allocated to that *connection point* under clause 3.15.5.

3.15.5 Unaccounted for energy adjustment – local areas

(a) For each *local area*, an amount representing unaccounted for *energy* is determined by *AEMO* for each *trading interval* by the following formula:

UFE = TME - DDME - ADME

where:

UFE is the total unaccounted for *energy* amount (in MWh) to be determined;

TME is the amount of electrical *energy*, expressed in MWh, flowing at each of the *transmission network connection points* in the *local area* in the *trading interval*, as recorded in the *metering data* in respect of each of the *transmission network connection points* for that *trading interval* (expressed as a positive value where the flow is towards the *transmission network*, and negative value where the flow is in the other direction);

DDME is the amount of electrical *energy*, expressed in MWh, flowing at each of the *distribution network connection points* in the *local area* which are connected to an adjacent *local area*, in the *trading interval*, as recorded in the *metering data* in respect of each of those *distribution network connection points* for that *trading interval* (expressed as a negative value where the flow is towards the adjacent *distribution network*, and positive value where the flow is in the other direction) adjusted by the *distribution loss factor* applicable at that *connection point*; and

ADME is the aggregate of the amounts represented by (ME x DLF) for that *trading interval* for each *connection point* assigned to the *transmission network connection point* or *virtual transmission node*, for which a *Market Participant* (other than a suspended *Market Participant*) is *financially responsible* (and in that aggregation positive and negative *adjusted gross energy* amounts are netted out to give a positive or negative aggregate amount).

Note

The DDME value for a local area that is connected to an adjacent local area will appear in the calculation of UFE for both local areas. A positive energy flow for the calculation of UFE for one local area would correspond to a negative flow for the calculation of UFE for the other local area.

Note

ME for a *connection point* in a *regulated SAPS* will not be included in the calculation of ADME under paragraph (a) as those *connection points* are not assigned to *transmission network connection points* or *virtual transmission nodes.*

(a1) For a *distribution network* of a *Distribution Network Service Provider* that includes one or more *regulated SAPS*, an amount representing the aggregate unaccounted for *energy* in all those *regulated SAPS* is determined by *AEMO* for each *trading interval* by the following formula:

UFE = - ADME

where:

UFE is the total unaccounted for *energy* amount (in MWh) to be determined; and

ADME is the aggregate of the amounts represented by (ME x DLF) for that *trading interval* for each *connection point* in those *regulated SAPS*, for which a *Market Participant* (other than a suspended *Market Participant*) is *financially responsible* (and in that aggregation positive and negative *adjusted gross energy* amounts are netted out to give a positive or negative aggregate amount).

(b) The unaccounted for *energy* amount determined by *AEMO* under paragraph (a) in a *local area* is to be allocated to all *market connection points* in that *local area* where the amount of electrical *energy* flowing at the *connection point* is expressed as a negative value.

(b1) The unaccounted for *energy* amount determined by *AEMO* under paragraph (a1) for a *distribution network* of a *Distribution Network Service Provider* is to be allocated to all *market connection points* in the *regulated SAPS* included in the *distribution network* where the amount of electrical *energy* flowing at the *connection point* is expressed as a negative value.

(c) The allocation under paragraph (b) or (b1) of the total unaccounted for *energy* amount determined under:

(1) paragraph (a), for every *distribution network connection point* in a *local area* that is classified as a *market load* where the amount of electrical *energy* flowing at the *connection point* is expressed as a negative value; or

(2) paragraph (a1), for every *distribution network connection point* in a *regulated SAPS* that is classified as a *market load* where the amount of electrical *energy* flowing at the *connection point* is expressed as a negative value,

is determined by *AEMO* by the following formula:

UFEA = UFE x (DME/ADMELA)

where:

UFEA is the allocation of the unaccounted for *energy* amount (in MWh) for the relevant *market connection point* and *trading interval*;

UFE is the unaccounted for *energy* amount~~amounts~~ determined under paragraph (a) for the *local area* or under paragraph (a1) for the *distribution* *network*, as applicable;

DME is the amount represented by (ME- x DLF) for the relevant *market connection point* and *trading interval* where:

ME- is the amount of electrical *energy*, expressed in MWh, flowing at the *market connection point* in the *trading interval*, as recorded in the *metering data* in respect of that *market connection point* and that *trading interval* (where the flow is away from the *transmission network connection point* to which the *market connection point* is assigned or the *regulated SAPS* as applicable);

DLF is the *distribution loss factor* applicable at that *market connection point*; and

ADMELA is the aggregate of the amounts represented by DME for that *trading interval* for each *market connection point* in that *local area* or each *market connection point* in *regulated SAPS* forming part of the *distribution network*, for which a *Market Customer* (other than a suspended *Market Customer*) is *financially responsible*.

(d) *AEMO* must *publish* information to enable each *Market Customer* in a *local area* or a *regulated SAPS* to verify the unaccounted for *energy* amounts allocated to that *Market Customer's market connection points* in that *local area* or *regulated SAPS* under paragraph (b) or (b1) for each *trading interval* in accordance with a procedure developed and *published* by *AEMO*.

3.15.6 Spot market transactions

(a) In each *trading interval*, in relation to each *connection point* and to each *virtual transmission node* for which a *Market Participant* is *financially responsible*, a *spot market transaction* occurs, which results in a *trading amount* for that *Market Participant* determined in accordance with the formula:

$$TA = AGE \times TLF \times RRP$$

where

TA is the *trading amount* to be determined (which will be a positive or negative dollar amount for each *trading interval*);

AGE is the *adjusted gross energy* for that *connection point* or *virtual transmission node* for that *trading interval*, expressed in MWh;

TLF for:

(1) a *transmission network connection point* or *virtual transmission node*, is the relevant *intra-regional loss factor* at that *connection point* or *virtual transmission node* respectively~~,~~;

(2) a *connection point* in a *regulated SAPS* is 1; and

(3) for any other *connection point*, is the relevant *intra-regional loss factor* at the *transmission network connection point* or *virtual transmission node* to which it is assigned in accordance with clause 3.6.2(b)(2); and

RRP is the *regional reference price* for the *regional reference node* to which the *connection point* or *virtual transmission node* is assigned, expressed in dollars per MWh.

Note

Where two *intra-regional loss factors* are determined for a *transmission network connection point* under clause 3.6.2(b)(2), *AEMO* will determine the relevant *intra-regional loss factor* for use under this clause in accordance with the procedure determined under clause 3.6.2(d1).

Where one *connection point* is assigned to both a single *transmission network connection point* and a *virtual transmission node*, the *intra-regional loss factor* for the *virtual transmission node* will apply.

(b) Except with respect to any *trading interval* in a *market suspension pricing schedule period* in relation to which *AEMO* has issued a *direction* to a *Market Suspension Compensation Claimant*, *AEMO* is entitled to the *trading amount* resulting from a *AEMO intervention event* and, for the purposes of determining *settlement amounts*, any such *trading amount* is not a *trading amount* for the relevant *Market Participant*.

(c) A *Directed Participant* is entitled to the *trading amount* resulting from any service, other than the service the subject of the *AEMO intervention event*, rendered as a consequence of that event.

3.15.6A Ancillary service transactions

(a) In each *trading interval*, in relation to each *enabled ancillary service generating unit* or *enabled ancillary service load*, an ancillary services transaction occurs, which results in a *trading amount* for the relevant *Market Participant* determined in accordance with the following formula:

$$TA = \text{the aggregate of } \frac{EA \times ASP}{(12)} \text{ for each } \textit{trading interval}$$

where:

TA (in $)	=	the *trading amount* to be determined (which is a positive number);
EA (in MW)	=	the amount of the relevant *market ancillary service* which the *ancillary service generating unit* or *ancillary service load* has been *enabled* to provide in the *trading interval*; and
ASP (in $ per MW per hour)	=	the *ancillary service price* for the *market ancillary service* for the *trading interval* for the *region* in which the *ancillary service generating unit* or *ancillary service load* has been *enabled*.

(b) In relation to each *NMAS provider* who provides *non-market ancillary services* under an *ancillary services agreement*, an *ancillary services* transaction occurs, which results in an amount payable by *AEMO* to the *NMAS provider* determined in accordance with that agreement.

(b1) Where an amount payable by *AEMO* under paragraph (b) is not determined on a *trading interval basis*, that amount is recovered in accordance with the relevant paragraphs (c8), (c9), (d) and (e), except that a reference to *trading interval* in the calculation of RBF, AGE, AAGE, TGE, ATGE, TSGE, ATSGE, TCE, ATCE is to be read as "the relevant period", and any other reference to *trading interval* in those paragraphs is to be read as the "relevant *billing period*".

(c) **[Deleted]**

(c1) In this clause:

regional benefit ancillary services procedures means the procedures to determine the relative benefit that each *region* is estimated to receive from the provision of *NMAS*.

regional benefit factors means the factors to allocate, between *regions*, the costs associated with the provision of *NMAS* under each *ancillary services agreement* in accordance with the regional benefit ancillary services procedures.

(c2) Subject to paragraph (b1), *AEMO* must recover its liabilities under *ancillary services agreements* for the provision of:

(1) *NSCAS* from *Market Customers* in each *region* in accordance with paragraphs (c8) and (c9); and

(2) *system restart ancillary services*, from:

(i) *Market Generators* and *Market Small Generation Aggregators* in each *region* in accordance with paragraph (d); and

(ii) *Market Customers* in each *region* in accordance with paragraph (e).

(c3) In the statements to be provided under clauses 3.15.14 and 3.15.15 to a *Market Customer*, *AEMO* must separately identify the portion of the total amount payable by *AEMO* in respect of the relevant *billing period* under *ancillary services agreements* for the provision of *NSCAS* that:

(1) benefits specific *regions* in which there is a *connection point* for which the *Market Customer* is *financially responsible* (being the *regional* amounts given by the first summated term in the paragraph (c8) formula); and

(2) does not benefit specific *regions* (being the amount TNSCASp in the paragraph (c9) formula).

(c4) *AEMO* must develop and *publish* the regional benefit ancillary services procedures in accordance with the *Rules consultation procedures*. Without limiting the matters to be included in the regional benefit ancillary services procedures, they must require *AEMO* to take into account:

(1) for an *NSCAS*, the estimated increase for each *region* of the gross economic benefit from increased *power transfer capability*; and

(2) for a *system restart ancillary service*, that can be used to restart *generating units* in two or more *regions*, the relative benefit provided by that service to each *region*.

(c5) Subject to paragraph (c6), *AEMO* may amend the regional benefit ancillary services procedures from time to time in accordance with the *Rules consultation procedures*.

(c6) *AEMO* may make minor and administrative amendments to the regional benefit ancillary services procedures without complying with the *Rules consultation procedures*.

(c7) From time to time, *AEMO* must determine the regional benefit factors.

(c8) In each *trading interval*, in relation to each *Market Customer* for each *region*, an *ancillary services* transaction occurs, which results in a *trading amount* for the *Market Customer* determined in accordance with the following formula:

$$TA_{P,R} = \left(\sum_{\text{for all 'S'}} \left(TNSCAS_{S,P} \times RBF_{S,P,R} \right) \right) \times \frac{AGE_{P,R}}{AAGE_{P,R}} \times -1$$

Where

Subscript 'P' is the relevant period;

Subscript 'R' is the relevant *region*

Subscript 'S' is the relevant *NSCAS*;

TAp,r (in $) =*trading amount* payable by the *Market Customer* in respect of the relevant *region* and *trading interval*;

TNSCASs,p the total amount payable by *AEMO* for the provision of the relevant *NSCAS* under an *ancillary services agreement* in respect of the relevant *trading interval*;

RBFs,p,r (number) = the latest regional benefit factor assigned to the provision of the relevant *NSCAS* under an *ancillary services agreement* in respect of the relevant *region* and *trading interval*, as determined by *AEMO* under paragraph (c7);

AGEp,r (in MWh) = the sum of the *adjusted gross energy* figures in respect of the *Market Customer's* relevant *connection points* located in the *region* for the relevant *trading interval*; and

AAGEp,r (in MWh) = the aggregate AGEp,r figures for all *Market Customers* in respect of the relevant *region* and *trading interval*.

(c9) In each *trading interval*, in relation to each *Market Customer*, an *ancillary services* transaction occurs, which results in a *trading amount* for the *Market Customer* determined in accordance with the following formula:

$$TA_P = TNSCAS_P \times \frac{AGE_P}{AAGE_P} \times -1$$

Where

Subscript 'P' is the relevant period;

TAp(in \$) = the *trading amount* payable by the *Market Customer* in respect of the relevant *trading interval*;

TNSCASp (in \$) = the sum of all amounts payable by *AEMO* for the provision of *NSCAS* under *ancillary services agreements* in respect of the relevant *trading interval* minus the sum of the *trading amounts* calculated for all *Market Customers* in respect of all of the relevant *trading interval* under paragraph (c8);

AGEp (in MWh) = the sum of the *adjusted gross energy* figures in respect of all the *Market Customer's* relevant *connection points* for the relevant *trading interval*; and

AAGEp (in MWh) = the aggregate AGEp figures for all *Market Customers* in respect of the relevant *trading interval*.

(c10) *AEMO* must *publish* the regional benefit factors determined under paragraph (c7);

(d) In each *trading interval*, in relation to each *Market Generator* and each *Market Small Generation Aggregator* for each *region*, an ancillary services transaction occurs, which results in a *trading amount* for the *Market Generator* or the *Market Small Generation Aggregator* determined in accordance with the following formula:

$$TA = \sum\left(\left(\frac{SRP_i \times RBF_{Ri}}{2}\right) \times \left(\frac{TGE_R + TSGE_R}{ATGE_R + ATSGE_R}\right)\right) \times -1$$

Where

TA (in \$) = the *trading amount* to be determined in respect of the relevant region and *trading interval* (which is a negative number);

SRP_i (in \$) = the amount payable by *AEMO* in respect of the *trading interval* under an individual *ancillary services agreement* in respect of the provision of a specific *system restart ancillary service*;

RBF_{Ri} (number) = the latest regional benefit factor assigned to the provision of the relevant *system restart ancillary service* under an individual *ancillary services agreement* in respect of the relevant *region* and *trading interval*, as determined by *AEMO* under paragraph (c7);

TGE_R (in MWh) = the *generator energy* for the *Market Generator* for the *trading interval* in that *region*;

$TSGE_R$ (in MWh) = the *small generator energy* for the *Market Small Generator Aggregator* for the *trading interval* in that *region*;

$ATGE_R$ (in MWh) = the aggregate of the *generator energy* figures for all *Market Generators* for the *trading interval* in that *region*; and

$ATSGE_R$ (in MWh) = the aggregate of the *small generator energy* figures for all *Market Small Generator Aggregators* for the *trading interval* in that *region*.

(e) In each *trading interval*, in relation to each *Market Customer*, for each *region*, an ancillary services transaction occurs, which results in a *trading amount* for the *Market Customer* determined in accordance with the following formula:

$$TA = \sum\left(\left(\frac{SRP_i \times RBF_{Ri}}{2}\right) \times \frac{TCE_R}{ATCE_R}\right) \times -1$$

Where

TA (in \$) = the *trading amount* to be determined in respect of the relevant *region* and *trading interval* (which is a negative number);

SRP_i (in \$) = has the meaning given in clause 3.15.6A(d);

RBF_{Ri} (number) = the latest regional benefit factor assigned to the provision of the relevant *system restart ancillary service* under an individual *ancillary services agreement* in respect of the relevant *region* and *trading interval*, as determined by *AEMO* under paragraph (c7);

TCE_R (in MWh) = the *customer energy* for the *Market Customer* for the *trading interval* in that *region*; and

$ATCE_R$ (in MWh) = the aggregate of the *customer energy* figures for all *Market Customers* for the *trading interval* in that *region*.

(f) The total amount calculated by *AEMO* under clause 3.15.6A(a) for each of the *fast raise service*, *slow raise service* or *delayed raise service* in respect of each *trading interval* must be allocated to each *region* in accordance with the following procedure and the information provided under clause 3.9.2A(b). *AEMO* must:

(1) allocate for each *region* and for the relevant *trading interval* the proportion of the total amount calculated by *AEMO* under clause 3.15.6A(a) for each of the *fast raise service*, *slow raise service* or *delayed raise service* between *global market ancillary services requirements* and *local market ancillary service requirement* pro-rata to the respective marginal prices for each such service;

(2) calculate for the relevant *trading interval* the sum of the costs of acquiring the *global market ancillary service requirements* for all *regions* and the sum of the costs of acquiring each *local market ancillary service requirement* for all *regions*, as determined pursuant to clause 3.15.6A(f)(1); and

(3) allocate for the relevant *trading interval* the sum of the costs of the

global market ancillary service requirement and each *local market ancillary service requirement* calculated in clause 3.15.6A(f)(2) to each *region* as relevant to that requirement pro-rata to the aggregate of the *generator energy* for the *Market Generators* and *small generator energy* for the *Market Small Generation Aggregators* in each *region* during the *trading interval*.

For the purpose of this clause 3.15.6A(f) **RTCRSP** is the sum of:

(i) the *global market ancillary service requirement* cost for that *region*, for the relevant *trading interval*, as determined pursuant to clause 3.15.6A(f)(3); and

(ii) all *local market ancillary service requirement* costs for that *region*, for the relevant *trading interval*, as determined pursuant to clause 3.15.6A(f)(3).

In each *trading interval*, in relation to each *Market Generator* and each *Market Small Generation Aggregator* in a given *region*, an ancillary services transaction occurs, which results in a *trading amount* for that *Market Generator* and that *Market Small Generation Aggregator* determined in accordance with the following formula:

$$TA = RTCRSP \times \frac{TGE + TSGE}{RATGE + RATSGE} \times -1$$

where:

TA (in $)	=	the *trading amount* to be determined (which is a negative number);
RTCRSP (in $)	=	the total of all amounts calculated by *AEMO* as appropriate to recover from the given *region* as calculated in this clause 3.15.6A(f) for the *fast raise service*, *slow raise service* or *delayed raise service* in respect of *trading interval*;
TGE (in MWh)	=	the *generator energy* for the *Market Generator* in that *region* for the *trading interval*;
TSGE (in MWh)	=	the *small generator energy* for the *Market Small Generator Aggregator* in that *region* for the *trading interval*;
RATGE (in MWh)	=	the aggregate of the *generator energy* figures for all *Market Generators* in that *region* for the *trading interval*; and
RATSGE (in MWh)	=	the aggregate of the *small generator energy* figures for all *Market Small*

Generator Aggregators in that *region* for the *trading interval*.

(g) The total amount calculated by *AEMO* under clause 3.15.6A(a) for each of the *fast lower service*, *slow lower service* or *delayed lower service* in respect of each *trading interval* must be allocated to each *region* in accordance with the following procedure and the information provided under clause 3.9.2A(b). *AEMO* must:

(1) allocate for each *region* and for the relevant *trading interval* the proportion of the total amount calculated by *AEMO* under clause 3.15.6A(a) for each of the *fast lower service*, *slow lower service* or *delayed lower service* between *global market ancillary service requirements* and *local market ancillary service requirement* pro rata to the respective marginal prices of each such service;

(2) calculate for the relevant *trading interval* the sum of the costs of acquiring the *global market ancillary service requirements* for all *regions* and the sum of the costs of acquiring each *local market ancillary service requirement* for all *regions*, as determined pursuant to clause 3.15.6A(g)(1); and

(3) allocate for the relevant *trading interval* the sum of the costs of the *global market ancillary service requirement* and each *local market ancillary service requirement* calculated in clause 3.15.6A(g)(2) to each *region* as relevant to that requirement pro-rata to the aggregate of the *customer energy* figures for all *Market Customers* in each *region* during the *trading interval*.

For the purpose of this clause 3.15.6A(g) **RTCLSP** is the sum of:

(i) the *global market ancillary service requirement* cost for that *region*, for the relevant *trading interval*, as determined pursuant to clause 3.15.6A(g)(3); and

(ii) all *local market ancillary service requirement* costs for that *region*, for the relevant *trading interval*, as determined pursuant to clause 3.15.6A(g)(3).

In each *trading interval*, in relation to each *Market Customer* in a given *region*, an ancillary services transaction occurs, which results in a *trading amount* for that *Market Customer* determined in accordance with the following formula:

$$TA = RTCLSP \times \frac{TCE}{RATCE} \times -1$$

where:

TA (in $)	=	the *trading amount* to be determined (which is a negative number);
RTCLSP (in $)	=	the total of all amounts calculated by *AEMO* as appropriate to recover from the given *region* as calculated in this clause

3.15.6A(g) for the *fast lower service*, *slow lower service* or *delayed lower service* in respect of *trading interval*;

TCE (in MWh) = the *customer energy* for the *Market Customer* in that *region* for the *trading interval*; and

RATCE (in MWh) = the aggregate of the *customer energy* figures for all *Market Customers* in that *region* for the *trading interval*.

(h) The total amount calculated by *AEMO* under paragraph (a) for the *regulating raise service* or the *regulating lower service* in respect of each *trading interval* must be allocated by *AEMO* to each *region* in accordance with the following procedure and the information provided under clause 3.9.2A(b):

(1) allocate on a pro-rata basis for each *region* and for the relevant *trading interval* the proportion of the total amount calculated by *AEMO* under paragraph (a) for the *regulating raise service* and *regulating lower service* between *global market ancillary service requirements* and *local market ancillary service requirements* to the respective marginal prices for each such service; and

(2) calculate for the relevant *trading interval* the sum of the costs of acquiring the *global market ancillary service requirements* for all *regions* and the sum of the costs of acquiring *local market ancillary service requirements* for all *regions*, as determined under subparagraph (1).

(i) In each *trading interval* in relation to:

(1) each *Market Generator*, *Market Small Generation Aggregator* or *Market Customer* which has *metering* to allow their individual contribution to the aggregate deviation in *frequency* of the *power system* to be assessed, an ancillary services transaction occurs, which results in a *trading amount* for that *Market Generator*, *Market Small Generation Aggregator* or *Market Customer* determined in accordance with the following formula:

$$TA = PTA \times -1$$

and

$$PTA = \text{the aggregate of} \left(TSFCAS \times \frac{MPF}{AMPF} \right)$$

for each *trading interval* for *global market ancillary service requirements* and *local market ancillary service requirements* where:

TA (in \$) = the *trading amount* to be determined (which is a negative number);

TSFCAS (in \$) = the total of all amounts calculated by

		AEMO under paragraph (h)(2) for the *regulating raise service* or the *regulating lower service* in respect of a *trading interval*;
MPF (a number)	=	the contribution factor last set by *AEMO* for the *Market Generator*, *Market Small Generation Aggregator* or *Market Customer*, as the case may be, under paragraph (j) for the *region* or *regions* relevant to the *regulating raise service* or *regulating lower service*; and
AMPF (a number)	=	the aggregate of the MPF figures for all *Market Participants* for the *trading interval* for the *region* or *regions* relevant to the *regulating raise service* or *regulating lower service*.

or

(2) in relation to each *Market Customer* for whom the *trading amount* is not calculated in accordance with the formula in subparagraph (1), an ancillary services transaction occurs, which results in a trading amount for that *Market Customer* determined in accordance with the following formula:

$TA = PTA \times -1$

and

$$PTA = \text{the aggregate of} \left(TSFCAS \times \frac{MPF}{AMPF} \times \frac{TCE}{ATCE} \right)$$

for each *trading interval* for *global market ancillary service requirements* and *local market ancillary service requirements* where:

TA (in \$)	=	the *trading amount* to be determined (which is a negative number);
TSFCAS (in \$)	=	has the meaning given in subparagraph (1);
MPF (a number)	=	the aggregate of the contribution factor set by *AEMO* under paragraph (j) for *Market Customers*, for whom the *trading amount* is not calculated in accordance with the formula in subparagraph (1) for the *region* or *regions* relevant to the *regulating raise service* or the *regulating lower service*;
AMPF (a number)	=	the aggregate of the MPF figures for all

		Market Participants for the *trading interval* for the *region* or *regions* relevant to the *regulating raise service* or *regulating lower service*;
TCE (in MWh)	=	the *customer energy* for the *Market Customer* for the *trading interval* in the *region* or *regions* relevant to the *regulating raise service* or *regulating lower service*; and
ATCE (in MWh)	=	the aggregate of the *customer energy* figures for all *Market Customers*, for whom the *trading amount* is not calculated in accordance with the formula in subparagraph (1), for the *trading interval* for the *region* or *regions* relevant to that *regulating raise service* or *regulating lower service*.

(j) *AEMO* must determine for the purpose of paragraph (i):

(1) a contribution factor for each *Market Participant*; and

(2) notwithstanding the estimate provided in paragraph (nb), if a *region* has or *regions* have operated asynchronously during the relevant *trading interval*, the contribution factors relevant to the allocation of *regulating raise service* or *regulating lower service* to that *region* or *regions*,

in accordance with the procedure prepared under paragraph (k).

(k) *AEMO* must prepare a procedure for determining contribution factors for use in paragraph (j) and, where *AEMO* considers it appropriate, for use in paragraph (nb), taking into account the following principles:

(1) the contribution factor for a *Market Participant* should reflect the extent to which the *Market Participant* contributed to the need for *regulation services*;

(2) the contribution factor for all *Market Customers* that do not have *metering* to allow their individual contribution to the aggregate need for *regulation services* to be assessed must be equal;

(3) for the purpose of paragraph (j)(2), the contribution factor determined for a group of *regions* for all *Market Customers* that do not have *metering* to allow the individual contribution of that *Market Customer* to the aggregate need for *regulation services* to be assessed, must be divided between *regions* in proportion to the total *customer energy* for the *regions*;

(4) the individual *Market Participant's* contribution to the aggregate need for *regulation services* will be determined over a period of time to be determined by *AEMO*;

(5) a *Registered Participant* which has classified a *scheduled generating unit*, *scheduled load*, *ancillary service generating unit* or *ancillary*

service load (called a **Scheduled Participant**) will not be assessed as contributing to the deviation in the *frequency* of the *power system* if within a *trading interval*:

(i) the Scheduled Participant achieves its *dispatch* target at a uniform rate;

(ii) the Scheduled Participant is *enabled* to provide a *market ancillary service* and responds to a control signal from *AEMO* to *AEMO's* satisfaction; or

(iii) the Scheduled Participant is not *enabled* to provide a *market ancillary service*, but responds to a need for *regulation services* in a way which tends to reduce the aggregate deviation;

(6) where contributions are aggregated for *regions* that are operating asynchronously during the calculation period under paragraph (i), the contribution factors should be normalised so that the total contributions from any non-synchronised *region* or *regions* is in the same proportion as the total *customer energy* for that *region* or *regions*; and

(7) a *Semi-Scheduled Generator* will not be assessed as contributing to the deviation in the *frequency* of the *power system* if within a *trading interval*, the *semi-scheduled generating unit*:

(i) achieves its *dispatch level* at a uniform rate;

(ii) is *enabled* to provide a *market ancillary service* and responds to a control signal from *AEMO* to *AEMO's* satisfaction; or

(iii) is not *enabled* to provide a *market ancillary service*, but responds to a need for *regulation services*.

(l) *AEMO* may amend the procedure referred to in clause 3.15.6A(j) from time to time.

(m) *AEMO* must comply with the *Rules consultation procedures* when making or amending the procedure referred to in clause 3.15.6A(k).

(n) *AEMO* must *publish*, in accordance with the *timetable*, the historical data used in determining a factor for each *Market Participant* for the purposes of clauses 3.15.6A(h) and (i) in accordance with the procedure contemplated by clause 3.15.6A(k).

(na) Notwithstanding any other provisions of the *Rules*, *AEMO* must *publish* the factors determined in accordance with clause 3.15.6A(j)(1) at least 10 *business days* prior to the application of those factors in accordance with clauses 3.15.6A(h) and 3.15.6A(i).

(nb) When a *region* is or *regions* are operating asynchronously, *AEMO* must *publish* (where appropriate in accordance with the procedure developed under paragraph (k)), an estimate of the contribution factors referred to in paragraph (j)(2) to be applied for information purposes only by *Market Participants* for the duration of the separation.

(o) In this clause 3.15.6A:

(1) '***generator energy***' in respect of a *Market Generator* for a *trading interval* means the sum of the *adjusted gross energy* figures calculated

for that *trading interval* in respect of that *Market Generator's* applicable *connection points*, provided that, if the sum of those figures is negative, then the *Market Generator's generator energy* for that *trading interval* is zero;

(2) a *connection point* is an applicable *connection point* of a *Market Generator* if:

(A) the *Market Generator* is *financially responsible* for the *connection point*; and

(B) the *connection point connects* a *market generating unit* to the *national grid*;

(3) '***customer energy***' in respect of a *Market Customer* for a *trading interval* means the sum of the *adjusted gross energy* figures calculated for that *trading interval* in respect of that *Market Customer's* relevant *connection points*;

(4) a *connection point* is a relevant *connection point* of a *Market Customer* if:

(A) the *Market Customer* is *financially responsible* for the *connection point*; and

(B) the *load* at that *connection point* has been classified (or is deemed to be classified) as a *market load*;

(5) '***small generator energy***' in respect of a *Market Small Generation Aggregator* for a *trading interval* means the sum of the *adjusted gross energy* figures calculated for that *trading interval* in respect of that *Market Small Generation Aggregator's* applicable *connection points*, provided that, if the sum of those figures is negative, then the *Market Small Generation Aggregator's small generator energy* for that *trading interval* is zero; and

(6) a *connection point* is an applicable *connection point* of a *Market Small Generator Aggregator* if:

(A) the *Market Small Generator Aggregator* is *financially responsible* for the *connection point*; and

(B) the *connection point* connects a *market generating unit* that is a *small generating unit* or a *large SAPS generator* ~~classified as a *market generating unit*~~ to the *national grid.*

(p) When *AEMO* dispatches a quantity of *regulating raise service* or *regulating lower service* in addition to the quantity it determines in accordance with the *dispatch algorithm*, *AEMO* must:

(1) for the purposes of paragraphs (f) and (g), include the additional quantity in the cost of *delayed services*; and

(2) for the purposes of paragraphs (h) and (i), exclude the additional quantity in the cost of *regulation services*,

taking into account the requirements in clauses 3.8.1(a) and (b) to maximise the value of *spot market* trading.

3.15.8 Funding of Compensation for directions

(a) *AEMO* must, in accordance with the *intervention settlement timetable*, calculate the *compensation recovery amount* being:

(1) the sum of:

(i) the total of the compensation payable to *AEMO* by *Affected Participants* and *Market Customers* under clause 3.12.2 in respect of a *direction* for the provision of *energy*; plus

(ii) the total of the amounts retained by *AEMO* pursuant to clause 3.15.6(b) in respect of a *direction* for the provision of *energy*;

(2) less the sum of:

(i) the total of the compensation payable by *AEMO* to *Affected Participants* and *Market Customers* pursuant to clause 3.12.2 in respect of a *direction* for the provision of *energy*; plus

(ii) the total of the compensation payable by *AEMO* to *Directed Participants* (other than *Directed Participants* who are also *Market Suspension Compensation Claimants*) pursuant to clause 3.15.7(a) in respect of a *direction* for the provision of *energy*; plus

(iii) the total amount payable by *AEMO* to the independent expert pursuant to clause 3.12.3(c).

(b) *AEMO* must, in accordance with the *intervention settlement timetable*, calculate a figure for each *Market Customer* in each *region* applying the following formula:

$$MCP = \frac{E}{\sum E} \times \frac{RB}{\sum RB} \times CRA$$

where

MCP is the amount payable or receivable by a *Market Customer* pursuant to this clause 3.15.8(b);

E is the sum of the *Market Customer's adjusted gross energy* amounts at each *connection point* for which the *Market Customer* is *financially responsible* in a *region*, determined in accordance with clauses 3.15.4 and 3.15.5 in respect of the relevant *intervention pricing 30-minute periods* excluding any *loads* in respect of which the *Market Customer* submitted a *dispatch bid* for the relevant *intervention pricing 30-minute period* in that *region*; and

RB is the regional benefit determined by *AEMO* pursuant to clause 3.15.8(b1) at the time of issuing the *direction*.

CRA is the *compensation recovery amount*.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(b1) *AEMO* must, as soon as practicable following the issuance of a *direction*, determine the relative benefit each *region* received from the issuance of a *direction* in accordance with the *regional benefit directions procedures*.

(b2) *AEMO* must develop in accordance with the *Rules consultation procedures* a procedure to determine the relative benefit each *region* receives from the issuance of a *direction* (the *regional benefit directions procedures*). Such procedures must take into account, where applicable to the reason the *direction* was given, the *load* at risk of not being supplied if the *direction* were not issued or the extent of improvement in available *energy* reserve in the *region*, capability to control *voltage* in the *region*, and capability to control *power system frequency* within the *region* and any other relevant matters.

(c) If the figure calculated for a *Market Customer* under clause 3.15.8(b) is negative, the absolute value of that amount is the amount payable by the *Market Customer* to *AEMO* pursuant to clause 3.15.8(b).

(d) Subject to clause 3.15.22, if the figure calculated for a *Market Customer* under clause 3.15.8(b) is positive, such amount is the amount receivable by the *Market Customer* from *AEMO* pursuant to clause 3.15.8(b), subject to the provisions of clause 3.15.22.

(e) *AEMO* must, in accordance with the *intervention settlement timetable*, calculate for each *ancillary service* the subject of a *direction*, the " ***ancillary service compensation recovery amount***" being:

(1) the sum of:

(i) the total of the compensation payable to *AEMO* by *Affected Participants* and *Market Customers* under clause 3.12.2 in respect of a *direction* for the provision of that *ancillary service*; plus

(ii) the total of the amounts retained by *AEMO* pursuant to clause 3.15.6(b) in respect of a *direction* for the provision of that *ancillary service*;

(2) less the sum of:

(i) the total of the compensation payable by *AEMO* to *Affected Participants* and *Market Customers* pursuant to clause 3.12.2 in respect of a *direction* for the provision of that *ancillary service*; plus

(ii) the total of the compensation payable by *AEMO* to *Directed Participants* pursuant to clause 3.15.7(a) in respect of a *direction* for the provision of that *ancillary service*; plus

(iii) the total amount payable by *AEMO* to the independent expert pursuant to clause 3.12.3(c), if the *direction* the subject of the independent expert's determination was with respect to that *ancillary service*.

(f) The *trading amount* must be calculated as follows:

(1) subject to clause 3.15.8(f)(2) and (3) *AEMO* must use the appropriate formula set out in clause 3.15.6A(c8), (c9), (d), (e), (f), (g), (h) or (i) depending on which *ancillary service* was the subject of the *direction*;

(2) TNSCASP, TSRP, RTCRSP, RTCLSP or TSFCAS (as applicable) in the relevant formula is equal to the *ancillary service compensation recovery amount* for the relevant *ancillary service* in respect of the *direction*; and

(3) if TCE, TGE, TSGE, AGE, ATCE, ATGE, ATSGE or AAGE is used in the relevant formula, then the words 'the *trading interval'* in the definitions of those terms in the formula are to be read as 'all of the *trading intervals* during which the *direction* applied'.

(g) Any compensation payable by *AEMO* under clause 3.12.2 and 3.15.7 not recovered under clauses 3.15.8(b) and 3.15.8(e) must be recovered from *Market Customers*, *Market Generators* and *Market Small Generation Aggregators*. *AEMO* must, in accordance with the *intervention settlement timetable*, calculate a figure for each *Market Customer*, *Market Generator* and *Market Small Generation Aggregator* in each *region* applying the following formula:

$$MCP = \frac{TGE + TSGE - TCE}{RATGE + RATSGE - RATCE} \times \frac{RB}{\Sigma\, RB} \times CRA \ \times -1$$

where:

MCP	=	the amount payable or receivable by a *Market Customer*, *Market Generator* or *Market Small Generation Aggregator* under this clause 3.15.8(g);
TGE	=	the generator energy for the *Market Generator* in that *region* of the relevant *trading interval* for the period of the *direction*;
TSGE	=	the small generator energy for the *Market Small Generation Aggregator* in that *region* of the relevant *trading interval* for the period of the *direction*;
TCE	=	the customer energy for the *Market Customer* in that *region* of the relevant *trading interval* for the period of the *direction*;
RATGE	=	the aggregate of the generator energy for all *Market Generators* in that *region* of the relevant *trading interval* for the period of the *direction*;
RATSGE	=	the aggregate of the small generator energy for all *Market Small Generation Aggregation* in that *region* of the relevant *trading interval* for the period of the *direction*;

RATCE	=	the aggregate of the customer energy for all *Market Customers* in that *region* of the relevant *trading interval* for the period of the *direction*;
RB	=	the regional benefit determined by *AEMO* under clause 3.15.8(b1) at the time of issuing the *direction*; and
CRA	=	the *compensation recovery amount*.

(h) In clause 3.15.8(g):

(1) **customer energy** in respect of a *Market Customer* for a *trading interval* means the sum of the *adjusted gross energy* figures calculated for that *trading interval* in respect of that *Market Customer's* relevant ~~connection points~~*connection points*;

(2) a *connection point* is a "relevant *connection point*~~connection point~~" of a *Market Customer* if:

(i) the *Market Customer* is *financially responsible* for the *connection point*; and

(ii) the *load* at that *connection point* has been classified (or is deemed to be classified) as a *market load*;

(3) **generator energy** in respect of a *Market Generator* for a *trading interval* means the sum of the *adjusted gross energy* figures calculated for that *trading interval* in respect of that *Market Generator's* applicable ~~connection points~~*connection points*, provided that, if the sum of those figures is negative, then the *Market Generator's* generator energy for that *trading interval* is zero;

(4) a *connection point* is an "applicable ~~connection point~~*connection point*" of a *Market Generator* if:

(i) the *Market Generator* is financially responsible for the *connection point*; and

(ii) the *connection point* connects a *market generating unit* to the *national grid*;

(5) **small generator energy** in respect of a *Market Small Generation Aggregator* for a *trading interval* means the sum of the *adjusted gross energy* figures calculated for that *trading interval* in respect of that *Market Small Generation Aggregator's* applicable *connection points* ~~connection points~~, provided that, if the sum of those figures is negative, then the *Market Small Generation Aggregator's* small generator energy for that *trading interval* is zero; and

(6) a *connection point* is an "applicable *connection point*~~connection point~~" of a *Market Small Generation Aggregator* if:

(i) the *Market Small Generation Aggregator* is *financially responsible* for the *connection point*; and

(ii) the *connection point* connects a *market generating unit* that is a *small generating unit* or *large SAPS generator*~~classified as a *market generating unit*~~ to the *national grid*.

3.21 Regulated stand-alone power systems

3.21.1 Application of this Chapter to a regulated SAPS

(a) This Chapter applies in respect of *regulated SAPS*, *SAPS energy*, *SAPS Participants*, *SAPS facilities* and *connection points* in a *regulated SAPS* in the manner provided for in this rule.

(b) The following provisions apply in respect of *regulated SAPS*, *SAPS energy*, *SAPS Participants*, *SAPS facilities* and *connection points* in a *regulated SAPS*:

(1) this rule;

(2) rule 3.3 including the calculation of *outstandings* taking into account *trading amounts* calculated in respect of the sale and purchase of *SAPS energy*;

(3) rule 3.15, including:

(i) the determination of the person who is financially responsible for a *market connection point* in a *regulated SAPS* in accordance with clause 3.15.3;

(ii) in accordance with clause 3.15.6, *spot market transactions* for *connection points* in a *regulated SAPS* for which a *Market Participant* is *financially responsible*;

Note

The amount of the *spot market* transaction is offset by the adjustment calculated under paragraph 3.21.3.

(iii) *ancillary services* transactions under clause 3.15.6A;

(iv) funding of compensation costs under clause 3.15.8;

(v) funding of the *market suspension compensation recovery amount* under clause 3.15.8A;

(vi) fees to fund *reserves* under clause 3.15.9;

(vii) administered price cap or administered floor price compensation payments under clause 3.15.10;

(viii) funding of restriction shortfall amounts under clause 3.15.10B; and

(ix) funding of market shortfalls or receipt of market surpluses under clause 3.15.23;

Note

Under Chapter 4A, procurer of last resort cost allocation (provided for under clause 3.15.9A) does not take into account *SAPS energy*.

(4) the participant compensation fund arrangements in rule 3.16; and

(5) the arrangements in rule 3.19 for access to the *market management*

systems.

(c) For the purposes of paragraph (b)(3) and rule 3.15:

(1) where a calculation under rule 3.15 requires the *adjusted gross energy* figures in respect of a *SAPS Participant*'s *connection points* located in a *region* to be determined, the *adjusted gross energy* figures for *connection points* in a *regulated SAPS* located in the *region* are to be treated as a *connection point* located in the *region*; and

(2) when calculating UFE for a *local area* under clause 3.15.5(a), the *adjusted gross energy* figures for *connection points* in a *regulated SAPS* in the *local area* must not be included.

(d) Except as provided for in this clause, this Chapter does not apply in respect of a *regulated SAPS, SAPS energy, SAPS Participants, SAPS facilities* or *connection points* in a *regulated SAPS.*

(e) Without limiting paragraph (d):

(1) a *SAPS Participant* must not participate in respect of any *SAPS facility* in the central *dispatch* process administered by *AEMO* under this Chapter nor (except in relation to *settlements* as provide for in this rule and rule 3.15) the *spot market*;

(2) the arrangements for determination of *distribution loss factors* under clause 3.6.3 and the assignment of *connection points* to *transmission network connection points* or *virtual transmission nodes* under clause 3.6.3 do not apply in relation to a *connection point* in a *regulated SAPS;* and

(3) the matters provided for in rules 3.6, 3.7, 3.8, 3.9, 3.10, 3.11, 3.12, 3.12A, 3.13 and 3.14, 3.18 and 3.20 do not apply in respect of *regulated SAPS, SAPS energy, SAPS Participants, SAPS facilities* or *connection points* in a *regulated SAPS.*

3.21.2 Determination of the SAPS settlement price

(a) The *SAPS settlement price* for a *regional reference node* for a *financial year* is equal to 80% of the average *regional reference price* for the *regional reference node* for the prior *financial year.*

(b) For paragraph (a), the average is calculated by adding the *regional reference prices* for the node for all *trading intervals* in the prior *financial year* and dividing by the number of *trading intervals* in the *financial year.*

(c) *AEMO* must as soon as practicable after the start of a *financial year* determine and *publish* the *SAPS settlement price* for each *regional reference node* for the *financial year.*

3.21.3 SAPS adjustment transaction trading amount

(a) In each *trading interval*, in relation to each *connection point* in a *regulated SAPS* for which a *SAPS Participant* is *financially responsible*, a *SAPS adjustment transaction* occurs, which results in a *trading amount* for that *SAPS Participant* determined in accordance with the formula:

$$TA = (AGE \times SAPSP) - (AGE \times RRP)$$

where:

TA	=	the *trading amount* to be determined (which will be a positive or negative dollar amount for each *trading interval*);
AGE	=	AGE is the *adjusted gross energy* for that *connection point* for that *trading interval*, expressed in MWh;
SAPSP	=	the *SAPS settlement price* for the *financial year* in which the *trading interval* falls and the *regional reference node* for the *region* in which the *regulated stand-alone power system* is located expressed in dollars per MWh; and
RRP	=	the *regional reference price* for the *regional reference node* for the *region* in which the *regulated stand-alone power system* is located, expressed in dollars per MWh.

(b) A *trading amount* for a *SAPS adjustment transaction* for a *trading interval* must be included in *settlement* under clause 3.15.

CHAPTER 4

Important note: This is a modified version of version 124 of Chapter 4 of the Rules. It incorporates changes made by the following Rules:

1 Schedule 2 of the *National Electricity Amendment (Register of distributed energy resources) Rule 2018 No 9* coming into effect on 1 December 2019.

2 Schedule 1 of the *National Electricity Amendment (Monitoring and reporting on frequency control framework) Rule 2019 No. 6* coming into effect on 1 January 2020.

3 Schedule 1 of the *National Electricity Amendment (Enhancement to the Reliability and Emergency Reserve Trader) Rule 2019 No. 3* coming into effect on 26 March 2020.

4 Schedule 2 of the *National Electricity Amendment (Five minute settlement) Rule 2017 No.15* coming into effect on 1 July 2021.

This version does not include any changes made by Rules made after 22 October 2019.

4. Power System Security

4.1 Introduction

4.1.1 Purpose

(a) This Chapter:

(1) provides the framework for achieving and maintaining a secure *power system*;

(2) provides the conditions under which *AEMO* can intervene in the processes of the *spot market* and issue *directions* to *Registered Participants* so as to maintain or re-establish a secure and reliable *power system*;

(3) has the following aims:

(i) to detail the principles and guidelines for achieving and maintaining *power system security*;

(ii) to establish the processes for the assessment of the adequacy of *power system* reserves;

(iii) to establish processes to enable *AEMO* to plan and conduct operations within the *power system* to achieve and maintain *power system security*; and

(iv) to establish processes for the actual *dispatch* of *scheduled generating units*, *semi-scheduled generating units*, *scheduled loads*, *scheduled network services* and *ancillary services* by *AEMO* and for *AEMO* to *enable inertia network services* or *system strength services*.

(b) By virtue of this Chapter and the *National Electricity Law*, *AEMO* has responsibility to maintain and improve *power system security*. This Chapter also requires the *Jurisdictional System Security Coordinator* for each *participating jurisdiction* to advise *AEMO* of the requirements of the *participating jurisdiction* regarding *sensitive loads* and priority of *load shedding* and requires *AEMO* to provide copies of the relevant *load shedding procedures* and *EFCS settings schedules* to the *Jurisdictional System Security Coordinator*.

4.1.2 Application to a regulated SAPS

This Chapter does not apply to or in respect of a *regulated SAPS*.

Note

Under section 109A of the Law, *AEMO's* power system security functions and obligations only extend to a *regulated SAPS* or a sensitive load supplied by means of a *regulated SAPS* to the extent provided for in the *Rules*.

CHAPTER 4A

4A Retailer Reliability Obligation

Part A Introduction

4A.A Definitions

4A.A.4 Peak demand

(a) For the purposes of section 14C of the *National Electricity Law*, the maximum electricity demanded is the highest actual demand in a *trading interval* in a *region* (in MW).

Note

Section 14C of the *National Electricity Law* states the peak demand, for a period in a *region*, means the maximum electricity demanded, in megawatts, in the region during the period, determined in accordance with the *Rules*.

(b) The actual demand for a *region* for a *trading interval* is:

(1) the demand for that *region* (excluding demand in a *regulated SAPS*);

(2) adjusted, to reflect what would have been the demand but for the following adjustments in the *market*:

(i) directions by *AEMO*;

(ii) *RERT activated* or *dispatched* by *AEMO*;

(iii) *load shedding* by *AEMO*; and

(iv) any other adjustments as set out in the *Reliability Forecast Guidelines*,

in each case as determined in accordance with the *Reliability Forecast Guidelines*.

(c) *AEMO* must publish the actual demand for a *trading interval* for all *regions* on its website as soon as practicable after the end of that *trading interval*.

Part D Liable Entities

4A.D.1 Application

This Part D applies in relation to each T-1 reliability instrument and a reference to:

(a) a matter is a reference to the matter for the *region* to which the T-1 reliability instrument applies;

(b) a *connection point* is a reference to a *connection point* in that *region*, but does not include a reference to a *connection point* in a *regulated SAPS*;

(c) a *reliability gap period* is a reference to that period stated in that T-1 reliability instrument;

(d) a T-3 reliability instrument is to be construed as a reference to the T-3 reliability instrument related to the T-1 reliability instrument (and vice versa); and

(e) a position day, opt-in cut-off day or opt-in register is a reference to those matters as stated in, or related to, that T-1 reliability instrument.

Part F Compliance with the Retailer Reliability Obligation

Division 1 Application

4A.F.1 Application

(a) This Part F applies in respect of a *region* if a T-1 reliability instrument has been made by the *AER* for that *region*.

(b) This Part F applies in relation to each T-1 reliability instrument and a reference to:

(1) a matter is a reference to the matter for the *region* to which the T-1 reliability instrument applies;

(2) a *reliability gap period*, gap trading interval and one-in-two year peak demand forecast, is a reference to those matters as stated in that T-1 reliability instrument; and

(3) a compliance TI or *PoLR TI* is a reference to those intervals which occur during the *reliability gap period* the subject of the T-1 instrument.

(c) In this Part F (other than this paragraph):

(1) a reference to a *connection point* does not include a reference to a *connection point* in a *regulated SAPS*; and

(2) the *adjusted gross energy* at a *connection point* in a *regulated SAPS* must not be taken into account in determining liable load for a compliance TI.

CHAPTER 5

Important note

This is a modified version of version 124 of Chapter 5 of the Rules. It incorporates changes made by the following Rules:

1 Schedule 2 of the National Electricity Amendment (Register of distributed energy resources) Rule 2018 No 9 which came into effect on 1 December 2019.

2 Schedule 1 of the National Electricity Amendment (Minor changes) Rule 2019 No 9 which came into effect on 21 November 2019.

3 Schedule 2 of the National Electricity Amendment (Transparency of new projects) Rule 2019 No 8 which came into effect on 1 December 2019.

This version <u>does not include</u> any changes made by Rules made after 25 November 2019.

5. Network Connection Access, Planning and Expansion

Part A Introduction

5.1 Introduction to Chapter 5

5.1.2 Overview of Part B and connection and access under the Rules

(a) Rule 5.1A sets out the purpose, application and principles for Part B.

(b) Rule 5.2 sets out the obligations of *Registered Participants* under Part B and other relevant Parts of this Chapter 5.

(c) Rule 5.2A sets out obligations and principles relevant to *connection* and access to *transmission networks* and *large dedicated connection assets*. This includes the classification of certain services relating to assets relevant to *connection* as *prescribed transmission services*, *negotiated transmission services* and *non-regulated transmission services*. Rule 5.2A does not apply to the *declared transmission system* of an *adoptive jurisdiction*.

(d) Rules 5.3, 5.3A and 5.3AA and Chapter 5A set out processes by which *Connection Applicants* can negotiate for connection and access to the *national grid* from a *Network Service Provider*. The process applicable will depend on the nature of the application. The table below sets out an overview of the relevant processes:

Connection Applicant	Process
A *Registered Participant* or a person intending to become a *Registered Participant* for a *generating plant connecting* to a *transmission network*	Rule 5.3 applies
A *Registered Participant* or a person intending to become a *Registered Participant* (or a person pursuant to clause 5.1A.1(c)) for a *load connecting* to a *transmission network*	Rule 5.3 applies
A *load connecting* to a *distribution network* where the *Connection Applicant* is a *Registered Participant* or a person intending to become a *Registered Participant* (and is not acting as the agent of a *retail customer*)	Rule 5.3 applies
A *distribution network* (including an *embedded network*) *connecting* to another *distribution network* or to a	Rule 5.3 applies

Connection Applicant	**Process**
transmission network where the *Connection Applicant* is a *Registered Participant*, intending to become a *Registered Participant* or will obtain an exemption from registration	
A *Market Network Service Provider* or person intending to register as one seeking *connection* to a *distribution network* or a *transmission network*	Rule 5.3 applies
An *embedded generating unit connecting* to a *distribution network* where the *Connection Applicant* is a *Registered Participant* or a person intending to become a *Registered Participant*	Rules 5.3 and 5.3A apply (see clause 5.3.1A for the interaction between the two rules)
A non-registered embedded generator who makes an election for rule 5.3A to apply instead of Chapter 5A	Rules 5.3 and 5.3A apply (see clause 5.3.1A for the interaction between the two rules) The election is not available where *connecting* to a *regulated SAPS*
A *Generator* wishing to alter a *connected generating plant* in the circumstances set out in clause 5.3.9	Clause 5.3.9 applies
A *Connection Applicant* for *prescribed transmission services* or *negotiated transmission services* that do not require the establishment or modification of a *connection* or alteration of a *connected generating plant* in the circumstances set out in clause 5.3.9	Rule 5.3 applies as modified by clause 5.2A.3(c)
An *Embedded Generator* or *Market Network Service Provider* applying for *distribution network user access*	Rule 5.3 or 5.3A (as applicable) and rule 5.3AA apply
A *load* or *generating plant connecting* to a *declared shared network*	Rule 5.3 as modified by clause 5.1A.1(d) to (g) and rule 5.3B apply
A *load connecting* to a *distribution network* where the *Connection Applicant* is not a *Registered Participant* and is not intending to	Chapter 5A applies

Connection Applicant	Process
become a *Registered Participant* (unless it is acting as the agent of a *retail customer*) Any *load connecting* to a *regulated SAPS* A non-registered embedded generator who does not make an election for Rule 5.3A to apply instead of Chapter 5A or is *connecting* to a *regulated SAPS*	
A *retail customer* (or a *retailer* on behalf of that customer) *connecting* a micro embedded generator to a *distribution network*	Chapter 5A applies

(e) In addition to the rules referred to in paragraph (d), in relation to *connection* and access to a *distribution network*:

(1) a *Distribution Network Service Provider* must comply with its *negotiating framework* and *Negotiated Distribution Service Criteria* when *negotiating the terms and conditions of access* to *negotiated distribution services*;

(2) disputes relating to the *terms and conditions of access* to a *direct control service* or to a *negotiated distribution service*, *access charges* or matters referred to in clause 5.3AA(f) (*negotiated use of system charges*) or 5.3AA(h) (avoided charges for the locational component of *prescribed TUOS services*) may be referred to the *AER* in accordance with Part L of Chapter 6;

(3) Part G of Chapter 5A provides for dispute resolution by the *AER* for certain disputes under Chapter 5A; and

(4) other disputes relating to *connection* and access may be subject to dispute resolution under rule 8.2.

(f) In addition to the rules referred to in paragraph (d), in relation to *connection* and access to a *transmission network*:

(1) schedule 5.11 sets out the negotiating principles which apply to negotiations between a *Transmission Network Service Provider* and a *Connection Applicant* for *negotiated transmission services*;

(2) rule 5.4 provides a framework for *Connection Applicants* and *Transmission Network Service Providers* to appoint an *Independent Engineer* to provide advice on certain technical matters; and

(3) rule 5.5 provides for commercial arbitration of disputes between a *Transmission Network Service Provider* and a *Connection Applicant* as to *terms and conditions of access* for the provision of *prescribed*

transmission services or for the provision of *negotiated transmission services*.

(g) Part B also provides for a *Dedicated Connection Asset Service Provider* to have an *access policy* for a *large dedicated connection asset* and for *commercial arbitration* under rule 5.5 to apply to a *large DCA services access dispute*.

5.1.3 Application to a connection to a regulated SAPS

The following provisions do not apply to or in respect of a *connection* or proposed *connection* to a *regulated SAPS*:

(a) rules 5.3 and 5.3A; and

(b) Part C.

Part B Network Connection and Access

5.2 Obligations

5.2.3 Obligations of network service providers

(a) To be registered by *AEMO* as a *Network Service Provider*, a person must satisfy the relevant requirements specified in Chapter 2 and submit an application to *AEMO* in such form as *AEMO* may require.

(b) A *Network Service Provider* must comply with the *power system* performance and quality of *supply* standards:

(1) described in schedule 5.1;

(2) in accordance with any *connection agreement* with a *Registered Participant*,

and if there is an inconsistency between schedule 5.1 and such a *connection agreement*:

(3) if compliance with the relevant provision of the *connection agreement* would adversely affect the quality or security of *network service* to other *Network Users*, schedule 5.1 is to prevail;

(4) otherwise the *connection agreement* is to prevail.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(c) Where the provisions of the *connection agreement* vary the technical requirements set out in the schedules to this Chapter, the relevant *Network Service Provider* must report on such variations to *AEMO* on an annual basis. *AEMO* must allow access to such information to all other *Network Service Providers* and the *Network Service Providers* must keep such information confidential.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(d) A *Network Service Provider* must:

(1) review and process *applications to connect* or modify a *connection* which are submitted to it and must enter into a *connection agreement* with each *Registered Participant* and any other person to which it has provided a *connection* in accordance with rules 5.3 or 5.3A (as is relevant) to the extent that the *connection point* relates to its part of the *national grid*;

(1A) co-operate with any other *Network Service Provider* who is processing a *connection* enquiry or *application to connect* to allow that *connection* enquiry or *application to connect* to be processed expeditiously and in accordance with rules 5.3 or 5.3A (as is relevant);

(2) ensure that, to the extent that a *connection point* relates to its part of the *national grid*, every arrangement for *connection* with a *Registered Participant* or any other arrangement involving a *connection agreement* with that *Network Service Provider* complies with all relevant provisions of the *Rules*;

(3) co-ordinate the design aspects of equipment proposed to be *connected* to its *networks* with those of other *Network Service Providers* in accordance with rule 5.6 in order to seek to achieve *power system* performance requirements in accordance with schedule 5.1;

(4) together with other *Network Service Providers*, arrange for and participate in planning and development of their *networks* and *connection points* on or with those *networks* in accordance with Part D of Chapter 5;

(5) permit and participate in inspection and testing of *facilities* and equipment in accordance with rule 5.7;

(6) permit and participate in commissioning of *facilities* and equipment which are to be *connected* to its *network* in accordance with rule 5.8;

(7) advise a *Registered Participant* or other person with whom there is a *connection agreement* upon request of any expected interruption characteristics at a *connection point* on or with its *network* so that the *Registered Participant* or other person may make alternative arrangements for *supply* during such interruptions, including negotiating for an alternative or backup *connection*;

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(8) use its reasonable endeavours to ensure that modelling data used for planning, design and operational purposes is complete and accurate and order tests in accordance with rule 5.7 where there are reasonable grounds to question the validity of data;

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(9) provide to *AEMO* and other *Network Service Providers* all data available to it and reasonably required for modelling the static and *dynamic performance* of the *power system*;

(10) forward to *AEMO* and other *Network Service Providers* subsequent updates of the data referred to in subparagraph (9) and, to the best of its ability and knowledge, ensure that all data used for the purposes referred to in rules 5.3 or 5.3A (as is relevant) is consistent with data used for such purposes by other *Network Service Providers*;

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(11) provide to *AEMO* the information required from *Generators* under schedule 5.2 and from *Customers* under schedule 5.3 and from *Market Network Service Providers* under schedule 5.3a in relation to a *connection agreement* and details of any *connection points* with other *Network Service Providers*; and

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(12) where *network augmentations*, setting changes or other technical issues arise which could impact across *regional* boundaries, provide *AEMO* with a written report on the impact and its effects.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(e) A *Network Service Provider* (including a *Dedicated Connection Asset Service Provider*) must arrange for operation of that part of the interconnected national electricity system ~~*national grid*~~ over which it has control in accordance with instructions given by *AEMO*.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(e1) A *Network Service Provider* must, except in so far as its *market network services* and parts of its *network* which are used solely for the provision of *market network services* are concerned, arrange for:

(1) management, maintenance and operation of its part of the *national grid* such that, in the *satisfactory operating state*, electricity may be transferred continuously at a *connection point* on or with its *network* up to the *agreed capability*;

(2) operation of its *network* such that the fault level at any *connection point* on or with that *network* does not breach the limits that have been specified in a *connection agreement*;

(3) management, maintenance and operation of its *network* to minimise the number of interruptions to *agreed capability* at a *connection point* on or with that *network* by using *good electricity industry practice*; and

(4) restoration of the *agreed capability* at a *connection point* on or with that *network* as soon as reasonably practicable following any interruption at that *connection point*.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(f) A *Network Service Provider* must comply with *applicable regulatory instruments*.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(g) Each *Network Service Provider* must in respect of new or altered equipment owned, operated or controlled by it for the purpose of providing a *market network service*:

(1) submit an *application to connect* and enter into a *connection agreement* with a *Network Service Provider* in accordance with rule 5.3 prior to that equipment being connected to the *network* of that *Network Service Provider* or altered (as the case may be);

(2) comply with the reasonable requirements of *AEMO* and the relevant *Network Service Provider* in respect of design requirements of equipment proposed to be *connected* to the *network* of that *Network Service Provider* in accordance with rule 5.6 and schedule 5.3a;

(3) provide forecast information to the relevant *Network Service Provider* in accordance with Part D of Chapter 5;

(4) permit and participate in inspection and testing of *facilities* and equipment in accordance with rule 5.7;

(5) permit and participate in commissioning of *facilities* and equipment which are to be *connected* to a *network* for the first time in accordance with rule 5.8; and

(6) **[Deleted]**

(7) give notice of intended voluntary permanent *disconnection* in accordance with rule 5.9.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(g1) A *Network Service Provider* must comply with any terms and conditions of a *connection agreement* for its *market network service facilities* that provide for the implementation, operation, maintenance or performance of a *system strength remediation scheme*.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(h) **[Deleted]**

(h1) **[Deleted]**

(h2) **[Deleted]**

(h3) **[Deleted]**

(i) This Chapter is neither intended to require, nor is it to be read or construed as having the effect of requiring, a *Network Service Provider* to permit *connection* to or to *augment* any part of its *network* which is solely used for the provision of *market network services*.

(j) If in *AEMO*'s reasonable opinion, there is a risk a *Network Service Provider*'s *plant* or equipment will:

(1) adversely affect *network capability*, *power system security*, quality or reliability of *supply*, *inter-regional power transfer capability*;

(2) adversely affect the use of a *network* by a *Network User*; or

(3) have an *adverse system strength impact*,

AEMO may request the *Network Service Provider* to provide information of the type described in clause 4.3.4(o), and following such a request, the *Network Service Provider* must provide the information to *AEMO* and any other relevant *Network Service Provider*(s) in accordance with the requirements and circumstances specified in the *Power System Model Guidelines*, the *Power System Design Data Sheet* and the *Power System Setting Data Sheet*.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(k) If in *AEMO*'s reasonable opinion, information of the type described in clause 4.3.4(o) is required to enable a *Network Service Provider* to conduct the assessment required by clause 5.3.4B, *AEMO* may request any other relevant *Network Service Provider* to provide the information, and following such a request, that *Network Service Provider* must provide the information to *AEMO* and the other relevant *Network Service Provider*.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(l) All information provided to *AEMO* and the relevant *Network Service Provider*(s) under paragraphs (j) and (k) must be treated as *confidential information* by those recipients.

5.3A Establishing or modifying connection - embedded generation

5.3A.2 Definitions and miscellaneous

(a) In this rule 5.3A and Schedules 5.4A and 5.4B:

detailed response means the response to a *connection* enquiry prepared under clause 5.3A.8.

establish a connection has the same meaning as in clause 5.3.1.

information pack means information relevant to the making of an *application to connect* specified in clause 5.3A.3(b).

preliminary response means the response to a *connection* enquiry prepared under clause 5.3A.7.

sub-transmission line has the same meaning as in clause 5.10.2.

zone substation has the same meaning as in clause 5.10.2.

(b) To the extent a *Distribution Network Service Provider* has provided information required to be provided under this clause 5.3A by the inclusion of that information in:

(1) its industry engagement document~~demand side engagement document~~ under clause 5.13.1(g); or

(2) a *Distribution Annual Planning Report*,

it will comply with the relevant information provision requirements of rule 5.3A by including hyperlinks to the relevant information in information provided to a *Connection Applicant*.

(c) Where this rule 5.3A fixes a time limit for the provision of information or a response then, for the purposes of calculating elapsed time, the period that:

(1) commences on the day when a dispute is initiated under clause 8.2.4(a); and

(2) ends on the day on which the dispute is withdrawn or is resolved in accordance with clauses 8.2.6D or 8.2.9(a),

is to be disregarded.

Part D Network Planning and Expansion

5.10 Network development generally

5.10.1 Content of Part D

(a) Clause 5.10.2 sets out local definitions used in Part D.

(b) Clause 5.11.1 sets out obligations regarding forecasts for connection points to the *transmission network*.

(c) Clause 5.11.2 sets out the obligations of *Network Service Providers* relating to the identification of network limitations.

(d) Clause 5.12 sets out planning and reporting obligations for *Transmission Network Service Providers*.

(e) Clause 5.13 sets out planning and reporting obligations for *Distribution Network Service Providers*.

(e1) Clause 5.13A sets out the obligations to provide distribution zone substation information.

(f) Clause 5.14 sets out joint planning obligations of *Network Service Providers*.

(f1) Rule 5.14B relates to guidelines for *Transmission Annual Planning Reports*.

(g) Clause 5.15 relates to regulatory investment tests generally.

(h) Clause 5.16 relates to the *regulatory investment test for transmission*.

(i) Clause 5.17 relates the *regulatory investment test for distribution*.

(j) Clause 5.18 relates to the construction of *funded augmentations*.

(j1) Rule 5.18A sets out the obligations of *Transmission Network Service Providers* in relation to a register of large generator connections.

(j2) Rule 5.18B sets out obligations of *Distribution Network Service Providers* in relation to completed embedded generation projects.

Note:

Rule 5.18B commence<u>d</u>~~s~~ operation on 1 July 2018 when clause 5.4.5 <u>was</u>~~is~~ renumbered as rule 5.18B under the National Electricity Amendment (Transmission Connection and Planning Arrangements) Rule 2017 No. 4

(k) Clause 5.19 relates to Scale Efficient Network Extensions.

(l) Clause 5.20 relates to *AEMO's* National Transmission Planning responsibilities.

(m) Clause 5.20A relates to *power system frequency* management planning.

(m1) Clause 5.20B sets out the process for identifying and providing the *inertia requirements* for *inertia sub-networks*.

(m2) Clause 5.20C sets out the process for identifying and providing the *system strength requirements* for each *region*.

(n) Clause 5.21 sets out *AEMO's* obligations to *publish* information and guidelines and provide advice regarding network development.

(o) Clause 5.22 relates to the *AEMC's last resort planning powers*.

5.10.2 Definitions

In this Part D and schedules 5.8, 5.9 and 5.4A:

<u>**adoptive SAPS jurisdiction** has the meaning in the *National Electricity Law*.</u>

<u>**adoptive SAPS network** means a *distribution network* in an adoptive SAPS jurisdiction in respect of which the law of the adoptive SAPS jurisdiction permits *regulated stand-alone power systems*;</u>

affected network user means, in relation to a proposal to undertake a *DNSP-led SAPS project*:

(a) each person supplied with a *distribution service* by means of the *network* that will form part of the *regulated SAPS*;

(b) each landowner for land on which is situated premises supplied by means of the *network* that will form part of the *regulated SAPS*.

asset management means the development and implementation of plans and processes, encompassing management, financial, consumer, engineering, information technology and other business inputs to ensure assets achieve the expected level of performance and minimise costs to consumers over the expected life cycle of the assets.

cost threshold means a cost threshold specified in clause 5.15.3(b) or 5.15.3(d) (as relevant).

cost threshold determination means a final determination under clause 5.15.3(i).

cost threshold review means a review conducted under clause 5.15.3(e).

credible option has the meaning given to it in clause 5.15.2(a).

~~**demand side engagement document** means the document *published* by the *Distribution Network Service Provider* under clause 5.13.1(g).~~

~~**demand side engagement register** means a facility by which a person can register with a *Distribution Network Service Provider* their interest in being notified of developments relating to *distribution network* planning and expansion.~~

~~**demand side engagement strategy** means the strategy developed by a *Distribution Network Service Provider* under clause 5.13.1(e) and described in its demand side engagement document.~~

de-rate means, in respect of a *Network Service Provider*, a reduction in the *network capability* of a *network element* in the *network* of that *Network Service Provider*.

design fault level means the maximum level of fault current that a *facility* can sustain while maintaining operation at an acceptable *performance standard*.

dispute notice has the meaning given in clause 5.16.5(c)(1) and 5.17.5(c)(1).

disputing party has the meaning given in clause 5.16.5(c) and 5.17.5(c).

distribution asset means the apparatus, equipment and plant, including *distribution lines*, *substations* and sub-transmission lines, of a *distribution system*.

draft project assessment report means the report prepared under clause 5.17.4(i).

final project assessment report means the report prepared under clauses 5.17.4(o) or (p).

firm delivery capacity means the maximum allowable output or load of a *network* or *facility* under *single contingency* conditions, including any short term overload capacity having regard to external factors, such as ambient temperature, that may affect the capacity of the *network* or *facility*.

forward planning period means the period determined by the *Distribution Network Service Provider* under clause 5.13.1(a)(1).

industry engagement document means the document *published* by the *Distribution Network Service Provider* under clause 5.13.1(g).

industry engagement register means a facility by which a person can register with a *Distribution Network Service Provider* their interest in being notified of developments relating to *distribution network* planning and expansion.

industry engagement strategy means the strategy developed by a *Distribution Network Service Provider* under clause 5.13.1(e) and described in its industry engagement document.

joint planning project means a project the purpose of which is to address a need identified under clause 5.14.1(d)(3) or clause 5.14.2(a) or clause 5.14.3(a).

landowner means, in relation to an area of land, each person who is an owner or lessee of the land.

load transfer capacity means meeting the *load* requirements for a *connection point* by the reduction of *load* or group of *loads* at the *connection point* and increasing the *load* or group of *loads* at a different *connection point*.

~~**non-network options report** means the report prepared under clause 5.17.4(b).~~

non-network provider means a person who provides *non-network options* or *SAPS support services*.

normal cyclic rating means the normal level of allowable *load* on a primary distribution feeder having regard to external factors, such as ambient temperature and wind speed, that may affect the capacity of the primary distribution feeder.

options screening report means the report prepared under clause 5.17.4(b).

potential credible option means an option which a RIT-D proponent or RIT-T proponent (as the case may be) reasonably considers has the potential to be a credible option based on its initial assessment of the *identified need*.

potential transmission project means investment in a transmission asset of a *Transmission Network Service Provider* which:

(a) is an *augmentation*; and

(b) has an estimated capital cost in excess of $5 million (as varied in accordance with a cost threshold determination); and

(c) the person who identifies the project considers is likely, if constructed, to relieve forecast constraints in respect of *national transmission flow paths* between *regional reference nodes*.

preferred option has the meaning given in clause 5.16.1(b) and 5.17.1(b).

primary distribution feeder means a *distribution line* connecting a sub-transmission asset to either other *distribution lines* that are not sub-transmission lines, or to distribution assets that are not sub-transmission assets.

project assessment conclusions report means the report prepared under clause 5.16.4(t) or (u).

project assessment draft report means the report prepared under clause 5.16.4(j).

project specification consultation report means the report prepared under clause 5.16.4(b).

protected event EFCS investment means investment by a *Transmission Network Service Provider* or a *Distribution Network Service Provider* for the purposes of installing or modifying an *emergency frequency control scheme* applicable in respect of the *Network Service Provider's transmission or distribution system* in accordance with a *protected event EFCS standard*.

reconfiguration investment has the meaning given to it in clause 5.16.3(a)(5).

regulatory investment test for distribution application guidelines means the guidelines developed and *published* by the *AER* in accordance with clause 5.17.2 as in force from time to time, and include amendments made in accordance with clause 5.17.2(e).

regulatory investment test for transmission application guidelines means the guidelines developed and *published* by the *AER* in accordance with clause 5.16.2 as in force from time to time, and include amendments made in accordance with clause 5.16.2(e).

reliability corrective action means investment by a *Transmission Network Service Provider* or a *Distribution Network Service Provider* in respect of its *transmission network* or *distribution network* for the purpose of meeting the service standards linked to the technical requirements of schedule 5.1 or in *applicable regulatory instruments* and which may consist of *network options* or *non-network options*.

RIT-D project means:

(a) a project the purpose of which is to address an *identified need* identified by a *Distribution Network Service Provider*; or

(b) a joint planning project that is not a RIT-T project.

RIT-D proponent means the *Network Service Provider* applying the *regulatory investment test for distribution* to a RIT-D project to address an *identified need*. The RIT-D proponent may be:

(a) if the *identified need* is identified during joint planning under clause 5.14.1(d)(3), a *Distribution Network Service Provider* or a *Transmission Network Service Provider*; or

(b) in any other case, a *Distribution Network Service Provider*.

RIT-T project means:

(a) a project the purpose of which is to address an *identified need* identified by a *Transmission Network Service Provider*; or

(b) a joint planning project if:

    (1) at least one potential credible option to address the *identified need* includes investment in a *network* or *non-network option* on a *transmission network* (other than *dual function assets*) with an estimated capital cost greater than the cost threshold that applies under clause 5.16.3(a)(2); or

    (2) the *Network Service Providers* affected by the joint planning project have agreed that the *regulatory investment test for transmission* should be applied to the project.

RIT-T proponent means the *Network Service Provider* applying the *regulatory investment test for transmission* to a RIT-T project to address an *identified need*. The RIT-T proponent may be:

(a) if the *identified need* is identified during joint planning under clause 5.14.1(d)(3), a *Distribution Network Service Provider* or a *Transmission Network Service Provider*; or

(b) in any other case (including under clause 5.14.3(a)), a *Transmission Network Service Provider*.

SAPS customer engagement document means the document *published* by the *Distribution Network Service Provider* under clause 5.13.4(b).

SAPS customer engagement objectives means the following objectives:

(a) providing relevant and timely information about *DNSP-led SAPS projects* and SAPS customer engagement strategies and processes; and

(b) engaging in timely and effective communications and other engagement with affected network users and landowners during the planning, development, construction and commissioning of a *DNSP-led SAPS project*.

SAPS customer engagement strategy means the strategy developed by a *Distribution Network Service Provider* under clause 5.13.4(a) and described in its SAPS customer engagement document.

sub-transmission means any part of the *power system* which operates to deliver electricity from the *transmission system* to the *distribution network* and which may form part of the *distribution network*, including zone substations.

sub-transmission line means a power line connecting a sub-transmission asset to either the *transmission system* or another sub-transmission asset.

system limitation means a limitation identified by a *Distribution Network Service Provider* under clause 5.13.1(d)(2).

system limitation template means a template developed and *published* by the *AER* under clause 5.13.3(a).

TAPR Guidelines means the guidelines *published* by the *AER* under clause 5.14B.1.

total capacity means the theoretical maximum allowable output or *load* of a *network* or *facility* with all network components and equipment intact.

transmission asset means the apparatus, equipment and plant, including *transmission lines* and *substations* of a *transmission system*.

transmission-distribution connection point means:

(a) subject to paragraph (b), the agreed point of supply established between a *transmission network* and a *distribution network*;

(b) in relation to the *declared transmission system* of an *adoptive jurisdiction*, the agreed point of supply between the transmission assets of the *declared transmission system operator* and a *distribution network*.

zone substation means a *substation* for the purpose of connecting a *distribution network* to a sub-transmission *network*.

5.13 Distribution annual planning process

5.13.1 Distribution annual planning review

Scope

(a) A *Distribution Network Service Provider* must:

(1) subject to paragraph (b), determine an appropriate forward planning period for its distribution assets; and

(2) analyse the expected future operation of its *network* over the forward planning period in accordance with this clause 5.13.1.

(b) The minimum forward planning period for the purposes of the *distribution* annual planning review is 5 years.

(c) The *distribution* annual planning review must include all assets that would be expected to have a material impact on the *Distribution Network Service Provider's network* over the forward planning period.

Requirements

(d) Each *Distribution Network Service Provider* must, in respect of its *network*:

(1) prepare forecasts covering the forward planning period of *maximum demands* for:

(i) sub-transmission lines;

(ii) zone substations; and

(iii) to the extent practicable, primary distribution feeders,

having regard to:

(iv) the number of customer *connections*;

(v) *energy* consumption; and

(vi) estimated total output of known *embedded generating units*;

(2) identify, based on the outcomes of the forecasts in subparagraph (1), limitations on its *network*, including limitations caused by one or more of the following factors:

(i) forecast *load* exceeding total capacity;

(ii) the requirement for asset refurbishment or replacement;

(iii) the requirement for *power system security* or *reliability* improvement;

(iv) design fault levels being exceeded;

(v) the requirement for *voltage* regulation and other aspects of quality of supply to other *Network Users*; and

(vi) the requirement to meet any *regulatory obligation or requirement*;

(3) identify whether corrective action is required to address any system limitations identified in subparagraph (2) and, if so, identify whether the *Distribution Network Service Provider* is required to:

(i) carry out the requirements of the *regulatory investment test for distribution*; and

(ii) carry out industry engagement obligations ~~demand side engagement obligations~~ as required under paragraph (f); and

(4) take into account any *jurisdictional electricity legislation*.

Industry engagement obligations~~Demand side engagement obligations~~

(e) Each *Distribution Network Service Provider* must develop a strategy for:

(1) engaging with non-network providers; ~~and~~

(2) considering *non-network options*;~~.~~ and

(3) in relation to an adoptive SAPS network, considering *SAPS options.*

(f) A *Distribution Network Service Provider* must engage with non-network providers and consider *non-network options* and *SAPS options* for addressing system limitations in accordance with its industry engagement strategy~~demand side engagement strategy~~.

(g) A *Distribution Network Service Provider* must develop and *publish* an industry engagement document setting out its industry engagement strategy~~demand side engagement strategy in a demand side engagement document which must be *published* by no later than 31 August 2013~~.

(h) A *Distribution Network Service Provider* must include the information specified in schedule 5.9 in its industry engagement document~~demand side engagement document~~.

(i) A *Distribution Network Service Provider* must review and *publish* a revised industry engagement document~~demand side engagement document~~ at least once every three years.

(j) A *Distribution Network Service Provider* must establish and maintain a facility by which parties can register their interest in being notified of developments relating to *distribution network* planning and expansion. A *Distribution Network Service Provider* must have in place a facility under this paragraph (j) no later than the date of publication of the *Distribution Network Service Provider's* industry engagement document~~demand side engagement document~~ under paragraph (g).

5.13.4 Converting network to a regulated SAPS

SAPS customer engagement strategy

(a) A *Distribution Network Service Provider* with an adoptive SAPS network must develop a strategy (**SAPS customer engagement strategy**) for engaging with affected network users in relation to *DNSP-led SAPS projects* being considered by the *Distribution Network Service Provider* in relation to the *network.*

(b) A *Distribution Network Service Provider* must develop and *publish* a SAPS customer engagement document that sets out its SAPS customer engagement strategy.

(c) In developing and amending its SAPS customer engagement document, a *Distribution Network Service Provider* must:

(1) have regard to any guidelines made by the *AER* under paragraph (f) and the SAPS customer engagement objectives;

(2) take into account the obligations of the *Distribution Network Service Provider* under paragraphs (i) to (n); and

(3) take into account obligations under planning and environmental laws that may apply in respect of a *DNSP-led SAPS project*.

(d) A *Distribution Network Service Provider* must review and *publish* a revised SAPS customer engagement document at least once every three years.

(e) A *Distribution Network Service Provider* must engage with affected network users in relation to a *DNSP-led SAPS project* relating to its *network* in accordance with its SAPS customer engagement document.

Note

The AEMC proposes to recommend that this clause be classified as a civil penalty provision.

SAPS customer engagement guidelines

(f) The *AER* may develop and *publish* and may from time to time amend guidelines about engaging with affected network users in relation to *DNSP-led SAPS projects*.

(g) In developing guidelines under paragraph (f), the *AER* may undertake such consultation as it considers appropriate.

(h) The guidelines developed under paragraph (f) may provide guidance on:

(1) the form and content of a SAPS customer engagement document;

(2) the steps to be taken to identify landowners and other persons likely to be affected by a *DNSP-led SAPS project*;

(3) general information to be included in a SAPS customer engagement document about supply by means of a *regulated SAPS*;

(4) information about a proposal to convert a part of a *network* to a *regulated SAPS* to be included in a notice under paragraph (i);

(5) addressing issues raised by affected network users relating to a *DNSP-led SAPS project*; and

(6) other matters the *AER* considers appropriate to promote the SAPS customer engagement objectives.

DNSP-led SAPS notice and consultation

(i) Subject to paragraph (n), a *Distribution Network Service Provider* who is developing a proposal to convert any part of its *network* to a *regulated SAPS* must give notice in accordance with paragraphs (j) to (m) and its SAPS customer engagement document.

Note

The AEMC proposes to recommend that this clause be classified as a civil penalty provision.

(j) A notice under paragraph (i) must be given to:

(1) each person who at the time of giving the notice is supplied with *distribution service* means of the *network* that will form part of the *regulated SAPS*;

(2) subject to paragraph (k), each person who is at the time of giving the notice a landowner for land on which is situated premises supplied by means of the *network* that will form part of the *regulated SAPS*; and

(3) the public in the area in which the *regulated SAPS* will be located.

(k) A notice under paragraph (i) must:

(1) provide reasonably detailed information about the proposal to which it relates;

(2) specify a reasonable period in which to comment on the proposal and explain how comments may be submitted; and

(3) refer to the *Distribution Network Service Provider's* SAPS customer engagement document and identify where it can be found.

(l) The notice to the public under paragraph (j)(3) must be given by way of a notice published in a readily-accessible part of the *Distribution Network Service Provider's* website.

(m) The *Distribution Network Service Provider* must have regard to any comments received in response to a notice given under paragraph (i).

(n) Where a *Distribution Network Service Provider* is developing a proposal to convert any part of its *network* to a *regulated SAPS* in order to address an urgent and unforeseen *network* issue as described in clause 5.17.3(a)(1), the *Distribution Network Service Provider* is not required to give notice under paragraph (i) but must use reasonable endeavours to meet the SAPS customer engagement objectives in relation to the proposal by other means appropriate in the circumstances.

5.14 Joint planning

5.14.1 Joint planning obligations of Transmission Network Service Providers and Distribution Network Service Providers

(a) Subject to paragraphs (b) and (c):

(1) each *Distribution Network Service Provider* must conduct joint planning with each *Transmission Network Service Provider* of the *transmission networks* to which the *Distribution Network Service Provider's networks* are *connected*; and

(2) each *Transmission Network Service Provider* must conduct joint planning with each *Distribution Network Service Provider* of the *distribution networks* to which the *Transmission Network Service Provider's networks* are *connected*.

(b) In the case of the *declared shared network* of an *adoptive jurisdiction*, the relevant *declared transmission system operator*, the relevant *Distribution Network Service Provider*, *AEMO* and any *interested party* that has informed *AEMO* of its interest in the relevant plans, shall conduct joint planning.

(c) For the purposes of this clause 5.14.1, a *Transmission Network Service Provider* does not include a *Network Service Provider* that is a *Transmission Network Service Provider* only because it owns, controls or operates *dual function assets*.

(d) The relevant *Distribution Network Service Provider* and *Transmission Network Service Provider* must:

(1) assess the adequacy of existing *transmission* and *distribution networks* and the assets associated with transmission-distribution connection points over the next five years and to undertake joint planning of projects which relate to both *networks* (including, where relevant, *dual function assets*);

(2) use best endeavours to work together to ensure efficient planning outcomes and to identify the most efficient options to address the needs identified in accordance with subparagraph (4);

(3) identify any limitations or constraints:

(i) that will affect both the *Transmission Network Service Provider's* and *Distribution Network Service Provider's network*; or

(ii) which can only be addressed by corrective action that will require coordination by the *Transmission Network Service Provider* and the *Distribution Network Service Provider*; and

(4) where the need for a joint planning project is identified under subparagraph (3):

(i) jointly determine plans that can be considered by relevant *Registered Participants*, *AEMO*, *interested parties*, and parties registered on the industry engagement register~~demand side engagement register~~ of each *Distribution Network Service Provider* involved in joint planning;

(ii) determine whether the joint planning project is a RIT-T project or a RIT-D project; and

(iii) may agree on a lead party to be responsible for carrying out the *regulatory investment test for transmission* or the *regulatory investment test for distribution* (as the case may be) in respect of the joint planning project.

(e) If a *Network Service Provider*, as the lead party for one or more *Network Service Providers*, undertakes the *regulatory investment test for transmission* or the *regulatory investment test for distribution* (as the case may be) in respect of a joint planning project, the other *Network Service Providers* will be taken to have discharged their obligation to undertake the relevant test in respect of that project.

5.15 Regulatory investment tests generally

5.15.2 Identification of a credible option

(a) A credible option is an option (or group of options) that:

(1) addresses the *identified need*;

(2) is (or are) commercially and technically feasible; and

(3) can be implemented in sufficient time to meet the *identified need*,

and is (or are) identified as a credible option in accordance with this clause~~paragraphs (b) or (d) (as relevant)~~.

(b) In applying the *regulatory investment test for transmission*, the RIT-T proponent must consider, in relation to a RIT-T project other than those described in clauses 5.16.3(a)(1)-(8), all options that could reasonably be classified as credible options taking into account:

(1) energy source;

(2) technology;

(3) ownership;

(4) the extent to which the credible option enables *intra-regional* or *inter-regional* trading of electricity;

(5) whether it is a *network option* or a *non-network option*;

(6) whether the credible option is intended to be regulated;

(7) whether the credible option has a proponent; and

(8) any other factor which the RIT-T proponent reasonably considers should be taken into account.

(c) In applying the *regulatory investment test for distribution*, the RIT-D proponent must consider, in relation to a RIT-D project other than those described in clauses 5.17.3(a)(1)-(7), all options that could reasonably be classified as credible options, without bias as to:

(1) energy source;

(2) technology;

(3) ownership; and

(4) whether it is a *network option*, ~~or~~ a *non-network option* or a *SAPS option*.

(d) The absence of a proponent does not exclude an option from being considered a credible option.

5.17 Regulatory investment test for distribution

5.17.1 Principles

(a) The *AER* must develop and *publish* the *regulatory investment test for distribution* in accordance with the *distribution consultation procedures* and this clause 5.17.1.

(b) The purpose of the *regulatory investment test for distribution* is to identify the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the *National Electricity Market* (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the *identified need* is for reliability corrective action.

(c) The *regulatory investment test for distribution* must:

(1) be based on a cost-benefit analysis that must include an assessment of reasonable scenarios of future supply and demand;

(2) not require a level of analysis that is disproportionate to the scale and likely impact of each of the credible options being considered;

(3) be capable of being applied in a predictable, transparent and consistent manner;

(4) require the RIT-D proponent to consider whether each credible option could deliver the following classes of market benefits:

(i) changes in voluntary *load* curtailment;

(ii) changes in involuntary *load shedding* and *customer* interruptions caused by *network* outages, using a reasonable forecast of the value of electricity to *customers*;

(iii) changes in costs for parties, other than the RIT-D proponent, due to differences in:

(A) the timing of new *plant*;

(B) capital costs; and

(C) the operating and maintenance costs;

(iv) differences in the timing of expenditure;

(v) changes in load transfer capacity and the capacity of *Embedded Generators* to take up *load*;

(vi) any additional option value (where this value has not already been included in the other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the *National Electricity Market*~~.~~;

(vii) changes in *electrical energy losses*; and

(viii) any other class of market benefit determined to be relevant by the *AER*.

(5) with respect to the classes of market benefits set out in subparagraphs (4)(i) and (ii), ensure that, if a credible option is for reliability corrective action, the consideration and any quantification assessment of these classes of market benefits will only apply insofar as the market benefit delivered by that credible option exceeds the minimum standard required for reliability corrective action;

(6) require the RIT-D proponent to consider whether the following classes of costs would be associated with each credible option and, if so, quantify the:

(i) financial costs incurred in constructing or providing the credible option;

(ii) operating and maintenance costs over the operating life of the credible option;

(iii) cost of complying with laws, regulations and applicable administrative requirements in relation to the construction and operation of the credible option; and

(iv) any other financial costs determined to be relevant by the *AER*.

(7) require a RIT-D proponent, in exercising judgement as to whether a particular class of market benefit or cost applies to each credible option, to have regard to any submissions received on the ~~non-network options report~~options screening report and/or draft project assessment report where relevant;

(8) provide that any market benefit or cost which cannot be measured as a market benefit or cost to persons in their capacity as *Generators*, *Distribution Network Service Providers*, *Transmission Network Service Providers* or consumers of electricity must not be included in any analysis under the *regulatory investment test for distribution*; and

(9) specify:

(i) the method or methods permitted for estimating the magnitude of the different classes of market benefits;

(ii) the method or methods permitted for estimating the magnitude of the different classes of costs;

(iii) the appropriate method and value for specific inputs, where relevant, for determining the discount rate or rates to be applied;

(iv) that a sensitivity analysis is required for modelling the cost-benefit analysis; and

(v) that the credible option that maximises the present value of net economic benefit to all those who produce, consume or transport electricity in the *National Electricity Market* may, in some circumstances, be a negative net economic benefit (that is, a net economic cost) where the *identified need* is for reliability corrective action.

(d) A RIT-D proponent ~~may~~must, under the *regulatory investment test for distribution*, quantify each class of market benefits under paragraph (c)(4) where the RIT-D proponent considers that:

(1) any applicable market benefits may be material; or

(2) the quantification of market benefits may alter the selection of the preferred option.

(e) The *regulatory investment test for distribution* permits a single assessment of an integrated set of related and similar investments.

5.17.4 Regulatory investment test for distribution procedures

(a) If a RIT-D project is subject to the *regulatory investment test for distribution* under clause 5.17.3, then the RIT-D proponent must consult with the following persons on the RIT-D project in accordance with this clause 5.17.4:

(1) all *Registered Participants*, *AEMO*, *interested parties* and non-network providers; and

(2) if the RIT-D proponent is a *Distribution Network Service Provider*, persons registered on its industry engagement register~~demand side engagement register~~.

Screening for ~~non-network~~ options

(b) Subject to paragraph (c), a RIT-D proponent must prepare and *publish* a ~~non-network options report~~options screening report under paragraph (e) if a RIT-D project is subject to the *regulatory investment test for distribution* under clause 5.17.3.

(c) A RIT-D proponent is not required to comply with paragraph (b) if it determines on reasonable grounds that there will not be a *non-network option* or a *SAPS option* that is a potential credible option, or that forms a significant part of a potential credible option, for the RIT-D project to address the identified need.

(d) If a RIT-D proponent makes a determination under paragraph (c), then as soon as possible after making the determination it must *publish* a notice setting out the reasons for its determination, including any methodologies and assumptions it used in making its determination.

Options screening report~~Non-network options report~~

(e) A ~~non-network options report~~options screening report must include:

(1) a description of the *identified need*;

(2) the assumptions used in identifying the *identified need* (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary);

(3) if available, the relevant annual deferred *augmentation* charge associated with the *identified need*;

(4) the technical characteristics of the *identified need* that a *non-network option* or (in relation to an adoptive SAPS network) a *SAPS option*~~non-network option~~ would be required to deliver, such as:

(i) the size of *load* reduction or additional *supply*;

(ii) location;

(iii) contribution to *power system security* or *reliability*;

(iv) contribution to *power system* fault levels as determined under clause 4.6.1; and

(v) the operating profile;

(5) a summary of potential credible options to address the *identified need*, as identified by the RIT-D proponent, including *network options*, ~~and~~ *non-network options* and (in relation to an *adoptive SAPS network*) *SAPS options*.

(6) for each potential credible option, the RIT-D proponent must provide information, to the extent practicable, on:

(i) a technical definition or characteristics of the option;

(ii) the estimated construction timetable and commissioning date (where relevant); and

(iii) the total indicative cost (including capital and operating costs); and

(7) information to assist non-network providers wishing to present alternative potential credible options including details of how to submit a ~~non-*network*~~ proposal for consideration by the RIT-D proponent.

(f) The ~~non-network options report~~options screening report must be *published* in a timely manner having regard to the ability of parties to identify the scope for, and develop, alternative potential credible options or variants to the potential credible options.

(g) At the same time as *publishing* the ~~non-network options report~~options screening report, the RIT-D proponent, if it is a *Distribution Network Service Provider*, must notify persons registered on its industry engagement register~~demand side engagement register~~ of the report's *publication*.

(h) *Registered Participants*, *AEMO*, *interested parties*, non-network providers and (if relevant) persons registered on the *Distribution Network Service Provider's* industry engagement register~~demand side engagement register~~ must be provided with not less than three months in which to make submissions on the ~~non-network options report~~options screening report from the date that the RIT-D proponent *publishes* the report.

Draft project assessment report

(i) If one or more *Network Service Providers* wishes to proceed with a RIT-D project following a determination under paragraph (c) or the *publication* of a ~~non-network options report~~options screening report then the RIT-D proponent, having regard, where relevant, to any submissions received on the ~~non-network options report~~options screening report, must prepare and *publish* a draft project assessment report within:

(1) 12 months of:

(i) the end of the consultation period on a ~~non-network options report~~options screening report; or

(ii) where a ~~non-network options report~~options screening report is not required, the publication of a notice under paragraph (d); or

(2) any longer time period as agreed to in writing by the *AER*.

(j) The draft project assessment report must include the following:

(1) a description of the *identified need* for the investment;

(2) the assumptions used in identifying the *identified need* (including, in the case of proposed reliability corrective action, reasons that the RIT-D proponent considers reliability corrective action is necessary);

(3) if applicable, a summary of, and commentary on, the submissions on the ~~non-network options report~~options screening report;

(4) a description of each credible option assessed;

(5) where a *Distribution Network Service Provider* has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit for each credible option;

(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure;

(7) a detailed description of the methodologies used in quantifying each class of cost and market benefit;

(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option;

(9) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;

(10) the identification of the proposed preferred option;

(11) for the proposed preferred option, the RIT-D proponent must provide:

(i) details of the technical characteristics;

(ii) the estimated construction timetable and commissioning date (where relevant);

(iii) the indicative capital and operating cost (where relevant);

(iv) a statement and accompanying detailed analysis that the proposed preferred option satisfies the *regulatory investment test for distribution*; and

(v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent; and

(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.

(k) The RIT-D proponent must *publish* a request for submissions on the matters set out in the draft project assessment report, including the proposed preferred option, from:

(1) *Registered Participants, AEMO*, non-network providers and *interested parties*; and

(2) if the RIT-D proponent is a *Distribution Network Service Provider*, persons on its industry engagement register~~demand side engagement register~~.

(l) If the proposed preferred option has the potential to, or is likely to, have an adverse impact on the quality of service experienced by consumers of electricity, including:

(1) anticipated changes in voluntary *load* curtailment by consumers of electricity; or

(2) anticipated changes in involuntary *load shedding* and customer interruptions caused by *network* outages,

then the RIT-D proponent must consult directly with those affected customers in accordance with a process reasonably determined by the RIT-D proponent.

(m) The consultation period on the draft project assessment report must not be less than six weeks from the *publication* of the report.

Exemption from the draft project assessment report

(n) A RIT-D proponent is not required to prepare and *publish* a draft project assessment report under paragraph (i) if:

(1) the RIT-D proponent made a determination under paragraph (c) and has *published* a notice under paragraph (d); and

(2) the estimated capital cost to the *Network Service Providers* affected by the RIT-D project of the proposed preferred option is less than $10 million (varied in accordance with a cost threshold determination).

Final project assessment report

(o) As soon as practicable after the end of the consultation period on the draft project assessment report, the RIT-D proponent must, having regard to any submissions received on the draft project assessment report, *publish* a final project assessment report.

(p) If the RIT-D project is exempt from the draft project assessment report stage under paragraph (n), the RIT-D proponent must *publish* the final project assessment report as soon as practicable after the publication of the notice under paragraph (d).

(q) At the same time as *publishing* the final project assessment report, a RIT-D proponent that is a *Distribution Network Service Provider* must notify persons on its industry engagement register~~demand side engagement register~~ of the report's *publication*.

(r) The final project assessment report must set out:

(1) if a draft project assessment report was prepared:

(i) the matters detailed in that report as required under paragraph (j); and

(ii) a summary of any submissions received on the draft project assessment report and the RIT-D proponent's response to each such submission; and

(2) if no draft project assessment report was prepared, the matters specified in paragraph (j).

(s) If the preferred option outlined in the final project assessment report has an estimated capital cost to the *Network Service Providers* affected by the RIT-D project of less than $20 million (varied in accordance with a cost threshold determination), the RIT-D proponent may discharge its obligations to *publish* its final project assessment report under paragraphs (o) and (p) by including the final project assessment report as part of its *Distribution Annual Planning Report* (where the RIT-D proponent is a *Distribution Network Service Provider*) or its *Transmission Annual Planning Report* (where the RIT-D proponent is a *Transmission Network Service Provider*).

Reapplication of regulatory investment test for distribution

(t) If:

(1) a RIT-D proponent has *published* a final project assessment report in respect of a RIT-D project;

(2) a *Network Service Provider* still wishes to undertake the RIT-D project to address the *identified need*; and

(3) there has been a material change in circumstances which, in the reasonable opinion of the RIT-D proponent means that the preferred option identified in the final project assessment report is no longer the preferred option,

then the RIT-D proponent must reapply the *regulatory investment test for distribution* to the RIT-D project, unless otherwise determined by the *AER*.

(u) For the purposes of paragraph (t), a material change in circumstances may include, but is not limited to, a change to the key assumptions used in identifying:

(1) the *identified need* described in the final project assessment report; or,

(2) the credible options assessed in, the final project assessment report.

(v) When making a determination under paragraph (t) the *AER* must have regard to:

(1) the credible options (other than the preferred option) identified in the final project assessment report;

(2) the change in circumstances identified by the RIT-D proponent; and

(3) whether a failure to promptly undertake the RIT-D project is likely to materially affect the *reliability* and *secure operating state* of the *distribution network* or a significant part of that *network*.

5.18B Completed embedded generation projects

5.18B.1 Definitions

(a) For the purposes of this rule 5.18B:

completed embedded generation projects means all *embedded generating units* owned, operated or controlled by:

(1) a *Generator*; or

(2) a person who was required to apply to *AEMO* for an exemption from the requirement to register as a *Generator* in respect of an *embedded generating unit*,

and are connected to the *Distributor Network Service Provider's network* or form part of a *regulated SAPS* forming part of the *Distribution Network Service Provider's network*.

DAPR date has the same meaning as in clause 5.13.2.

Schedule 5.1a System standards

S5.1a.8 Fault clearance times

(a) Faults anywhere within the *power system* should be cleared sufficiently rapidly that:

(1) the *power system* does not become unstable as a result of faults that are *credible contingency events*;

(2) *inter-regional* or *intra-regional power transfers* are not unduly *constrained*; and

(3) consequential equipment damage is minimised.

(b) The *fault clearance time* of a primary *protection system* for a *short circuit fault* of any *fault type* anywhere:

(1) within a *substation*;

(2) within *connected plant*; or

(3) on at least the half of a power line nearer to the *protection system*,

should not exceed the relevant time in column 2 of Table S5.1a.2 for the *nominal voltage* that applies at the fault location.

(c) The *fault clearance time* of a primary *protection system* for a *short circuit fault* of any *fault type* anywhere on the remote portion of a power line for which the near portion is protected by a primary *protection system* under clause S5.1a8(b) should not exceed the relevant time in column 3 of Table S5.1a.2 for the *nominal voltage* that applies at the fault location.

(d) The *fault clearance time* of a *breaker fail protection system* or similar back-up *protection system* for a *short circuit fault* of any *fault type* should not exceed the relevant time in column 4 of Table S5.1a.2 for the *nominal voltage* that applies at the fault location.

(e) The owner of the faulted element may require shorter *fault clearance times* to minimise *plant* damage.

(f) The allowable *fault clearance times* specified in Table S5.1a.2 apply in accordance with the provisions of clause S5.1.9 to *facilities* constructed or modified on or after the *performance standards commencement date*.

(g) For *facilities* other than those referred to in clause S5.1a.8(f), the applicable allowable *fault clearance times* must be derived by the relevant *Network Service Provider* from the existing capability of each *facility* on the *performance standards commencement date*.

(h) This clause does not apply in relation to a *regulated SAPS*.

Table S5.1a.2

Nominal voltage at fault location(kV)	Time(milliseconds)		
Column 1	**Column 2**	**Column 3**	**Column 4**
400kV and above	80	100	175

Nominal voltage at fault location(kV)	Time(milliseconds)		
Column 1	**Column 2**	**Column 3**	**Column 4**
at least 250kV but less than 400kV	100	120	250
more than 100kV but less than 250kV	120	220	430
less than or equal 100 kV	As necessary to prevent *plant* damage and meet stability requirements		

Schedule 5.1 Network Performance Requirements to be Provided or Co-ordinated by Network Service Providers

S5.1.2 Network reliability

S5.1.2.1 Credible contingency events

Network Service Providers must plan, design, maintain and operate their *transmission networks* and *distribution networks* to allow the transfer of power from *generating units* to *Customers* with all *facilities* or equipment associated with the *power system* in service and may be required by a *Registered Participant* under a *connection agreement* to continue to allow the transfer of power with certain facilities or *plant* associated with the *power system* out of service, whether or not accompanied by the occurrence of certain faults (called ***credible contingency events***).

The following *credible contingency events* and practices must be used by *Network Service Providers* for planning and operation of *transmission networks* and *distribution networks* (excluding *regulated SAPS* forming part of a *distribution network*) unless otherwise agreed by each *Registered Participant* who would be affected by the selection of *credible contingency events*:

(a) The *credible contingency events* must include the *disconnection* of any single *generating unit* or *transmission line*, with or without the application of a single circuit two-phase-to-ground solid fault on lines operating at or above 220 kV, and a single circuit three-phase solid fault on lines operating below 220 kV. The *Network Service Provider* must assume that the fault will be cleared in primary protection time by the faster of the duplicate protections with installed intertrips available. For existing *transmission lines* operating below 220 kV but above 66 kV a two-phase to earth fault criterion may be used if the modes of operation are such as to minimise the probability of three-phase faults occurring and operational experience shows this to be adequate, and provided that the *Network Service Provider* upgrades performance when the opportunity arises.

(b) For lines at any *voltage* above 66 kV which are not protected by an overhead earth wire and/or lines with tower footing resistances in excess of 10 ohms, the *Network Service Provider* may extend the criterion to include a single circuit three-phase solid fault to cover the increased risk of such a fault occurring. Such lines must be examined individually on their merits by the relevant *Network Service Provider*.

(c) For lines at any *voltage* above 66 kV a *Network Service Provider* must adopt operational practices to minimise the risk of slow fault clearance in case of inadvertent closing on to earths applied to equipment for maintenance purposes. These practices must include but not be limited to:

(1) Not leaving lines equipped with intertrips alive from one end during maintenance; and

(2) *Off-loading* a three terminal (tee connected) line prior to restoration, to ensure switch on to fault *facilities* are operative.

(d) The *Network Service Provider* must ensure that all *protection systems* for lines at a *voltage* above 66 kV, including associated intertripping, are well maintained so as to be available at all times other than for short periods (not greater than eight hours) while the maintenance of a *protection system* is being carried out.

S5.1.3 Frequency variations

A *Network Service Provider* must ensure that within the *extreme frequency excursion tolerance limits* all of its *power system* equipment and *regulated SAPS* equipment will remain in service unless that equipment is required to be switched to give effect to manual *load shedding* in accordance with clause S5.1.10, or is required by *AEMO* to be switched for operational purposes or is required to be switched or *disconnected* for operation of an *emergency frequency control scheme*.

Sustained operation outside the *extreme frequency excursion tolerance limits* need not be taken into account by *Network Service Providers* in the design of *plant* which may be *disconnected* if this is necessary for the protection of that *plant*.

S5.1.8 Stability

In conforming with the requirements of the *system standards*, the following criteria must be used by *Network Service Providers* for both planning and operation (except in relation to a *regulated SAPS*):

For stable operation of the *national grid*, both in a *satisfactory operating state* and following any *credible contingency events* or any *protected event* described in clause S5.1.2.1:

(a) the *power system* will remain in synchronism;

(b) damping of *power system* oscillations will be adequate; and

(c) *voltage* stability criteria will be satisfied.

Damping of *power system* oscillations must be assessed for planning purposes according to the design criteria which states that *power system damping* is considered adequate if after the most critical *credible contingency event* or any *protected event*, simulations calibrated against past performance indicate that the halving time of the least damped electromechanical mode of oscillation is not more than five seconds.

To assess the damping of *power system* oscillations during operation, or when analysing results of tests such as those carried out under clause 5.7.7 of the *Rules*, the *Network Service Provider* must take into account statistical effects. Therefore, the *power system damping* operational performance criterion is that at a given operating point, real-time monitoring or available test results show that there is less than a 10 percent probability that the halving time of the least damped mode of oscillation will exceed ten seconds, and that the average halving time of the least damped mode of oscillation is not more than five seconds.

The *voltage* control criterion is that stable *voltage* control must be maintained following the most severe *credible contingency event* or any *protected event*. This requires that an adequate *reactive power* margin must be maintained at every *connection point* in a *network* with respect to the *voltage* stability limit as determined from the *voltage*/reactive *load* characteristic at that *connection point*. Selection of the appropriate margin at each *connection point* is at the discretion of the relevant *Network Service Provider*, subject only to the requirement that the margin (expressed as a capacitive *reactive power* (in MVAr)) must not be less than one percent of the maximum fault level (in MVA) at the *connection point*.

In planning a *network* a *Network Service Provider* must consider *non-credible contingency events* such as *busbar* faults which result in tripping of several circuits, uncleared faults, double circuit faults and multiple contingencies which could potentially endanger the stability of the *power system*. In those cases where the consequences to any *network* or to any *Registered Participan*t of such events are likely to be severe disruption a *Network Service Provider* and/or a *Registered Participant* must in consultation with *AEMO*, install, maintain and upgrade emergency controls within the *Network Service Provider's* or *Registered Participant's* system or in both, as necessary, to minimise disruption to any *transmission* or *distribution network* and to significantly reduce the probability of cascading failure.

A *Registered Participant* must co-operate with a *Network Service Provider* to achieve stable operation of the *national grid* and must use all reasonable endeavours to negotiate with the *Network Service Provider* regarding the installation of emergency controls as described in the previous paragraph. The cost of installation, maintenance and operation of the emergency controls must be borne by the *Network Service Provider* who is entitled to include this cost when calculating the *Transmission Customer use of system* price.

S5.1.9 Protection systems and fault clearance times

Network Users

(a) A *Network Service Provider* must determine the *automatic access standard* and *minimum access standard* that applies to the protection zone of each *protection system* in relation to the *connection point* and the *plant* to be *connected*, as follows:

(1) The *automatic access standard* for *fault clearance time* for any *fault type* is the lesser of the *system standard* set out in clause S5.1a.8 that applies to the highest *nominal voltage* within the *protection system's* protection zone and the corresponding *minimum access standard* determined under clauses S5.1.9(a)(2) or S5.1.9(a)(3) as applicable.

(2) The *minimum access standard* for *fault clearance time* of a primary *protection system* is:

(i) for a *fault type* that constitutes a *credible contingency event* in the relevant protection zone, the longest time such that a *short circuit fault* of that *fault type* that is cleared in that time would not cause the *power system* to become unstable when operating at any level of *inter-regional* or *intra-regional power transfer* that would be permissible (taking into account all other limiting criteria) if the *fault clearance time* for such a fault at the *connection point* were the *system standard* set out in clause S5.1a.8 that applies to the *nominal voltage* at the *connection point*; and

(ii) for a *fault type* that does not constitute a *credible contingency event* in the relevant protection zone:

(A) if a two phase to ground fault in that protection zone constitutes a *credible contingency event*, the corresponding *fault clearance time* for a two phase to ground *short circuit fault* in that protection zone as determined under clause S5.1.9(a)(2)(i); and

(B) otherwise, the shortest of the *fault clearance times* for a two phase to ground *short circuit fault* in each adjoining protection zone (excluding *transformer* protection zones and dead zones) as determined under clauses S5.1.9(a)(2)(i) or S5.1.9(e).

(3) The *minimum access standard* for *fault clearance time* of a *breaker fail protection system* or similar back-up *protection system* is the longest time such that a *short circuit fault* of any *fault type* that is cleared in that time would not damage any part of the *power system* or *regulated SAPS* (other than the faulted element) while the fault current is flowing or being interrupted.

(b) [**Deleted**]

Transmission systems and distribution systems

(c) Subject to clauses S5.1.9(k) and S5.1.9(l), a *Network Service Provider* must provide sufficient primary *protection systems* and back-up *protection systems* (including *breaker fail protection systems*) to ensure that a fault of any *fault type* anywhere on its *transmission system* or *distribution system* is automatically *disconnected* in accordance with clause S5.1.9(e) or clause S5.1.9(f).

(d) If the *fault clearance time* determined under clause S5.1.9(e) of a primary *protection system* for a two phase to ground *short circuit fault* is less than 10 seconds, the primary *protection system* must have sufficient redundancy to ensure that it can clear *short circuit faults* of any *fault type* within the relevant *fault clearance time* with any single protection element (including any communications facility upon which the *protection system* depends) out of service.

(e) The *fault clearance time* of a primary *protection system* of a *Network Service Provider* must not exceed:

(1) for any *fault type* that constitutes a *credible contingency event* in the relevant protection zone, the longest time such that a *short circuit fault* of that *fault type* that is cleared in that time would not cause the *power system* to become unstable when operating at any level of *inter-regional* or *intra-regional power transfer* that would be permissible (taking into account all other limiting criteria) if the *fault clearance time* for such a fault in that protection zone were the relevant *system standard* set out in clause S5.1a.8; and

(2) for any *fault type* that does not constitute a *credible contingency event* in the relevant protection zone:

(i) if a two phase to ground fault in that protection zone is a *credible contingency event*, the corresponding *fault clearance time* for a two phase to ground fault in that protection zone as determined under clause S5.1.9(e)(1); and

(ii) otherwise, the shortest of the *fault clearance times* for a two phase to ground fault in each adjoining protection zone (excluding *transformer* protection zones and dead zones) as determined under clauses S5.1.9(a)(2)(i), S5.1.9(e)(1)or S5.1.9(e)(2)(i).

(f) The *fault clearance time* of each *breaker fail protection system* or similar back-up *protection system* of a *Network Service Provider* must be such that a *short circuit fault* of any *fault type* that is cleared in that time would not damage any part of the *power system* or *regulated SAPS* (other than the faulted element) while the fault current is flowing or being interrupted.

(g) A *Network Service Provider* must demonstrate to *AEMO* that each *fault clearance time* for a primary *protection system* that is longer than the relevant *system standard* set out in clause S5.1a.8 and is less than 10 seconds would not cause or require an *inter-regional* or *intra-regional power transfer capability* to be reduced.

(h) A *Network Service Provider* must include in each *connection agreement* entered into after the *performance standards commencement date*:

(1) the *fault clearance times* for each *fault type* of each of its *protection systems* that could reasonably be expected to interrupt *supply* to or from the relevant *connection point*; and

(2) an agreement to not increase those *fault clearance times* without the prior written agreement of the other party.

(i) *Network Service Providers* must coordinate and cooperate with *Network Users* to implement *breaker fail* protection for circuit breakers provided to isolate the *Network User's facility* from the *Network Service Provider's facilities*.

(j) Where practicable and economic to achieve, investments should meet the *system standard* for *fault clearance times* as specified in clause S5.1a.8 for two phase to ground *short circuit faults*.

(k) A primary *protection system* may clear faults other than *short circuit faults* slower than the relevant *fault clearance time*, provided that such faults would be cleared sufficiently promptly to not adversely impact on *power system* *security* compared with its operation for the corresponding *short circuit fault*. In the case of a fault within equipment at a station, the corresponding *short circuit fault* is to be taken as a two phase to ground *short circuit fault* at the external connections of the equipment.

(l) *Protection systems* may rely on *breaker fail protection systems* or other back-up *protection systems* to completely clear faults of any *fault type* that:

(1) occur within a *substation* between a protection zone and a circuit breaker adjacent to that protection zone that is required to open to clear the fault (a **dead zone**); and

(2) remain connected through a power line or *transformer* after operation of a primary *protection system*,

provided that the relevant *Network Service Provider* assesses that the likelihood of a fault occurring within the dead zone is not greater than the likelihood of a fault occurring on *busbars*.

(m) For the purposes of this clause S5.1.9, a *credible contingency event* includes any event that clause S5.1.2.1 requires a *Network Service Provider* to consider as a *credible contingency event*.

(n) The provisions of clause S5.1.9(d) apply to *facilities* constructed or modified on or after the *performance standards commencement date*.

(o) For *facilities* other than those referred to in clause S5.1.9(n), the requirement for primary *protection system* redundancy must be derived by the *Network Service Provider* from the existing capability of each *facility* on the *performance standards commencement date*.

Schedule 5.3 Conditions for Connection of Customers

S5.3.1a Introduction to the schedule

(a) This schedule applies to the following classes of *Network User*:

(1) a *First-Tier Customer* in respect of its *first-tier load*;

(2) a *Second-Tier Customer* in respect of its *second-tier load*;

(3) a *Market Customer* in respect of its *market load*;

(4) a *Non-Registered Customer* in respect of *supply* it takes from a *network*; and

(5) a *Distribution Network Service Provider* in respect of its *distribution network*.

(b) For the purposes of this schedule 5.3 the term ***Network Service Provider*** must be interpreted to mean the *Network Service Provider* with whom the *Connection Applicant* has sought, or is seeking, a *connection* in accordance with clause 5.3.2 of the *Rules*.

(c) All *Network Users* must comply with the requirements for the establishment of *performance standards* in accordance with provisions contained in schedule 5.1a for *system standards* or schedule 5.1 for *Network Service Providers* and this schedule 5.3 for *Customers*.

(d) If the *Connection Applicant* is a *Registered Participant* in relation to the proposed *connection*, the *Network Service Provider* may include as terms and conditions of the *connection agreement* any provision of this schedule that is expressed as an obligation on a *Network User*. If the *Connection Applicant* is not a *Registered Participant* in relation to the proposed *connection*, the *Network Service Provider* must include as terms and conditions of the *connection agreement*:

(1) each provision of this schedule that is expressed as an obligation on a *Network User*; and

(2) each agreed *performance standard* and an obligation to comply with it.

(e) The purpose of this schedule is to:

(1) describe the information that must be exchanged for the *connection* enquiry and *application to connect* processes described in rule 5.3 of the *Rules*;

(2) establish the *automatic access standards* and *minimum access standards* that will apply to the process of negotiating access standards under clause 5.3.4A of the *Rules*; and

(3) establish obligations to apply prudent design standards for the *plant* to be *connected*.

(f) This schedule does not apply to a *Network Service Provider* or a *Network User* in relation to a *connection* to a *regulated SAPS*.

Schedule 5.8 Distribution Annual Planning Report

Note

The local definitions in clause 5.10.2 apply to this schedule.

For the purposes of clause 5.13.2(c), the following information must be included in a *Distribution Annual Planning Report*:

(a) information regarding the *Distribution Network Service Provider* and its *network*, including:

(1) a description of its *network*;

(2) a description of its operating environment;

(3) the number and types of its distribution assets;

(4) methodologies used in preparing the *Distribution Annual Planning Report*, including methodologies used to identify system limitations and any assumptions applied; and

(5) analysis and explanation of any aspects of forecasts and information provided in the *Distribution Annual Planning Report* that have changed significantly from previous forecasts and information provided in the preceding year;

(b) forecasts for the forward planning period, including at least:

(1) a description of the forecasting methodology used, sources of input information, and the assumptions applied;

(2) *load* forecasts:

(i) at the transmission-distribution connection points;

(ii) for sub-transmission lines; and

(iii) for zone substations,

including, where applicable, for each item specified above:

(iv) total capacity;

(v) firm delivery capacity for summer periods and winter periods;

(vi) *peak load* (summer or winter and an estimate of the number of hours per year that 95% of *peak load* is expected to be reached);

(vii) *power factor* at time of *peak load*;

(viii) load transfer capacities; and

(ix) generation capacity of known *embedded generating units*;

(3) forecasts of future transmission-distribution connection points (and any associated *connection assets*), sub-transmission lines and zone substations, including for each future transmission-distribution connection point and zone substation:

(i) location;

(ii) future *loading level*; and

(iii) proposed commissioning time (estimate of month and year);

(4) forecasts of the *Distribution Network Service Provider's* performance against any reliability targets in a *service target performance incentive scheme*; and

(5) a description of any factors that may have a material impact on its *network*, including factors affecting;

(i) fault levels;

(ii) *voltage* levels;

(iii) other *power system security* requirements;

(iv) the quality of *supply* to other *Network Users* (where relevant); and

(v) ageing and potentially unreliable assets;

(b1) for all *network* asset retirements, and for all *network* asset de-ratings that would result in a system limitation, that are planned over the forward planning period, the following information in sufficient detail relative to the size or significance of the asset:

(1) a description of the *network* asset, including location;

(2) the reasons, including methodologies and assumptions used by the *Distribution Network Service Provider*, for deciding that it is necessary or prudent for the *network* asset to be retired or de-rated, taking into account factors such as the condition of the *network* asset;

(3) the date from which the *Distribution Network Service Provider* proposes that the *network* asset will be retired or de-rated; and

(4) if the date to retire or de-rate the *network* asset has changed since the previous *Distribution Annual Planning Report*, an explanation of why this has occurred;

(b2) for the purposes of subparagraph (b1), where two or more *network* assets are:

(1) of the same type;

(2) to be retired or de-rated across more than one location;

(3) to be retired or de-rated in the same calendar year; and

(4) each expected to have a replacement cost less than $200,000 (as varied by a cost threshold determination),

those assets can be reported together by setting out in the *Distribution Annual Planning Report*:

(5) a description of the *network* assets, including a summarised description of their locations;

(6) the reasons, including methodologies and assumptions used by the *Distribution Network Service Provider*, for deciding that it is necessary or prudent for the *network* assets to be retired or de-rated, taking into account factors such as the condition of the *network* assets;

(7) the date from which the *Distribution Network Service Provider* proposes that the *network* assets will be retired or de-rated; and

(8) if the calendar year to retire or de-rate the *network* assets has changed since the previous *Distribution Annual Planning Report*, an explanation of why this has occurred;

(c) information on system limitations for sub-transmission lines and zone substations, including at least:

(1) estimates of the location and timing (month(s) and year) of the system limitation;

(2) analysis of any potential for load transfer capacity between *supply* points that may decrease the impact of the system limitation or defer the requirement for investment;

(3) impact of the system limitation, if any, on the capacity at transmission-distribution connection points;

(4) a brief discussion of the types of potential solutions that may address the system limitation in the forward planning period, if a solution is required; and

(5) where an estimated reduction in forecast *load* would defer a forecast system limitation for a period of at least 12 months, include:

(i) an estimate of the month and year in which a system limitation is forecast to occur as required under subparagraph (1);

(ii) the relevant *connection points* at which the estimated reduction in forecast *load* may occur; and

(iii) the estimated reduction in forecast *load* in MW or improvements in *power factor* needed to defer the forecast system limitation;

(d) for any primary distribution feeders for which a *Distribution Network Service Provider* has prepared forecasts of *maximum demands* under clause 5.13.1(d)(1)(iii) and which are currently experiencing an overload, or are forecast to experience an overload in the next two years the *Distribution Network Service Provider* must set out:

(1) the location of the primary distribution feeder;

(2) the extent to which load exceeds, or is forecast to exceed, 100% (or lower utilisation factor, as appropriate) of the normal cyclic rating under normal conditions (in summer periods or winter periods);

(3) the types of potential solutions that may address the overload or forecast overload; and

(4) where an estimated reduction in forecast *load* would defer a forecast overload for a period of 12 months, include:

(i) estimate of the month and year in which the overload is forecast to occur;

(ii) a summary of the location of relevant *connection points* at which the estimated reduction in forecast *load* would defer the overload;

(iii) the estimated reduction in forecast *load* in MW needed to defer the forecast system limitation;

(d1) for an *adoptive SAPS network*, information on system limitations in the forward planning period for which a potential solution is a *regulated SAPS*, including at least:

(1) estimates of the location and timing (month(s) and year) of the system limitation; and

(2) a brief discussion of the types of potential *stand-alone power systems* that may address the system limitation;

(e) a high-level summary of each RIT-D project for which the *regulatory investment test for distribution* has been completed in the preceding year or is in progress, including:

(1) if the *regulatory investment test for distribution* is in progress, the current stage in the process;

(2) a brief description of the *identified need*;

(3) a list of the credible options assessed or being assessed (to the extent reasonably practicable);

(4) if the *regulatory investment test for distribution* has been completed a brief description of the conclusion, including:

(i) the net economic benefit of each credible option;

(ii) the estimated capital cost of the preferred option; and

(iii) the estimated construction timetable and commissioning date (where relevant) of the preferred option; and

(5) any impacts on *Network Users*, including any potential material impacts on *connection* charges and *distribution use of system* charges that have been estimated;

(f) for each identified system limitation which a *Distribution Network Service Provider* has determined will require a *regulatory investment test for distribution*, provide an estimate of the month and year when the test is expected to commence;

(g) a summary of all committed investments to be carried out within the forward planning period with an estimated capital cost of $2 million or more (as varied by a cost threshold determination) that are to address an urgent and unforeseen *network* issue as described in clause 5.17.3(a)(1), including:

(1) a brief description of the investment, including its purpose, its location, the estimated capital cost of the investment and an estimate of the date (month and year) the investment is expected to become operational;

(2) a brief description of the alternative options considered by the *Distribution Network Service Provider* in deciding on the preferred investment, including an explanation of the ranking of these options to the committed project. Alternative options could include, but are not limited to, *generation* options, demand side options, and options involving other *distribution* or *transmission networks*;

(h) the results of any joint planning undertaken with a *Transmission Network Service Provider* in the preceding year, including:

(1) a summary of the process and methodology used by the *Distribution Network Service Provider* and relevant *Transmission Network Service Providers* to undertake joint planning;

(2) a brief description of any investments that have been planned through this process, including the estimated capital costs of the investment and an estimate of the timing (month and year) of the investment; and

(3) where additional information on the investments may be obtained;

(i) the results of any joint planning undertaken with other *Distribution Network Service Providers* in the preceding year, including:

(1) a summary of the process and methodology used by the *Distribution Network Service Providers* to undertake joint planning;

(2) a brief description of any investments that have been planned through this process, including the estimated capital cost of the investment and an estimate of the timing (month and year) of the investment; and

(3) where additional information on the investments may be obtained;

(j) information on the performance of the *Distribution Network Service Provider's network*, including:

(1) a summary description of reliability measures and standards in *applicable regulatory instruments*;

(2) a summary description of the quality of *supply* standards that apply, including the relevant codes, standards and guidelines;

(3) a summary description of the performance of the *distribution network* against the measures and standards described under subparagraphs (1) and (2) for the preceding year;

(4) where the measures and standards described under subparagraphs (1) and (2) were not met in the preceding year, information on the corrective action taken or planned;

(5) a summary description of the *Distribution Network Service Provider's* processes to ensure compliance with the measures and standards described under subparagraphs (1) and (2); and

(6) an outline of the information contained in the *Distribution Network Service Provider's* most recent submission to the *AER* under the *service target performance incentive scheme*;

(k) information on the *Distribution Network Service Provider's* asset management approach, including:

(1) a summary of any asset management strategy employed by the *Distribution Network Service Provider*;

(1A) an explanation of how the *Distribution Network Service Provider* takes into account the cost of *distribution losses* when developing and implementing its asset management and investment strategy;

(2) a summary of any issues that may impact on the system limitations identified in the *Distribution Annual Planning Report* that has been identified through carrying out asset management; and

(3) information about where further information on the asset management strategy and methodology adopted by the *Distribution Network Service Provider* may be obtained;

(l) information on the *Distribution Network Service Provider's* demand management activities, including:

(1) a qualitative summary of:

(i) *non-network options* that have been considered in the past year, including *generation* from *embedded generating units*;

(ii) key issues arising from *applications to connect embedded generating units* received in the past year;

(iii) actions taken to promote non-*network*~~non-network~~ proposals or (for an adoptive SAPS network) SAPS proposals in the preceding year, including *generation* from *embedded generating units*; and

(iv) the *Distribution Network Service Provider's* plans for demand management and *generation* from *embedded generating units* over the forward planning period;

(2) a quantitative summary of:

(i) *connection* enquiries received under clause 5.3A.5;

(ii) *applications to connect* received under clause 5.3A.9; and

(iii) the average time taken to complete *applications to connect*;

(m) information on the *Distribution Network Service Provider's* investments in information technology and communication systems which occurred in the preceding year, and planned investments in information technology and communication systems related to management of *network* assets in the forward planning period; ~~and~~

(n) a regional development plan consisting of a map of the *Distribution Network Service Provider's network* as a whole, or maps by regions, in accordance with the *Distribution Network Service Provider's* planning methodology or as required under any *regulatory obligation or requirement*, identifying:

(1) sub-transmission lines, zone substations and transmission-distribution connection points; and

(2) any system limitations that have been forecast to occur in the forward planning period, including, where they have been identified, overloaded primary distribution feeders; and

(o) for an adoptive SAPS network, information on the *Distribution Network Service Provider's* activities in relation to *DNSP-led SAPS projects* including:

(1) opportunities to develop *DNSP-led SAPS projects* that have been considered in the past year;

(2) committed projects to implement a *regulated SAPS* over the forward planning period; and

(3) a quantitative summary of:

(i) the total number of *regulated SAPS* in the *network*; and

(ii) the number of customer premises supplied by means of those *regulated SAPS*.

Schedule 5.9 Industry engagement document~~Demand side engagement document~~ (clause 5.13.1(h))

Note

The local definitions in clause 5.10.2 apply to this schedule.

For the purposes of clause 5.13.1(h), the following information must be included in a *Distribution Network Service Provider's* industry engagement document~~demand side engagement document~~:

(a) a description of how the *Distribution Network Service Provider* will investigate, develop, assess and report on potential *non-network options* and (in relation to a *network* in a participating SAPS jurisdiction) potential *SAPS options*;

(b) a description of the *Distribution Network Service Provider's* process to engage and consult with potential non-network providers to determine their level of interest and ability to participate in the development process for potential *non-network options* or where applicable, potential *SAPS options*;

(c) an outline of the process followed by the *Distribution Network Service Provider* when negotiating with non-network providers to further develop a potential *non-network option* or *SAPS option*;

(d) an outline of the information a non-network provider is to include in a non-*network* or *DNSP-led SAPS project* proposal, including, where possible, an example of a best practice ~~non-network~~ proposal;

(e) an outline of the criteria that will be applied by the *Distribution Network Service Provider* in evaluating non-*network* or *DNSP-led SAPS project* proposals;

(f) an outline of the principles that the *Distribution Network Service Provider* considers in developing the payment levels for *non-network options* or (where applicable) *SAPS options*;

(g) a reference to any applicable incentive payment schemes for the implementation of *non-network options* or *SAPS options* and whether any specific criteria is applied by the *Distribution Network Service Provider* in its application and assessment of the scheme;

(h) the methodology to be used for determining *avoided Customer TUOS charges*, in accordance with clauses 5.4AA and 5.5; ~~and;~~

(i) a summary of the factors the *Distribution Network Service Provider* takes into account when negotiating *connection agreements* with *Embedded Generators*;

(j) the process used, and a summary of any specific regulatory requirements, for setting charges and the terms and conditions of *connection agreements* for *embedded generating units*;

(k) the process for lodging an *application to connect* for an *embedded generating unit* and the factors taken into account by the *Distribution Network Service Provider* when assessing such applications;

(l) worked examples to support the description of how the *Distribution Network Service Provider* will assess potential *non-network options* or *SAPS options* in accordance with paragraph (a);

(m) a hyperlink to any relevant, publicly available information produced by the *Distribution Network Service Provider*;

(n) a description of how parties may be listed on the industry engagement register~~demand side engagement register~~; and

(o) the *Distribution Network Service Provider's* contact details.

CHAPTER 5A

Important note: This is a modified version of version 124 of Chapter 5A of the Rules. It incorporates changes made by the following Rules:

1 Schedule 2 of the National Electricity Amendment (Register of distributed energy resources) Rule 2018 No 9 coming into effect on 1 December 2019.
2 Schedule 2 of the National Electricity Amendment (Minor changes) Rule 2019 No 9

This version does not include any changes made by Rules made after 27 November 2019.

5A. Electricity connection for retail customers

Part A Preliminary

5A.A.1 Definitions

In this Chapter:

basic connection service

means a *connection service* related to a *connection* (or a proposed *connection*) between a *distribution system* and a *retail customer's* premises (excluding a non-registered *embedded generator's* premises) in the following circumstances:

(a) either:

(1) the *retail customer* is typical of a significant class of *retail customers* who have sought, or are likely to seek, the service; or

(2) the *retail customer* is, or proposes to become, a *micro embedded generator*; and

(b) the provision of the service involves minimal or no *augmentation* of the *distribution network*; and

(c) a *model standing offer* has been approved by the *AER* for providing that service as a *basic connection service*.

basic micro EG connection service

means a *basic connection service* for a *retail customer* who is a *micro embedded generator*.

confidential information

means, in relation to a *Registered Participant*, *AEMO* or a *connection applicant*, information which is or has been provided to that *Registered Participant*, *AEMO* or *connection applicant* under or in connection with the *Rules* and which is stated under the *Rules*, or by *AEMO*, the *AER* or the *AEMC*, to be *confidential information* or is otherwise confidential or commercially sensitive. It also includes any information which is derived from such information.

connection

means a physical link between a *distribution system* and a *retail customer's* premises to allow the flow of electricity.

connection alteration

means an alteration to an existing *connection* including an addition, upgrade, *extension*, expansion, *augmentation* or any other kind of alteration.

connection applicant

means an applicant for a *connection service* of 1 of the following categories:

(a) *retail customer*;

(b) *retailer* or other person acting on behalf of a *retail customer*;

(c) *real estate developer*.

connection application

means an application under clause 5A.D.3.

connection charge

means a charge imposed by a *Distribution Network Service Provider* for a *connection service*.

connection charge guidelines

– see clause 5A.E.3.

connection charge principles

– see clause 5A.E.1.

connection contract

means a contract formed by the making and acceptance of a *connection offer*.

connection offer

means an offer by a *Distribution Network Service Provider* to enter into a *connection contract* with:

(a) a *retail customer*; or

(b) a *real estate developer*.

connection policy

means a document, approved as a *connection policy* by the *AER* under Chapter 6, Part E, setting out the circumstances in which *connection charges* are payable and the basis for determining the amount of such charges.

connection service

means either or both of the following:

(a) a service relating to a *new connection* for premises;

(b) a service relating to a *connection alteration* for premises,

but, to avoid doubt, does not include a service of providing, installing or maintaining a *metering installation* for premises.

contestable

– a service is *contestable* if the laws of the *participating jurisdiction* in which the service is to be provided permit the service to be provided by more than one supplier as a *contestable* service or on a competitive basis.

customer connection contract

– see section 67 of the *NERL*.

embedded generator

means a person that owns, controls or operates an *embedded generating unit*.

enquiry

means a preliminary *enquiry* under clause 5A.D.2.

micro EG connection

means a *connection* between an *embedded generating unit* and a *distribution network* of the kind contemplated by *Australian Standard* AS 4777 (Grid connection of energy systems via inverters).

micro embedded generator

means a *retail customer* who operates, or proposes to operate, an *embedded generating unit* for which a *micro EG connection* is appropriate.

model standing offer

means a document approved by the *AER* as a *model standing offer* to provide *basic connection services* (see clause 5A.B.3) or as a *model standing offer* to provide *standard connection services* (see clause 5A.B.5).

negotiated connection contract

– see clause 5A.C.1.

new connection

means a *connection* established or to be established, in accordance with this Chapter and applicable *energy laws*, where there is no existing *connection*.

non-registered embedded generator

means an *embedded generator* that is neither a *micro embedded generator* nor a *Registered Participant*.

premises connection assets

means the components of a *distribution system* used to provide *connection services*.

real estate developer

means a person who carries out a *real estate development*.

real estate development

means the commercial development of land including its development in 1 or more of the following ways:

(a) subdivision;

(b) the construction of commercial or industrial premises (or both);

(c) the construction of multiple new residential premises.

retail customer

includes:

(a) in all cases, a ~~non-registered *embedded generator*~~ *non-registered embedded generator* and a *micro embedded generator*; and

(b) in relation to a *regulated SAPS*, a *Registered Participant* or *Intending Participant*.

standard connection service

means a *connection service* (other than a *basic connection service*) for a particular class (or sub-class) of *connection applicant* and for which a *model standing offer* has been approved by the *AER*.

supply service

means a service (other than a *connection service*) relating to the *supply* of electricity.

5A.A.2 Application of this Chapter

(a) This Chapter does not apply to, or in relation to, a *connection applicant* that is a *Registered Participant* or an *Intending Participant* unless:

(1) the *Registered Participant* or *Intending Participant* is acting as the agent of a *retail customer*; ~~.~~ or

(2) the *connection applicant* is seeking *connection* or *connection services* in relation to a *regulated SAPS*.

(b) Where a *non-registered embedded generator* wishing to *connect* an *embedded generating unit* to a *Distribution Network Service Provider's network*:

(1) falls within a particular class (or subclass) of *connection applicant* for which that *Distribution Network Service Provider* provides a *standard connection service*, this Chapter will apply;

(2) does not fall within a particular class (or subclass) of *connection applicant* for which that *Distribution Network Service Provider* provides a *standard connection service*, paragraph (c) will apply.

(c) A *non-registered embedded generator* that meets the requirements in paragraph (b)(2) may elect to seek *connection* of the relevant *embedded generating unit* under rule 5.3A instead of this Chapter. A *non-registered embedded generator* seeking to *connect* to a *regulated SAPS* is not entitled to elect to seek *connection* under rule 5.3A.

(d) Any election made by a *non-registered embedded generator* under paragraph (c) must be:

(1) made before an *enquiry* is made or if no *enquiry* is made, before a *connection application* is lodged with the relevant *Distribution Network Service Provider*;

(2) in writing; and

(3) delivered to the relevant *Distribution Network Service Provider* at the same time as lodging an *enquiry* under clause 5.3A.5.

(e) For the avoidance of doubt, clause 5A.C.1(a)(2) is still applicable when a *non-registered embedded generator* meets the requirements in paragraph (b)(1).

5A.A.3 Small Generation Aggregator deemed to be agent of a retail customer

A *Market Small Generation Aggregator* is deemed to be the agent of a *retail customer*, where there is an agreement between the *Market Small Generation Aggregator* and the *retail customer* relating to the *retail customer's small generating unit* or *large SAPS generating unit* under which the *Market Small Generation Aggregator* is *financially responsible* for the *market connection point* at which the relevant ~~*small*~~ *generating unit* is connected to the *national grid*.

5A.A.4 Connection to or by means of a regulated SAPS

A *Distribution Network Service Provider* must not establish a new *connection* to its *network* by converting a part of its *network* to a *regulated SAPS* or establishing a new *regulated SAPS*.

Note

The AEMC proposes to recommend that this clause be classified as a civil penalty provision.

Part D Application for connection service

Division 1 Information

5A.D.1 Publication of information

(a) A *Distribution Network Service Provider* must publish on its website the following:

(1) an application form for a *new connection* or a *connection alteration*; and

(2) a description of how an application for a *new connection* or a *connection alteration* is to be made (including a statement of the information required for the application); and

(3) a description of the *Distribution Network Service Provider's basic connection services* and *standard connection services* and the classes (or subclasses) of *retail customer* to which they apply. If the *Distribution Network Service Provider* does not provide *standard connection services* for all or some *non-registered embedded generators*~~non-registered embedded generators~~, a clear statement to this effect must also be included in the description; and

(4) an explanation of the *connection applicant's* right to negotiate with the *Distribution Network Service Provider* for a negotiated *connection contract* and a description of the negotiation process; and

(5) the requirements for an expedited *connection*; and

(6) the basis for calculation of *connection charges*; and

(7) information set out in clauses 5.3A.3(b)(1)(vii) and 5.3A.3(b)(2)-(7) as such information relates to the *connection* of *embedded generating units* by a *non-registered embedded generator*.

(b) To the extent a *Distribution Network Service Provider* has provided the information required under paragraph (a)(7) by including that information in its information pack *published* under clause 5.3A.3(a)(3), it will be taken to have complied with paragraph (a)(7).

5A.D.1A Register of completed embedded generation projects

(a) For the purposes of this clause 5A.D.1A:

completed non-registered embedded generation projects means all *embedded generating units*, operated or controlled by a *non-registered* *embedded generator* ~~non-registered embedded generator~~ that are *connected* to the *Distribution Network Service Provider's network*.

DAPR date has the same meaning as in clause 5.13.2.

(b) In relation to completed non-registered embedded generation projects, a *Distribution Network Service Provider* must establish and *publish*, on its website, a register of the *plant*, including but not limited to:

(1) technology of *generating unit* (e.g. *synchronous generating unit*, induction generator, photovoltaic array, etc) and its make and model;

(2) maximum power *generation* capacity of all *embedded generating units* comprised in the relevant *generating system*;

(3) contribution to fault levels;

(4) the size and rating of the relevant *transformer*;

(5) a single line diagram of the *connection* arrangement;

(6) *protection systems* and communication systems;

(7) *voltage* control, *power factor* control and/or *reactive power capability* (where relevant); and

(8) details specific to the location of a *facility connected* to the *network* that are relevant to any of the details in subparagraphs (1)-(7).

(c) The *Distribution Network Service Provider* must not *publish confidential information* as part of, or in connection with, the register, unless disclosure of the information is authorised:

(1) by the party to whom the duty of confidentiality is owed; or

(2) under:

(i) the *National Electricity Law* or the *Rules*; or

(ii) any other law.

(d) The *Distribution Network Service Provider* must:

(1) by the DAPR date each year, include in the register the details contained in paragraph (b) for all completed non-registered embedded generation projects since the date the register referred to in paragraph (b) is established; and

(2) in the fifth year after the establishment of the register, and in each year thereafter, update the register by the DAPR date with details of all completed non-registered embedded generation projects in the 5 year period preceding the DAPR date.

(e) To the extent a *Distribution Network Service Provider* includes the information required under paragraphs (b) and (d) in its register established under rule 5.18B, it will be taken to have complied with paragraphs (b) and (d).

Division 2 Preliminary enquiry

Part E Connection charges

5A.E.1 Connection charge principles

(a) This clause states the ***connection charge principles***.

(b) A *retail customer* (other than a *non-registered embedded generator*, ~~or~~ a *real estate developer*, a *Registered Participant* or an *Intending Participant*) who applies for a *connection service* for which an *augmentation* is required cannot be required to make a capital contribution towards the cost of the *augmentation* (insofar as it involves more than an *extension*) if:

(1) the application is for a *basic connection service*; or

(2) a relevant threshold set in the *Distribution Network Service Provider's connection policy* is not exceeded.

Note

In general, the intention is to exclude deep system *augmentation* charges for *retail customers*.

(c) Subject to paragraph (b), in determining *connection charges* in accordance with its *connection policy*, a *Distribution Network Service Provider* must apply the following principles:

(1) if an *extension* to the *distribution network* is necessary in order to provide a *connection service*, *connection charges* for the service may include a reasonable capital contribution towards the cost of the *extension* necessary to provide the service;

(2) if *augmentation* of *premises connection assets* at the *retail customer's connection* point is necessary in order to provide a *connection service*, *connection charges* for the service may include a reasonable capital contribution towards the cost of the *augmentation* of *premises connection assets* at the *connection point* necessary to provide the service;

(3) if *augmentation* of the *distribution system* is necessary in order to provide a *standard connection service*, *connection charges* for the service may include a reasonable capital contribution towards the cost of the *augmentation* necessary to provide the service;

(4) if *augmentation* of the *distribution system* is necessary in order to provide a *connection service* under a negotiated *connection contract*, *connection charges* for the service may, subject to any agreement to the contrary, include a reasonable capital contribution towards the cost of *augmentation* of the *distribution system* to the extent necessary to provide the service and to any further extent that a prudent service provider would consider necessary to provide efficiently for forecast *load* growth;

(5) despite subparagraphs (1) to (4) if *augmentation* of the *distribution system* is necessary in order to provide, on the application of a *real estate developer*, *Registered Participant* or *Intending Participant connection services* for premises comprised in a *real estate*

development, *connection charges* for the services may, subject to any agreement to the contrary, include a reasonable capital contribution towards the cost of *augmentation* of the *distribution system* to the extent necessary to provide the services and to any further extent that a prudent service provider would consider necessary to provide efficiently for forecast *load* growth;

(6) however, a capital contribution may only be required in the circumstances described in subparagraphs (1) to (5) if provision for the costs has not already been made through existing *distribution use of system* charges or a tariff applicable to the *connection*.

(d) If:

(1) a *connection asset* ceases, within 7 years after its construction or installation, to be dedicated to the exclusive use of the *retail customer* occupying particular premises; and

(2) the *retail customer* is entitled, in accordance with the *connection charge guidelines*, to a refund of *connection charges*,

the *Distribution Network Service Provider* must make the refund, and may recover the amount of the refund, by way of a *connection charge*, from the new users of the asset.

(e) For the purposes of paragraph (d), a person is taken to be a new user of a *connection asset* if the asset comes to be used to provide a *connection* to that person's premises

(f) For the purposes of this clause capital contribution includes a prepayment or financial guarantee.

5A.E.3 Connection charge guidelines

(a) The *AER* must develop and *publish* guidelines (***connection charge guidelines***) for the development of *connection policies* by *Distribution Network Service Providers*.

(b) The purpose of the guidelines is to ensure that *connection charges*:

(1) are reasonable, taking into account the efficient costs of providing the *connection services* arising from the *new connection* or *connection alteration* and the revenue a prudent operator in the circumstances of the relevant *Distribution Network Service Provider* would require to provide those *connection services*; and

(2) provide, without undue administrative cost, a user-pays signal to reflect the efficient cost of providing the *connection services*; and

(3) -limit cross-subsidisation of *connection* costs between different classes (or subclasses) of *retail customer*; and

(4) if the *connection services* are *contestable* – are competitively neutral.

(c) The guidelines must:

(1) describe the method for determining charges for *premises connection assets*; and

(2) describe the circumstances (or how to determine the circumstances) under which a *Distribution Network Service Provider* may receive a capital contribution, prepayment or financial guarantee from a *retail customer* or *real estate developer* for the provision of a *connection service*; and

(3) describe how the amount of any such capital contribution, prepayment or financial guarantee is to be determined; and

(4) establish principles for fixing a threshold (based on capacity or any other measure the *AER* thinks fit) below which *retail customers* (not being a *non-registered embedded generator*, ~~or~~ a *real estate developer*, a *Registered Participant* or an *Intending Participant*) are exempt from any requirement to pay *connection charges* (or to give consideration in the form of a capital contribution, prepayment or financial guarantee) for an *augmentation* (other than an *extension*) to the *distribution network* necessary to make the *connection*; and

(5) describe the methods for calculating the *augmentation* component for the *connection assets* and, if the *augmentation* consists of or includes an *extension*, the *extension* component of a *connection charge*; and

(6) describe the method for calculating:

(i) the amount of a refund of *connection charges* for a *connection asset* when an *extension* asset originally installed to *connect* the premises of a single *retail customer* is used, within 7 years of its installation, to *connect* other premises and thus comes to be used for the benefit of 2 or more *retail customers*; and

(ii) the threshold below which the refund is not payable; and

(7) describe the treatment of *augmentation* assets.

(d) The principles for establishing an exemption under paragraph (c)(4) must ensure that the exemption only operates in the following circumstances:

(1) the *connection* is a low *voltage connection*; and

(2) the *connection* would not normally require *augmentation* of the *network* beyond the *extension* to the *distribution network* necessary to make the *connection*; and

(3) the *connection* is not expected to increase the *load* on the *distribution network* beyond a level the *Distribution Network Service Provider* could reasonably be expected to cope with in the ordinary course of managing the *distribution network*.

(e) In developing the guidelines, the *AER* must have regard to:

(1) historical and geographical differences between *networks*; and

(2) inter-jurisdictional differences related to regulatory control mechanisms, classification of services and other relevant matters; and

(3) the circumstances in which *connection services* may be provided by persons other than *Distribution Network Service Providers* (and are therefore *contestable*).

(f) In developing guidelines dealing with the method for calculating the amount of a refund of *connection charges* paid before a *connection asset* becomes a shared asset, the *AER* must have regard to:

(1) the *Distribution Network Service Provider's* obligation to make the refund; and

(2) future projections of *distribution network* expansion and usage and any consequent effect on the *Distribution Network Service Provider's* capacity to finance the acquisition of *augmentation* assets out of increased revenue; and

(3) the fact that the *Distribution Network Service Provider's* obligation to make the refund will expire after 7 years.

(g) In developing guidelines under this clause, the *AER* must act in accordance with the *distribution consultation procedures*.

5A.E.4 Payment of connection charges

(a) *Connection charges* payable in respect of a *connection service* must be paid to the *Distribution Network Service Provider* by the *retail customer's retailer* unless:

(1) the *retailer* did not apply for the *connection service* and the *Distribution Network Service Provider* has notified the *retail customer* that the *retail customer* must pay the *connection charge* directly; or

(2) the *retail customer* asks to pay the *connection charge* directly and the *Distribution Network Service Provider* agrees; or

(3) the *Distribution Network Service Provider* and the *retailer* agree that the *Distribution Network Service Provider* is to recover the *connection charge* from the *retail customer*.

(b) If the *retail customer* pays, or is required to pay, a *connection charge* directly to a *Distribution Network Service Provider* under paragraph (a), the *Distribution Network Service Provider* must not recover that charge from the *retail customer's retailer*.

(c) The *Distribution Network Service Provider* must separately identify each *connection charge* on the statement or invoice to the *retailer* or other person.

Note

Rule 25 of the *National Energy Retail Rules* requires the listing of *connection charges* that are passed through by a *retailer* to a retail customer in the customer's bill.

CHAPTER 6

Important note: This is a modified version of version 124 of Chapter 6 of the Rules. It incorporates changes made by Schedule 3 of the National Electricity Amendment (Five minute settlement) Rule 2017 No.15 coming into effect on 1 July 2021.

This version does not include changes to be made by the following Rules:

1 Schedule 2 of the National Electricity Amendment (Global settlement and market reconciliation) Rule 2018 which will come into effect on 6 February 2022

2 Any changes made by rules made after 22 October 2019.

6. Economic Regulation of Distribution Services

Part B Classification of Distribution Services and Distribution Determinations

6.2 Classification

6.2.1A Classification of distribution services provided by means of a SAPS

(a) The *AER* must give effect to the principles in this clause when classifying *distribution services* provided by means of a *stand-alone distribution system* forming part of a *regulated SAPS* as:

(1) *direct control services* or *negotiated distribution services*; or

(2) *standard control services* or *alternative control services*.

(b) Subject to paragraph (c), a *distribution service* provided by means of a *regulated SAPS* must be given the same classification that it would have been given if the *distribution service* were not provided by means of a *regulated SAPS*.

(c) The activities of a *Distribution Network Service Provider* in establishing, operating or maintaining a *regulated SAPS* or arranging for the provision of services or *facilities* required for the operation of a *regulated SAPS* must be classified as a *standard control service* or treated as an input into a *standard control service*.

Note

To provide a *regulated SAPS*, a *Distribution Network Service Provider* may contract with a service provider to design, install, operate and maintain a *generation system* to supply electricity to the *regulated SAPS*. The activities of the *Distribution Network Service Provider* in relation to that contract (including payment of contract charges) will be classified under paragraph (c). However, the generation of electricity consumed by *retail customers connected* to the *regulated SAPS* and the sale of the electricity by a *retailer* are not *distribution services* and are not classified under paragraph (c).

6.2.3A Distribution Service Classification Guidelines

(a) The *AER* must, in accordance with the *distribution consultation procedures*, develop, maintain and *publish* guidelines (the *Distribution Service Classification Guidelines)* that set out the approach the *AER* proposes to take when classifying *distribution services* as:

(1) *direct control services* or *negotiated distribution services* under clause 6.2.1(a); and

(2) *standard control services* or *alternative control services* under clause 6.2.2(a).

(b) The *Distribution Service Classification Guidelines* must set out an explanation of the *AER*'s proposed approach (including worked examples) to:

(1) determining whether to classify a *distribution service*;

(2) applying the factors set out in:

(i) clause 6.2.1(c), when classifying *distribution services* as *direct control services* or *negotiated distribution services*; and

(ii) clause 6.2.2(c), when classifying *direct control services* as *standard control services* or *alternative control services*; and

(3) distinguishing between *distribution services* (including, but not limited to, those that are classified as *direct control services*) and the operating and capital inputs that are used to provide such services~~.~~; and

(4) applying the principles in clause 6.2.1A, when classifying services provided by means of, or in relation to, a *regulated SAPS*.

(c) Nothing prevents the *AER* from *publishing* the *Distribution Service Classification Guidelines* in the same document as another guideline *published* under this Chapter.

Part C Building Block Determinations for standard control services

6.5 Matters relevant to the making of building block determinations

6.5.6 Forecast operating expenditure

(a) A *building block proposal* must include the total forecast operating expenditure for the relevant *regulatory control period* which the *Distribution Network Service Provider* considers is required in order to achieve each of the following (the *operating expenditure objectives*):

(1) meet or manage the expected demand for *standard control services* over that period;

(2) comply with all applicable *regulatory obligations or requirements* associated with the provision of *standard control services*;

(3) to the extent that there is no applicable *regulatory obligation or requirement* in relation to:

(i) the quality, reliability or security of supply of *standard control services*; or

(ii) the reliability or security of the *distribution system* through the supply of *standard control services*,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of *standard control services*; and

(iv) maintain the reliability and security of the *distribution system* through the supply of *standard control services*; and

(4) maintain the safety of the *distribution system* through the supply of *standard control services*.

(b) The forecast of required operating expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal* must:

(1) comply with the requirements of any relevant *regulatory information instrument*;

(2) be for expenditure that is properly allocated to *standard control services* in accordance with the principles and policies set out in the *Cost Allocation Method* for the *Distribution Network Service Provider*; and

(3) include both:

(i) the total of the forecast operating expenditure for the relevant *regulatory control period*; and

(ii) the forecast operating expenditure for each *regulatory year* of the relevant *regulatory control period*.

(c) The *AER* must accept the forecast of required operating expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal* if the *AER* is satisfied that the total of the forecast operating expenditure for the *regulatory control period* reasonably reflects each of the following (the *operating expenditure criteria*):

(1) the efficient costs of achieving the *operating expenditure objectives*; and

(2) the costs that a prudent operator would require to achieve the *operating expenditure objectives*; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the *operating expenditure objectives*.

(d) If the *AER* is not satisfied as referred to in paragraph (c), it must not accept the forecast of required operating expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal*.

(e) In deciding whether or not the *AER* is satisfied as referred to in paragraph (c), the *AER* must have regard to the following (the *operating expenditure factors*):

(1) [**Deleted**]

(2) [**Deleted**]

(3) [**Deleted**]

(4) the most recent *annual benchmarking report* that has been *published* under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient *Distribution Network Service Provider* over the relevant *regulatory control period*;

(5) the actual and expected operating expenditure of the *Distribution Network Service Provider* during any preceding *regulatory control periods*;

(5A) the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the *Distribution Network Service Provider* in the course of its engagement with electricity consumers;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between operating and capital expenditure;

(8) whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the *Distribution Network Service Provider* under clauses 6.5.8 or 6.6.2 to 6.6.4;

(9) the extent the operating expenditure forecast is referable to arrangements with a person other than the *Distribution Network Service Provider* that, in the opinion of the *AER*, do not reflect arm's length terms;

(9A) whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a *contingent project* under clause 6.6A.1(b);

(10) the extent the *Distribution Network Service Provider* has considered, and made provision for, efficient and prudent *non-network options* or *SAPS options*; and

(11) any relevant final project assessment report (as defined in clause 5.10.2) *published* under clause 5.17.4(o), (p) or (s);

(12) any other factor the *AER* considers relevant and which the *AER* has notified the *Distribution Network Service Provider* in writing, prior to the submission of its revised *regulatory proposal* under clause 6.10.3, is an *operating expenditure factor*.

6.5.7 Forecast capital expenditure

(a) A *building block proposal* must include the total forecast capital expenditure for the relevant *regulatory control period* which the *Distribution Network Service Provider* considers is required in order to achieve each of the following (the *capital expenditure objectives*):

(1) meet or manage the expected demand for *standard control services* over that period;

(2) comply with all applicable *regulatory obligations or requirements* associated with the provision of *standard control services*;

(3) to the extent that there is no applicable *regulatory obligation or requirement* in relation to:

(i) the quality, reliability or security of supply of *standard control services*; or

(ii) the reliability or security of the *distribution system* through the supply of *standard control services*,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of *standard control services*; and

(iv) maintain the reliability and security of the *distribution system* through the supply of *standard control services*; and

(4) maintain the safety of the *distribution system* through the supply of *standard control services*.

(b) The forecast of required capital expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal* must:

(1) comply with the requirements of any relevant *regulatory information instrument*;

(2) be for expenditure that is properly allocated to *standard control services* in accordance with the principles and policies set out in the *Cost Allocation Method* for the *Distribution Network Service Provider*;

(3) include both:

(i) the total of the forecast capital expenditure for the relevant *regulatory control period*; and

(ii) the forecast capital expenditure for each *regulatory year* of the relevant *regulatory control period*; and

(4) identify any forecast capital expenditure for the relevant *regulatory control period* that is for an option that has satisfied the *regulatory investment test for transmission* or the *regulatory investment test for distribution* (as the case may be); and

(5) not include *expenditure for a restricted asset*, unless:

(i) to the extent that any such expenditure includes an amount of unspent capital expenditure for a *contingent project* in accordance with paragraph (g), an *asset exemption* has been granted by the *AER* under clause 6.4B.1(a)(2) in respect of that asset or that class of asset for that *contingent project*;

(ii) to the extent that any such expenditure relates to a *positive pass through amount*, an *asset exemption* has been granted by the *AER* under clause 6.4B.1(a)(3) in respect of that asset or that class of asset for that *positive pass through amount*; or

(iii) otherwise, the *Distribution Network Service Provider* has submitted an *exemption application* with the *regulatory proposal* requesting an *asset exemption* under clause 6.4B.1(a)(1) for the *regulatory control period* in respect of that asset or class of asset.

(c) The *AER* must:

(1) subject to subparagraph (c)(2), accept the forecast of required capital expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal* if the *AER* is satisfied that the total of the forecast capital expenditure for the *regulatory control period* reasonably reflects each of the following (the *capital expenditure criteria*):

(i) the efficient costs of achieving the *capital expenditure objectives*;

(ii) the costs that a prudent operator would require to achieve the *capital expenditure objectives*; and

(iii) a realistic expectation of the demand forecast and cost inputs required to achieve the *capital expenditure objectives*.

(2) not accept the forecast of required capital expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal* if that forecast includes *expenditure for a restricted asset*, unless:

(i) to the extent that any such expenditure includes an amount of unspent capital expenditure for a *contingent project* in accordance with paragraph (g), an *asset exemption* has been granted by the *AER* under clause 6.4B.1(a)(2) in respect of that asset or that class of asset for that *contingent project*;

(ii) to the extent that any such expenditure relates to a *positive pass through amount*, an *asset exemption* has been granted by the *AER* under clause 6.4B.1(a)(3) in respect of that asset or that class of asset for that *positive pass through amount*; or

(iii) otherwise:

(A) that *Distribution Network Service Provider* has requested an *asset exemption* under subparagraph (b)(5) in respect of that asset or that class of asset; and

(B) the *AER* has granted that *asset exemption*.

(d) If the *AER* is not satisfied as referred to in paragraph (c), it must not accept the forecast of required capital expenditure of a *Distribution Network Service Provider*.

(e) In deciding whether or not the *AER* is satisfied as referred to in paragraph (c), the *AER* must have regard to the following (the *capital expenditure factors*):

(1) [**Deleted**]

(2) [**Deleted**]

(3) [**Deleted**]

(4) the most recent *annual benchmarking report* that has been *published* under rule 6.27 and the benchmark capital expenditure that would be incurred by an efficient *Distribution Network Service Provider* over the relevant *regulatory control period*;

(5) the actual and expected capital expenditure of the *Distribution Network Service Provider* during any preceding *regulatory control periods*;

(5A) the extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the *Distribution Network Service Provider* in the course of its engagement with electricity consumers;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between operating and capital expenditure;

(8) whether the capital expenditure forecast is consistent with any incentive scheme or schemes that apply to the *Distribution Network Service Provider* under clauses 6.5.8A or 6.6.2 to 6.6.4;

(9) the extent the capital expenditure forecast is referable to arrangements with a person other than the *Distribution Network Service Provider* that, in the opinion of the *AER*, do not reflect arm's length terms;

(9A) whether the capital expenditure forecast includes an amount relating to a project that should more appropriately be included as a *contingent project* under clause 6.6A.1(b);

(10) the extent the *Distribution Network Service Provider* has considered, and made provision for, efficient and prudent *non-network options* or *SAPS options*;

(11) any relevant final project assessment report (as defined in clause 5.10.2) *published* under clause 5.17.4(o), (p) or (s); and

(12) any other factor the *AER* considers relevant and which the *AER* has notified the *Distribution Network Service Provider* in writing, prior to the submission of its revised *regulatory proposal* under clause 6.10.3, is a *capital expenditure factor*.

Forecast capital expenditure and contingent projects

(f) Paragraphs (g) - (j) apply where:

(1) in a *regulatory control period* (the **first *regulatory control period***), the *AER* determines under clause 6.6A.2(e)(1)(iii) that the likely completion date for a *contingent project* is a date which occurs in the immediately following *regulatory control period* (the **second *regulatory control period***); and

(2) there is an unspent amount of capital expenditure for that *contingent project* under paragraph (g).

(g) Subject to paragraphs (ga) and (j), a *Distribution Network Service Provider's regulatory proposal* for the second *regulatory control period* must include in the forecast of required capital expenditure referred to in paragraph (a) an amount of any unspent capital expenditure for each *contingent project* as described in subparagraph (f)(2), that equals the difference (if any) between:

(1) the total capital expenditure for that *contingent project*, as determined by the *AER* in the first *regulatory control period* under clause 6.6A.2(e)(1)(ii); and

(2) the total of the capital expenditure actually incurred (or estimated capital expenditure for any part of the first *regulatory control period* for which actual capital expenditure is not available) in the first *regulatory control period* for that *contingent project*.

(ga) For the purposes of calculating any unspent capital expenditure in accordance with paragraph (g), the total or estimate of capital expenditure referred to in subparagraph (g)(2) must not include *expenditure for a restricted asset*, unless:

(1) the *Distribution Network Service Provider* has submitted an *exemption application* under clause 6.6A.1(a1) for the previous *regulatory control period*, which requested an *asset exemption* under clause 6.4B.1(a)(2) in respect of that asset or class of asset for that *contingent project*; and

(2) the *AER* has granted that *asset exemption*.

(h) The *AER* must include in any forecast capital expenditure for the second *regulatory control period* which is accepted in accordance with paragraph (c) or substituted in accordance with clause 6.12.1(3)(ii) (as the case may be) the amount of any unspent capital expenditure calculated in accordance with paragraph (g).

(i) Without limiting the requirement in paragraph (h), in deciding whether or not to accept the forecast of required capital expenditure of a *Distribution Network Service Provider* for the second *regulatory control period* in accordance with this clause 6.5.7, the *AER* must not:

(1) assess the reasonableness of the amount of unspent capital expenditure for a *contingent project* referred to in paragraph (g) or the remaining period to which the *contingent project* applies;

(2) assess the reasonableness of the timing of the unspent capital expenditure within the remaining period for a *contingent project* referred to in paragraph (g) except as part of the assessment of the total forecast capital expenditure under paragraph (c); or

(3) take into account any amount which represents for a *contingent project* referred to in paragraph (g) the difference between:

(i) the amount representing the sum of the forecast capital expenditure for that *contingent project* for each year of the immediately preceding *regulatory control period* referred to in clause 6.6A.2(e)(1)(i); and

(ii) the total capital expenditure actually incurred (or estimated capital expenditure for any part of the preceding *regulatory control period* for which actual capital expenditure is not available) in the immediately preceding *regulatory control period* for that *contingent project*.

(j) A *regulatory proposal* in respect of the second *regulatory control period* must not include in the forecast of required capital expenditure referred to in paragraph (a) any capital expenditure for a *contingent project* for the first *regulatory control period*:

(1) to the extent that the capital expenditure was included in the amount of capital expenditure for that *contingent project* as determined in the first *regulatory control period* under clause 6.6A.2(e)(1)(i); and

(2) the capital expenditure actually incurred (or estimated capital expenditure for any part of the first *regulatory control period* for which actual capital expenditure is not available) in the first *regulatory control period* for that *contingent project* exceeded the capital expenditure referred to in subparagraph (1).

6.5.8 Efficiency benefit sharing scheme

(a) The *AER* must, in accordance with the *distribution consultation procedures*, develop and *publish* an incentive scheme or schemes (*efficiency benefit sharing scheme*) that provide for a fair sharing between *Distribution Network Service Providers* and *Distribution Network Users* of:

(1) the efficiency gains derived from the operating expenditure of *Distribution Network Service Providers* for a *regulatory control period* being less than; and

(2) the efficiency losses derived from the operating expenditure of *Distribution Network Service Providers* for a *regulatory control period* being more than,

the forecast operating expenditure accepted or substituted by the *AER* for that *regulatory control period*.

(b) An *efficiency benefit sharing scheme* may (but is not required to) be developed to cover efficiency gains and losses related to *distribution losses*.

(c) In developing and implementing an *efficiency benefit sharing scheme*, the *AER* must have regard to:

(1) the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for *Distribution Network Service Providers*;

(2) the need to provide *Distribution Network Service Providers* with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure~~.~~;

(3) the desirability of both rewarding *Distribution Network Service Providers* for efficiency gains and penalising *Distribution Network Service Providers* for efficiency losses;

(4) any incentives that *Distribution Network Service Providers* may have to capitalise expenditure; and

(5) the possible effects of the scheme on incentives for the implementation of *non-network options* or *SAPS options*.

(d) The *AER* may, from time to time and in accordance with the *distribution consultation procedures*, amend or replace an *efficiency benefit sharing scheme*.

6.6 Adjustments after making of building block determination.

6.6.2 Service target performance incentive scheme

(a) The *AER* must, in accordance with the *distribution consultation procedures*, develop and *publish* an incentive scheme or schemes (*service target performance incentive scheme*) to provide incentives (which may include targets) for *Distribution Network Service Providers* to maintain and improve performance.

(b) In developing and implementing a *service target performance incentive scheme*, the *AER*:

(1) must consult with the authorities responsible for the administration of relevant *jurisdictional electricity legislation*; and

(2) must ensure that service standards and service targets (including guaranteed service levels) set by the scheme do not put at risk the *Distribution Network Service Provider's* ability to comply with relevant service standards and service targets (including guaranteed service levels) as specified in *jurisdictional electricity legislation*; and

Note:

A *service target performance incentive scheme* operates concurrently with any average or minimum service standards and guaranteed service level schemes that apply to the *Distribution Network Service Provider* under *jurisdictional electricity legislation*.

(3) must take into account:

(i) the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for *Distribution Network Service Providers*; and

(ii) any *regulatory obligation or requirement* to which the *Distribution Network Service Provider* is subject; and

(iii) the past performance of the *distribution network*; and

(iv) any other incentives available to the *Distribution Network Service Provider* under the *Rules* or a relevant distribution determination; and

(v) the need to ensure that the incentives are sufficient to offset any financial incentives the *Distribution Network Service Provider* may have to reduce costs at the expense of service levels; and

(vi) the willingness of the customer or end user to pay for improved performance in the delivery of services; and

(vii) the possible effects of the scheme on incentives for the implementation of *non-network options* or *SAPS options*; and

(4) must have regard to the *Distribution Reliability Measures Guidelines*.

(c) The *AER* may, from time to time and in accordance with the *distribution consultation procedures*, amend or replace any scheme that is developed and *published* under this clause.

Note:

A *Distribution Network Service Provider* is not precluded from entering into a contract with a third party (such as a network support service provider) under which the benefits of a *service target performance incentive scheme* are passed on to the third party, or the third party is required to indemnify the provider for penalties to which the provider becomes liable under the scheme.

6.6.3 Demand management incentive scheme

(a) The *AER* must develop a *demand management incentive scheme* consistent with the *demand management incentive scheme objective*.

(b) The objective of the *demand management incentive scheme* is to provide *Distribution Network Service Providers* with an incentive to undertake efficient expenditure on relevant *non-network options* relating to demand management (the *demand management incentive scheme objective*).

(c) In developing, and applying, any *demand management incentive scheme*, the *AER* must take into account the following:

(1) the scheme should be applied in a manner that contributes to the achievement of the *demand management incentive scheme objective*;

(2) the scheme should reward *Distribution Network Service Providers* for implementing relevant *non-network options* that deliver net cost savings to *retail customers*;

(3) the scheme should balance the incentives between expenditure on *network options* or *SAPS options* and *non-network options* relating to demand management. In doing so, the *AER* may take into account the net economic benefits delivered to all those who produce, consume and transport electricity in the *market* associated with implementing relevant *non-network options*;

(4) the level of the incentive:

(i) should be reasonable, considering the long term benefit to *retail customers*;

(ii) should not include costs that are otherwise recoverable from any another source, including under a relevant distribution determination; and

(iii) may vary by *Distribution Network Service Provider* and over time;

(5) penalties should not be imposed on *Distribution Network Service Providers* under any scheme;

(6) the incentives should not be limited by the length of a *regulatory control period*, if such limitations would not contribute to the achievement of the *demand management incentive scheme objective*; and

(7) the possible interaction between the scheme and:

(i) any other incentives available to the *Distribution Network Service Provider* in relation to undertaking efficient expenditure on, or implementation of, relevant *non-network options* relating to demand management;

(ii) particular control mechanisms and their effect on a *Distribution Network Service Provider's* available incentives referred to in sub-paragraph (i); and

(iii) meeting any *regulatory obligation or requirement*.

(d) The *AER*:

(1) must develop and *publish* the scheme; and

(2) may, from time to time, amend or replace the scheme developed and *published* under this clause,

in accordance with the *distribution consultation procedures*.

6.6.3A Demand management innovation allowance mechanism

(a) The *AER* must develop a *demand management innovation allowance mechanism* consistent with the *demand management innovation allowance objective*.

(b) The objective of the *demand management innovation allowance mechanism* is to provide *Distribution Network Service Providers* with funding for research and development in demand management projects that have the potential to reduce long term *network* costs (the *demand management innovation allowance objective*).

(c) In developing and applying any *demand management innovation allowance mechanism*, the *AER* must take into account the following:

(1) the mechanism should be applied in a manner that contributes to the achievement of the *demand management innovation allowance objective*;

(2) demand management projects, the subject of the allowance, should:

(i) have the potential to deliver ongoing reductions in demand or peak demand; and

(ii) be innovative and not be otherwise efficient and prudent *non-network options* relating to demand management that a *Distribution Network Service Providers* should have provided for in its *regulatory proposal*;

(3) the level of the allowance:

(i) should be reasonable, considering the long term benefit to *retail customers*;

(ii) should only provide funding that is not available from any another source, including under a relevant distribution determination; and

(iii) may vary by *Distribution Network Service Provider* and over time;

(4) the allowance may fund demand management projects which occur over a period longer than a *regulatory control period*.

(d) Any mechanism developed and applied by the *AER* must require *Distribution Network Service Providers* to *publish* reports on the nature and results of demand management projects the subject of the allowance.

(e) The *AER*:

(1) must develop and *publish* the mechanism; and

(2) may, from time to time, amend or replace any mechanism developed and *published* under this clause,

in accordance with the *distribution consultation procedures*.

Part DA Connection policies

6.7A Connection policy requirements

This *Rule* deals with the preparation of, requirements for and approval of *connection policies*.

6.7A.1 Preparation of, and requirements for, connection policy

(a) A *Distribution Network Service Provider* must prepare a document (its proposed *connection policy*) setting out the circumstances in which it may require a *retail customer* (as defined in Chapter 5A) or *real estate developer* to pay a *connection charge*, for the provision of a *connection service* under Chapter 5A.

(b) The proposed *connection policy*:

(1) must be consistent with:

(i) the *connection charge principles*; and

(ii) the *connection charge guidelines*; and

(2) must specify:

(i) the categories of persons that may be required to pay a *connection charge* and the circumstances in which such a requirement may be imposed; and

(ii) the aspects of a *connection service* for which a *connection charge* may be made; and

Example

The *Distribution Network Service Provider* might (for example) make separate *connection charges* for the provision of a *distribution connection asset* and for making a necessary *extension* to, or other *augmentation* of, the *distribution network*.

(iii) the basis on which *connection charges* are determined; and

(iv) the manner in which *connection charges* are to be paid (or equivalent consideration is to be given); and

Examples

The payment (or equivalent consideration) might take the form of a capital contribution, prepayment or financial guarantee.

(v) a threshold (based on capacity or any other measure identified in the *connection charge guidelines*) below which a *retail customer* (not being a non-registered *embedded generator*, ~~or~~ a *real estate developer*, a *Registered Participant* or an *Intending Participant*) will not be liable for a *connection charge* for an *augmentation* other than an *extension*.

Part I Distribution Pricing Rules

6.18 Distribution Pricing Rules

6.18.4 Principles governing assignment or re-assignment of retail customers to tariff classes and assessment and review of basis of charging

(a) In formulating provisions of a distribution determination governing the assignment of *retail customers* to *tariff classes* or the re-assignment of *retail customers* from one *tariff class* to another, the *AER* must have regard to the following principles:

(1) *retail customers* should be assigned to *tariff classes* on the basis of one or more of the following factors:

(i) the nature and extent of their usage;

(ii) the nature of their *connection* to the *network*;

(iii) whether remotely-read interval metering or other similar metering technology has been installed at the *retail customer's* premises as a result of a *regulatory obligation or requirement*;

(2) *retail customers* with a similar *connection* and usage profile should be treated on an equal basis, subject to subparagraphs (3) and (4);

(3) ~~however,~~ *retail customers* with micro-generation facilities should be treated no less favourably than *retail customers* without such facilities but with a similar load profile;

(4) *retail customers connected* to a *regulated SAPS* should be treated no less favourably than *retail customers* with a similar load profile *connected* to the interconnected national electricity system; and

(~~4~~5) a *Distribution Network Service Provider's* decision to assign a customer to a particular *tariff class*, or to re-assign a customer from one *tariff class* to another should be subject to an effective system of assessment and review.

Note:

If (for example) a customer is assigned (or reassigned) to a *tariff class* on the basis of the customer's actual or assumed *maximum demand*, the system of assessment and review should allow for the reassignment of a customer who demonstrates a reduction or increase in *maximum demand* to a *tariff class* that is more appropriate to the customer's *load* profile.

(b) If the *charging parameters* for a particular tariff result in a basis of charge that varies according to the usage or load profile of the customer, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged.

CHAPTER 10

Important note:

This document shows changes proposed to Chapter 10 of the National Electricity Rules by the draft report for distributor-led stand-alone power systems. The changes are shown in a modified version of Chapter 10 that incorporates changes made by the Rules listed below. This modified version of Chapter 10 is provided to assist in responding to the draft Rule and should not be used for any other purpose.

1 Schedule 4 of the National Electricity Amendment (Retailer Reliability Obligation) Rule 2019 which came into effect on 1 July 2019

2 Schedule 3 of the National Electricity Amendment (Register of distributed energy resources) Rule 2018 which came into effect on 1 December 2019

3 Schedule 6 of the National Electricity Amendment (Five minute settlement) Rule 2017 which will come into effect on 1 July 2021

4 Schedule 2 of the National Electricity Amendment (Participant compensation following market suspension) Rule 2018 which will come into effect on1 July 2021

This document does not include changes made by the following Rules:

1 Schedule 4 of the National Electricity Amendment (Global settlement and market reconciliation) Rule 2018 which will come into effect on 6 February 2022

2 Schedule 5 of the National Electricity Amendment (Five minute settlement and global settlement implementation amendments) Rule 2019 which will come into effect on 6 February 2022

3 Any Rules made after 22 October 2019 (other than a correction to the numbering in the definition of *transmission or distribution system*). As at 26 November 2019, these are the National Electricity Amendment (Transparency of new projects) Rule 2019 No 8 and the National Electricity Amendment (Minor changes) Rule 2019 No 9.

10. Glossary

distribution system

A *distribution network*, together with the *connection assets* associated with the *distribution network*, which is:

(a) *connected* to another *transmission or distribution system*; or

(b) comprised in a *regulated SAPS*.

Connection assets on their own, and *dedicated connection assets* in respect of which a *Primary Transmission Network Services Provider* is registered, do not constitute a *distribution system*.

DNSP-led SAPS project

A project undertaken by a *Distribution Network Service Provider* to address system limitations (as defined in clause 5.10.2) and that involves the planning, development, construction and commissioning of a *stand-alone power system.*

large SAPS generating unit

A *generating unit,* other than a *small generating unit,* that is *connected* to a *regulated SAPS.*

market

Any of the markets or exchanges described in the *Rules*, for so long as the market or exchange is conducted by *AEMO*.

A *market* includes the arrangements in rules 3.15 and 3.21 for sale and purchase of *SAPS energy.*

Market Small Generation Aggregator

A person who:

(a) has classified one or more *small generating units* or *large SAPS generating units* as a *market generating unit*; and

(b) is registered by *AEMO* as a *Market Small Generation Aggregator* under Chapter 2.

national grid

The sum of all *connected transmission systems* and *distribution systems* and *regulated SAPS* within the *participating jurisdictions*.

network option

A means by which an *identified need* can be fully or partly addressed by expenditure on a transmission asset or a distribution asset which is undertaken by a *Network Service Provider*, but excluding a *SAPS option*.

For the purposes of this definition, **transmission asset** and **distribution asset** has the same meaning as in clause 5.10.2.

non-network option

A means by which an *identified need* can be fully or partly addressed other than by a *network option* or a *SAPS option*.

power system

The electricity power system of the *national grid* including associated *generation* and *transmission* and *distribution networks* for the *supply* of electricity but excluding *regulated SAPS*, operated as an integrated arrangement.

regulated SAPS, regulated stand-alone power system

A *stand-alone power system* implemented as a *DNSP-led SAPS project.*

SAPS adjustment market transaction

A transaction as defined pursuant to clause 3.21.3(a) which occurs in relation to *SAPS energy.*

SAPS energy

Electrical *energy* flowing at a *connection point* (including a *child connection point*) in a *regulated SAPS.*

SAPS facility

A *facility* comprised in or *connected*, directly or indirectly, to a *regulated SAPS.*

SAPS option

A means by which an *identified need* can be fully or partly addressed by converting a part of a *distribution network* to a *regulated SAPS.*

SAPS Participant

A *Registered Participant* in its capacity as:

(a) the owner, operator or controller of a *SAPS facility*; or

(b) the *financially responsible Market Participant* in respect of a *connection point* in a *regulated SAPS.*

SAPS settlement price

For a *trading interval*, the price determined in accordance with clause 3.21.2 to be the *SAPS settlement price* for the *financial year* in which the *trading interval* falls.

Small Generation Aggregator

A person who:

(a) intends to supply, or supplies, electricity from one or more *small generating units* or *large SAPS generating units* that are connected to a *transmission or distribution system*; and

(b) is registered by *AEMO* as a *Small Generation Aggregator* under Chapter 2.

stand-alone distribution system

Has the meaning given in the *National Electricity Law.*

stand-alone power system

Has the meaning given in the *National Electricity Law.*

transmission or distribution system

A *transmission system* or *distribution system* that:

(a) is used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail); and

(b) is *connected* to another such system or is a *regulated SAPS*.

CHAPTER 11

11. Savings and Transitional Rules

Part [XXX] Distributor-led SAPS

11.[xxx] Rules consequential on the making of the National Electricity Amendment ([Name of rule]) Rule 2020

11.[xxx].1 Definitions

(a) In this rule 11.[xxx]:

adoptive SAPS network has the same meaning as in new clause 5.10.2.

Amending Rule means the National Electricity Amendment ([Name of rule]) Rule 2020.

effective date means the date of commencement of Schedules [x, y and z] of the Amending Rule.

industry engagement document has the same meaning as in new clause 5.10.2.

industry engagement strategy means has the same meaning as in new clause 5.10.2.

new Chapter 10 means Chapter 10 as in force immediately after the effective date.

new clause 5.10.2 means clause 5.10.2 as in force immediately after the effective date.

new clause 5.13.4 means clause 5.13.4 as in force immediately after the effective date.

SAPS application date means the date from which a network becomes an adoptive SAPS network.

SAPS customer engagement document has the same meaning as in new clause 5.10.2.

SAPS customer engagement strategy has the same meaning as in new clause 5.10.2.

(b) Italicised terms used in this rule 11.[xxx] have the same meaning as in new Chapter 10.

11.[xxx].2 Amendments to AEMO documents

(a) By the effective date, *AEMO* must review and where necessary amend and *publish* the following documents to take into account the Amending Rule:

(1) the generator registration exemption guidelines made by *AEMO* under rule 2.2.1(c);

(2) the *Market Management Systems Access Procedures*;

(3) the *PoLR costs procedures*; and

(4) the *Reliability Forecast Guidelines*.

(b) Amendments made in accordance with paragraph (a) must take effect on and from the effective date.

11.[xxx].3 Amendments to AER documents

(a) By the effective date, the *AER* must review and where necessary amend and *publish* the following documents to take into account the Amending Rule:

(1) the regulatory investment test for distribution application guidelines made by the *AER* under clause 5.17.2;

(2) the *connection charge guidelines* made by the *AER* under clause 5A.E.3

(3) the *Distribution Service Classification Guidelines*;

(4) the *Asset Exemption Guidelines*;

(5) the *Cost Allocation Guidelines*;

(6) the *Distribution Ring-Fencing Guidelines*;

(7) the *Distribution Reliability Measures Guidelines*;

(8) the Forecasting Best Practice Guidelines made by the AER under clause 4A.B.5;

(9) the Contracts and Firmness Guidelines made by the *AER* in accordance with clause 4A.E.8;

(10) the Reliability Compliance Procedures and Guidelines (as defined in the *National Electricity Law*); and

(11) the MLO Guidelines made by the *AER* under clause 4A.G.25.

(b) Amendments made in accordance with paragraph (a) must take effect on and from the effective date.

11.[xxx].4 Industry engagement obligations

(a) A *Distribution Network Service Provider* for an adoptive SAPS network must, by the date determined under paragraph (c), review and where necessary amend and *publish* its industry engagement strategy and industry engagement document to take into account the Amending Rule.

(b) A *Distribution Network Service Provider* for an adoptive SAPS network must, in accordance with new clause 5.13.4 and by the date determined under paragraph (c):

(1) develop its initial SAPS customer engagement strategy; and

(2) develop and *publish* its initial SAPS customer engagement document.

(c) The date for completion of the activities required under paragraph (a) and (b) is the later of:

(1) the SAPS application date for the adoptive SAPS network; and

(2) the date falling 6 months after the making of jurisdictional legislation or other instrument by reason of which the *Distribution Network Service Provider's network* became an adoptive SAPS network.

NATIONAL ENERGY RETAIL RULES

Part 1 Preliminary

Division 1 Introduction and definitions

3 Definitions

Note—

Words and expressions used in these Rules have the same meanings as they have, from time to time, in *the Law* or relevant provisions of *the Law*, except so far as the contrary intention appears in these Rules. See clause 13 of Schedule 2 to the NGL (as applied by section 8 of *the Law*).

In these Rules—

acceptable identification, in relation to:

(a) a residential customer—includes any one of the following:

(i) a driver licence (or driver's licence) issued under *the law* of a State or Territory, a current passport or another form of photographic identification;

(ii) a Pensioner Concession Card or other entitlement card, issued under *the law* of the Commonwealth or of a State or Territory;

(iii) a birth certificate; or

(b) a business customer that is a sole trader or partnership—includes one or more of the forms of identification for a residential customer for one or more of the individuals that conduct the business or enterprise concerned; or

(c) a business customer that is a body corporate—means Australian Company Number or Australian Business Number of the body corporate;

bill issue date means the date, included in a bill under rule 25 (1) (e), on which the bill is sent by the retailer to a small customer;

cooling off period—see rule 47 (2);

customer authorised representative means a person authorised by a:

(a) small customer to act on its behalf under rules 56A and 56B; or

(b) customer to act on its behalf under rule 86A.

disconnection warning notice—see rule 110;

distributor planned interruption—see rule 88;

dual fuel market contract means:

(a) one market retail contract between a small customer and a retailer for the sale of both electricity and gas by the retailer to the small customer; or

(b) two market retail contracts with the same small customer, one for the sale of electricity and the other for the sale of gas to the customer, where the prices or conditions of one or both contracts are contingent on the customer entering into both contracts.

e-marketing activity has the meaning given by section 109A of the *Telecommunications Act 1997* of the Commonwealth;

good electricity industry practice has the same meaning as in the NER;

interruption:

(a) in the case of Division 9A of Part 2, means a temporary unavailability or temporary curtailment of the supply of electricity to a customer's premises; and

(b) in all other cases, means a temporary unavailability or temporary curtailment of the supply of energy to a customer's premises, but does not include unavailability or curtailment in accordance with the terms and conditions of a customer retail contract or customer connection contract, and any applicable tariff, agreed with the customer;

Temporary unavailability or temporary curtailment of the supply of energy to a customer's premises to implement a *regulated SAPS conversion* must be treated as an *interruption* for the purposes of these Rules and the *Law* (and not a de-energisation or disconnection).

Note:

Rule 107(4) provides that Part 6 (relating to de-energisation or disconnection of premises) does not apply to *interruptions* under Division 6 of Part 4 or under Division 9A of Part 2.

life support equipment means any of the following:

(a) an oxygen concentrator;

(b) an intermittent peritoneal dialysis machine;

(c) a kidney dialysis machine;

(d) a chronic positive airways pressure respirator;

(e) crigler najjar syndrome phototherapy equipment;

(f) a ventilator for life support;

(g) in relation to a particular customer—any other equipment that a registered medical practitioner certifies is required for a person residing at the customer's premises for life support;

maintenance replacement means the replacement of a small customer's existing electricity *meter* arranged by a retailer that is based on the results of sample testing of a *meter* population carried out in accordance with Chapter 7 of the NER:

(a) which indicates that it is necessary or appropriate, in accordance with *good electricity industry practice*, for the *meter* to be replaced to ensure compliance with the *metering rules*; and

(b) details of which have been provided to the retailer under Chapter 7 of the NER, together with the results of the sample testing that support the need for the replacement;

meter, in relation to a customer, means the device that measures the quantity of energy passing through it or records the consumption of energy at the customer's premises;

metering coordinator, in the case of electricity—has the same meaning as "*Metering Coordinator*" in the NER;

metering data has the same meaning as:

(a) in the case of electricity—in the NER; or

(b) in the case of gas—in the applicable Retail Market Procedures;

metering data provision procedures has the same meaning as in the NER.

metering installation malfunction has the same meaning as in the NER;

metering rules:

(a) for electricity—means the applicable Retail Market Procedures and Chapter 7 of the NER;

(b) for gas—means the applicable Retail Market Procedures;

NEM Representative means a related body corporate (within the meaning of the *Corporations Act 2001* of the Commonwealth) of an electricity retailer that is registered with AEMO as a market customer under the NER and that, directly or indirectly, sells electricity to the retailer for on-sale to customers;

new meter deployment means the replacement of the existing electricity *meter* of one or more small customers which is arranged by a retailer other than where the replacement is:

(a) at the request of the relevant small customer or to enable the provision of a product or service the customer has agreed to acquire from the retailer or any other person;

(b) a *maintenance replacement*;

(c) as a result of a *metering installation malfunction*; or

(d) required under section 59(2) of *the Law*;

pay-by date—see rule 26;

regulated SAPS conversion means the conversion of a part of a distribution system to a regulated stand-alone power system;

relevant authority means:

(a) AEMO; or

(b) State or federal police; or

(c) a person or body who has the power under law to direct a distributor to de-energise premises;

reminder notice—see rule 109;

responsible person, in the case of gas - means the person who, under the applicable Retail Market Procedures, is responsible for *meter* reading;

retailer planned interruption—see rule 59B;

security deposit means an amount of money paid or payable, in accordance with the Rules, to a retailer as a security against non-payment of a bill;

telemarketing call has the same meaning as in the *Telecommunications Act 1997* of the Commonwealth;

the Law means the National Energy Retail Law;

unplanned interruption—see rule 88.

void transfer means the transfer of a small customer from a retailer to another retailer which is void under section 41(1) of *the Law*.

void transfer date means the date of the *void transfer*.

Part 4 Relationship between distributors and customers

Division 6 Distributor interruption to supply

88 Definitions

In this Division:

distributor planned interruption means an *interruption* of the supply of energy for:

(a) the planned maintenance, repair or augmentation of the transmission system or a *regulated SAPS conversion*; or

(b) the planned maintenance, repair or augmentation of the distribution system, including planned or routine maintenance of *metering* equipment (excluding a *retailer planned interruption*); or

(c) the installation of a new connection or a connection alteration;

transmission system:

(a) for electricity—means a transmission system within the meaning of the NEL; or

(b) for gas—means a transmission pipeline within the meaning of the NGL;

unplanned interruption means an *interruption* of the supply of energy to carry out unanticipated or unplanned maintenance or repairs in any case where there is an actual or apprehended threat to the safety, reliability or security of the supply of energy, and includes:

(a) an *interruption* in circumstances where, in the opinion of the distributor, a customer's installation or the distribution system poses an immediate threat of injury or material damage to any person, any property or the distribution system; or

(b) an *interruption* in circumstances where:

   (i) there are health or safety reasons warranting an *interruption*; or

   (ii) there is an emergency warranting an *interruption*; or

   (iii) the distributor is required to *interrupt* the supply at the direction of a *relevant authority*; or

(c) an *interruption* to shed demand for energy because the total demand for energy at the relevant time exceeds the total supply available; or

(d) an *interruption* to restore supply to a customer.