Electricity transmission network service providers
Pricing methodology guidelines

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AUSTRALIAN ENERGY REGULATOR

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1 Nature and authority

1.1 Introduction

These *guidelines* specify or clarify a number of aspects in relation to the preparation of a *Transmission Network Service Provider's* (*TNSP*) proposed *pricing methodology* to be submitted to the *Australian Energy Regulator* (*AER*).

1.2 Authority

Clause 6A.25.1(a) of the *National Electricity Rules* requires the *AER* to develop, in accordance with the *transmission consultation procedures*, *guidelines* relating to the preparation of a proposed *pricing methodology* by a *TNSP*.

1.3 Role of these guidelines

These *guidelines* specify or clarify:

(a) the information that is to accompany a proposed *pricing methodology*;

(b) permitted pricing structures for the recovery of the locational component of providing *prescribed TUOS services*;

(c) permitted postage stamp pricing structures for *prescribed common transmission services* and the recovery of the adjusted non-locational component of providing *prescribed TUOS services*;

(d) the types of *transmission system* assets that are *directly attributable* to each *category of prescribed transmission service*;

(e) those parts of a proposed *pricing methodology*, or the information accompanying it that will not be publicly disclosed without the consent of the *TNSP*;

(f) the information that is to be included in the *pricing methodology* of a *TNSP* who is a *Co-ordinating Network Service Provider (CNSP)*, including information related to the calculation and allocation of *modified load export charges*; and

(g) permitted methodologies for determining the *system strength unit price* component of the *system strength charge*, and

(h) principles for determining *forecast annual system strength revenue* and *estimated actual annual system strength revenue*.

1.4 Relationship between these guidelines and the National Electricity Rules

(a) Each *TNSP* must develop a proposed *pricing methodology* for submission to the AER in accordance with the requirements of these *guidelines* and the *National Electricity Rules*.

(b) The *pricing methodology* approved by the *AER* must be used by the relevant *TNSP*, in conjunction with the *National Electricity Rules*, for the purpose of determining *transmission* prices in each *regulatory year* of a *regulatory control* *period, including* the *system strength unit price* for the *system strength charging period*.

(c) Clause 6A.17.1 of the *National Electricity Rules* provides for information to be provided by the *TNSP* to the *AER* which the *AER* may use to monitor, report on and enforce compliance with a *transmission determination*, including a *TNSP*'s *pricing methodology*. A failure by a *TNSP* to comply with its *pricing methodology* may constitute a breach of clause 6A.24.1(d) of the *National Electricity Rules*.

1.5 Confidentiality

The *AER*'s obligations regarding confidentiality and the disclosure of information provided to it by a *TNSP* are governed by the *Competition and Consumer Act 2010*, the *National Electricity Law* and the *National Electricity Rules*.

1.6 Definitions and interpretation

(a) In these *guidelines* the words and phrases presented in italics have the meaning given to them in:

(1) the glossary; or

(2) if not defined in the glossary, the *National Electricity Rules*.

(b) Explanations in these *guidelines* about why certain information is required are provided for guidance only.

1.7 Processes for revision

The *AER* may amend or replace the *guidelines* from time to time in accordance with clause 6A.25.1 of the *National Electricity Rules*.

1.8 Version history and effective date

A version number and an effective date of issue will identify every version of these *guidelines*.

2 Pricing methodology guidelines

2.1 Information requirements

A *TNSP*'s proposed *pricing methodology* must contain the following information:

(a) Whether the *TNSP* is the sole provider of *prescribed transmission services* within its *region* or whether there are multiple *TNSP*s providing *prescribed transmission services* within its region.

(b) Whether the *TNSP* is, or has been appointed as, the *CNSP* for a *region* under clause 6A.29.1 of the *National Electricity Rules* and is therefore responsible, under clause 6A.29.2(a)(1) of the *National Electricity Rules*, for the allocation of the *total regional aggregate annual revenue requirement* (*total regional AARR*) for its *region* to services and the allocation of the *annual service revenue requirement* (*ASRR*) for services in the region to connection points and related adjustments.

(c) Details of how the *TNSP*'s *aggregate annual revenue requirement* (*AARR*) will be derived including an explanation of how the amounts subtracted from the *maximum allowed revenue* in accordance with clause 6A.22.1(2), of the *National Electricity Rules* will be determined and how they will be recovered via *transmission* prices.

(d) Where a *TNSP* is a *CNSP*, details of how the *total regional AARR* will be derived in accordance with clause 6A.22.5 of the *National Electricity Rules*, including:

   (1) an explanation of how any *interconnector transfer amount* is calculated and incorporated into the *total regional AARR*.

   (2) hypothetical examples of the derivation of the *total regional AARR* setting out the components identified in clauses 6A.22.5(a)–(d).

(e) Details of how the *AARR*, and/or the *total regional AARR* as relevant, will be allocated to derive the *ASRR* for each *category of prescribed transmission service*, including:

   (1) how the *attributable cost shares* for each *category of prescribed transmission service* will be calculated in accordance with clause 6A.22.3 of the *National Electricity Rules* including:

      (A) an explanation of how the costs referred to in clause 6A.22.3(a) and/or clause 6A.22.3(b), as relevant, of the *National Electricity Rules* will be calculated; and

      (B) hypothetical worked examples for each *category of prescribed transmission service*;

   (2) how the priority ordering approach outlined in clause 6A.22.3(c) of the *National Electricity Rules* will be applied, including a hypothetical worked example; and

   (3) how asset costs which may be attributable to both *prescribed entry services* and *prescribed exit services* will be allocated.

(f) Details of how the *ASRR* for each *category of prescribed transmission service* will be allocated to each *transmission connection point*, including:

(1) how the *attributable connection point cost share* for both *prescribed entry services* and *prescribed exit services* will be calculated in accordance with clause 6A.22.4 of the *National Electricity Rules*, including:

(A) an explanation of how the costs referred to in clause 6A.22.4(a) of the *National Electricity Rules* will be calculated;

(B) hypothetical worked examples; and

(C) how asset costs allocated to *prescribed entry services* and *prescribed exit services* at a *connection point*, which may be attributable to multiple *Transmission Network Users*, will be allocated;

(2) how the pre-adjusted locational and pre-adjusted non-locational components of *prescribed TUOS services* will be allocated in accordance with 6A.23.3(a) of the *National Electricity Rules*;

(3) how the adjusted locational and adjusted non-locational components of *prescribed TUOS services* will be determined and allocated to *connection points* in accordance with clauses 6A.23.3(b)–(g) of the *National Electricity Rules*.

(g) In relation to price structures:

(1) confirm that separate prices will be developed for each *category of prescribed transmission service*;

(2) confirm that the prices for *prescribed entry services* and *prescribed exit services* will be a fixed annual amount, and describe how these amounts will be calculated;

(3) outline how the pricing structure for the recovery of the locational component of *prescribed TUOS services* complies with these *guidelines* and clauses 6A.23.4(b)-(d) of the *National Electricity Rules* including outlining:

(A) the time period for the allocation of *generation* to *load* as prescribed in clause S6A.3.2(3) of the *National Electricity Rules*;

(B) how prices will be structured to comply with the *National Electricity Rules* and these *guidelines*; and

(C) the process for deriving the locational charge for each *billing period* and details of any adjustment mechanism applied to a measure of forecast demand once actual demand is known.

(4) outline how the postage stamp pricing structure for the recovery of the adjusted non locational component of *prescribed TUOS services* complies with these *guidelines* and clause 6A.23.4(e) of the National Electricity Rules; and

(5) outline how the postage stamp pricing structure for the recovery of *prescribed common transmission services* complies with these *guidelines* and clause 6A.23.4(f) of the *National Electricity Rules*.

(h) Details of how the *TNSP* intends to set the *prescribed TUOS service* locational price at new *connection points* or at *connection points* where the *load* has changed significantly after *prescribed TUOS service* locational prices have been determined and published by the *TNSP*.

(i) If a *TNSP* expects to calculate a postage stamped price in accordance with either section 2.3(c)(4)(C) or 2.3(d)(3)(C) of these *guidelines*, it must explain the likely circumstances surrounding the use of *current metered energy offtake* or *current metered maximum demand offtake* in its proposed *pricing methodology*.

(j) The information in relation to inter-regional charging arrangements required by section 2.6 of these *guidelines*.

(k) Whether the *TNSP* is the *System Strength Service Provider* for its *region*.

(l) Where the *TNSP* is the *System Strength Service Provider* for its *region*:

(1) confirm that a *System Strength Transmission Service User* for a *system strength connection point* will pay an *annual system strength charge* for the *system strength connection point* in equal monthly instalments from the time referred to in paragraph (2) in accordance with clause 6A.23.5 of the *National Electricity Rules* and these *guidelines*;

(2) explain the time at which the *system strength charge* will commence to be payable by a *System Strength Transmission Service User*;

(3) confirm that the monthly instalments for the *system strength charge* will be calculated on a pro rata basis for the remaining months of the *regulatory year* if the obligation to pay the *system strength charge* commences part way through a *regulatory year*;

(4) explain the methodologies it will apply to determine the *system strength unit price* for each *system strength node* on its *transmission network* for the *system strength charging period*, including an explanation of its methodology for forecasting its long run average costs of providing *system strength transmission services*;

(5) set out whether the *system strength unit price* will be updated for indexation for each *regulatory year* in the *system strength charging period* and, if so, the basis for indexation;

(6) explain how the methodologies and prices referred to in paragraphs (4) to (5) comply with the requirements in section 2.7(a) and (b) of these *guidelines* and clause 6A.23.5 of the *National Electricity Rules;*

(7) explain how it will calculate the adjustments required under clause 6A.23.3A(b) of the *National Electricity Rules*, including the methodologies it will apply to determine forecast *annual system strength revenue* and estimated actual *annual system strength revenue*; and

(8) explain how the methodologies referred to in paragraph (7) give effect to, and are consistent with, clause 6A.23.3A of the *National Electricity Rules* and the principles in section 2.8 of these *guidelines*.

(m) Where the *TNSP* is not the *System Strength Service Provider* for its *region*:

(1) explain how it will set charges applicable to each *system strength connection point* on its *transmission network* to recover on a pass through basis the *annual system strength charge* for the *system strength connection point* determined by the relevant *System Strength Service Provider*; and

(2) explain how the charges referred to in paragraph (1) comply with the requirements of clause 6A.23.6 of the *National Electricity Rules*, including:

(A) how the amount, structure and timing of the charges referred to in paragraph (1) replicates as far as reasonably practical the amount, structure and timing of the corresponding *system strength charge* billed to the *TNSP* by the *System Strength Service Provider*; and

(B) an explanation of the reasons for any differences between the amount, structure and timing of the charges referred to in paragraph (1) and the amount, structure and timing of the corresponding *system strength charge* billed to the *TNSP* by the *System Strength Service Provider*;

(3) the requirements in paragraphs (1) and (2) do not apply to a *TNSP*:

(A) in an *adoptive jurisdiction*; or

(B) that can establish to the *AER*'s satisfaction that it is unlikely to have any *system strength connection points* on its *transmission network* during the period over which the proposed *pricing methodology* will apply.

(n) A statement of how the *pricing methodology* gives effect to and is consistent with, the *pricing principles for prescribed transmission services* including an explanation of how any alternative pricing structure which the *TNSP* wishes to apply meets the requirements of clause 6A.23.4 of the *National Electricity Rules*.

(o) Details of any proposed transitional arrangements the *TNSP* considers necessary as a result of the implementation of its *pricing methodology*.

(p) Information relating to any prudent discounts for *prescribed transmission services* previously submitted to the *AER* or expected to be submitted to the *AER* within the next *regulatory control period* and how those discounts are proposed to be recovered from *Transmission Network Users* in accordance with clause 6A.26 of the *National Electricity Rules*.

(q) Details of billing arrangements with *Transmission Network Users* and transfers between *TNSP*s conducted in accordance with clause 6A.27 of the *National Electricity Rules*.

(r) Details of the nature of prudential requirements as outlined in clause 6A.28 of the *National Electricity Rules* and how any capital contributions will be taken into account in determining a *Transmission Network Users*' prices for *prescribed transmission services*.

(s) If a *TNSP* has, in accordance with section 2.5 of these *guidelines*, provided the *AER* with a confidential version of its proposed *pricing methodology*, the non confidential version of the proposed *pricing methodology* must outline the area or areas where the *TNSP* is making a claim for confidentiality and why.

(t) Details of any derogation in accordance with chapter 9 of the *National Electricity Rules*.

(u) Details of any transitional arrangements which apply in accordance with chapter 11 of the *National Electricity Rules*.

(v) The period over which the proposed *pricing methodology* will apply, including the periods of the *regulatory control period* and the *system strength charging period*.

(w) A description of any differences between the current *pricing methodology* and that proposed for the next *regulatory control period* and *system strength charging period*.

(x) Details of how the *TNSP* intends to monitor and develop records of its compliance with its approved *pricing methodology*, the *pricing principles for prescribed transmission services* and more broadly Part J of Chapter 6A of the *National Electricity Rules*.

2.2 Permitted (locational) pricing structures

(a) Prices for the recovery of the locational component of *prescribed TUOS services* must be based on demand at times of greatest utilisation of the *transmission network* and for which network investment is most likely to be contemplated in accordance with clause 6A.23.4(b) of the *National Electricity Rules*.

(b) The *CRNP* methodology and modified *CRNP* methodology outlined in S6A.3 of the *National Electricity Rules* provide guidance on the process for cost allocation for the locational component of *prescribed TUOS services* and results in a lump sum dollar amount to be recovered at each *transmission connection point*.

(c) The following measures of demand are be applied to the lump sum dollar amount referred to section 2.2(b) to derive the locational price at each *transmission connection point*:

  (1) The current *contract agreed maximum demand* (prevailing at the time *transmission* prices are published) as negotiated in a *transmission customer*'s connection agreement or the *transmission customer*'s maximum demand in the previous 12 months if the *transmission customer* has exceeded its current *contract agreed maximum demand*, expressed as $/MW/day; or

  (2) The average of the *transmission customer*'s half-hourly maximum demand recorded at a *connection point* on the 10 weekdays when system demand was highest between the hours of 11:00 and 19:00 in the local time zone during the previous 12 months, expressed as $/MW/day.

(d) A *TNSP* (or *CNSP*) may propose alternative pricing structures for the recovery of the locational component of *prescribed TUOS services* which it considers give effect to, and are consistent with the *pricing principles for prescribed transmission services* in the *National Electricity Rules*.

(e) If a *TNSP* (or *CNSP*) proposes an alternative pricing structure for the recovery of the locational component of *prescribed TUOS services,* it must clearly demonstrate to the AER that the alternative pricing structure:

(1) gives effect to, and is consistent with the *pricing principles for prescribed transmission services* in the *National Electricity Rules*;

(2) improves on the permitted pricing structures outlined in section 2.2(c) of these *guidelines*; and

(3) contributes to the *national electricity objective*.

(f) If historical data is unavailable for a *connection point* for use in either the allocation of costs to a *connection point* using the *CRNP* or modified *CRNP* methodology outlined in S6A.3 or the calculation of locational prices outlined in section 2.2(c) of these *guidelines*, an estimate of demand must be used instead.

(g) The *contract agreed maximum demand* must only be used for the calculation of the locational component of *prescribed TUOS services* pricing structure if the *transmission customer*'s connection agreement or other enforceable instrument governing the terms of connection of the *transmission customer*:

(1) nominates a fixed maximum demand for the *connection point*; and

(2) specifies penalties for exceeding the *contract agreed maximum demand*.

(h) The locational *TUOS* price calculated in accordance with these *guidelines* must be applied to a measure of actual, forecast or contract demand to derive the locational charge.

2.3 Permitted (postage stamp) pricing structures

(a) Prices for *prescribed common transmission services* and the recovery of the adjusted non-locational component of *prescribed TUOS services* are to be set on a *postage stamp basis* in accordance with clause 6A.23.4(f) and clause 6A.23.4(e) of the *National Electricity Rules* respectively.

(b) Permissible postage stamp pricing structures for either the non-locational component of *prescribed TUOS services* or *prescribed common transmission services* must be based on any one of the following:

(1) either *contract agreed maximum demand* or historical *energy*;

(2) *maximum demand*; or

(3) an alternative pricing structure.

(c) If a postage stamped structure is based on either *contract agreed maximum demand* or historical *energy* it must be calculated as follows:

(1) Each *financial year* a *TNSP* (or *CNSP*) must determine the following two prices:

(A) an energy based price that is a price per unit of historical metered energy or current metered energy at a *connection point*; and

(B) a *contract agreed maximum demand* price that is a price per unit of *contract agreed maximum demand* at a *connection point*.

(2) Either the energy based price or the *contract agreed maximum demand* price applies at a *connection point* except for those *connection points* where a *transmission customer* has negotiated reduced charges for *prescribed common transmission services* or the adjusted non-locational component of *prescribed TUOS services* in accordance with clause 6A.26.1 of the *National Electricity Rules*.

(3) The energy based price and the *contract agreed maximum demand* price referred to in section 2.3(c)(1) of these *guidelines* must be determined so that:

(A) a *transmission customer* with a load factor in relation to its *connection point* equal to the median load factor for *connection points* with *transmission customers* connected to the *transmission network* in the *region* or *regions* is indifferent between the use of the energy based price and the *contract agreed maximum demand* price; and

(B) the total amount to be recovered by the *prescribed common transmission services* or the adjusted non-locational component of *prescribed TUOS services* does not exceed the *ASRR* for each *category of prescribed transmission service*.

(4) The charge for either the *prescribed common transmission service* or the adjusted non locational component of *prescribed TUOS services* using the energy based price for a *billing period* in a *financial year* for each *connection point* must be calculated by:

(A) multiplying the energy based price by the metered energy offtake at that *connection point* in the corresponding *billing period* two years earlier (i.e. *historical metered energy offtake*); or

(B) multiplying the energy based price by the metered energy offtake at that *connection point* in the same *billing period* (*current metered energy offtake*) if the *historical metered energy offtake* is not available; or

(C) multiplying the energy based price by the *current metered energy offtake* if the *historical metered energy offtake* is significantly different to the *current metered energy offtake*.

(5) The charge calculated for *prescribed common transmission services* or the adjusted non-locational component of *prescribed TUOS services* using the *contract agreed maximum demand* price for a *billing period* in a *financial year* for each *connection point* must be calculated by multiplying the *contract agreed maximum demand* price by the maximum demand for the *connection point* in that *financial year* and then dividing this amount by the number of *billing periods* in the *financial year*.

(6) The energy based price or the *contract agreed maximum demand* price that applies for *prescribed common transmission services* or the adjusted non-locational component of *prescribed TUOS services* must be the one which results in the lower estimated charge for that *prescribed transmission service*.

(7) A *contract agreed maximum demand* price must only be used for the calculation of the *prescribed common transmission services* charge or the adjusted non-locational component of *prescribed TUOS services* charge if the *Transmission customer*'s connection agreement or other enforceable instrument governing the terms of connection of the *transmission customer*:

(A) nominates a *contract agreed maximum demand* for the *connection point*; and

(B) specifies penalties for exceeding the *contract agreed maximum demand*.

(d) If a postage stamped pricing structure is based on *maximum demand* it must be calculated as follows:

(1) Each *financial year* a *TNSP* (or *CNSP*) must determine the *maximum demand* based price that is a price per unit of *historical metered maximum demand* or actual metered *maximum demand* measured at a *connection point*;

(2) The *maximum demand* based price applies at a *connection point* except for those *connection points* where a *transmission customer* has negotiated reduced charges for *prescribed common transmission services* or the adjusted non-locational component of *prescribed TUOS services* in accordance with clause 6A.26.1 of the *National Electricity Rules*.

(3) The charge for either the *prescribed common transmission services* or the adjusted non-locational component of *prescribed TUOS services* using the *maximum demand* based price for a *billing period* in a *financial year* for each *connection point* must be calculated by:

(A) multiplying the *maximum demand* based price by the *maximum demand* at that *connection point* in the corresponding *billing period* two years earlier (i.e. *historical metered maximum demand offtake*); or

(B) multiplying the *maximum demand* based price by the *maximum demand* at that *connection point* in the same *billing period* (*current metered maximum demand offtake*) if the *historical maximum demand offtake* is not available;

(C) multiplying the *maximum demand* based price by the *current metered maximum demand offtake* if the *historical metered maximum demand offtake* is significantly different to the *current metered maximum demand offtake*.

(e) A *TNSP* (or *CNSP*) may propose alternative postage stamp pricing structures which it considers give effect to, and are consistent with the *pricing principles for* *prescribed transmission services* in the *National Electricity Rules*, in which case it must clearly demonstrate to the *AER* that the alternative pricing structure is least distortionary to *Transmission Network Users'* behaviour and:

(1) gives effect to, and is consistent with the *pricing principles for prescribed transmission services* in the *National Electricity Rules*;

(2) improves on the permitted pricing structures outlined in section 2.3(c) and (d) of these *guidelines*; and

(3) contributes to the *national electricity objective*.

2.4 Attribution of transmission system assets to categories of prescribed transmission services

(a) The following sections outline the types of *transmission system assets* that are *directly attributable* to each *category of prescribed transmission service*.

(1) The types of *transmission system assets* that are *directly attributable* to *prescribed entry services* are limited to:

(A) *substation* buildings, *substation* land and associated infrastructure (such as fences, earthing equipment etc);

(B) switchgear and *plant* associated with *generators' generating systems* connection and *generator transformers*;

(C) secondary systems associated with primary systems providing *prescribed entry services*;

(D) *transmission lines* owned by *TNSP*s connecting *generators' generating systems* to the *TNSP*'s *transmission network*; and

(E) *meters* associated with *prescribed entry services* and owned by the *TNSP*.

(2) The types of *transmission system* assets that are *directly attributable* to *prescribed exit services* are limited to:

(A) *substation* buildings, *substation* land and associated infrastructure (such as fences, earthing equipment etc);

(B) switchgear used to supply the sub-*transmission voltage* and associated switchgear at both the *transmission* and sub-*transmission voltage* level;

(C) transformers which supply the sub-*transmission voltage* level and associated switchgear at both the *transmission* and sub-*transmission voltage* level;

(D) secondary systems associated with primary systems providing *prescribed exit services*;

(E) *meters* associated with *prescribed exit services* and owned by the *TNSP*; and

(F) *reactive plant* installed for *power factor* correction which provides benefit to *Transmission customers* connected at the *connection point*.

(3) The types of *transmission system* assets that are *directly attributable* to *prescribed TUOS services* are limited to:

(A) *substation* buildings, *substation* land and associated infrastructure (such as fences, earthing equipment etc);

(B) *transmission lines* and associated easements;

(C) switchgear on *transmission lines* and auto-transformers which are part of the *transmission network* and are switched at the *substation* including associated bus work and control and protection schemes;

(D) auto-transformers which transform *voltage* between *transmission* levels;

(E) static and dynamic *reactive plant* and associated switchgear and transformers regardless of the *voltage* level; and

(F) all system controls required for monitoring and control of the integrated *transmission system* including remote monitoring and associated communications, *load shedding* and special control schemes and *voltage* regulating *plant* required for operation of the integrated *transmission system*.

(4) The types of *transmission system* assets that are *directly attributable* to *prescribed common transmission services* are limited to:

(A) *substation* buildings, *substation* land and associated infrastructure (such as fences, earthing equipment etc);

(B) *power system* communications networks;

(C) *control systems*;

(D) network switching centres (excluding *generation* and system control functions);

(E) static and dynamic reactive control *plant* and associated switchgear;

(F) spare *plant* and equipment including that installed at *substations*;

(G) fixed assets such as buildings and land that are not associated with *substation* or line easements, (head office buildings, land for future *substations* etc.); and

(H) motor vehicles and construction equipment.

(b) In its proposed *pricing methodology*, a *TNSP* may include additional types of *transmission system* assets that it considers are *directly attributable* to one or more *category of prescribed transmission service*.

(c) A *TNSP* must justify the inclusion of any additional types of *transmission system assets* referred to in section 2.4(b) of the *guidelines* and the *AER* will consider each when assessing the *TNSP*'s proposed *pricing methodology*.

2.5 Disclosure of information

(a) A *TNSP* should develop its proposed *pricing methodology* so that it can be publicly released by the *AER*.

(b) If a *TNSP* identifies information which it considers to be confidential or commercially sensitive and it considers that providing that information to the *AER* is necessary in order to demonstrate that its proposed *pricing methodology* complies with the *National Electricity Rules*, it should include that information in a confidential version of its proposed *pricing methodology* and provide it to the *AER*.

(c) The *AER* will not publicly disclose a confidential version of a proposed *pricing methodology*.

(d) The *AER* considers that confidential or commercially sensitive information is likely to include details of, or information that could readily be used to infer an individual *transmission customer*'s price or charge, premises, negotiated discounts, prudential requirements or other commercial arrangements relating to its electricity supply.

(e) If a *TNSP* considers that other information should not be made publicly available, it must justify its claim for confidentiality to the *AER*.

(f) If the *AER* disagrees with a *TNSP*'s claim that information provided to it is of a confidential or commercially sensitive nature, the *AER* will:

  (1) notify the *TNSP* of its view, and

  (2) allow the *TNSP* to withdraw the information or rescind its claim for confidentiality.

(g) If information is withdrawn under section 2.5(f) the *AER* will:

  (3) not take the information into consideration when assessing the *TNSP*'s proposed *pricing methodology*, and

  (4) not publicly disclose that information.

2.6 Inter-regional transmission charging arrangements

(a) Where a *TNSP* is the *CNSP* for one or more *regions*, it is required to detail how it will calculate the *modified load export charge* payable to it by the *CNSP* for each interconnected *region*, in accordance with clause 6A.29A.2 of the *NER*.

(b) Where there is more than one *TNSP* in a *region*, the *CNSP* must provide details in its *pricing methodology* regarding how it will allocate any amounts receivable by or payable to other *TNSPs* in accordance with clause 6A.29A.5 of the *NER*.

(c) When allocating any amounts receivable by or payable to other *TNSPs* as per clause 6A.29A.5 of the *NER*, a *CNSP* is required to specify in its *pricing methodology* that the allocation of those amounts will be conducted according to intra–regional, rather than inter–regional, network utilisation.

(d) If a *TNSP* has appointed a *CNSP* in its *region*, then that *CNSP* must specify the timetable for provision of all necessary data to it for the calculation of the inter– and intra–regional *transmission* charges.

(e) Where a *TNSP* is a *CNSP* in its *region*, it must undertake in its *pricing methodology* to publish details of *modified load export charges* that are to apply for the following *financial year* on its website and in accordance with the timeframes specified in the *NER*.

(f) Where a *TNSP* is a *CNSP* in its *region*, it is required to specify in its *pricing methodology* that the '*regulatory year*' for which it will run its *modified load export charge cost reflective network pricing methodology* (*MLEC CRNP*) is the previous *financial year* completed at the time at which the *MLEC CRNP* is being calculated.

2.7 Permitted system strength charging methodologies

(a) Where the *TNSP* is the *System Strength Service Provider* for a *region*, its proposed methodologies for determining the *system strength unit price* component of the *system strength charge* must:

(1) be based on a forecast of its long run average costs of providing *system strength transmission services* at the relevant *system strength node*;

(2) use a period of at least 10 years when forecasting long run costs;

(3) set a price on a dollars per *MVA* per year basis;

(4) set a price that is fixed for the *system strength charging period*, except where updated for indexation in accordance with paragraph (b); and

(5) set a price for each *system strength node* on its *transmission network*.

(b) If the *system strength unit price* is updated for indexation for each *regulatory year* in the *system strength charging period*:

(1) except where paragraph (2) applies, the basis for indexation must be consistent with the approach used for inflation indexation of the *TNSP*'s *maximum allowed revenue* under its *revenue determination*;

(2) where the *TNSP* is the Australian Energy Market Operator (*AEMO)*, the *TNSP* must propose a basis for indexation in its proposed *pricing methodology*.

2.8 Principles for determining forecast annual system strength revenue and estimated actual annual system strength revenue

(a) Where the *TNSP* is the *System Strength Service Provider* for a *region*, its proposed methodologies for determining forecast *annual system strength revenue* and estimated actual *annual system strength revenue* must give effect to, and be consistent with, the following principles:

(1) the methodologies should be reasonable and appropriate for their purpose;

(2) the cost of implementing the methodologies should be proportionate to the expected level of materiality of the impact of any inaccuracy in estimates or forecasts;

(3) the methodologies should utilise relevant existing information to the extent possible, including information from *connection agreements* and, where relevant, *applications to connect*;

(4) the methodologies should be consistent with any relevant parts of the *system strength requirements methodology* and *system strength impact assessment guidelines*;

(5) the methodologies should be consistent with other relevant parts of the *TNSP*'s proposed *pricing methodology* and the *TNSP*'s approach to other relevant forecasts or estimates; and

(6) estimated actual *annual system strength revenue* should be based on actual data for part of the *regulatory year* where actual data is available and updated forecasts for the remainder of the *regulatory year*.

2.9 Requirements relating to interconnector cost allocation agreements

(a) Where a *TNSP* is named as the *TNSP* for a *specified interconnector* under an *interconnector cost allocation agreement*, its proposed *pricing methodology* must:

(1) be accompanied by a copy of the relevant *interconnector cost allocation agreement* in accordance with clause 6A.10.1(j) of the *National Electricity Rules*.

(2) demonstrate how the *interconnector cost allocation agreement* satisfies each of the implementation criteria in clause 6A.29.4(b).

(3) demonstrate how it provides for the recovery from the appropriate *region* of *interconnector transfer amounts* in accordance with clause 6A.24.1(b2)(1).

(4) explain how, under that *interconnector cost allocation agreement*, the *interconnector transfer amount* that each *CNSP* is responsible for allocating will be determined for each *implementation year* as required under clause 6A.29.4(d)(1) of the *National Electricity Rules*.

(5) explain how the *interconnector transfer amount* determined in paragraph 2.9(a)(4) will affect the *total regional AARR* for the regions specified in the *interconnector cost allocation agreement*.

(6) explain how the *TNSP* will avoid double counting and other distortions as set out in clause 6A.29.4(h) of the *National Electricity Rules*.

(7) provide hypothetical examples of the calculations and allocations set out in paragraphs 2.9(a)(4) to 2.9(a)(6).

(b) If a *TNSP* is, or has been appointed as a *CNSP* in its *region*, and is responsible for allocation of an *interconnector transfer amount* calculated under an *interconnector cost allocation agreement*, the *CNSP*’s proposed *pricing methodology* must:

(1) specify an indicative timetable for provision of all necessary information to it for the implementation of any *interconnector cost allocation agreement* that is consistent with the timing requirements in the *National Electricity Rules*.

(2) undertake to publish details of *interconnector transfer amounts* that are to be allocated by the *CNSP* for the following *financial year* on its website by 15 March each year in accordance with the timeframes specified in the *National Electricity Rules*.

(3) explain, with hypothetical examples, how the *CNSP* will avoid double counting and other distortions as set out in clauses 6A.29.4(g) and(i) of the *National Electricity Rules*.

3 Glossary

Shortened forms

Shortened form	Extended form
AARR	Aggregate Annual Revenue Requirement
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASRR	Annual Service Revenue Requirement
CNSP	Co-ordinating Network Service Provider
CRNP	Cost reflective network pricing
MLEC CRNP	Modified load export charge cost reflective network pricing
MVA	Megavolt amperes
TNSP	Transmission network service provider
TUOS	Transmission use of system

Terms

Contract agreed maximum demand means the agreed maximum demand negotiated between a *TNSP* and a *transmission customer*.

Current metered energy offtake means metered energy measured at a connection point in the current billing period.

Current metered maximum demand offtake means metered maximum demand measured at a connection point in the current billing period.

Directly attributable in relation to *transmission assets* refers to assets that are used or required to provide the relevant pricing *category of prescribed transmission service*.

Guidelines means the *pricing methodology guidelines*.

Historical metered energy offtake means metered energy measured at a connection point in the corresponding billing period two years earlier.

Historical metered maximum demand offtake means metered maximum demand measured at a connection point in the corresponding billing period two years earlier.

National Electricity Rules means the rules as defined in the *National Electricity Law*.