# DRAFT DECISION

## AEMO
## Transmission Determination
## 2022 to 2027

October 2021

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: 1300 585 165

Email: AERInquiry@aer.gov.au

AER reference: AER212713

# Contents

# Invitation for submissions

We invite interested stakeholders to attend an AER online public forum on our draft decision on 9 November 2021, 2pm to 3pm (AEDT). The following link provides more information including on how stakeholders wishing to attend the public forum can register their attendance: registration page.

In response to our draft decision, the Australian Energy Market Operator (AEMO) now has the opportunity to submit a revised proposal for its upcoming 2022–27 regulatory control period by **15 December 2021**.

Interested parties are also invited to make submissions on both our draft decision and AEMO's revised proposal (once received) by **24 January 2022**.

We will consider and respond to all submissions received by that date in our final decision, which will be published by **29 April 2022**.

Submissions should be sent to: AEMO2021@aer.gov.au

Alternatively, submissions can be sent to:

Warwick Anderson
General Manager, Network Pricing
Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

Submissions should be in Microsoft Word or another text readable document format.

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. We will treat submissions as public documents unless otherwise requested.

We request parties wishing to submit confidential information:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be placed on the AER's website.[1]

[1] For further information regarding our use and disclosure of information provided to it, see the ACCC/AER Information Policy, which is available on our website.: https://www.aer.gov.au/publications/corporate-documents/accc-and-aer-information-policy-collection-and-disclosure-of-information

# Review timeline

The key milestones for our review of AEMO's regulatory proposal are set out below:

| Milestone | Date |
|---|---|
| *AEMO submitted its proposal* | *19 April 2021* |
| *AER issues paper published* | *15 June 2021* |
| *Public forum on AEMO's proposal held* | *29 June 2021* |
| *Submissions on AER's issues paper and AEMO's proposal close* | *27 July 2021* |
| AER draft decision published | 12 October 2021 |
| Public forum on draft decision | 9 November |
| AEMO submit revised proposal | 15 December 2021 |
| Submissions on draft decision and revised proposal close | 24 January 2022 |
| AER final decision to be published | 29 April 2022 |

# 1 Overview

We, the Australian Energy Regulator (AER), work to make all Australian energy consumers better off, now and in the future. We regulate energy networks in all jurisdictions except Western Australia. Our work is guided by the National Electricity Objective (NEO) which promotes efficient investment in, and operation and use of, electricity services in the long term interests of consumers.[2]

We must make a transmission determination for the Australian Energy Market Operator (AEMO) consisting of a pricing methodology and a negotiated transmission service criteria (NTSC).[3] We do not make a revenue determination for AEMO. Rather, AEMO is required to develop and publish its own revenue methodology for the services it provides in Victoria, which is available on its website: aemo.com.au.

Under the National Electricity Rules (NER), AEMO is required to submit its 2022–27 proposed pricing methodology to the AER for approval. This was submitted to us on 19 April 2021 and was open for consultation until 27 July 2021. We also published our Issues Paper for the AEMO pricing methodology on 15 June 2021.[4]

We are also required to consult on the negotiated transmission service criteria (NTSC) that will apply to AEMO in the 2022–27 regulatory control period. We published the NTSC for AEMO on 25 August 2021.[5]

## 1.1 Victorian electricity transmission arrangements

Victorian households and businesses consume electricity, which is supplied through a network of 'poles and wires’. The electricity network in Victoria is commonly divided into two parts:

- a transmission network, which carries electricity from the large generators to the major load centres
- distribution networks, which carry electricity from the points of connection with the transmission network to virtually every building, house and apartment in Victoria.

The Victorian transmission arrangements are different to other regions in the National Electricity Market.

As part of its functions, AEMO is responsible for providing shared transmission services. These consist of prescribed transmission use of system (TUOS) services

---

2 NEL, s. 7.

3 Schedule 6A.4.2(f) of the National Electricity Rules (NER) sets out the application of chapter 6A of the NER to AEMO.

4 See: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/aemo-determination-2022-27

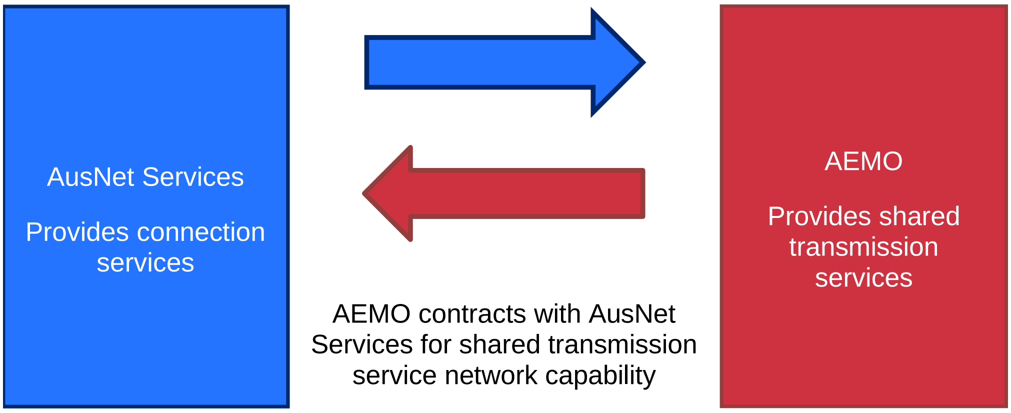
5 See: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/aemo-determination-2022-27/proposal

and prescribed common transmission services. Hence, AEMO is a transmission network service provider (TNSP) under the NER.[6]

AEMO does not actually own assets that provide transmission services. Rather, it procures network capability under long-term contracts. Additionally, AEMO does not provide connection services to customers. AusNet Services owns and operates Victoria's shared electricity transmission network and provides connection services. AusNet Services is also the main source from which AEMO procures shared transmission services under contract. Figure 1.1 provides a basic overview of the Victorian transmission arrangements.

AEMO also has a substantial planning role under the Victorian transmission arrangements. It forecasts demand for prescribed transmission services, identifies network constraints, and commissions network augmentations.

#### Figure 1.1 Overview of the Victorian transmission arrangements




In addition to AusNet Services and AEMO, Murraylink provides transmission services in Victoria. Where there are multiple TNSPs in a region, those providers must appoint a coordinating network service provider responsible for allocating all the AER-determined regulated revenue in that region.[7] Both AusNet Services and Murraylink appointed AEMO as the co-ordinating network service provider for Victoria.

Under this arrangement, AusNet Services and Murraylink provide AEMO information regarding their regulated revenues. AEMO then uses this information, among others, to derive prices for prescribed TUOS services and prescribed common transmission services in the Victorian region.

### 1.1.1 Transmission services

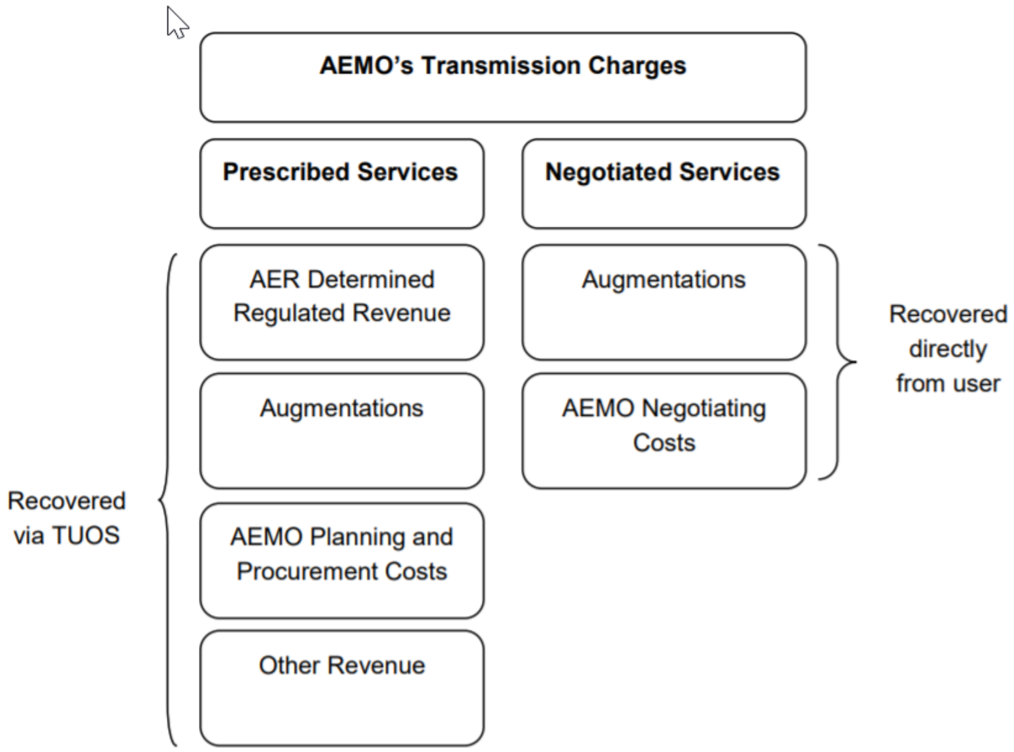
Transmission services can be "prescribed" or "negotiated". Figure 1.2 provides an overview of how AEMO charges for each service. Most charges for prescribed transmission services are allocated to distribution network service providers (DNSPs) with some allocated to large customers directly connected to the

6 NER, sch. 6A.4.1.

7 NER, cl. 6A.29.1(a).

transmission system. Negotiated services, by contrast, are dedicated to an individual or small group of users. In these cases, any charges associated with those services are recovered from that user.[8]

### Figure 1.2 AEMO's Victorian transmission charging components




Source: AEMO, *Revenue methodology for Victoria's electricity transmission system*, 1 July 2011, p. 5.

## 1.1.2 How AEMO calculates its revenue requirement

The revenue AEMO recovers comprises three main components. They are AER regulated revenue for Victoria, contestable augmentations, and AEMO's planning and procurement costs.

Under the Victorian transmission arrangements, AEMO collects the regulated revenues of AusNet Services and Murraylink. It then passes the revenues on to the TNSPs under long term contracts.

The cost of new augmentation forms part of AEMO's revenue in certain circumstances. Under the Victorian planning arrangements, there is an opportunity for multiple parties to build, own and operate elements of the transmission system. This contestable process will occur if the capital cost of the augmentation is reasonably expected to exceed $10 million and it can be provided as a distinct and definable service.[9] Where this competitive tendering process is used to procure a new service, the cost of the augmentation is charged to AEMO under contract. The

8 AEMO, *Revenue methodology for Victoria's electricity transmission system*, 1 July 2011, p. 5.

9 AEMO, *Revenue methodology for Victoria's electricity transmission system*, 1 July 2011, p. 7.

terms of these contracts are typically 30 years or in line with the technical life of the asset involved. The charges largely reflect the annual cost of the service being provided.

In the case of an augmentation being provided by an asset owner who is subject to our regulation (AusNet Services or Murraylink), the asset may be rolled into their regulated asset base (RAB) at the commencement of the next regulatory control period.[10] Alternatively it can continue to be charged under contract.

AEMO performs numerous energy market functions. The costs that AEMO incurs in planning the Victorian transmission network and procuring network investment are passed onto transmission customers. Those costs form part of the revenue that AEMO recovers.

---

10 AEMO, *Revenue methodology for Victoria's electricity transmission system*, 1 July 2011, p. 7.

# 2 Pricing methodology

A pricing methodology must be specified as part of our transmission determination.

This attachment sets out our draft decision on AEMO's proposed pricing methodology for the 2022–27 regulatory control period.

The role of a pricing methodology is to answer the question 'who should pay how much'[11] in order for a transmission business to recover its costs. To do this, a pricing methodology must provide a 'formula, process or approach'[12] that when applied:

- allocates the aggregate annual revenue requirement (AARR) to the categories of prescribed transmission services that a TNSP provides[13]
- provides for the manner and sequence of adjustments to the annual service revenue requirement (ASRR)[14] and allocates that requirement to transmission network connection points[15]
- determines the structure of prices that a TNSP may charge for each category of prescribed transmission services.[16]

An approved pricing methodology does not relate to negotiated transmission services or other transmission services not subject to economic regulation under chapter 6A of the NER.

## 2.1 Draft decision

Our draft decision is to not approve AEMO's pricing methodology for the 2022–27 regulatory control period (proposed pricing methodology).

We consider AEMO's proposal to exempt energy storage systems from prices for prescribed transmission services (transmission prices) is not consistent with the requirements of the NEL and the NER—particularly the pricing principles for prescribed transmission services (pricing principles).[17] We therefore consider AEMO should remove from its pricing methodology the section setting out its policy to exempt energy storage from transmission prices.[18] We discuss this in detail in section 2.4.1.1.

Other amendments we require in AEMO's revised proposal are:

---

11 AEMC, *Rule determination: National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22*, 21 December 2006, p. 1.

12 NER, cl. 6A.24.1(b).

13 NER, cl. 6A.24.1(b)(1).

14 NER, cl. 6A.24.1(b)(2).

15 NER, cl. 6A.24.1(b)(3).

16 NER, cl. 6A.24.1(b)(4).

17 NER, cl. 6A.23.

18 AEMO, *Pricing methodology for prescribed shared transmission services: 1 July 2022 to 30 June 2027*, 19 April 2021, p. 14.

- amending the basis for calculating a customer's locational charges. AEMO should calculate a customer's locational charge by multiplying the locational price by the lower of the contract agreed maximum demand and the customer's actual average demand. We discuss this in detail in section 2.4.1.4.
- explicitly state in its revised pricing methodology the specific date in March in which it will publish transmission prices. We discuss this in detail in section 2.4.1.6.

Further, we accept AEMO's proposal to change its method for calculating locational prices. Nevertheless, we expect AEMO to consult more widely with customers on the customer impact analysis of this change. This would enable customers to make submissions on these customer impacts for consideration in our final decision. We discuss this in detail in section 2.4.1.3.

## 2.2 AEMO's proposal

AEMO's proposed pricing methodology makes the following amendments to the pricing methodology it applied in the 2014–19 regulatory control period[19] (current pricing methodology):

- Inclusion of a new section clarifying the treatment of energy storage systems. AEMO proposed not to charge energy storage systems transmission prices for either supply or consumption (exemption policy), except in some circumstances.[20]
- Adoption of a new demand measure to derive locational prices. In short, AEMO proposed to use the "365 day method", which uses the maximum demand recorded on any day of the year. This would replace the "MD10 method", which uses demand recorded during the 10 business days in which the system experienced peak demand.[21]
- Setting to zero all negative half-hourly energy and demand values at transmission connection points for the purposes of deriving transmission prices.[22]
- Various changes to harmonise definitions and phrases as relevant with those in the NER, NEL and the AER Guidelines.
- Accounting for National Transmission Planner (NTP) function fees applicable to AEMO as a Co-ordinating Network Service Provider under clause 2.11.3(ba) of the NER.[23]

---

19 For the 2019–20 to 2021–22 years, AEMO applied the pricing methodology we approved for the 2014–19 regulatory control period through an enforceable undertaking with the AER. See https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/aemo-determination-2014-19/update.

20 AEMO, *Pricing methodology for prescribed shared transmission services: 1 July 2022 to 30 June 2027*, 19 April 2021, p. 14.

21 AEMO, *Pricing methodology for prescribed shared transmission services: 1 July 2022 to 30 June 2027*, 19 April 2021, pp. 11–12.

22 AEMO, *Pricing methodology for prescribed shared transmission services: 1 July 2022 to 30 June 2027*, 19 April 2021, pp. 11–13.

- Accounting for the treatment of costs associated with Ministerial Orders pursuant to section 16Y of the National Electricity (Victoria) Act 2005 (NEVA).[24]
- Changes to energy/demand data used to calculate prices and charges resulting from a change in transmission pricing publication dates. This was necessitated by a change to the timing of the Victorian DNSPs' pricing proposal process from calendar years to financial years.[25]

## 2.3 Assessment approach

We must approve a proposed pricing methodology if satisfied it:

- gives effect to, and complies with, the pricing principles for prescribed transmission services
- complies with information requirements of the pricing methodology guidelines.[26]

These requirements guided our assessment of AEMO's proposed pricing methodology.

## 2.4 Reasons for draft decision

The following sections set out the reasons for our draft decision.

### 2.4.1 Assessment of amendments in the proposed pricing methodology

#### 2.4.1.1 Transmission prices for energy storage

We do not accept AEMO's proposal to exempt energy storage from transmission prices because we consider it is not consistent with the requirements of the NEL and the NER. In particular, we consider this proposal is not consistent with the pricing principles.

We therefore require AEMO to remove from its pricing methodology the section setting out its policy to exempt energy storage from transmission prices.

##### *Inefficient investment*

We consider AEMO's exemption policy may lead to inefficient investment by energy storage proponents. This outcome is not consistent with the National Electricity Objective (NEO) in that it would not "promote efficient investment in, and efficient

---

23 AEMO, *Pricing methodology for prescribed shared transmission services: 1 July 2022 to 30 June 2027*, 19 April 2021, pp. 10 and 23.

24 AEMO, *Pricing methodology for prescribed shared transmission services: 1 July 2022 to 30 June 2027*, 19 April 2021, p. 9.

25 AEMO, *Pricing methodology for prescribed shared transmission services: 1 July 2022 to 30 June 2027*, 19 April 2021, pp. 10–13 and 20–24.

26 NER, cl. 6A.24.1(c); AER, *Electricity transmission service providers pricing methodology guidelines*, July 2014.

operation and use of, electricity services for the long term interests of consumers of electricity with respect to price."[27]

Our position is supported by stakeholders who consider it could lead energy storage proponents to invest at the transmission network, even if investment at the distribution network would be more efficient if appropriate pricing signals were in place.

Firm Power considered AEMO's proposed exemption for energy storage is not appropriate and does not reflect the efficient cost of providing the proposed services. Firm Power considers AEMO's proposal not to impose transmission prices on energy storage will lead to inequitable concentration of batteries at the transmission level compared to distribution.[28]

Similarly, CitiPower, Powercor and United Energy (CPU) did not support AEMO's proposed exemption for batteries. CPU noted the AER's recent distribution determinations required distribution-connected energy storage in Victoria to incur network prices, which incorporate prices for prescribed transmission services. The differing treatment of transmission and distribution networks will result in inefficient location of energy storage in the electricity network.[29] CPU further noted a statement from ARENA that the current arrangement is driving energy storage away from the distribution network.[30]

### *Price shocks*

There is also the risk that allowing a blanket exemption for energy storage at this stage may introduce price shocks at a later stage. Again, this is not consistent with the NEO.

As discussed above, the exemption from transmission prices may incentivise energy storage proponents to locate at the transmission rather than the distribution network. If energy storage numbers in the transmission network reaches a certain level, AEMO may consider that they are a driver of transmission investment. At that stage, AEMO may decide to charge transmission prices to energy storage if they receive prescribed transmission services. This could introduce a price shock to energy storage after having been exempted from transmission prices.

### *Revenue recovery principle*

Under the NER, TNSPs must set prices to recover revenues for providing prescribed transmission services (the revenue recovery principle).[31] We consider AEMO's proposed exemption policy would violate this revenue recovery principle.

---

[27] NEL, s. 7.

[28] Firm Power, *Submission on AEMO proposal and AER issues paper*, 29 July 2021, pp. 1–2.

[29] CPU, *Submission on AEMO proposal and AER issues paper*, 27 July 2021, p. 1.

[30] CPU, *Submission on AEMO proposal and AER issues paper*, 27 July 2021, p. 1.

[31] NER, cl. 6A.23.4.

We understand energy storage connected to transmission networks are able to request and receive prescribed transmission services. In order to comply with the pricing principles for prescribed transmission services in rule 6A.23, we consider AEMO is required to set and charge prices to customers, including energy storage, who receive prescribed transmission services. This would enable AEMO to recover the revenues associated with the provision of these services.

Major Energy Users (MEU) similarly considered power flows from the grid to the end user—including energy storage—should incur network costs related to the peak demand of the flow. Hence, MEU did not agree with exempting storage devices when they are acting as consumers of electricity.[32]

Among stakeholder submissions, only the Energy Networks Australia (ENA) stated it agreed with exempting energy storage from transmission prices. However, the ENA stated the pricing methodology should clarify the exemption only applies when energy storage is scheduled or semi scheduled (and not receiving prescribed transmission services).[33]

### *Pricing principles*

We also consider the proposed exemption policy could violate the pricing principles regarding the setting of locational prices.

As part of its proposed exemption policy, AEMO stated the connection point of an energy storage customer will not be considered as a connection point for the purposes of the proposed pricing methodology.[34]

Where energy storage receives prescribed transmission services, this policy violates the pricing principle that a TNSP is to allocate revenues associated with locational prices to connection points on the basis of their proportionate use of the relevant transmission system assets.[35] Revenue that would have been properly allocated to energy storage is instead allocated to other transmission customers.

### *AEMC draft rule change*

We also note AEMO's exemption policy is not consistent with the AEMC's draft rule determination on the "Integrating energy storage systems into the NEM" rule change (AEMC draft determination).

The AEMC draft determination did not exempt energy storage from transmission and distribution prices. The AEMC considered an exemption would not promote the

32 MEU, *Submission on AEMO proposal and AER issues paper*, 27 July 2021, p. 3.

33 ENA, *Submission on AEMO proposal and AER issues paper*, 27 July 2021, p. 1.

34 AEMO, *Pricing methodology for prescribed shared transmission services: 1 July 2022 to 30 June 2027*, 19 April 2021, p. 14.

35 NER, cl. 6A.23.3(c).

NEO as it would not reflect the efficient cost of providing services or the impact it may have on the network.[36]

Further, the AEMC stated it did not consider a TNSP can apply a blanket exemption to energy storage systems from prices for prescribed transmission services even under the current version of the NER.[37] This is consistent with our assessment of AEMO's proposed exemption policy as discussed in detail above.

We acknowledge the AEMC draft determination is a draft only, and so was not a direct input into our draft decision, so we based our assessment in our draft decision on the current version of the NER. We understand the AEMC plans to publish its final rule determination on the "Integrating energy storage systems into the NEM" rule change on 28 October 2021.[38] We will consider this final rule determination when we make our final decision on AEMO's proposed pricing methodology (due by April 2022).

#### 2.4.1.2 Demand measures for deriving locational prices

We consider AEMO's proposal to change to measuring demand using the 365 day method is consistent with the NER requirements and our pricing methodology guidelines.

When considering AEMO's proposed shift to the 365 day method, we had regard to the pricing principles. In particular, we considered whether the 365 day method better reflects the principle that locational prices:[39]

> …must be based on demand at times of greatest utilisation of the transmission network by Transmission Customers and for which network investment is most likely to be contemplated.

MEU generally supported the proposed approach but considered the AER should require AEMO to demonstrate that the 365 day method would result in prices that are more cost reflective than the MD10 method.[40]

We consider the 365 day method better reflects this principle than the MD10 method, based on available evidence.

In its proposal, AEMO stated that choosing a subset of conditions at peak demand times (as under the MD10 method) to derive locational prices is now "problematic". This is because the period "of greatest utilisation of the transmission network" is no longer simply the maximum demand of the power system. AEMO stated renewable energy generation is now the main driver of transmission investment rather than

---

36 AEMC, *Draft rule determination national electricity amendment (Integrating energy storage systems into the NEM) Rule 2021*, 15 July 2021, p. 103.

37 AEMC, *Draft rule determination national electricity amendment (Integrating energy storage systems into the NEM) Rule 2021*, 15 July 2021, pp. 110–114.

38 As indicated on the AEMC website as of 4 October 2021.

39 NER, cl. 6A.23.4(b)(1).

40 MEU, *Submission on AEMO proposal and AER issues paper*, 27 July 2021, p. 3.

reducing unserved energy at peak demands. AEMO cited the Western Victorian Transmission Network Project as an example project with such a driver.[41]

Two submissions also provide anecdotal evidence of the changing drivers of investment in the transmission network. AusNet Services supported the shift to the 365 day method because it acknowledges the shift in the generation mix in the transmission system.[42] Similarly, the ENA supported the 365 day method because it allows locational prices to better reflect times of greatest use of the transmission network.[43]

AEMO provided further evidence that the energy landscape in Victoria continues to change, driven by strong investment in large-scale and distributed renewable generation. AEMO noted new large-scale investment in the west of the state is creating additional supply centres, while an increasing penetration of non-synchronous generation continues to impact the stability and complexity of the power system.[44]

AEMO stated that planning for network investment could previously be undertaken on the basis of a supply mix with relatively predictable patterns of operation. Further, transmission network utilisation across maximum demand periods would be relatively similar. However, the generator mix is shifting to more variable, intermittent energy resources and a greater geographic diversity of supply, as noted above. Hence, network investment planning requires an hour-by-hour assessment of supply-demand at each transmission connection point, with different network utilisation across the day depending on new generation patterns.[45]

In addition to the above considerations, the NER requires that our pricing methodology guidelines specify the structures of locational prices having regard to:[46]

> …the desirability of consistent pricing structures across the NEM

AEMO is currently the only transmission network in the NEM that uses the MD10 method exclusively. The 365 day method, as AEMO proposed, brings it in line with the method other transmission networks in the NEM use to derive locational prices.[47]

The ENA supported the 365 day method because it aligns with other TNSPs' approach.[48]

---

41 AEMO, *TUOS pricing methodology issues paper*, September 2020, pp. 10–11.

42 AusNet Services, *Submission on AEMO proposal and AER issues paper*, 23 July 2021, p. 1.

43 ENA, *Submission on AEMO proposal and AER issues paper*, 27 July 2021, p. 1.

44 AEMO, *Response to AER Information Request #002 - Questions on proposed pricing methodology arising from submissions*, 26 August 2021, pp. 2–3 (CONFIDENTIAL).

45 AEMO, *Response to AER Information Request #002 - Questions on proposed pricing methodology arising from submissions*, 26 August 2021, pp. 3–4 (CONFIDENTIAL).

46 NER, cl. 6A.25.2(b)(1).

47 There are slight differences between transmission networks. For example, TransGrid calculates locational prices with a demand measure consistent with AEMO's proposed method. ElectraNet and TasNetworks use the contract agreed maximum demand only to calculate their locational prices.

48 ENA, *Submission on AEMO proposal and AER issues paper*, 27 July 2021, p. 1.

#### 2.4.1.3 Consultation on the customer impacts of the 365 day method

While we accept AEMO's 365 day method, we expect AEMO to consult more widely with customers on the customer impact analysis of this change. This would enable customers to make submissions on these customer impacts for consideration in our final decision.

AEMO began consultation on 16 September 2020 when it published an issues paper discussing the changing nature of the power system and how that may affect AEMO's pricing methodology.[49] On 25 November 2020, AEMO published a consultation paper which set out AEMO's proposed changes to the pricing methodology to address the aspects raised in the AEMO issues paper.[50] AEMO also met with stakeholders individually during the consultation period summarised above.[51]

The MEU's members commented that AEMO's consumer engagement in developing its proposed pricing methodology "has been much better than in the past, and that AEMO should be congratulated for this improvement."[52]

However, we understand AEMO did not model the change to the 365 day method during its consultation for the proposed pricing methodology. AEMO stated this is because it requires modelling a state of the network that does not yet exist and requires assumptions regarding changes to customer behaviour.[53]

Upon our request, AEMO provided to us a customer impact analysis of the move from the MD10 method to the 365 day method using actual data from the latest available year.[54] This analysis showed approximately 54 per cent of AEMO's connection points will experience an increase in locational charges due to the move to the 365 day method.

While price changes can elicit changes to customer behaviour, there is also an argument that responses to electricity price changes is rather inelastic, particularly in the short term. Hence, we consider such an analysis is informative for the purpose of assessing the impacts of changing to the 365 day method.

We expect AEMO to consult with customers on the customer impact analysis of this change, such as the one described above.

#### 2.4.1.4 Basis for calculating a customer's locational charges

We require AEMO to amend the basis for calculating a customer's locational charges. That is, AEMO should calculate a customer's locational charge by multiplying the locational TUOS price by the <u>lower</u> of:

---

49 AEMO, *TUOS pricing methodology issues paper*, September 2020.

50 AEMO, *TUOS pricing methodology consultation paper*, November 2020.

51 AEMO, *Cover letter: Draft pricing methodology 2022–2027*, 19 April 2021, p. 3.

52 MEU, *Submission on AEMO proposal and AER issues paper*, 27 July 2021, p. 3.

53 AEMO, *TUOS pricing methodology decision paper*, March 2021, pp. 4–5.

54 AEMO, *Response to AER Information Request #001 – TUOS Price Methodology impacts MD10 to D365*, 10 August 2021 (CONFIDENTIAL).

- the contract agreed maximum demand (CAMD), if the customer has agreed to a CAMD, and
- the customer's actual average demand at the time of the monthly maximum demand for financial year t–2 for their respective connection point.

AEMO's proposed pricing methodology for the 2022–27 regulatory control period proposed to calculate a customer's locational charge by multiplying the locational TUOS price by the <u>higher</u> of CAMD and the customer's actual average demand.[55]

AEMO proposed the change in calculation method because it considers CAMD is the most appropriate demand to use in deriving locational charges. It represents the level of demand that AEMO endeavours to support with shared network capability.[56]

However, AEMO stated it would agree with our suggestion to using the lower of CAMD and the actual average demand to calculate locational charges in the 2022–27 control period to mitigate customer impacts.[57] This includes the customer impact analysis we discussed in section 2.4.1.3.

We note that using the <u>lower</u> of the CAMD and the average maximum demand to derive a customer's locational charge is consistent with the calculation method in the current pricing methodology.[58]

#### 2.4.1.5 Treatment of negative demand and consumption values

We consider AEMO's proposal to treat all negative consumption and demand values as zero when deriving transmission prices is consistent with the NER requirements.

AEMO noted the transmission system was originally conceived to deliver energy from large generators to major load centres. However, transmission connection points are now experiencing reverse flows due to new technologies (distributed energy generation, energy storage and so on). In the absence of transmission prices for generators, there is a question of how to price connection points when there are reverse flows.[59]

AEMO proposed to consider only half-hourly demand and energy intervals with positive values for the purposes of the pricing methodology. AEMO proposed to treat all negative consumption and demand values as zero as this is less distortionary than other options.[60]

---

55 AEMO, *Pricing methodology for prescribed shared transmission services: 1 July 2022 to 30 June 2027*, 19 April 2021, pp. 11–12.

56 AEMO, *Response to AER Information Request #004 - Time periods for calculating prices and charges*, 22 September 2021, p. 2.

57 AEMO, *Response to AER Information Request #004 - Time periods for calculating prices and charges*, 22 September 2021, p. 2.

58 AEMO, *Proposed pricing methodology for prescribed shared transmission services*, 21 February 2014 (approved April 2014), p. 11.

59 AEMO, *TUOS pricing methodology decision paper*, March 2021, p. 2.

60 AEMO, *TUOS pricing methodology consultation paper*, November 2020, pp. 2–3.

Like MEU, we support the approach to exclude negative flows from the calculation of transmission prices. MEU stated the network is designed to deliver electricity from generators to load centres. Hence, it makes sense to exclude negative amounts to avoid inappropriate bias of data reflecting usage at connections points.[61]

High usage of the network—at particular times, when such flows into a connection point cause strain in the network—are the principal drivers of investment. Transmission prices should therefore reflect these (positive) consumption/demand measures.

Low usage, or indeed negative usage, at other times do not lower or “cancel out” network strain at times of high usage. TNSPs should therefore not incorporate negative flows to derive transmission prices for a connection point.

#### 2.4.1.6 Publication date of transmission prices

We understand AEMO proposed to publish transmission prices by March each year, rather than May as it currently does.[62] However, AEMO did not specify the earlier publication date of March in the proposed pricing methodology document.

We therefore request AEMO to explicitly state in its revised pricing methodology document the specific date in March in which it will publish transmission prices.[63]

A March publication date would be consistent with the publication dates in other NEM jurisdictions and, importantly, better align with the Victorian DNSPs’ recent shift to regulatory years on a financial year basis and our pricing proposal process.[64]

CPU considers AEMO should be able to publish TUOS prices by the end of February each year. DNSPs submit annual pricing proposals to the AER by the end of March, which necessitates the use of estimated transmission charges. CPU stated its experience shows estimates can be inaccurate, leading to volatility in network charges. If AEMO published transmission prices in March, it will enable DNSPs to use actual transmission prices in their annual pricing proposals.[65]

We agree with AEMO that it is not possible under the current arrangements in the NER to publish transmission prices in February.

AEMO noted it is legally obligated to publish its modified load export charges (MLEC) by 15 February each year.[66] The NER requires TNSPs, other than AEMO, to publish transmission prices by 15 March each year.[67]

---

61 MEU, *Submission on AEMO proposal and AER issues paper*, 27 July 2021, p. 3.

62 AEMO is required to publish TUOS prices by May each year under schedule 6A.4.2 of the NER.

63 We note AEMO stated it intended to publish transmission prices on 15 March in its consultation paper, but on 1 March in its decision paper. See AEMO, *TUOS pricing methodology consultation paper*, November 2020, pp. 7–8; AEMO, *TUOS pricing methodology decision paper*, March 2021, p. 6.

64 AEMO, *TUOS pricing methodology consultation paper*, November 2020, pp. 7–8.

65 CPU, *Submission on AEMO proposal and AER issues paper*, 27 July 2021, p. 2.

66 NER, cl. 6A.24.2(b).

67 NER, cl. 6A.24.2(c)(1).

The AEMC included the lag in these publication dates so TNSPs have sufficient time to determine the impact of the inter-regional transmission charge on their intra-regional charges.[68] This is because the MLEC is an input into the transmission prices co-ordinating network service providers must calculate.[69]

Moving the publication date of transmission prices to February would not give AEMO sufficient time to incorporate the impacts of the MLEC into its transmission prices.

#### 2.4.1.7 Timing of data used to derive transmission prices

We consider AEMO's proposal to use data from the latest completed financial year (year t–2) to derive transmission prices is reasonable.

AEMO uses data from the most recent year ending 28 February (year t–1) under its current pricing methodology. This is because it has been publishing its transmission prices in May each year as allowed under the NER.[70]

However, AEMO proposed to change to using t–2 data so it is able to publish transmission prices by March each year. As we discuss in section 2.4.1.6, the March publication date better aligns with the Victorian DNSPs' recent shift to financial years and brings it in line with the other TNSPs in the NEM.

MEU does not agree with the proposal to use the most recently completed full financial year in the pricing methodology. MEU considers AEMO should continue using data up to the end of February in the current financial year as per the current pricing methodology.[71]

Given the new proposed date to publish transmission prices, AEMO stated the most recent dataset it could use would be data up to the end of December. However, AEMO does not consider such a dataset would be ideal because it splits the summer months, with the higher demand periods occurring in January and February at the start of the dataset. AEMO also preferred to use load and generation data from the last full financial year for consistency with the dataset for the MLEC calculation.[72]

#### 2.4.1.8 Avoided TUOS

The NER requires distribution network services providers (DNSPs) to pass through to embedded generators the locational prices the DNSP would have incurred, had

---

68 AEMC, *Rule determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, p. 99; AEMC, *Rule determination: National Electricity Amendment (Inter-regional transmission charging) Rule 2013*, 28 February 2013, p. 46.

69 NER, cl. 6A.23.3(b)(2).

70 NER, sch. 6A.4.2

71 MEU, *Submission on AEMO proposal and AER issues paper*, 27 July 2021, p. 2.

72 AEMO, *Response to AER Information Request #004 - Time periods for calculating prices and charges*, 22 September 2021, p. 2.

the embedded generator not been connected to the distribution network.[73] These pass through amounts are known as "avoided TUOS".

CPU submitted that to calculate avoided TUOS, DNSPs require the locational price and additional demand that would have occurred had the generator not connected to the distribution network. To ensure retail customers do not pay too much or too little for avoided transmission costs, CPU asked that AEMO be required to provide locational prices with and without embedded generators.[74]

We consider we cannot require TNSPs to calculate two sets of locational prices for each connection point under the NER. This is because the NER requires TNSPs to determine locational prices in order to recover revenues for providing prescribed TUOS services (adjusted locational component).[75] A second set of prices as CPU suggested would not be used to recover these revenues.

### 2.4.2 Calculation and allocation of the aggregate annual revenue requirement (AARR)

We accept AEMO's method for calculating and allocating the AARR as we consider it meets the NER requirements.

The AARR is the 'maximum allowed revenue' adjusted:[76]

- for a number of factors such as cost pass throughs, service target performance incentive scheme outcomes and contingent projects[77]
- by subtracting the operating and maintenance costs expected to be incurred in the provision of prescribed common transmission services
- by any allocation of the AARR within and between regions as agreed between TNSPs.[78]

Table 2.1 summarises our review of how AEMO's proposed pricing methodology calculates and allocates the business' AARR.

#### Table 2.1 AEMO's proposed calculation and allocation of the AARR against the NER requirements

| NER requirements | AER assessment |
|---|---|
| Requirement for the AARR to be calculated as defined in the NER—clause 6A.22.1. | Section 3.3 of AEMO's proposed pricing methodology satisfies this requirement. |
| Requirement for the AARR to be allocated to each category of prescribed transmission services in accordance with attributable cost share for each such | Section 3.3 of AEMO's proposed pricing methodology satisfies this requirement. |

73 NER, cl. 5.3AA(h).
74 CPU, *Submission on AEMO proposal and AER issues paper*, 27 July 2021, pp. 1–2.
75 NER, cll. 6A.23.4(a) and (b).
76 NER, cl. 6A.22.1.
77 NER, cl. 6A.3.2.
78 NER, cl. 6A.29.3.

| | |
|---|---|
| category of service—clause 6A.23.2(a). | |
| Requirement for every portion of the AARR to be allocated and for the same portion of AARR not to be allocated more than once—clause 6A.23.2(c). | Section 3.3 of AEMO's proposed pricing methodology satisfies this requirement. |
| Subject to clause 11.6.11 of the NER, requirement for adjusting attributable cost share and priority ordering approach to asset costs that would otherwise be attributed to the provision of more than one category of prescribed transmission services—clause 6A.23.2(d). | Section 3.3 of AEMO's proposed pricing methodology satisfies this requirement. |

### 2.4.3 Allocation of the annual service revenue requirement (ASRR) to transmission network connection points

We accept AEMO's proposed pricing methodology for allocating the ASRR as we consider it meets the NER requirements. Table 2.2 summarises our assessment.

#### Table 2.2 AEMO's proposed allocation of the ASRR against the NER requirements

| NER requirements | AER assessment |
|---|---|
| Requirement for the whole ASRR for prescribed entry services to be allocated to transmission network connection points in accordance with the attributable connection point cost share for prescribed entry services that are provided by the TNSP at that connection point—clause 6A.23.3(i). | Not applicable. |
| Requirement for the whole ASRR prescribed exit services to be allocated to transmission network connection points in accordance with the attributable connection point cost share for prescribed exit services that are provided by the TNSP at that connection point—clause 6A.23.3(j) | Not applicable. |
| Requirement for the ASRR for prescribed TUOS services to be allocated between pre-adjusted locational components and pre-adjusted non-locational components—clause 6A.23.3(a). | Section 3.3 and appendix B of AEMO's proposed pricing methodology satisfy this requirement. |
| Requirement for the recovery of the ASRR for prescribed common transmission services and the operating and maintenance costs incurred in the provision of those services to be recovered through prices charged to transmission customers and network service and network service provider transmission connection points set in accordance with price structure principles set out in clause 6A.23.4—clause 6A.23.3(h). | Sections 3.3 and 3.5 and appendix B of AEMO's proposed pricing methodology satisfy this requirement. |

### 2.4.4 Development of price structure

We accept AEMO's proposed pricing methodology and process for developing different prices for recovering the ASRR as we consider it meets the NER requirements. Table 11.3 summarises our assessment.

### Table 2.3 AEMO's proposed pricing structure against the NER requirements

| NER requirements | AER assessment |
|---|---|
| Requirement for separate prices for each category of prescribed transmission services—clause 6A.23.4(a) | Sections 3.4 and 3.5 and appendix B of AEMO's proposed pricing methodology satisfy this requirement. |
| Requirement for fixed annual amount prices for prescribed entry services and prescribed exit services—clause 6A.23.4(g) | Not applicable. |
| Requirement for postage stamped prices for prescribed common transmission services—clause 6A.23.4(f) | Section 3.5.3 of AEMO's proposed pricing methodology satisfies this requirement. |
| Requirement for prices for locational component of prescribed TUOS services to be based on demand at times of greatest use of the transmission network and for which network investment is most likely to be contemplated—clause 6A.23.4(b)(1) | Sections 3.4 and 3.5 and appendix B of AEMO's proposed pricing methodology satisfy this requirement. |
| Requirement for prices for the locational component of ASRR for prescribed TUOS services not to change by more than 2 per cent per year compared with the load weighted average prices for this component for the relevant region—clause 6A.23.4(b)(2) | Section 3.5 and appendix B of AEMO's proposed pricing methodology satisfy this requirement. |
| Requirement for prices for the adjusted non-locational component of prescribed TUOS services to be on a postage stamp basis—clause 6A.23.4(e) | Section 3.5 and appendix B of AEMO's proposed pricing methodology satisfy this requirement. |
| Setting of TUOS locational prices between annual price publications–clause 6A.23.4(b) | Section 3.5 and appendix B of AEMO's proposed pricing methodology satisfy this requirement. |

## 2.4.5 Information requirements

We are satisfied AEMO's proposed pricing methodology complies with the pricing methodology guidelines' information requirements.

Key features of the proposal include:

- acknowledging AEMO is the coordinating network service in Victoria
- using the priority ordering approach under clause 6A.23.3(d) of the NER to implement priority ordering
- describing billing arrangements as in clause 6A.27 of the NER
- describing prudential requirements as in clause 6A.28 of the NER
- including hypothetical examples
- describing how AEMO intends to monitor and develop records of its compliance with its approved pricing methodology.

# 3 Negotiated services

Our transmission determinations generally impose control over revenues that a TNSP can recover from its provision of prescribed transmission services.[79] But we do not determine the terms and conditions of negotiated transmission services. Under the NER, negotiated services are provided under an agreement or as a result of a determination of a commercial arbitrator. These processes are facilitated by:

- a negotiating framework, and
- the NTSC.

A negotiating framework sets out procedures for negotiating the terms and conditions of access to a negotiated transmission service. The NTSC set out criteria that a TNSP must apply in negotiating those terms and conditions, including the prices and access charges for negotiated transmission services. They also contain the criteria that a commercial arbitrator must apply to resolve disputes about such terms and conditions and/or access charges.

These requirements apply only to Victoria due to its unique transmission arrangements. This is because Victoria is the only National Electricity Market (NEM) jurisdiction in which the Australian Energy Market Operator (AEMO) is authorised to exercise declared network functions.[80] Where such arrangements apply, there is a separation of ownership of the declared transmission system from certain aspects of the operation and control of that system. The framework for connections to the transmission network in Victoria is therefore different to the rest of the NEM.

The NER previously required all TNSPs in the NEM to submit negotiating frameworks for AER approval as part of their revenue determination. In 2017, the AEMC removed this requirement from the NER for all NEM jurisdictions, except for Victoria (2017 rule change).[81] Rather, the AEMC elevated to the NER the principles that will underpin negotiations between connecting parties and incumbent TNSPs as part of the 2017 rule change.[82]

In Victoria, clause 11.98.8 preserves chapter 6A of version 109 of the NER, which contain the provisions regarding negotiating frameworks and the NTSC.[83]

## 3.1 Draft decision

Our draft decision is that the NTSC we published for consultation on 25 August 2021 will apply to AEMO in the 2022–27 regulatory control period, as those criteria give effect to the negotiated transmission service principles.[84]

---

79 As we discussed in chapter 1, we do not make a revenue determination for AEMO.

80 For more information regarding AEMO's declared network functions, see National Electricity Law, s. 50C.

81 NER, clause 11.98.8.

82 AEMC, *Rule Determination: National Electricity Amendment (Transmission Connection and Planning Arrangements) Rule 2017*, 23 May 2017, pp. 198–203.

83 See also AEMC, *Rule Determination: National Electricity Amendment (Transmission Connection and Planning Arrangements) Rule 2017*, 23 May 2017, p. 75.

84 NER, clause 6A.9.1; 11.98.8.

In section 3.2, we discuss the negotiating framework that will apply to AEMO for the 2022–27 regulatory control period.

## 3.2 AEMO's negotiating framework

The 2017 rule change preserved the requirement for AEMO to have a negotiating framework in place. On the other hand, AEMO is not required to submit one to the AER for approval.[85] This is the reason AEMO did not submit a negotiating framework as part of its regulatory proposal on 19 April 2021. However, we are required, in our determination, to set out requirements in respect of the preparation, replacement, application or operation of the provider's negotiating framework.[86] From discussions with AEMO and AusNet Services, we understand AEMO intends to continue with its negotiating framework from the 2014–19 regulatory control period (current negotiating framework).[87]

This negotiating framework is, in substance, identical to the negotiating framework AusNet Services included in the revised proposal to its 2022–27 transmission determination.[88] This would continue AEMO's and AusNet Services' practice of submitting a joint and co-branded negotiating framework.

We require that:

- AEMO's negotiating framework be the same as AusNet Services, due to the benefits that arise from this approach. When AEMO receives an application to connect to the Victorian Transmission Network, that service applicant must also negotiate with AusNet Services for connection services. For this reason, a common negotiating framework that both AEMO and AusNet Services apply during their negotiations with service applicants is appropriate.
- AEMO's negotiating framework continues to meet the minimum requirements set out in the NER as in force before the 2017 rule change.[89]

We ask that AEMO, in its revised proposal, formally confirm that it intends to continue to apply the current negotiating framework in the 2022–27 regulatory period.

## 3.3 Negotiated transmission service criteria

Our draft decision is that the NTSC we published on 25 August 2021 (reproduced in section 3.3.2) should apply to AEMO for the 2022–27 regulatory control period.

### 3.3.1 Reasons for draft decision

85 Sch. 6A.4.2(f)(1), (5) and (8) (as specifically amended in NER version 110).

86 NER, cl 11.98.8, and sch. 6A.4.2(e) and cl 6A.9.3 of NER version 109.

87 AER, *File note: Discussion on AEMO negotiating framework*, 12 August 2021.

88 AusNet Services, *Transmission revenue review 2023-2027: Revised revenue proposal: PUBLIC*, p. 166.

89 NER, clause 11.98.8, and sch. 6A.4.2(e) and cl 6A.9.5 of NER version 109 .

Our draft decision is that the NTSC as reproduced in section 3.3.2 should apply to AEMO for the 2022–27 regulatory control period. This is because it adopts the negotiated transmission service principles as its criteria.[90]

We note that this NTSC is identical to the NTSC that have applied in Victoria (for AEMO and AusNet Services) since July 2014.

Shell submitted that, under the proposed NTSC, flexible scheduled load proponents negotiating their transmission service bear the risk that:[91]

- the TNSP may set a price that is higher than what is cost-reflective
- the TNSP may impose unreasonably onerous non-price conditions
- the TNSP may offer different pricing to different proponents seeking the same type of negotiated services, which could disadvantage the proponent compared to its competitors
- the price does not become known until quite late in the project timeline, creating needless uncertainty during the development phase.

To mitigate these risks, Shell suggested the NTSC should define "interruptible services" as a sub-category of negotiated transmission services. This definition would capture the services required by a scheduled load willing to be constrained off or down during times of peak network utilisation and/or at times of local network congestion.[92]

Shell further suggested the NTSC should require AEMO to explicitly have regard to whether a connection request is for an interruptible service when determining the costs of providing a negotiated service.[93]

It is unclear to us whether including Shell's suggestions for interruptible services improves the NTSC. We consider the NTSC in section 3.3.2 already address Shell's concerns while retaining the flexibility to allow parties to negotiate for the efficient prices and terms and conditions for negotiated transmission services.

Criteria 2 to 3, for example, require that the terms and conditions of access for negotiated transmission services must not be unreasonably onerous

Regarding price, criteria 5 to 7 require TNSPs to set prices for negotiated transmission services that are cost reflective. That is, the TNSP must set prices having regard to the cost of providing that service, whether it is interruptible, or have other characteristics that affect costs.

---

90 NER (version 109), cll. 6A.9.1 and 6A.9.4(b).

91 Shell also considers these risks apply to the NER framework for negotiated transmission services framework in general. Shell, *Submission to proposed negotiated transmission service criteria for AEMO*, 7 October 2021, p. 2.

92 Shell, *Submission to proposed negotiated transmission service criteria for AEMO*, 7 October 2021, p. 3.

93 Shell, *Submission to proposed negotiated transmission service criteria for AEMO*, 7 October 2021, p. 4.

Criterion 9, meanwhile, requires that the price for a negotiated transmission service must be the same for all customers unless there is a material difference in the costs of providing the services.

Nevertheless, we acknowledge that the increasing presence of new technologies such as batteries in electricity networks may pose challenges under the current regulatory regime.

We therefore welcome further submissions on the NTSC from interested parties in response to our draft decision. In particular, we encourage submissions that provide evidence showing how the NTSC—or a TNSP's application of the NTSC—may not be resulting in prices or terms and conditions that reflect the negotiated transmission service principles as its criteria.[94]

We will consider all submissions on the NTSC in making our final decision for AEMO's transmission determination.

Shell also made the points noted above in its submission to the AEMC's "Integrating energy storage systems into the NEM" rule change.[95] We understand the AEMC plans to publish its final rule determination on this rule change on 28 October 2021.[96] We will consider whether this final rule determination has implications for the NTSC for AEMO when we make our final decision on AEMO's proposed pricing methodology (due by  April 2022).

Shell also suggested changes to our Cost Allocation Methodology Guidelines and Pricing Methodology Guidelines. These are beyond the scope of this transmission determination. However, we will consider these suggestions in our future work program.

### 3.3.2 The NTSC

#### *National Electricity Objective*

1. The terms and conditions of access for a negotiated transmission service, including the price that is to be charged for the provision of that service and any access charges, should promote the achievement of the National Electricity Objective.

#### *Criteria for terms and conditions of access*

*Terms and conditions of access*

2. The terms and conditions of access for a negotiated transmission service must be fair, reasonable, and consistent with the safe and reliable operation of the power system in accordance with the NER.

94 NER (version 109), cll. 6A.9.1 and 6A.9.4(b).

95 Shell, *Submission to proposed negotiated transmission service criteria for AEMO*, 7 October 2021, p. 1.

96 As indicated on the AEMC website as of 4 October 2021.

3. The terms and conditions of access for negotiated transmission services, particularly any exclusions and limitations of liability and indemnities, must not be unreasonably onerous. Relevant considerations include the allocation of risk between the TNSP and the other party, the price for the negotiated transmission service and the cost to the TNSP of providing the negotiated service.
4. The terms and conditions of access for a negotiated transmission service must take into account the need for the service to be provided in a manner that does not adversely affect the safe and reliable operation of the power system in accordance with the NER.

*Price of services*

5. The price of a negotiated transmission service must reflect the cost that the TNSP has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the Cost Allocation Methodology.
6. Subject to criteria 7 and 8, the price for a negotiated transmission service must be at least equal to the avoided cost of providing that service but no more than the cost of providing it on a stand-alone basis.
7. If the negotiated transmission service is a shared transmission service that:
   (a) exceeds any network performance requirements which it is required to meet under any relevant electricity legislation; or
   (b) exceeds the network performance requirements set out in schedule 5.1a and 5.1 of the NER then the difference between the price for that service and the price for the shared transmission service which meets network performance requirements must reflect the TNSP's incremental cost of providing that service (as appropriate).
8. For shared transmission services, the difference in price between a negotiated transmission service that does not meet or exceed network performance requirements and a service that meets those requirements should reflect the TNSP's avoided costs. Schedule 5.1a and 5.1 of the NER or any relevant electricity legislation must be considered in determining whether any network service performance requirements have not been met or exceeded.
9. The price for a negotiated transmission service must be the same for all Transmission Network Users. The exception is if there is a material difference in the costs of providing the negotiated transmission service to different Transmission Network Users or classes of Transmission Network Users.
10. The price for a negotiated transmission service must be subject to adjustment over time to the extent that the assets used to provide that service are subsequently used to provide services to another person. In such cases the adjustment must reflect the extent to which the costs of that asset are being recovered through charges to that other person.
11. The price for a negotiated transmission service must be such as to enable the TNSP to recover the efficient costs of complying with all regulatory obligations associated with the provision of the negotiated transmission service.

### *Criteria for access charges*

*Access charges*

12. Any access charges must be based on the costs reasonably incurred by the TNSP in providing Transmission Network User access. This includes the compensation for foregone revenue referred to in clause 5.4A(h) to (j) of the NER and the costs that are likely to be incurred by a person referred to in clause 5.4A(h) to (j) of the NER (as appropriate).

# Shortened forms

| Shortened form | Extended form |
|---|---|
| AARR | Aggregate annual revenue requirement |
| ASRR | Annual service revenue requirement |
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| DNSP | Distribution network service provider |
| NEL | National Electricity Law |
| NEM | National Electricity Market |
| NEO | National Electricity Objective |
| NER | National Electricity Rules |
| NSP | Network service provider |
| TNSP | Transmission network service provider |