Australian Energy Market Commission

RULE

Consultation paper

National Electricity Amendment (Cost recovery for network augmentations - Package 1 & 2) Rule 2027

Proponent

The Hon Chris Bowen MP, Minister for Climate Change and Energy

24 September 2026

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Reference: ERC0448 & ERC0456

About the AEMC

The AEMC reports to the energy ministers. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the energy ministers.

Acknowledgement of Country

The AEMC acknowledges and shows respect for the Traditional Custodians of the many different lands across Australia on which we live and work. The AEMC office is located on the land of the Gadigal people of the Eora nation. We pay respect to all Elders past and present, and to the enduring connection of Aboriginal and Torres Strait Islander peoples to Country.

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Summary

1 Data centres are emerging as a fast-growing source of electricity consumption in the National Electricity Market (NEM) due to rising demand for artificial intelligence (AI), cloud computing and other digital services. This data centre growth can support Australia's digital sovereignty, attract high-value investment, enable innovation and strengthen Australia's competitiveness in the global digital economy.

2 In its August 2026 Electricity Statement of Opportunities (ESOO) report, the Australian Energy Market Operator (AEMO) forecasted that data centre consumption could triple from present-day levels by 2030. Network service providers (NSPs) across the NEM have also reported a significant increase in potential data centre capacity, based on the connection enquiries and applications they have received.

3 As described in our data centre advice to the Energy and Climate Change Ministerial Council (ECMC), with the right regulatory approach, data centres can support, rather than hinder, Australia's decarbonisation efforts. They can provide the long-term demand and revenue certainty needed to support investment in new renewable generation and firming capacity, helping to accelerate the energy transition.

4 However, due to the unprecedented speed and scale of expected future data centre demand, it is critical to ensure that the NEM's regulatory settings are fit for purpose so that consumers are not left worse off. If rules and regulations do not properly account for large loads and connections that may occur more frequently due to data centre growth, then there is a risk that electricity for consumers becomes costlier or less reliable.[1]

5 On 22 July 2026, the Honourable Chris Bowen MP (the proponent) submitted two rule change requests relating to network cost recovery arrangements in the NEM. The rule change requests seek to ensure that connecting data centres and other large electricity loads properly contribute to the network costs they cause or accelerate, reducing the risk that costs are unfairly recovered from existing electricity consumers.

6 Additionally, the proponent seeks to ensure that the risks and costs of stranded network assets arising from any future data centre connections are not passed on to consumers.

7 The AEMC has commenced its consideration of the two rule change requests, and this consultation paper is the first stage for both processes.

8 We are seeking your feedback on the proponent's identified issues with the existing cost recovery arrangements, the proposed solutions or any alternative solutions that will promote the long-term interests of consumers.

These rule changes form part of a broader AEMC data centre work program

The rule change requests reflect the Australian Government's expectations of data centres and AI infrastructure developers

9 Recognising that data centres can have significant environmental impacts through their large water use and large electricity consumption, the Australian Government has published:

1 Note that there is no NER definition of 'large load'. The proponent uses both data centres and smelters as examples of 'large loads,' in terms of their size and potential impact on the electricity network.

- a National AI Plan, which aims to '[harness] opportunities from the growth of data centres to promote investment in renewable energy and maintain affordable energy for households and businesses'[2]
- five expectations of data centres and AI infrastructure developers,[3] where the Australian Government indicated that it will prioritise data centre proposals that are most closely aligned with the expectations.

10 Expectation 2 states that[4]

> New data centres and AI infrastructure should not place upward pressure on energy prices and should make a positive contribution to Australia's energy transition. This includes working in coordination with energy regulators and suppliers to:
>
> - secure new and additional clean energy generation and/or storage to offset demand
> - cover their share of transmission and distribution infrastructure costs
> - minimise their energy demand and emissions by adopting industry-leading efficiency measures and technologies
> - improve the overall security and stability of the energy grid, including by enhancing demand flexibility and opportunities for peak-load management and appropriate sharing of consumption data.

11 The proponent's rule change requests directly relate to the aspect of Expectation 2 above that data centres and AI infrastructure should 'cover their share of transmission and distribution infrastructure costs'.

The AEMC intends to progress several rule change requests related to data centres

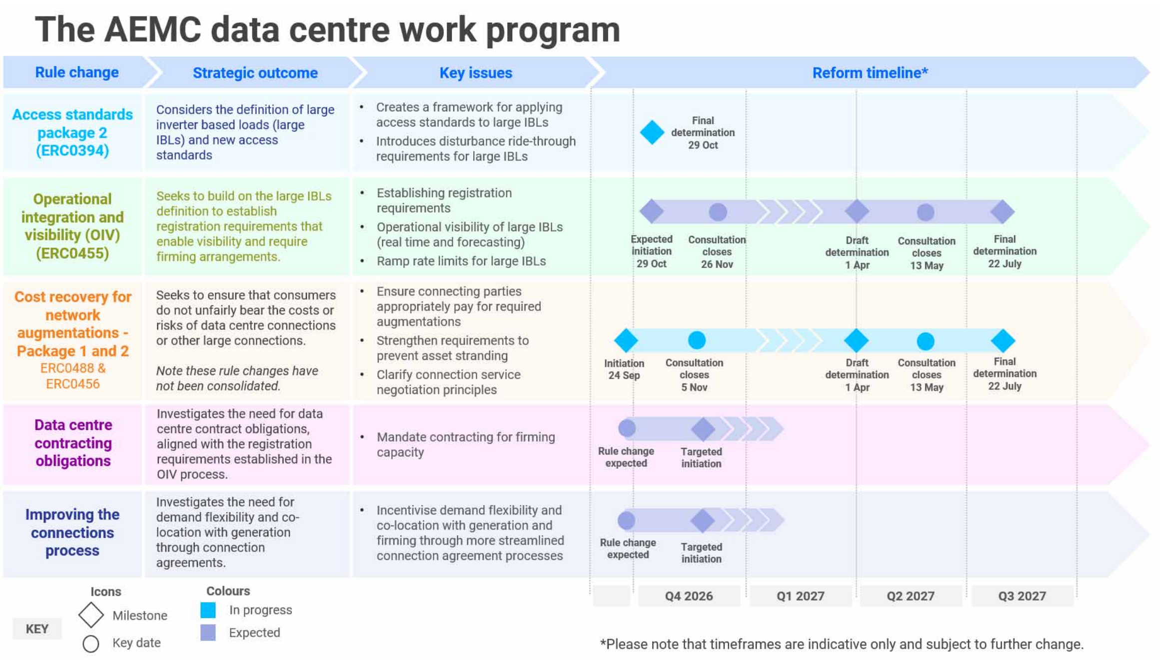
12 The proponent's two rule change requests were developed in collaboration with states and territories and aim to ensure cost recovery arrangements in the NEM do not result in consumers inappropriately bearing the costs associated with large connections.

13 To action the recommendations in the AEMC's data centre advice to the ECMC, we intend to consider and progress several upcoming ECMC rule changes, as well as AEMO's Operational integration and visibility of large inverter based loads rule change request (referred to as the OIV rule change request).

14 See section 1.3 for more information on these related rule change requests and Figure 1 for an overview of the Commission's work plan for data centre-related rule change requests.

2 Department of Industry, Science and Resources, National AI Plan, December 2025, p. 11-12.
3 Department of Industry, Science and Resources, Expectations of data centres and AI infrastructure developers, March 2026.
4 Ibid.

Figure 1: The AEMC intends to progress several data centre-related rule changes



Source: AEMC
Note: Timeframes are indicative only and are subject to further change.

Connecting parties currently pay for the costs of works required to facilitate their connection

Connecting parties pay charges for connection services and shared network services

15 When a customer (who is not an NSP) seeks to connect a new plant to the NEM, they must pay for:

- **connection services**, which include the design and construction of new infrastructure to enable a new connection to a distribution or transmission network (some of these works may include the construction of augmentations or extensions to the network that may be required to facilitate the connection)
- **shared services**, which are for the use of the shared network to convey electricity to the customer for consumption; these are typically ongoing transmission use-of-system (TUOS) or distribution use-of-system (DUOS) charges, but may be negotiated in some circumstances.

16 Arrangements for generators seeking to connect to the network are different. Generators pay for their connection services, but do not pay for the use of shared services through TUOS or DUOS. This is because they are not classified as Transmission Customers or Distribution Customers under the NER. Generators have no ‘firm right’ to use shared services at any point in time.[5]

17 This distinction between connection and shared services is important, as the rule change request primarily identifies issues where the proponent considers that charges for **connection services** may not fully cover the costs associated with facilitating a large load connection to the NEM. Nevertheless, the charges for the use of **shared services** are directly relevant to the regulatory framework for determining and negotiating connection charges, especially for large

5 This is often referred to the ‘open access’ arrangement of the NEM.

augmentations that may be constructed for a large load to later use.

18 Moreover, the regulatory classification of transmission and distribution services differs, where:

- in transmission, the NER more explicitly defines different types of transmission services without an AER classification decision of transmission services
- in distribution, the AER makes distribution service classification decisions in its (typically) five-yearly distribution determinations for every DNSP, according to its service classification guidelines.

19 For more information on current network service arrangements, see section 2.1 of this consultation paper.

Transmission services can be classified as prescribed, negotiated or non-regulated

20 Transmission services are classified by the NER as either:

- **prescribed transmission services**, which include (but are not limited to) shared transmission services that meet network performance requirements or requirements under jurisdictional legislation, and services necessary to maintain the integrity and security of the power system. These are subject to economic regulation by the AER under chapter 6A of the NER.
- **negotiated transmission services**, which are provided to a specific user or group of users of a transmission network. The terms, conditions and charges for negotiated transmission services are determined through negotiation consistent with the negotiating principles under Chapter 5 of the NER.
- **non-regulated transmission services**, which include contestable connection services and any other service not classified as either prescribed or negotiated under the NER. The prices and terms of non-regulated transmission charges are determined solely through commercial agreements between the TNSP and the customer.

21 New transmission connection services are either a **negotiated transmission service** or a **non-regulated transmission service**. See section 2.1.1 for more information.

Distribution services include direct control services, negotiated or non-regulated services

22 In contrast to transmission, the AER classifies distribution services as part of its distribution determinations, which it makes for every DNSP for each regulatory control period (typically every five years). There are three broad types of distribution services that can be provided by a DNSP:

- **Direct control services**, which are monopoly services that cannot be provided by a party other than the relevant DNSP, and are subject to economic regulation by the AER and chapter 6 of the NER. There are two sub-classes of direct control service:
  - **Standard control services**, which include the bulk of a DNSP's typical activities operating as a natural monopoly
  - **Alternative control services**, which are only used or requested by certain customers.
- **Negotiated distribution services**, where prices, terms and conditions are determined between relevant parties through negotiation consistent with the negotiating principles in rule 6.7 of the NER, and must be provided by a functionally separate affiliate of the DNSP.
- **Unclassified distribution services**, which are not regulated under the NER or by the AER.

23 Distribution connection services are typically classified as either a **standard control service** or an **alternative control service.** See section 2.1.2 for more information.

Shared network service charges are typically ongoing TUOS or DUOS payments, but may be negotiated in some circumstances

24 At transmission, the classification of shared transmission services depends on whether the shared service provided to the customer meets or exceeds network performance requirements set out in the NER or under jurisdictional electricity legislation.

- If the use of a shared transmission service is a *prescribed transmission service*, the customer will pay ongoing transmission use-of-system (TUOS) charges. The AER regulates and approves TUOS pricing and methodologies.
- If the use of a shared transmission service is a *negotiated transmission service,* the customer will pay the TNSP an amount that has been negotiated in accordance with the NER (note that the negotiated charge may be zero).

25 At distribution, shared services are typically either *standard control services* or *alternative control services*, which are paid for through ongoing distribution use-of-system charges (DUOS) and other charges (such as capital contributions or pioneer scheme charges) calculated according to the AER's connection charge guideline. The AER regulates and approves DUOS pricing and methodologies.

We are seeking your views on whether there is a risk that consumers inappropriately bear risks and costs from large connections

26 As outlined above, the regulatory frameworks for determining and negotiating connection charges differ in many ways between transmission and distribution, due to the typical scope and scale of works that are required to facilitate new connections. The intent of these frameworks is to allocate connection costs in a manner that promotes efficient investment in, and use of, the electricity system.

27 The proponent considers that the nature, scale and speed of future data centre connections represent a significant change that was not anticipated when the relevant frameworks were developed. Without its rule change requests, the proponent considers that consumers could unfairly bear a potentially significant share of the expenditure required to accommodate large loads.

28 In its rule change requests, the proponent put forward scenarios that, in its view, highlight several potential gaps in the current regulatory frameworks that may increase the risk of consumers unfairly bearing costs:

1. A large load connects to a distribution (low voltage) network and triggers the need for upstream transmission (high voltage) augmentation, which may result in some of the augmentation costs being paid for by other customers (see section 3.1.2)
2. Network investment proceeds to support a future large load, but that large load does not proceed or uses less capacity than anticipated; due to inadequate prudential requirements, the NSP may subsequently recover costs from other customers (see section 3.2.2 and section 3.3.2)
3. Insufficient public information about large loads may make demand forecasting and network planning more challenging for AEMO, NSPs and market participants, potentially increasing costs for consumers (see section 3.4.2)
4. Clustered large loads can drive the need for significant shared augmentations, but the National Electricity Rules (NER) may be unclear on cost recovery arrangements for these types of augmentations (see section 3.5.2)

5. A large load that connects to the transmission network may not be liable for jurisdictional scheme costs under the NER (see section 3.6.2)
6. A large load connects to the transmission network and triggers the need for augmentation of the shared network, but the NER may not provide adequate guidance on the pricing of connection and augmentation costs (see section 3.7.2).

29 We seek your views on each of the proponent's identified issues and the materiality of those issues, in the context of future large connections to the NEM.

We are also seeking your views on the proponent's proposed solutions to address its identified gaps in the current cost recovery arrangements

30 As part of its rule change requests, the proponent has also put forward several proposed solutions to address its identified issues with the existing cost recovery arrangements.

31 Its proposed solutions can be summarised as follows:

1. Ensure that the costs of upstream augmentations are appropriately allocated to connecting parties, including a mechanism to account for differences between actual and forecast augmentation costs
2. Require NSPs to apply prudential requirements for all large connections above a certain threshold
3. Reduce the ability for an NSP to seek AER approval to recover the costs of stranded assets from its broader consumer base
4. Require NSPs to provide detailed information about existing and prospective large loads for the Australian Energy Market Operator (AEMO) to create a new public large load register
5. Reduce regulatory barriers to more easily allow connecting parties to voluntarily fund the costs (or bring forward the timing) of large augmentations
6. Create a new mechanism in the NER to allow transmission NSPs (TNSPs) to pass through jurisdictional scheme costs to transmission customers
7. Require the AER to publish a new guideline that sets out transmission access and connection pricing principles or methodologies to promote consistency across jurisdictions.

32 We seek your views on each of the proponent's proposed solutions and on related topics that the Commission will consider in its assessment of those solutions. See chapter 3 for more details on each of the identified issues, proposed solutions and related topics.

The Commission will coordinate with relevant parties on related consultation processes

33 The Commission is aware of other consultation processes that are highly relevant to the Commission's consideration of these two rule change requests. These include (but are not limited to):

- consultation on the AER's connection charge guidelines for distribution, to ensure it aligns with the Commonwealth's Expectations of Data Centres and AI Infrastructure Developers.[6]
- AEMO's Market Visibility Framework consultation, where AEMO proposed new visibility and participation modes for consumer energy resources, aggregated storage assets and large loads.

6 See section 1.5 for more information on its upcoming consultation.

- amendments to regulations under the NSW Electricity Infrastructure Investment Act 2020 (EII Act) to improve network cost allocation and recovery for large connections to NSW networks (see paragraphs 36 to 38 for more information).

34 The Commission will work closely with other market bodies and jurisdictions to ensure that our reforms are aligned and complementary, to the extent possible within our separate processes.

35 The Commission is also currently progressing an electricity network regulation review in two packages.[7] As these rule change requests cover issues that are related to the network regulation review, the Commission will have regard to relevant stakeholder submissions lodged to the review when considering whether to make a rule for this rule change request.

Jurisdictions are progressing similar reforms to the proponent's rule change requests

36 On 17 September 2026, the Department of the Prime Minister and Cabinet commenced consultation on new national AI standards that would apply to new data centres. Among other minimum requirements, the standards aim to ensure data centres 'impose no net costs on consumers and communities'.

37 Given the proponent's rule changes and certain elements of the proposed national AI standards have similar objectives, the Commission will, where appropriate, collaborate with the Department of the Prime Minister and Cabinet through our respective consultation processes.

38 Additionally, on 17 August 2026, the NSW government published a consultation paper on proposed new regulations to improve network cost allocation and recovery. Most elements of the NSW proposed reforms are very similar to the proposed solutions of the two rule change requests that are the subject of this consultation paper.

39 Due to a very high volume of proposed data centres planning to connect to NSW in the near future, the NSW government intends to give effect to its proposed reforms in Q4 of 2026.

40 We encourage all interested stakeholders who have engaged with the NSW consultation process to also consider lodging a submission to this consultation paper, given the close similarities and overlap between the NSW government's proposed reforms and the proponent's rule change requests.

41 Several other jurisdictions have also released guidelines, expectations or action plans that aim to mitigate the impact of data centres on the costs of electricity for other consumers. See section 1.8 for more information.

We consider that there are three assessment criteria that are most relevant to this rule change request

42 Considering the National Electricity Objective (NEO)[8] and the issues raised in the rule change request, the Commission proposes to assess the rule change request against three assessment criteria.

43 Please provide feedback on our proposal to assess the request against:

- **Outcomes for consumers:** we will consider how different types of customers and consumers are accounted for, so that the costs associated with connecting large customers are not inappropriately borne by other consumers.

7 See the Package 1 project page here: https://www.aemc.gov.au/market-reviews-advice/electricity-network-regulation-review-package-1. See the Package 2 project page here: https://www.aemc.gov.au/market-reviews-advice/electricity-network-regulation-review-package-2.

8 Section 7 of the NEL.

- **Safety, security and reliability:** we will consider whether any potential changes to the NER would continue to contribute to the provision of reliable, secure and safe provision of energy at efficient cost, to benefit consumers over the long term
- **Principles of market efficiency:** we will consider how the relevant frameworks and any potential changes promote efficient planning and investment of the power system by allocating risk to parties best suited to manage the risk, increasing information transparency and encouraging competition.

44 We note that the rule change request and the proponent use the words 'equitable' and 'fair' when discussing identified issues, proposed solutions or potential benefits.

45 We seek stakeholder views on how equity-related factors should be considered in our decision-making, noting that the Commission can only make a rule that contributes to achieving the NEO. For more information on how we consider equity, refer to section 4.1.6 of How the national energy objectives shape our decisions.

46 See section 4.3 for more information on the Commission's proposed assessment criteria to assess these rule change requests.

Submissions are due by 5 November 2026 with other engagement opportunities to follow

47 There are multiple options to provide your feedback throughout the rule change process.

48 Written submissions responding to this consultation paper must be lodged with the Commission by 5 November 2026 via the Commission's website, www.aemc.gov.au.

49 There are other opportunities for you to engage with us, such as one-on-one discussions or industry briefing sessions. See the section of this paper about "How to engage with us" for further instructions and contact details for the project leader.

50 Due to the complexity of the rule change requests, the Commission's timeline for progressing these two cost recovery rule changes has been extended. This will also provide stakeholders with a better ability to consider potential interlinkages with other rule changes in our data centre work program when engaging in our consultation process.

Full list of consultation questions

Question 1: Do you have feedback on our summary of current network service arrangements?

- Do you have comments or feedback on how we have described the current arrangements for relevant network services in section 2.1 of this consultation paper?
- Do you have comments or feedback on our summary of how the current arrangements would apply to a new connecting data centre or large load?

Question 2: Do you consider that the costs of upstream augmentation may not be appropriately allocating to distribution connections?

- Do you agree with the proponent that the application of rule 5.3AA should be expanded to cover large loads and data centres?
- Do you agree with the proponent that the existing requirement to negotiate charges in 'good faith' is not robust enough to ensure other consumers do not bear the costs of upstream augmentations? If so, how should distribution negotiation and pricing principles under rule 5.3AA be strengthened?
- If the actual cost of an upstream augmentation is different to the estimated cost at the time of connection, do you consider that there should be a mechanism to ensure actual augmentation costs are later recovered from the connection applicant? If so, do you have views on the details of how such a mechanism should work?
- Are DNSPs and TNSPs currently able to sufficiently coordinate and liaise with each other to determine whether upstream augmentations are required for a distribution connection, and to estimate any costs? Are there any other DNSP or TNSP interactions that you think the Commission should consider, such as the RIT-T/D or competition concerns?
- If rule 5.3AA were to be amended, do you have views on whether any other changes are required to promote consistency across all distribution connections?

Question 3: Do you consider that existing prudential requirements sufficiently protect consumers from the risk of paying for assets originally built for large loads or customers?

- Do the existing prudential requirement rules effectively protect consumers from the costs associated with stranded assets? If not, why?
- If changes are required, what amendments should be made to the NER?
- Are there any other approaches, including those suggested by the proponent and the NSW Government?
- If amendments are made to the NER, what types of connections should be covered?
- Should there be a threshold for the types of load that any amendment applies to, and what should it be?
- To what extent should the transmission and distribution prudential requirement frameworks be aligned, ie, rule 6A.28 and rule 6.21, and are there any differences that should be retained?

Question 4: Do you consider there should be additional conditions or limitations on an NSP to reallocate the value of assets into their regulated asset base (RAB)?

- Do the existing safeguards adequately protect consumers from the reallocation of customer-specific asset costs? If not, why not?
- Would further limiting the circumstances in which customer-specific assets can be reallocated into the RAB improve consumer protections? What benefits, risks or unintended consequences could arise from doing so?

- If additional restrictions are warranted, how should they be implemented and how should they apply?

Question 5: Do you consider that there is limited public information about large loads?

- To what extent is there an information gap regarding prospective and existing large load developments and how material is the impact it has on planning, forecasting and investment decisions?
- What information should be collected, shared or published to address any identified information gaps?
- How should any reforms to the collection, sharing or publication of information on large loads be designed and implemented?
- How should confidentiality, competition and other risks associated with the collection, sharing or publication of information be managed?

Question 6: Do you consider there are barriers for connection applicants to fund 'deep' shared augmentations?

- Have you ever been involved in discussions regarding a potential funded augmentation under rule 5.18 or otherwise? If so, what factors influenced your decision to pursue or not pursue a funded augmentation of the shared transmission or distribution network?
- Do you agree with the proponent that the 'first mover disadvantage' and the lack of clarity in the NER are barriers to funding augmentations of the shared network? If so, do you have a view on what the definition of 'funded augmentation' should be amended to, or what particular aspects the NER should provide better clarity on?
- Do you consider that a mechanism to compensate for the 'first mover disadvantage', such as a pioneer scheme, is an effective way to promote funded augmentations? If so, what is your view on the details of how such a mechanism should work?
- Do you consider that the proponent's suggested solutions should be extended to distribution networks for shared distribution augmentations?

Question 7: Do you consider that the costs of jurisdictional schemes should be recovered from transmission customers?

- Should the NER enable jurisdictional scheme amounts to be recovered from transmission customers? Why or why not?
- How should any transmission-level jurisdictional scheme framework be implemented?
- What issues could arise from introducing a transmission-level jurisdictional scheme framework, and how could these be addressed?

Question 8: Do you consider that there should be more explicit guidance on how TNSPs determine or negotiate prices for negotiated transmission services?

- Do you agree with the proponent that the relative lack of detail for transmission connection services may increase the risk of inefficient cross-subsidisation? Why or why not?
- Do you support the proponent's proposal for the AER to develop and publish a new guideline for transmission connection services, similar to its existing connection charge guidelines for distribution?
- If so, should any new guidance prescribe methodologies for how transmission service charges are calculated (similar to how the AER's connection charge guideline details the calculation of 'unit rates'), or is a more principles-based approach preferable?
- Are there any aspects of the guidance provided for distribution connections that should be adapted for transmission to reduce the risk of inefficient cross-subsidisation?

Question 9: Assessment framework

Do you agree with the proposed assessment criteria? Are there additional criteria that the Commission should consider or criteria included here that are not relevant?

How to make a submission

We encourage you to make a submission

Stakeholders can help shape the solutions by participating in the rule change process. Engaging with stakeholders helps us understand the potential impacts of our decisions and, in so doing, contributes to well-informed, high quality rule changes.

We have included questions in each chapter to guide feedback, and the full list of questions is above. However, you are welcome to provide feedback on any additional matters that may assist the Commission in making its decision.

How to make a written submission

Due date: Written submissions responding to this consultation paper must be lodged with Commission by 5 November 2026.

How to make a submission: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code ERC0448 or ERC0456.[9]

You may, but are not required to, use the stakeholder submission form published with this consultation paper.

Tips for making submissions are available on our website.[10]

Publication: The Commission publishes submissions on its website. However, we will not publish parts of a submission that we agree are confidential, or that we consider inappropriate (for example offensive, defamatory, vexatious or irrelevant content, or content that is likely to infringe intellectual property rights).[11]

Other opportunities for engagement

There are other opportunities for you to engage with us, such as one-on-one discussions or industry briefing sessions. Please reach out to the project team if you would like to arrange a discussion by navigating to the project page and clicking on the 'Contact Project Leader' button.

For more information, you can contact us

Please contact us with questions or feedback at any stage, noting the project code.

Email:	aemc@aemc.gov.au
Telephone:	(02) 8296 7800

9 If you are not able to lodge a submission online, please contact us and we will provide instructions for alternative methods to lodge the submission.

10 See: https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/submission-tips

11 Further information is available here: https://www.aemc.gov.au/contact-us/lodge-submission

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Figures

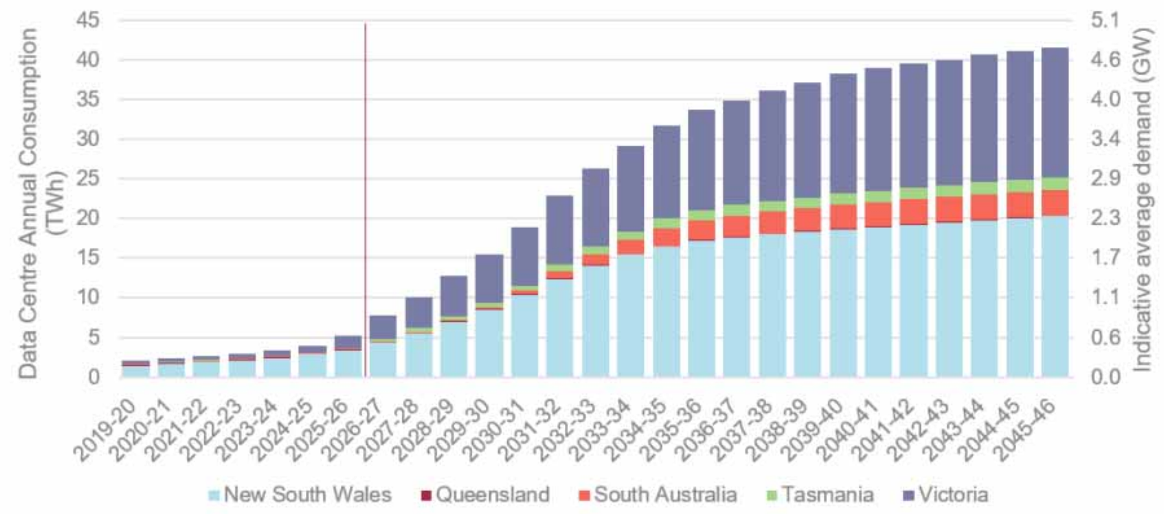
1 The context for these rule change requests

This consultation paper seeks stakeholder feedback on the two rule change requests submitted by the Honourable Chris Bowen MP, which aim to ensure that data centres and other large loads make an appropriate contribution to the network costs they cause or accelerate when they connect to the NEM. In the proponent's view, this would reduce the risk that these network costs are unfairly recovered from existing electricity consumers.

1.1 Data centre demand is expected to increase

Data centres are emerging as a fast-growing source of electricity demand in the NEM due to rising demand for artificial intelligence (AI), cloud computing and other digital services. In its 2026 Electricity Statement of Opportunities, AEMO forecasts that data centre demand could triple by 2030, from about 5 TWh per year in 2025-26 (about 2.8% of operational consumption[12]) to around 15 TWh per year by 2029-2030 (about 8% of operational consumption).[13] By 2044-45, AEMO's forecast of data centre consumption is expected to rise to about 41 TWh, or about 13.5% of operational consumption. See Figure 1.1 for AEMO's ESOO forecast of data centre consumption.

Figure 1.1: AEMO's average data centre consumption and indicative average demand forecast



Source: AEMO, 2026 NEM Electricity Statement of Opportunities, Figure 16, based on its *Step Change* demand scenario.
Note: AEMO noted that since its forecast was finalised, it became aware of greater interest in Queensland than is represented in these 2026 ESOO forecasts.

The scale and nature of future data centre connections may require significant augmentations to the distribution and transmission networks at a pace not seen before in the NEM. Data centres are also different to other kinds of 'traditional' loads for a variety of reasons:

- data centres often seek a higher degree of reliability compared to other loads, which may drive requests for multiple points of supply or additional network augmentation

12 Operational consumption refers to the total amount of energy transferred to consumers from 'large' producers of electricity in the NEM. This is distinct from underlying consumption, which includes self-consumption of rooftop solar, on-site generation and other forms of consumer energy resources (CER).

13 AEMO, 2026 NEM Electricity Statement of Opportunities, Figure 16 and its 2026 ESOO Results Workbook.

- data centres tend to be geographically concentrated close to metropolitan areas (especially Sydney, Melbourne and Brisbane) to (among other things)[14] reduce latency for their customers, which may increase the prevalence or severity of local constraints on already-congested areas of the network
- data centres are typically inverter based loads, which can pose unique system security challenges not necessarily presented by other types of loads (see the AEMC's Improving the NEM access standards – Package 2 rule change for more information)

Therefore, mitigating potential reliability impacts and managing potential cost impacts on other consumers are key policy considerations for data centres.

Another key focus of the Australian Government is ensuring that future data centre growth does not pose a challenge to its target of 82% renewable electricity by 2030.[15] Recognising that data centres can be large users of water and may have other significant environmental impacts, the Commonwealth has also published:

- a National AI Plan, which stated the government's aim of 'harnessing opportunities from the growth of data centres to promote investment in renewable energy and maintain affordable energy for households and businesses'[16]
- five expectations of data centres and AI infrastructure developers, where the Commonwealth has indicated that it will prioritise data centre proposals that are most closely aligned with the expectations.

Under this context of expected data centre growth, the proponent has stated that its two rule change requests aim to:[17]

> ensure that data centres and other large electricity loads make an appropriate contribution to the network costs they cause or accelerate, reducing the risk that these costs are recovered from existing electricity consumers.

1.2 The AEMC has provided advice to Energy Ministers on data centres

On 8 May 2026, the Energy and Climate Change Ministerial Council (ECMC) requested advice from the AEMC on 'implementation options to support government objectives relating to renewable generation, firming and flexible operation expectations, and geographic location within transmission and distribution systems, for data centres.'[18] This included advice on regulatory pathways to require data centres to fully offset their demand by investing in renewable generation and firming, and by providing demand flexibility.[19]

The Commission presented its advice to the ECMC for consideration at its 28 July 2026 meeting. We made four main policy recommendations to the ECMC:

1. Drive investment in new renewable generation by mandating data centres to offset their energy consumption with Renewable Electricity Guarantee of Origin (REGO) certificates

14 For example, metropolitan areas often have dense fibre optic networks, more labour and capital, easier logistics and more robust infrastructure than other areas.

15 The Hon Chris Bowen MP, Speech to the National Press Club, Canberra, 5 August 2026. See also AEMC, Emissions targets statement under the national energy laws, p. 2.

16 Department of Industry, Science and Resources, National AI Plan, December 2025, p. 11-12.

17 Rule change request, letter to AEMC Chair.

18 Energy and Climate Change Ministerial Council meetings and communiques, 8 May 2026.

19 AEMC, Data centre energy obligation, Advice to Energy and Climate Change Ministers, Summary for Ministers, p. 3.

2. Ensure there is sufficient firming capacity by requiring data centres to demonstrate that their financial contracts would cover their load, or by investing in storage and demand flexibility
3. Improve operational visibility of large loads by introducing market registration requirements and voluntary incentives for large data centres to participate in the wholesale market
4. Support demand flexibility and co-location with generation through the connection agreement process.

More information about the AEMC's data centre advice to the ECMC is available on our project page.

1.3 The AEMC intends to progress other rule changes related to data centres

As part of the data centre advice discussed in section 1.2, the Commission recognised that further consideration and policy design would be required to progress and action our policy recommendations.[20] At the 28 July 2026 ECMC meeting, Ministers agreed to develop additional rule change requests for ECMC's consideration in September, and the Commonwealth committed to developing and introducing legislation requiring new data centres to purchase REGOs (see policy recommendation 1 above).[21]

The rule change requests that will action our policy recommendations from our data centre advice, include:

- The *Operational integration and visibility of large inverter-based loads* rule change request (referred to as the OIV rule change request), where the Hon Chris Bowen MP, on behalf of supporting jurisdictions, supports the rule change to be an appropriate vehicle to progress policy recommendation 3[22]
- an upcoming rule change request on **data centre contracting obligations** that would progress policy recommendation 2
- an upcoming rule change request on **streamlining the connections process** that would progress policy recommendation 4.[23]

Many of the issues identified in the OIV rule change request are interlinked with those in the proponent's cost recovery rule change requests. As the regulatory processes for connection pricing often depend upon the registration status (or requirements) of a connection applicant, any potential policy solutions for the OIV rule change should take into account policy considerations for connection pricing in these two cost recovery rule changes, and vice versa.

Given that the rule change requests have raised complex issues and issues interrelated with other proposed AEMC rule change projects, the Commission has extended the timeline for progressing these two cost recovery rule changes.[24] This will provide stakeholders with a better ability to consider the possible interlinkages with other rule changes in our data centre work program when engaging in our consultation process.

Additionally, there are interlinkages and interdependencies across the broader suite of data centre-related rule changes that the Commission will consider as relevant throughout the rule change

20 Ibid., p. 10.

21 With Qld and NT ministers opposing; see Energy and Climate Change Ministerial Council meetings and communiques, 28 July 2026.

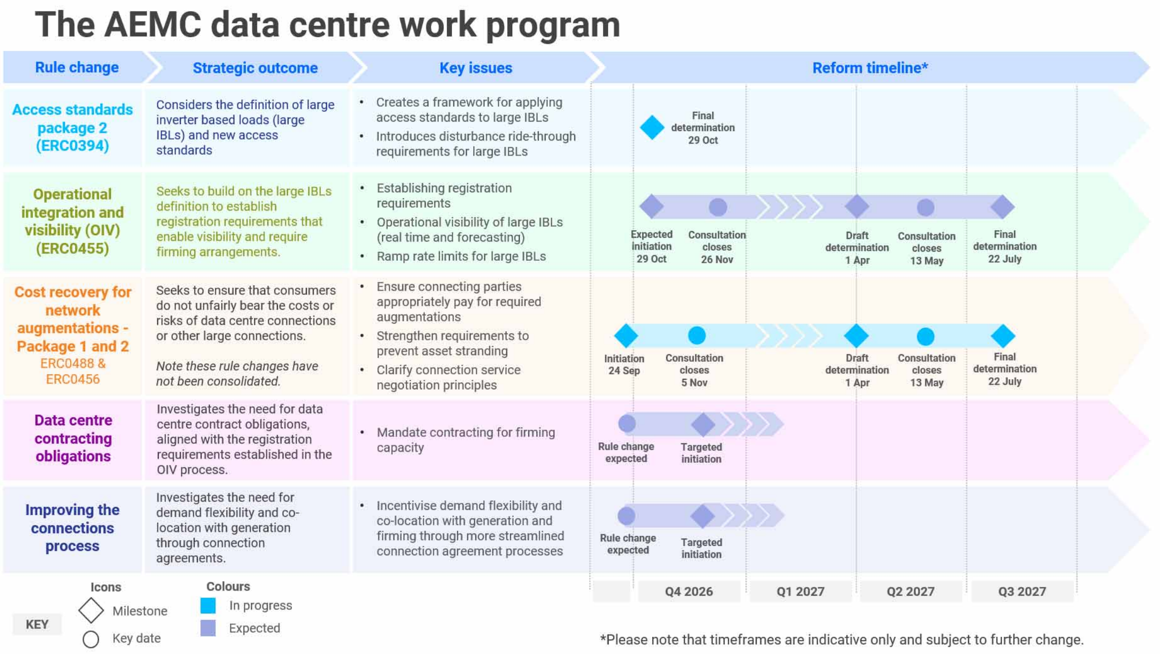
22 Letter from Minister Bowen to AEMC, 10 September 2026.

23 These upcoming rule change requests have not yet been submitted to the AEMC. After we receive them, we will publish them on our website.

24 Under s. 107 of the NEL, the Commission has extended the period of time for making a draft rule determination until Thursday, 1 April 2027, because the rule change requests raise issues of sufficient complexity or difficulty such that it is necessary that the period of time be extended. See the s. 107 statutory notice on the project webpage.

processes. See Figure 1.2 for an overview of the Commission's indicative work plan for data centre-related rule change requests.

Figure 1.2: The AEMC intends to progress several data centre-related rule changes



Source: AEMC
Note: Timeframes are indicative only and are subject to further change.

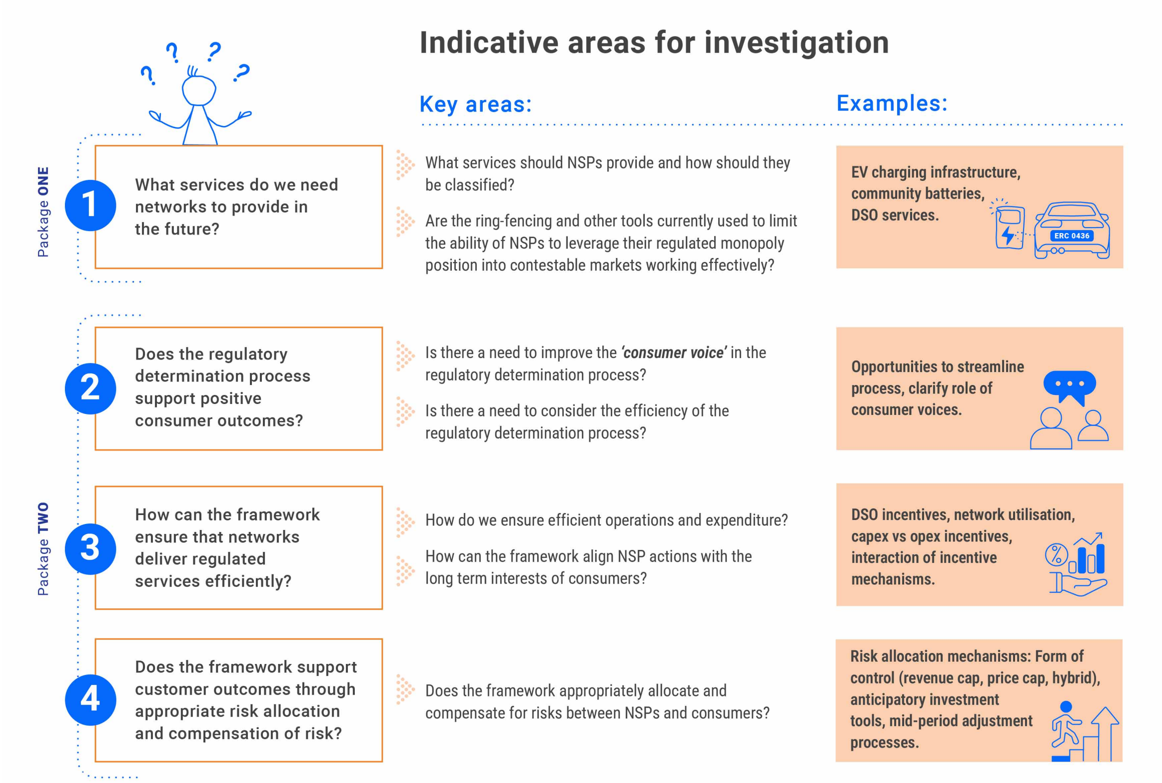
1.4 The AEMC is progressing an electricity network regulation review

The Commission is currently progressing an electricity network regulation review in two packages:

- Package 1, which focuses on network service classification and ring fencing frameworks, as well as incorporating two rule change requests relating to ring fencing and electric vehicle charging infrastructure
- Package 2, which focuses on the revenue determination process, network incentives and risk allocation to ensure that regulation remains fit for purpose and continues to support efficient, consumer-focused outcomes throughout the energy transition.

See Figure 1.3 for a broad outline of the key questions and scope in both Network Regulation Review packages.

Figure 1.3: Key questions and scope of the AEMC's Network Regulation Review



Source: AEMC, Electricity Network Regulation Review (Package 2), consultation paper, Figure 1.2.

As these rule change requests cover issues that are related to the network regulation review, the Commission will have regard to relevant stakeholder submissions lodged to the review when considering whether to make a rule for this rule change request.

We encourage all interested stakeholders to contact the project teams for the network regulation review packages by navigating to the project pages hyperlinked above and clicking on the 'Contact Project Leader' button.

1.5 The AER will commence a review of its distribution connection charge guidelines

In its 8 May 2026 Communique, the ECMC asked the AER to progress a review of its connection charge guidelines for distribution to ensure it aligned with the Commonwealth's Expectations of Data Centres and AI Infrastructure Developers (see section 1.1).[25]

The AER's connection charge guideline is highly relevant to the Commission's consideration of the proponent's identified issues and proposed solutions for these two rule change requests. In particular:

25 Energy and Climate Change Ministerial Council meetings and communiques, 28 July 2026. The AER's connection charge guideline is made under clause 5A.E.3 of the NER for the development of DNSP connection policies.

- the guideline's existing cost-revenue test for capital contributions that pay for new augmentations of the shared network[26] is relevant when considering how to best price upstream augmentations for large connections (most relevant to Gap 1, see section 3.1)
- chapter 10 of the guideline (titled 'Security fee') is relevant when considering any potential new requirements or guidelines for NSPs imposing prudential arrangements on connection applicants (Gap 2, see section 3.2)
- any AER clarifications on transmission cost recovery arrangements, and its consideration of whether additional transmission guidance is needed, are directly relevant to the proponent's proposal to introduce a new AER guideline for transmission access and charges (Gap 7, see section 3.7)

Given the interdependencies between our work programs, we will work closely with the AER to ensure that our reforms are aligned and complementary. We will seek to promote clarity and transparency across both the distribution and transmission frameworks, and to ensure that the interaction between the NER and any AER guidelines is clear and contributes to the NEO.

1.6 The Department of the Prime Minister and Cabinet is consulting on minimum requirements for new data centres

On 17 September 2026, the Department of the Prime Minister and Cabinet released a consultation paper that seeks feedback on national AI standards. The consultation paper describes that the national standards would require data centres to:

- make a positive contribution to Australia's energy transition by
  - bringing forward new renewable generation to fully offset their energy demand (with appropriate firming through gas, batteries or hydro)
  - providing demand flexibility
  - operate in ways that minimise costs for businesses and consumers
- use innovative, efficient and sustainable solutions to minimise water use
- impose no net costs on consumers and communities
- engage meaningfully with local communities and councils
- contribute to building skills and training opportunities.[27]

The consultation paper also seeks feedback on an appropriate size threshold to apply the government's AI standards, referencing the *Improving the NEM access standards - Package 2* draft rule's proposal to introduce a tiered application of the NER access standards.[28]

Given the proponent's rule changes and certain elements of the proposed national AI standards have similar objectives, the Commission will, where appropriate, collaborate with the Department of the Prime Minister and Cabinet through our respective consultation processes.

26 AER, Connection charge guidelines for electricity customers, Chapter 5.

27 Department of the Prime Minister and Cabinet, Getting it right: Building AI infrastructure that works for Australia: Consultation paper, September 2026.

28 Ibid., p. 8.

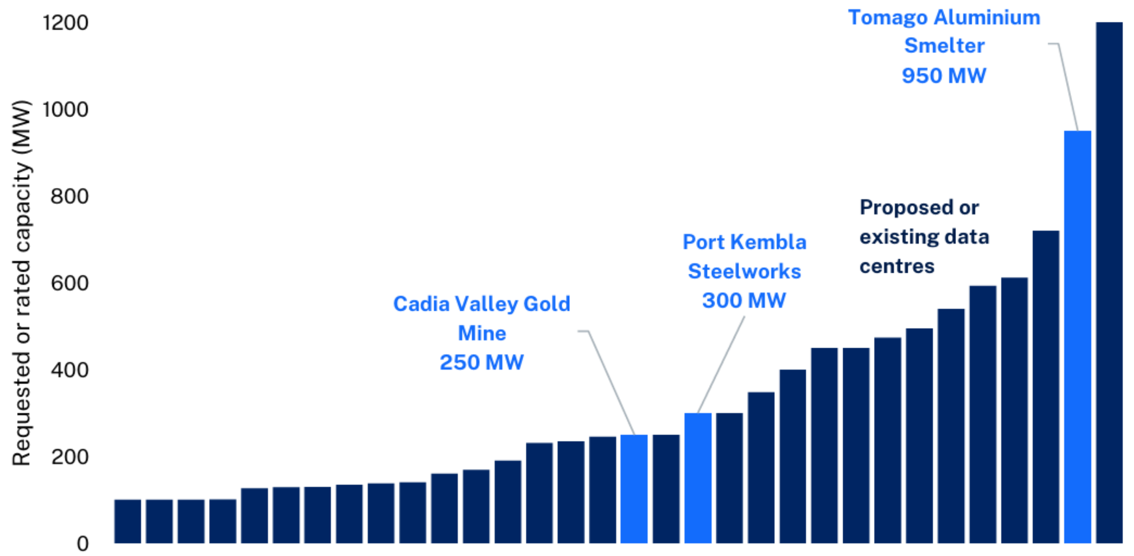
1.7 NSW intends to make new regulations to enact similar reforms to the proposals in these rule change requests

On 17 August 2026, the NSW Government published a consultation paper on proposed new regulations that would be made under the *Electricity Infrastructure Investment Act 2020* (EII Act) to:

- improve network connections and planning
- improve network cost allocation and recovery
- support implementation of measures in the NSW Data Centre Guidelines.

In its consultation paper, the NSW Department of Climate Change, Energy, the Environment and Water (NSW DCCEEW) noted that, as of July 2026, approximately 28 GW of data centre capacity were seeking to connect to NSW networks, with 13 GW in 'advanced discussions' to connect.[29] It added that Transgrid's 2025 forecast of additional data centre demand by 2035 increased twentyfold relative to its 2024 forecast,[30] and that some proposals are 'set to become the largest individual electrical loads in NSW.'[31] NSW DCCEEW compared some proposed and existing data centres with existing large loads, such as the Tomago Aluminium Smelter (see Figure 1.4 below).

Figure 1.4: Selected existing and prospective data centres in NSW relative to existing large loads



Source: NSW Department of Climate Change, Energy, the Environment and Water, Reforming electricity network connection and cost recovery arrangements for data centres in NSW, Figure 2, p. 2.

Under this context of a very high volume of proposed data centres connecting to NSW electricity network in the near future, the NSW government has indicated that it intends to make a new regulation under the EII Act in Q4 of 2026 to give effect to its proposed reforms (subject to the passage of the Electricity Infrastructure Investment Amendment Bill 2026).[32]

29 Department of Climate Change, Energy, the Environment and Water, Reforming electricity network connection and cost recovery arrangements for data centres in NSW, pp. v, 1-2.

30 Ibid., p. 1; see also Transgrid, 2025 Transmission Annual Planning Report, p. 87.

31 Department of Climate Change, Energy, the Environment and Water, Reforming electricity network connection and cost recovery arrangements for data centres in NSW, p. 2. See also the NSW DNSPs' joint response to the NSW Parliament's Public Accountability and Works Committee Inquiry into Data Centres from March 2026, where they confirmed the peak demand of the largest single industrial load connected to its connected was around 30 MVA.

32 Ibid., p. 30.

1.7.1 Most elements of the NSW proposed reforms are very similar to the rule change request

In its consultation paper, NSW DCCEEW has outlined 10 reform proposals, most of which overlap with the proponent's identified gaps in its rule change requests (see section 2.3.1 and section 2.3.2).[33] The NSW proposals and the identified 'gaps' in the proponent's rule change requests are related as follows:

- Proposal 1, which would require data centre connection applicants to pay an entry bond:[34] this is most relevant to **Gap 2** of the rule change request.
- Proposal 2, which would strengthen requirements for NSPs to collect and share information about prospective and existing data centre connections:[35] this is most relevant to **Gap 4** of the rule change requests.
- Proposal 3, which would strengthen requirements for NSPs to develop and share information about load forecasts and transfer capacity, and to conduct joint planning for data centres: this is also most relevant to **Gap 4** of the rule change requests.
- Proposal 5, which would require DNSPs to recover appropriate transmission network upgrade costs from data centres connecting to distribution networks: this is most relevant to **Gap 1** of the rule change requests.
- Proposal 6, which would require data centres to guarantee they will pay the costs of capacity made available to them, regardless of whether they use it: this is most relevant to **Gap 2** of the rule change requests.
- Proposal 7, which would require data centre connection applicants to pay a Major Network Upgrade Fee: this is most relevant to **Gap 7** of the rule change requests.
- Proposal 8, which would require transmission-connected data centres to contribute to the costs of jurisdictional schemes: this is most relevant to **Gap 6** of the rule change requests.

Submissions to the NSW DCCEEW consultation paper closed on 14 September 2026. We encourage all interested stakeholders who submitted to that process to also consider lodging a submission to this consultation paper, given the close similarities and overlap between the NSW Government's proposed reforms and the proponent's rule change requests.

1.8 Other jurisdictions have taken steps to limit the impact of data centres

Several jurisdictions have already taken steps to manage the potential impacts of large data centre loads on electricity networks and consumers. For example:

- South Australia's Technical Regulator released a *Requirements for Data Centres* guideline, which applies to proposed data centres larger than 100 MW. The guideline explicitly provides that '*where network augmentation is required to accommodate the proposed load, all associated costs must be borne by the proponent*'. It also requires proponents to assess network impacts and demonstrate that any required augmentations will be funded by the proponent.
- The Victorian government has published a Sustainable Data Centre Action Plan, which aims to 'power data centres sustainably and integrate them smoothly into the energy system, while maintaining energy reliability and security for all Victorians.'
- The Tasmanian government released draft Expectations for Data Centres and AI Infrastructure, where it states that 'proponents of data centre and AI infrastructure developments are

33 Ibid., pp. vi-vii.
34 Ibid., pp. 13-14.
35 Ibid., pp. 14-15.

required to pay their fair share of network costs and pay for all connection costs, so that there [is] no net cost on existing Tasmanian customers.'

1.9 We have started the rule change process

The proponent submitted two related rule change requests. This paper consults on both proposals due to their shared subject matter and common objective of considering the cost recovery arrangements for data centres and other large loads connecting to the NEM. Following consultation on this paper, the Commission may consolidate the two rule change requests.[36]

We are seeking stakeholder feedback on the proponent's identified issues in the cost recovery arrangements for distribution and transmission, as well as views on the proponent's proposed solutions and related matters.

- Chapter 2 describes the proponent's objective of its rule change requests, in the context of previous reforms to network pricing and cost recovery
- Chapter 3 describes each of the proponent's identified gaps, relevant current arrangements, its proposed solutions and specific questions for stakeholders to consider and respond to
- Chapter 4 discusses the Commission's legal considerations when making our decision on a rule change request and our proposed assessment criteria.

1.9.1 The AEMC's rule change process

A standard rule change request includes the following formal stages:

- a proponent submits a rule change request
- the Commission commences the rule change process by publishing a consultation paper and seeking stakeholder feedback
- stakeholders lodge submissions on the consultation paper and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a draft determination and draft rule (if relevant)
- stakeholders lodge submissions on the draft determination and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a final determination and final rule (if relevant).

Following receipt of stakeholder submissions, the Commission is required to make a draft determination on both rule change requests by 1 April 2027, subject to any further extensions made by the Commission pursuant to section 107 of the NEL. The Commission may only make an extension if the rule change request raises issues of sufficient complexity or difficulty, or there is a material change in circumstances that necessitates the extension.[37]

If the Commission determines that an extension is necessary, we will communicate the new timeline to stakeholders through our website, our newsletter and through the SA Gazette.

Information on how to provide your submission and other opportunities for engagement is set out at the front of this document on page xii.

You can find more information on the rule change process on our website.[38]

36 See section 93 of the NEL.

37 Section 107 of the NEL.

38 See our website: https://www.aemc.gov.au/our-work/changing-energy-rules

2 The problem raised in these rule change requests

This chapter provides:

- a high-level overview of network service and charging concepts relevant to the issues identified in the rule change requests (see section 2.1)
- a brief description of how the nature of connections has changed over the course of the NEM's history (section 2.2)
- the proponent's overarching objective and considerations in its two rule change requests (see section 2.3).

2.1 Connecting parties pay a range of different charges depending on their plant and services sought

When a customer (who is not an NSP) seeks to connect a new plant to the NEM, they must pay for two types of network services:

- **connection services**, which broadly include the design and construction of new infrastructure to enable a new connection to a transmission or distribution network. For example, this may include (but is not limited to):
  - the design, construction or specification of new assets required to facilitate a connection, such as a substation or an *identified user shared asset*[39]
  - the design or construction of new power lines or facilities to connect the plant to the network, which could include the construction of augmentations or extensions to the network[40]
- **shared services**, which are the ongoing use of the shared transmission or distribution network to convey electricity to a customer for consumption.

Charges for **shared services** are typically levied through transmission use-of-system (TUOS) or distribution use-of-system (DUOS) charges, but may be negotiated in some circumstances.

Generators **do not** pay for the use of shared services through TUOS or DUOS, because they are not classified as Transmission Customers or Distribution Customers under the NER. This is for a number of reasons, including that generators have no 'firm right' to use shared services at any point in time.[41]

This distinction between connection and shared services is important, as the rule change request primarily identifies issues where the proponent considers that charges for **connection services** may not fully cover the costs associated with facilitating a large load connection to the NEM. Nevertheless, the charges for the use of **shared services** are directly relevant to the regulatory framework for determining and negotiating connection charges, especially for large augmentations that may be constructed for a large load to later use.

Moreover, the regulatory classification of transmission and distribution services differs, where:

- in transmission, the NER more explicitly defines different types of transmission services without an AER classification decision of transmission services (see section 2.1.1)

39 An *identified user shared asset* (IUSA) is located at the interface between a transmission network and a *dedicated connection asset* or a *designated network asset*, which cannot be electrically isolated from the transmission network without affecting the provision of *shared* transmission services to other transmission customers. See the NER chapter 10 definition of an *identified user shared asset.*

40 See the NER definitions of *augmentation* and *extension.*

41 This is often referred to as the 'open access' arrangement of the NEM.

- in distribution, the AER makes distribution service classification decisions in its (typically) five-yearly distribution determinations for every DNSP, according to its service classification guidelines (see section 2.1.2).

2.1.1 Transmission services can be classified as prescribed, negotiated or non-regulated

There are three broad types of transmission services that a TNSP can provide. These are:

- **Prescribed transmission services**, which are subject to economic regulation by the AER and chapter 6A of the NER. These include (but are not limited to):
  - shared transmission services that meet the applicable network performance requirements
  - services required under the NER or jurisdictional legislation
  - services necessary to maintain the integrity and security of the power system
  - certain network-to-network connection services
  - system strength transmission services.[42]
- **Negotiated transmission services**, which are provided to a specific user or group of users of a transmission network. The terms, conditions and charges for negotiated transmission services are determined through negotiation consistent with the negotiating principles under Chapter 5 of the NER.[43] These services include (but are not limited to):
  - non-contestable connection services to the transmission network[44]
  - system strength connection works[45]
  - other user-specific transmission services that are subject to the access framework in the NER, but are not classified as prescribed services.
- **Non-regulated transmission services**, which are provided outside the prescribed and negotiated transmission services framework, meaning that the prices and terms of non-regulated transmission charges are determined solely through commercial agreements between the TNSP and the customer. This includes contestable connection services (as specified under clause 5.2A.4 of the NER) and any other service that is not classified as a prescribed transmission service or negotiated transmission service under the NER.

New transmission connection services are either negotiated or non-regulated

Transmission connection services refer to the linking of a person's facility to the transmission network. They include the design and construction of new infrastructure to enable a new connection to a transmission network.

Transmission connection services are classified as either *negotiated transmission services* or *non-regulated transmission services*, depending on the degree of contestability of the type of connection service.[46]

Specifically, a connection service that:

42 See NER, chapter 10 definition of *prescribed transmission services*.

43 For example, see Schedule 5.11 of the NER, which include negotiating principles for negotiated transmission services.

44 NER, clause 5.2A.4(a)(2).

45 System strength connection works are NSP works that remedy or avoid a *general system strength impact* arising from establishing a connection or from alteration to connected plant. See the NER chapter 10 definition of *system strength connection works*.

46 NER, clause 5.2A.4. Connection services provided to a Transmission Network User by using pre-13 February 2009 assets (or replacements of those assets) are deemed to be *prescribed connection services,* by virtue of rule 11.6.11 of the NER. Connection services provided to a non-market NSP are also classified as prescribed transmission service - see paragraph (c) of the definition of *prescribed transmission service.*

- cannot be provided in a contestable market, is provided by the TNSP as a **negotiated transmission service**, with terms and conditions negotiated between the TNSP and the connection applicant in accordance with negotiating principles under chapter 5 of the NER
- can be provided in a contestable market, may be provided by the TNSP (or another party) as a **non-regulated transmission service**, with prices and terms determined through a commercial agreement.

The connection framework in clause 5.2A.4 of the NER details the principles and guidelines governing connection to a network.

The Commission understands that connection service charges are typically upfront payments, paid in full before the new plant is commissioned and connected to the network.

Shared transmission services are either prescribed transmission services or negotiated transmission services

Shared transmission services are services provided to a transmission network user for the use of a transmission network to convey electricity.[47]

The classification of shared transmission services depends on the level of shared service a transmission network user receives and on whether the user is a Transmission Customer (as defined in the NER). If:

- the transmission network user is a Transmission Customer and is receiving a shared transmission service that meets network performance requirements set out in the NER or under jurisdictional electricity legislation, then the use of shared services is a **prescribed transmission service**[48]
- the transmission network user is a Transmission Customer but has negotiated with the TNSP to receive a level of service which may not meet network performance requirements set out in the NER or under jurisdictional electricity legislation, then the use of shared services is a **negotiated transmission service**[49]
- the transmission network user is not a Transmission Customer (for example, a generator), then the user does not pay any charges for shared services and they have no 'firm right' or 'firm access' to use the transmission network.[50]

Figure 2.1 provides an overview of how transmission services (both connection services and shared services) are classified under the NER.

47 NER, chapter 10 definition of *shared transmission service.*

48 A shared transmission service may also exceed network performance requirements. If it does so as a consequence of investments that benefit multiple transmission network users at more than one connection point, then it is an *above-standard system shared transmission service*, which is also a prescribed transmission service. See the NER glossary definition of *above-standard system shared transmission service* and subparagraph (a)(3) of the definition of *prescribed transmission service.*

49 If the shared service exceeds NER or jurisdictional network performance requirements as a consequence of investments that have benefits for transmission network users at a single connection point, then it may also be classified as a negotiated transmission service.

50 This is often referred to the 'open access' arrangement of the NEM. For more information, see our fact sheet on how transmission frameworks work in the NEM.

Figure 2.1: Classification of transmission services

	Prescribed transmission services	Negotiated transmission services	Non-regulated transmission services
	Prescribed services benefit more than one transmission customer	*Negotiated services benefit a single customer or a small group of customers*	*Non-regulated services are contestable, competitive and not subject to regulation*
Connection services	• Services necessary to ensure the integrity of the network • Connection services to other networks that are not market network service providers	• Non-contestable connection services provided to persons who are not a (non-market) network service provider • Construction of augmentations or upgrades that may be required to connect a customer • System strength connection works	• Contestable connection services • Services that are neither a prescribed nor a negotiated service
Shared services	Use of shared services that meet network performance requirements	Use of shared services that do not exceed network performance requirements	
	Use of shared services that exceed network performance requirements, but only as a consequence of investments that benefit multiple transmission network users at more than one connection point (an *above-standard system shared transmission service*)	Use of shared services that exceed network performance requirements as a consequence of investments that have benefits for transmission network users at a single connection point	

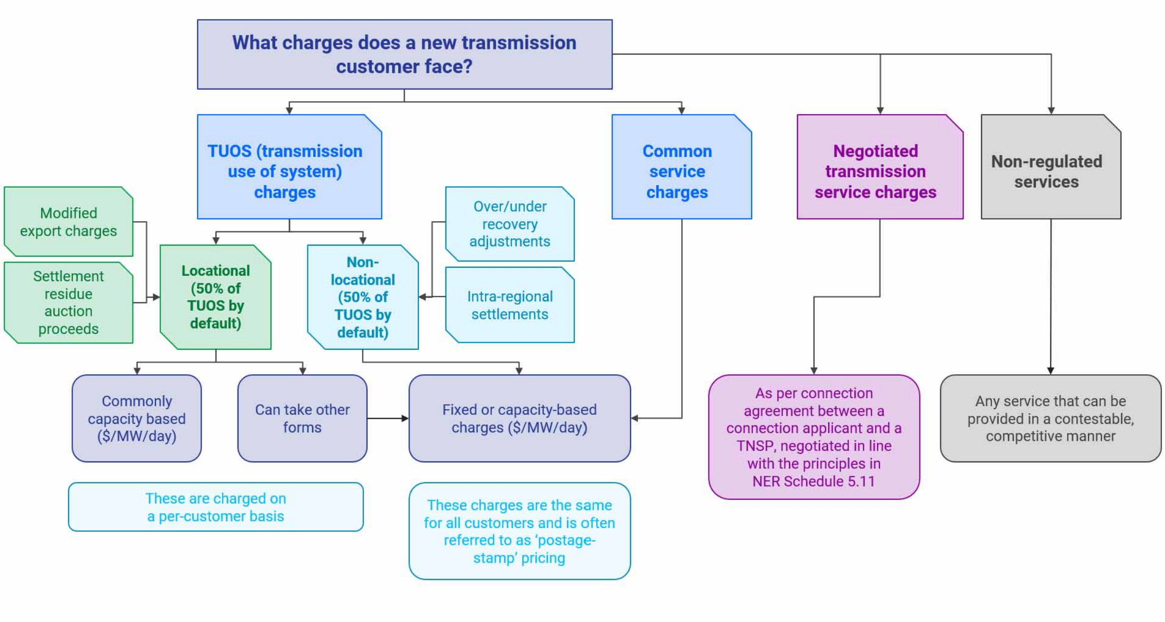
Source: AEMC
Note: This figure is high-level and indicative only.

Transmission Customers pay for prescribed transmission services through TUOS and prescribed common service charges.

As part of its transmission determinations for each TNSP, the AER regulates and approves pricing and methodologies for all prescribed transmission services, according to chapter 6A of the NER.

Figure 2.2 provides a high-level overview of the charges that apply to new Transmission Customers.

Figure 2.2: High-level overview of transmission charges which apply to a new customer



Source: AEMC
Note: This figure is high-level and indicative only.

2.1.2 Distribution connection services include direct control services, negotiated or non-regulated services

There are three broad types of distribution services that can be provided by a DNSP:

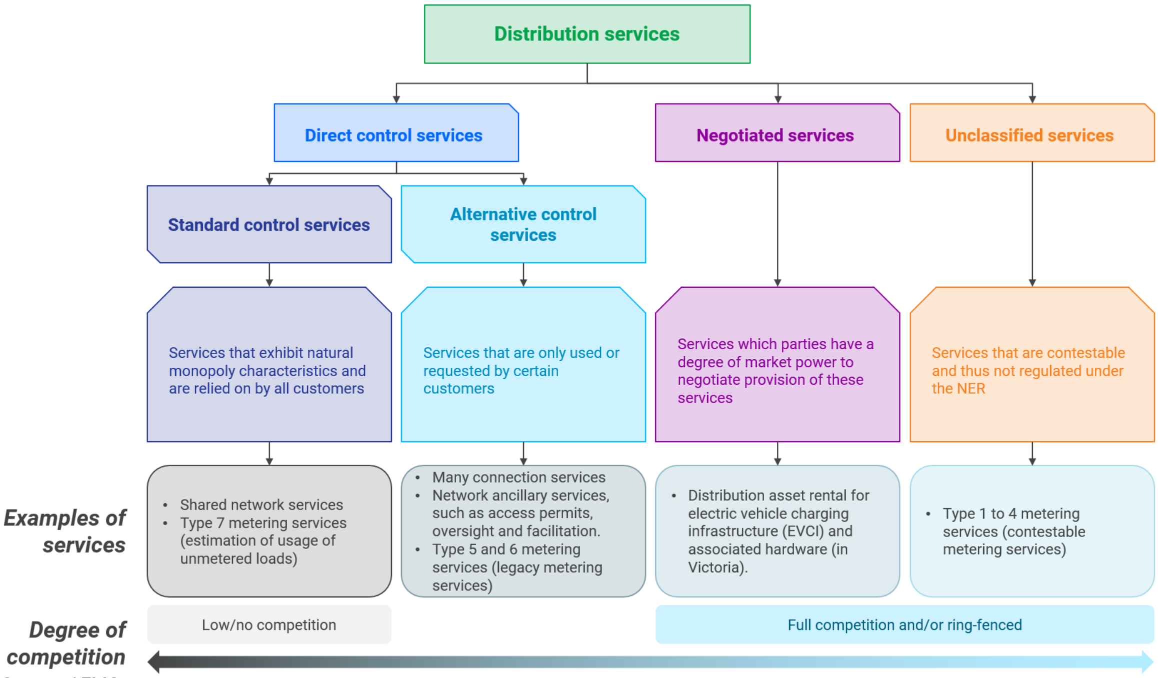
- **Direct control services**, which are subject to economic regulation by the AER and chapter 6 of the NER, because they are monopoly services that cannot be provided by a party other than the DNSP. There are two sub-classes of direct control services under the NER:
  - **Standard control services**, which include the bulk of a DNSP's typical activities operating as a natural monopoly, are bundled together and form the basic charges for use of the distribution system, and may not be directly attributable to a person or group of people to whom the service is provided. Standard control services are subject to a control mechanism based on a DNSP's total revenue requirement.
  - **Alternative control services**, which are only used or requested by certain customers, and are attributable to the person to whom the service is provided.[51]
- **Negotiated distribution services**, where prices, terms and conditions are determined between relevant parties through negotiation consistent with the negotiating principles in rule 6.7 of the NER, and must be provided by a functionally separate affiliate of the DNSP[52]
- **Unclassified distribution services**, which are not regulated under the NER or by the AER.

51 A distribution service that is a direct control service but not a standard control service is an alternative control service. See the NER definition of *alternative control service.*

52 AER, Service classification guideline, p. 9. The NEL defines a negotiated network service as an electricity network service that is not a direct control network service, and that the Rules specify as a negotiated network service or (if the Rules do not do so) the AER specifies as a negotiated network service in a distribution determination or transmission determination.

The AER makes classification decisions as part of its distribution determinations, which it makes for every DNSP for each regulatory control period (typically every five years).[53] See Figure 2.3 for examples of the different kinds of distribution services.

Figure 2.3: Classification of distribution services



Source: AEMC
Note: This figure is high-level and indicative only.

Connection services are typically classified as either a standard control or alternative control service

Under chapter 5A of the NER, there are three kinds of distribution connection services:[54]

- a **basic connection service** is one that requires minimal or no augmentation of the distribution network and has a model standing offer approved by the AER as a basic connection service[55]
- a **standard connection service** is a connection service (other than a basic connection service) for a particular class or sub-class of connection applicant, and for which a model standing offer has been approved by the AER.
- a **negotiated connection** is one where a connection applicant and a DNSP establish connection services under a negotiated connection contract. This arises where the connection service being sought is neither a basic nor a standard connection service, or where the connection applicant has elected to negotiate the terms and conditions on which the service is to be provided (even if it may be a basic or standard connection service).

A basic, standard or negotiated connection service may be either an alternative control service or a standard control service. This is because (in jurisdictions where distribution connection services are not contestable) the DNSP is a monopoly provider of connection services.

53 Ibid., p. 1.

54 Note that under rule 9.15 of the NER, chapter 5A does not apply to NSW contestable services. This is because, under NSW legislation, distribution connection services in NSW may be contestable and provided by a party other than the DNSP.

55 The retail customer seeking a basic connection service must also be typical of a significant class of retail customers who have sought, or are likely to seek, the service; or is (or proposes to become a *micro resource operator*. See clause 5A.A.1 of the NER.

The classification of a distribution connection service as either an alternative or standard control service is determined by the AER in accordance with its service classification guidelines. The AER's service classification may differ across NEM jurisdictions due to differences in whether certain distribution services are contestable, as determined by state legislation. Figure 2.4 shows the AER's 'baseline' classification for connection services, under certain jurisdictional assumptions outlined in the guideline.

Figure 2.4: Baseline classification of distribution connection services

Baseline	Premises	Extension	Augmentation
Basic connection service	ACS	n.a.	n.a.
Standard connection service	ACS	SCS – apply cost revenue test to extension and augmentation costs to determine capital contribution, if any	
Negotiated connection (includes property developers, embedded generators and connection made under chapter 5)	ACS	SCS – apply cost revenue test to extension and augmentation costs to determine capital contribution, if any	

Source: AER, Service classification guidelines, p. 17. See pp. 18-19 of the guidelines for the AER's assumptions in determining this baseline connection service classification table.

Note: ACS means alternative control service. SCS means standard control service. n.a. means not applicable, because basic connection services do not include any extension or augmentation works, by definition.

Note: The cost revenue test, as outlined in the AER's connection charge guidelines, is used to determine capital contributions that may be required from connection applicants to fund extensions or augmentations associated with a connection. See chapter 5 of the AER's connection charge guidelines and section 3.5.1 of this paper for more information.

The use of shared distribution services is paid for through DUOS by distribution customers

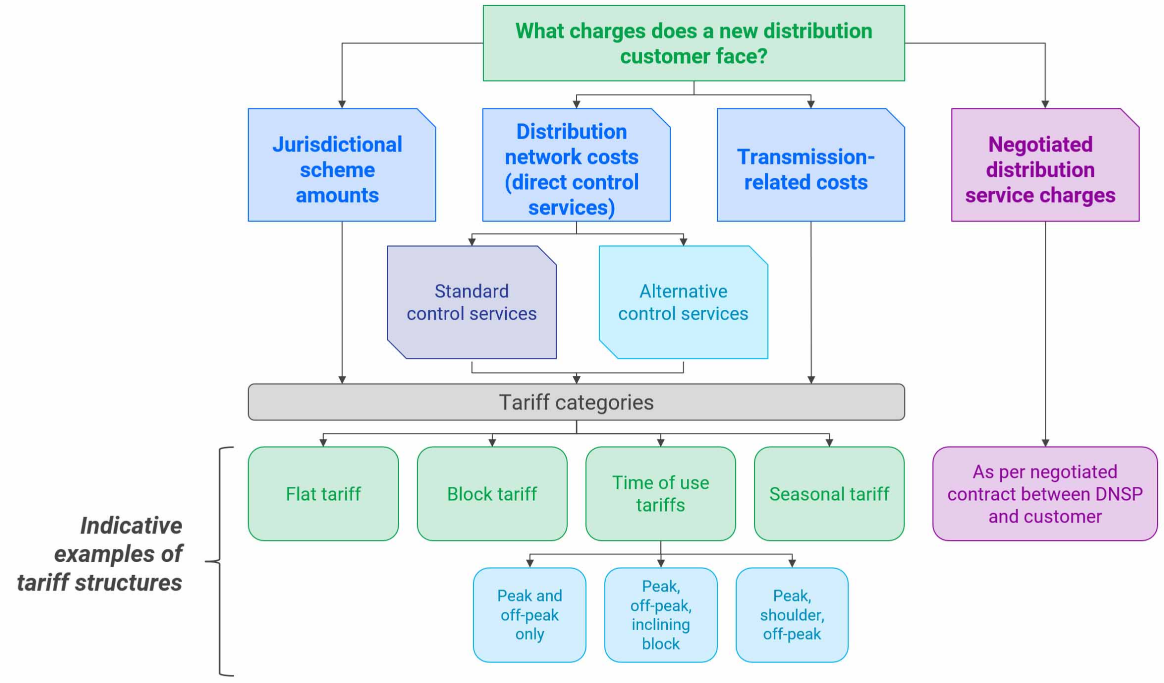
Shared distribution services are services provided to a distribution network user for the use of a distribution network to convey electricity.[56] As this is the primary bulk of a DNSP's monopoly service, shared distribution services are direct control services.

DNSPs recover the cost of providing shared distribution services through ongoing distribution use-of-system (DUOS) charges to its distribution customers. They do so by categorising their customers into tariff classes and determining appropriate tariff structures and prices, which are then approved by the AER.[57] See Figure 2.5 below for a high-level overview of the components that make up a distribution customer's ongoing charges.

56 NER, chapter 10 definition of *shared distribution service.*

57 See Part I of Chapter 6 of the NER.

Figure 2.5: High-level overview of distribution charges which apply to a new customer



Source: AEMC
Note: This figure is high-level and indicative only.

As with transmission, generators do not pay DUOS and are not classified as distribution customers, because they have no 'firm access' to the distribution network.

2.1.3 Large loads and data centres would typically pay upfront connection charges as well as ongoing network charges

Having summarised the applicable connection service and shared service charges that a connection applicant may be required to pay, the Commission understands that a new data centre (or similar large load) seeking to connect would likely:

- pay connection charges:
  - if connecting to a transmission network, for **negotiated or non-regulated transmission services** for transmission connection works
  - if connecting to a distribution network, for **alternative control services** for a standard or negotiated connection service, plus any **capital contributions** as may be required for any extensions or augmentations under the AER's connection charge guideline[58]
- pay ongoing network charges:
  - in the form of TUOS and common transmission service charges, if the applicant will be a transmission customer[59]
  - in the form of DUOS through an applicable network tariff, if the applicant will be a distribution customer.

58 A data centre or similar large load is unlikely to seek a basic connection service, as it would not be a service typical of a significant class of retail customers, and would likely require some degree of extension or augmentation.

59 Given that data centres and other similar large loads seek a high level of reliability and service, we consider it is unlikely that they would negotiate a level of shared service that does not meet network performance requirements.

The term 'large load' is not defined in the NER or by the proponent

The term 'large load' has been used by the proponent in its rule change requests. However, we note that there is no NER definition of 'large load'. The proponent uses both data centres and smelters as examples of 'large loads,' in terms of their size and potential impact on the shared network.[60]

As detailed below, the proponent seeks to ensure that the regulatory framework is fit-for-purpose to ensure that costs associated with connecting 'large loads' are not inappropriately recovered from other consumers.

Question 1: Do you have feedback on our summary of current network service arrangements?

- Do you have comments or feedback on how we have described the current arrangements for relevant network services in section 2.1 of this consultation paper?
- Do you have comments or feedback on our summary of how the current arrangements would apply to a new connecting data centre or large load?

2.2 Growing data centre connections are testing existing cost recovery arrangements

2.2.1 The NER were not initially developed with numerous large load connections in mind

When the NEM commenced in 1998, the transmission and distribution connection frameworks were designed for a power system that looked very different to today's NEM. Electricity supply was dominated by a relatively small number of large, centralised generators, predominantly coal-fired power stations, while electricity demand was largely comprised of households and small businesses connected to distribution networks. Although some large industrial loads connected directly to the transmission network, such as smelters and other energy-intensive industrial facilities, these customers were comparatively few. As a result, the transmission and distribution frameworks were not designed to support large numbers of new, transmission-scale loads seeking connection to the network.

2.2.2 The type and size of connections have changed significantly over time and are likely to continue to change into the future

The type and size of connections have changed significantly over time

The NER has continued to evolve since its introduction in 1998, reflecting significant changes in the NEM and broader energy sector. A key driver of these changes has been the ongoing energy transition, supported by rapid technological developments.

The generation mix has shifted from a relatively small number of large, centralised power stations towards a more diverse portfolio of solar and wind generation, battery storage and distributed energy resources (DER). As a result, generation is now provided by a much larger number of participants across a range of sizes and technologies.

60 Rule change request, p. 9.

The nature of electricity demand has also changed. In addition to traditional residential, commercial and industrial loads, new forms of large-scale electricity consumption, including data centres, are increasingly seeking connection to the power system.

Electricity flows from consumer resources have become increasingly bidirectional. Households and businesses with rooftop solar and other consumer energy resources often both consume and export electricity to the grid, with some larger commercial or industrial facilities also consuming and exporting electricity.

These developments have altered the type, size and characteristics of connections across the NEM. Customers now connect to both transmission and distribution networks, and connection arrangements must accommodate a broader range of technologies and use cases than when the original frameworks were developed.

The type and size of connections are likely to continue to change into the future

The changes described above are likely to continue as the energy transition progresses.

Coal-fired generation is expected to continue retiring, while a broader range of technologies, including renewable generation, utility-scale battery storage and distributed energy resources, play an increasingly important role in supplying and supporting the power system.

At the same time, electricity demand is expected to increase as sectors such as transport, industry and buildings continue to electrify. The location, timing and characteristics of demand are also evolving as patterns of generation and consumption change across the power system.

New forms of large-scale electricity demand are also emerging. In particular, data centres are forecast to account for a growing share of electricity consumption over coming years (see section 1.1 for more discussion on data centre growth).

2.3 The rule change requests seek to protect consumers from inappropriately bearing the risks and costs from large load connections

The proponent considers that the existing regulatory framework may not adequately address the risks arising from the rapid growth of large load connections, and that revisions may be required to ensure the costs and risks associated with accommodating data centres are allocated efficiently and equitably.

2.3.1 The proponent outlined several scenarios where costs and risks may not be allocated fairly between consumers

The current cost recovery arrangements are intended to allocate network costs in a manner that promotes efficient investment in, and use of, the electricity system. Currently, proponents of large loads, including data centres, are funding certain network augmentations that are required to facilitate their connection under the existing framework.

However, the proponent considers that the nature, scale and speed of data centre connections represent a significant change that was not anticipated when the rules were initially set out. Without changes to the NER, the proponent considers that a potentially significant portion of the capital expenditure associated with network investments required to accommodate large loads could be recovered from customers other than the large electricity customers driving the need for those investments.

The proponent has identified seven potential scenarios where a gap in the current framework could occur:

- **Scenario for gap 1:** A large load connects to a distribution network and triggers the need for upstream transmission augmentation, resulting in a portion of the augmentation costs potentially being recovered from other customers.
- **Scenario for gap 2:** The NSP undertakes investment to support a large load that subsequently does not proceed, or uses less capacity than anticipated. The NSP was not required or incentivised to include prudential requirements in the connection agreement, so it recovers the costs from other customers.
- **Scenario for gap 3:** Similar to the scenario for gap 2, the NSP undertakes investment to support a large load that subsequently does not proceed, or uses less capacity than anticipated. The NSP did not include prudential requirements in the connection agreement because it may have the ability and incentive to roll the stranded asset into its regulated asset base (RAB), so it is able to recover costs from other customers later.
- S**cenario for gap 4:** Information about large loads is not subject to the same reporting and publication requirements as information about generators, which may make demand forecasting and network planning more challenging for AEMO, NSPs and other market participants.
- **Scenario for gap 5:** Large loads, particularly when geographically clustered, can drive the need for significant shared transmission augmentations. However, the NER is unclear about cost recovery arrangements for funded augmentations, and there is a potential 'first mover disadvantage'.
- **Scenario for gap 6:** A large load connects to the transmission network instead of the distribution network, meaning that it is not liable for jurisdictional scheme costs under the NER.
- **Scenario for gap 7:** A large load connects to the transmission network through a negotiated transmission service and triggers the need for deep upstream augmentation, but the NER does not provide consolidated guidance on the pricing of the connection and associated augmentation.

2.3.2 The proponent considers current cost recovery arrangements may not be adequate for the nature and scale of data centre connections

The proponent considers that, under the current rules, there is a risk that network investments triggered by large load connections will be paid for in part by consumers other than those large loads that trigger the need for the expenditure. The proponent further considers that efficient investment outcomes are promoted when costs and risks are allocated to the parties best placed to manage them. Accordingly, the proponent considers that addressing these issues 'requires changes to the NER to align the connection incentives of large load proponents with the NEO's commitment to economic efficiency.'[61]

Through the scenarios discussed in section 2.3.1 above, the proponent identified potential gaps in how the rules operate to allocate cost, along with proposed solutions.

These gaps can be linked to the two primary concerns identified by the proponent in its statement of issues:

1. Current rules allow connection costs to be shifted onto other customers

61 Rule change request, p. 8.

2. Data centre connections may increase the risk of network asset stranding, but have limited exposure to its costs

The first concern is reflected in gaps 1, 5, 6 and 7. Collectively, these gaps relate to circumstances where the proponent considers that large loads may not appropriately contribute to all costs associated with their connection to (or use of) the network. The proponent considers that the current framework may not adequately recover the costs of certain upstream network augmentations required to accommodate large loads, or support customers' funding of network augmentations.

In addition, it may not recover certain jurisdictional scheme costs from transmission-connected customers. According to the proponent, these outcomes may shift costs from large load proponents to other consumers.

The second concern is reflected primarily in gaps 2, 3 and 4. Gaps 2 and 3 relate to circumstances in which network investment is undertaken in anticipation of future large load demand that does not subsequently materialise, resulting in network assets becoming underutilised or stranded. Under these circumstances, the proponent considers there are risks that electricity consumers may bear the risk of under-utilisation or asset stranding. In the proponent's view, the risks should be borne by parties best placed to manage them, which includes both data centre developers and NSPs.

Gap 4 relates to the second concern because the proponent's proposed solution seeks to improve the information available to AEMO, NSPs and the public, thereby supporting more efficient planning and investment decisions. The proponent considers that without this public information, it is harder for NSPs to identify speculative, duplicative and dormant applications, adjust load forecasts and efficiently allocate connection resources, to the detriment of consumers.

2.4 This consultation paper seeks views on the proponent's proposed solutions and other potential approaches

We are assessing the rule change requests to determine the nature and materiality of the issues identified by the proponent, and whether changes to the NER are warranted to address them.

As set out in Chapter 3 and 4, our assessment will consider:

- the current arrangements in the NER
- the proponent's identified issues with the current arrangements and their materiality
- the proposed solutions in the rule change requests and how the solutions may contribute to the National Electricity Objective
- any alternative approaches that may address those concerns more effectively or proportionately.

We are seeking stakeholder views on the materiality of the issues, the merits and drawbacks of the proposed solutions, and any alternative approaches or relevant considerations.

3 Current arrangements and the proponent's proposed solutions to address identified issues

The following subsections set out the proponent's perceived 'gaps' in the current network cost recovery arrangements, a summary of the current arrangements, and the proponent's proposed solutions. For each gap, we seek your input and have prepared questions to help the Commission better understand the identified issues and develop effective policy solutions that are likely to contribute to the NEO.

3.1 Gap 1 - Pricing of upstream augmentations and negotiation process for distribution connections

The proponent notes that if a new distribution connection is large enough to require a transmission augmentation to connect, there may be a risk that the cost of the augmentation is shared across a wide range of distribution customers.

The proponent considers that the costs of any upstream augmentations should be passed on to these large distribution connections by ensuring that DNSPs consider all affected networks (distribution and transmission) when determining connection charges.

3.1.1 The Rules regulate distribution connections according to the type of plant to be connected and the nature of the person seeking connection

When a person intends to connect a plant to a distribution network, Chapters 5 and 5A of the NER provide the process for connections, the relevant provisions depending on the type of plant being connected and the type of person seeking the connection. See clause 5.1.2 of the NER for a summary of the relevant Rules that apply to persons seeking a connection to a distribution network.

While Rule 5.3 and 5.3A detail the relevant processes for establishing a distribution connection, they do not contain provisions on how NSPs should determine prices for connection services. Instead, Rule 5.3AA, Chapter 5A and the AER's connection charge guideline outline several requirements and pricing principles for any network augmentations that are required to facilitate the connection of new plant.

For example, NER clause 5.3AA(f)(3)(i) provides that the DNSP and the Connection Applicant must negotiate in good faith to reach agreement as appropriate on, among other things, the charge to be paid by the Connection Applicant in relation to any augmentations or extensions required to be undertaken on all affected transmission networks and distribution networks.

NER clause 5.3AA(h) also provides that a DNSP must pass through to a Connection Applicant the amount calculated in accordance with paragraph (i) for the locational component of prescribed TUOS services that would have been payable by the DNSP to a TNSP had the Connection Applicant not been connected to its distribution network.[62]

3.1.2 Issues identified by the proponent

In its rule change request, the proponent noted that rule 5.3AA does not apply to loads, including data centres. This means the requirement on a DNSP and a connection applicant to negotiate in

62 Note this clause 5.3AA(h) is classified as a tier 3 civil penalty provision.

good faith to pay for the costs of any transmission or distribution augmentation required for the connection does not apply.[63]

The proponent considered that even if rule 5.3AA applied to data centres and other loads, the requirement to 'negotiate in good faith' is unlikely to be sufficiently robust to protect small customers from cross-subsidy risks.

The proponent also considered that, as DNSPs compete to secure revenue from large loads connecting to their networks, there may be an incentive to offer connection services at prices and terms that are not fully cost-reflective of any actual upstream augmentation caused by the connecting party. If negotiations are more robust, the connection process is likely to take longer, and a DNSP risks the connecting party seeking connection with another DNSP.[64]

This 'speed' incentive may lead other consumers to unfairly bear the costs of upstream augmentation caused by connecting parties over time. If these other consumers bear greater costs, they may not necessarily receive proportionate benefits from those upstream augmentations, which would not contribute to the NEO.

Additionally, the proponent considers that there is a lack of transparency as to how the 'good faith' negotiations described by rule 5.3AA take place. The proponent considers this is contrary to the NEO because it means investment decisions are not made on a transparent or efficient basis and risks are ultimately borne by those parties least able to manage them.

3.1.3 Proposed solutions by the proponent

To address the risk that distribution connections do not pay appropriate connection charges for any upstream augmentations that they cause, the proponent's proposed solution is to:

- amend rule 5.3AA to ensure that large distribution-connected loads are appropriately covered by this rule and costs are appropriately allocated.
- ensure that the costs of any upstream augmentations are appropriately allocated to a connecting party
- consider whether a requirement to negotiate charges in good faith under clause 5.3AA(f)(3)(i) is sufficiently robust to ensure upstream costs are accurately estimated and reflected in distribution level connection costs to avoid the risk of cross-subsidy
- consider whether a mechanism to ensure actual costs are recovered from large loads if they exceed the costs forecast at the time the connection agreement is executed.[65]

The Commission is interested in stakeholder views on whether the Rules should include more detailed requirements about how negotiations should occur and how prices should be set.

3.1.4 We seek your views on how to ensure that the costs of upstream augmentations are appropriately passed on to distribution connection applicants

There are related issues we will consider when determining the policy approach to ensure that upstream augmentations are better reflected in distribution connection service charges. These include:

- how a DNSP should determine whether an upstream transmission or distribution augmentation is caused by a single distribution connection, a group of connection applicants,

63 Rule change request, p. 12.

64 Ibid., pp. 12-13.

65 Ibid., p. 13.

general demand growth from existing distribution customers, or a mix of all three, and how the DNSP should apportion costs appropriately

- how a DNSP and a relevant TNSP should engage with each other to accurately identify and estimate the costs of necessary upstream augmentations, noting that the two parties may be competing for potential load connections to increase revenues
- in respect of any transmission augmentations that may be clearly attributable to a specific connection applicant, how the DNSP and TNSP should liaise and engage with each other
- whether or not a RIT-T or RIT-D is required where the costs of any upstream augmentation exceed the relevant thresholds[66]
- whether proposed connection service charges on a distribution connection applicant should be taken into account in an applicable RIT-T or RIT-D[67]
- in respect of any upstream transmission augmentations, interactions with the construction of funded augmentation provision in rule 5.18 of the NER (see also section 3.5).

We are seeking your views on whether and how to best ensure that any upstream augmentation costs are appropriately captured by distribution charges, through negotiations between a DNSP and a connection applicant.

Question 2: Do you consider that the costs of upstream augmentation may not be appropriately allocating to distribution connections?

- Do you agree with the proponent that the application of rule 5.3AA should be expanded to cover large loads and data centres?
- Do you agree with the proponent that the existing requirement to negotiate charges in 'good faith' is not robust enough to ensure other consumers do not bear the costs of upstream augmentations? If so, how should distribution negotiation and pricing principles under rule 5.3AA be strengthened?
- If the actual cost of an upstream augmentation is different to the estimated cost at the time of connection, do you consider that there should be a mechanism to ensure actual augmentation costs are later recovered from the connection applicant? If so, do you have views on the details of how such a mechanism should work?
- Are DNSPs and TNSPs currently able to sufficiently coordinate and liaise with each other to determine whether upstream augmentations are required for a distribution connection, and to estimate any costs? Are there any other DNSP or TNSP interactions that you think the Commission should consider, such as the RIT-T/D or competition concerns?
- If rule 5.3AA were to be amended, do you have views on whether any other changes are required to promote consistency across all distribution connections?

3.2 Gap 2 - Prudential arrangements for asset stranding

NSPs have the ability to manage asset stranding risk through prudential requirements in connection agreements. However, the proponent considers that the existing framework may not provide NSPs with sufficient incentive to use or enforce these prudential requirements.

66 Currently, the RIT-T threshold is $8 million, while the RIT-D threshold is $7 million.

67 For example, the payment by a connection applicant for their connection service charges could be treated as a kind of 'concessional finance payment' to the NSP, potentially affecting the outcome of the RIT-T or RIT-D. See Sharing concessional finance benefits with consumers | AEMC for more information.

The proponent considers that the prudential arrangements under the NER should be strengthened and aligned. This includes by requiring the use of specific prudential requirements, to minimise the impact on other customers bearing the costs of stranded assets.

3.2.1 The NER allows NSPs to manage asset risk through prudential arrangements

The NER contains provisions that allow NSPs to manage the risk that assets constructed to facilitate a connection become underutilised or stranded if the expected demand or generation does not eventuate.[68]

Rule 6.21 sets out types of arrangements a DNSP may use to minimise financial risk associated with investment in distribution network assets, including requiring a customer to establish prudential requirements in a connection agreement. These prudential requirements are a matter of negotiation between the NSP and customer, and any terms must be included in the connection agreement. The rule sets out that the prudential requirements may incorporate, but are not limited to, one or more of the following arrangements:

1. financial capital contributions
2. non-cash contributions
3. distribution service charge prepayments
4. guaranteed minimum distribution service charges for an agreed period
5. guaranteed minimum distribution service quantities for an agreed period
6. provision for financial guarantees for distribution service charges.

The rule also prevents DNSPs from receiving income twice for the same assets through prudential requirements and distribution service prices.

Rule 6A.28 provides for arrangements by which TNSPs minimise financial risk associated with investment in transmission network assets. It provides that TNSP may require a Transmission Network User to establish prudential requirements in a connection agreement, to minimise financial risk associated with investment in network assets. However, rule 6A.28 contains less guidance regarding the types of prudential arrangements that may be used than the corresponding distribution framework. It provides that these prudential requirements may take the form of, but need not be limited to, capital contributions, pre-payments or financial guarantees. The rule also sets out provisions governing how capital contributions and prepayments may apply.

Neither framework requires that prudential requirements must be established for a particular connection.

3.2.2 Issues identified by the proponent

The proponent considers that as a result of large load connections, NSPs may be triggered to invest in new connection assets and/or network augmentations before the forecast demand associated with the connection has materialised. Where a connection applicant subsequently delays its project, scales back its operations, or fails to proceed as expected, some of those assets may become underutilised or stranded. In these circumstances, the proponent considers without effective prudential s, a portion of the costs incurred by the NSP may not be recovered from the party that triggered the investment, and may ultimately be borne by other customers.

The proponent notes that that under the current prudential frameworks, NSPs and connecting customers are not obliged to use prudential requirements to manage stranding risk.

68 NER, Rules 6.21 (DNSPs) and 6A.28 (TNSPs).

The proponent also considers some prudential requirements may require enforcement by the network. However, the NSP may have limited incentive to undertake enforcement action.

The proponent considers the suggested transmission and distribution prudential arrangements in the NER also differ in their level of guidance. While both suggested arrangements are intended to minimise the financial risks associated with investment in network assets, rule 6.21 provides more detail on the forms of prudential arrangements than rule 6A.28.

3.2.3 Proposed solution by the proponent

The proponent proposes to align the prudential requirements for NSPs in the NER by amending rule 6A.28 to specify arrangements available to TNSPs, reflecting the approach in rule 6.21 for DNSPs.

The proponent also proposes to strengthen both sets of prudential requirements by requiring NSPs to implement specified prudential arrangements. These arrangements would apply to connections above a certain threshold, determined by a measure such as a nameplate capacity or a capital expenditure. These amendments should prioritise protections that do not require legal action to enforce, such as prepayment and bank guarantees, and should require the NSP to take legal action where necessary rather than recover the shortfall from other customers. Where NSPs take prepayments, the amendments should include a mechanism to reconcile forecast and actual expenditure so that cost overruns are not recovered from other consumers.

The proponent considers that putting these arrangements in place is urgent. Accordingly, the proponent considers that the requirements for DNSPs should be included in the NER to commence in DNSPs connection policies for the next five-year regulatory period, as well as requiring DNSPs to revise their connection policies mid-regulatory period.[69]

3.2.4 We are seeking your views on how to ensure consumers don’t inappropriately bear the costs of assets originally built for large loads

We are interested in stakeholders’ views on whether the existing rules for the use of prudential arrangements remain fit for purpose. Specifically, in the context of protecting consumers from the costs of the rapidly increasing number of large connections.

We seek stakeholder views on:

- whether the existing optional prudential arrangements are sufficient to protect consumers from stranded-asset risk associated with large load connections, including which types of connecting customers are capable of causing asset stranding risk
- what changes could be made to the existing prudential requirements and pricing arrangements, to further protect consumers from risk associated with stranded asset risk. This includes consideration of the options proposed by the proponent and NSW Government, but also any other alternatives, or a combination of options
- the types of connections the amendments could apply to, the circumstances they could apply in, and the extent to which they require legal enforcement/action
- any costs, risks, implementation issues or other considerations that could arise from amending the existing prudential requirement rules and how these could be managed

69 The proponent states that requirements such as these for DNSPs would normally be put in the connection policies of each distribution network. However, these are normally only amended and approved at the time of the five-yearly distribution determinations. The proponent considers that the urgency of the situation warrants not waiting until the next regulatory period.

- the extent to which the situation is urgent, necessitating requirements to be implemented through non-standard methods
- whether NSP stakeholders consider there are risks or issues recovering costs of negotiated services from persons subject to a connection agreement where the business becomes insolvent
- whether any differences between the transmission and distribution prudential requirement rules justified.

Our questions are set out in the boxes below. Stakeholders are encouraged to support their views with evidence and examples.

Question 3: Do you consider that existing prudential requirements sufficiently protect consumers from the risk of paying for assets originally built for large loads or customers?

- Do the existing prudential requirement rules effectively protect consumers from the costs associated with stranded assets? If not, why?
- If changes are required, what amendments should be made to the NER?
- Are there any other approaches, including those suggested by the proponent and the NSW Government?
- If amendments are made to the NER, what types of connections should be covered?
- Should there be a threshold for the types of load that any amendment applies to, and what should it be?
- To what extent should the transmission and distribution prudential requirement frameworks be aligned, ie, rule 6A.28 and rule 6.21, and are there any differences that should be retained?

3.3 Gap 3 - Safeguards for reallocating the costs of network assets

The proponent considers that, in certain circumstances, it is possible for an NSP to reallocate part of an asset's value from a negotiated service to a prescribed service and include that value in its regulated asset base (RAB). This means that the costs of a network asset built to support a connection are not fully recovered from the data centre customer.

The proponent considers that limiting the opportunities to reallocate certain customer-specific assets would provide a strong financial incentive for network providers to ensure that assets supporting specific customer connections are recovered from those customers in all conceivable scenarios.

3.3.1 NSPs are able to reallocate the value of assets provided as negotiated service costs into the RAB

In certain circumstances, a TNSP may reallocate part of the value of an asset from a negotiated service cost to a prescribed service cost and include that value in its RAB. For transmission networks, cost allocation principles, including when costs of negotiated transmission services may be reallocated to prescribed transmission services, are provided for under clause 6A.19.2 of the NER. The cost allocation principles applicable to DNSPs are provided for in cause 6.15.2 of the NER. For DNSPs, costs which have been allocated to a particular service cannot be reallocated to another service during the course of a regulatory control period. [70]. Where the NSP is able to roll part or all of a cost of an asset into the RAB, it may recover those costs from the broader

70 Clause 6.15.2(g)

electricity customer base, rather than solely from the customer that originally triggered or funded the asset.

The NER provides frameworks for the classification of different types of transmission and distribution services and how these may be recovered from respective regulated revenues as determined by the AER in 5 yearly revenue determinations.

3.3.2 Issues identified by the proponent

The proponent considers a scenario where a data centre contracts a certain hosting capacity, but the expected demand does not eventuate, meaning the cost of a network asset built to support the connection is not fully recovered from the data centre customer.

The proponent considers there are three safeguards on this 'roll-in process'. Assets can only be reallocated where:

- they will provide shared services; and
- capital costs have not yet been recovered; and
- the AER approves the roll in as part of the determination process.

The proponent considers these safeguards provide strong, but not complete, assurance that assets originally built to service very large loads will not ultimately be paid for by existing electricity consumers.

Given the large number and value of network assets expected to be built as part of negotiated services provided to data centre customers, the NER should provide stronger protections to ensure costs and risks of network assets are appropriately allocated between customers.

NSPs may have less incentive to use prudential requirements if they can reallocate assets into the RAB at a later date.

The proponent is concerned that assets initially built to service large loads may ultimately be paid for by existing electricity consumers.

3.3.3 Proposed solution by the proponent

The proponent proposes to limit the opportunities for NSPs to reallocate certain customer-specific assets into the RAB, through changes to NER clause 6A.19.2(8) and Schedule 6.2.1(e)(8) to further restrict reallocation of specified assets.

Alternatively, the AER could be provided further guidance on how it should consider roll-in applications from NSPs, and NSPs could be given more specific obligations about the information they need to supply to the AER to support its assessment of whether rolling the capital expenditure into the regulated asset base is appropriate.

The proponent also proposes that the rules should include a classification for the customer specific assets that would be subject to the enhanced protections, for example based on a capital expenditure threshold, specified asset types or use cases could be considered.

3.3.4 We are seeking your views on whether action needs to be taken to prevent NSPs from reallocating the value of assets into the RAB

We are interested in stakeholders' views on whether the existing safeguards in clause 6A.19.2(8) (for transmission) and clause 6.15.2 (for distribution) adequately protect consumers from the reallocation of customer-specific asset costs, and any ways that they should potentially be changed.

We seek stakeholder views on:

- the types of customer-specific assets that are subject to stranding risk – are these just assets associated with large load, or also extend to assets to connect generation infrastructure
- whether investment costs brought forward to service specific customers (e.g., the costs of bringing forward deep augmentation to service a data centre) are subject to the proponent's perceived issue
- the extent to which consumers benefit from assets being rolled into the RAB, including whether any benefits they receive tend to outweigh the costs that they pay
- whether the safeguards in clause 6A.19.2(8) and Schedule 6.2.1(e)(8) sufficiently protect consumers from bearing the costs of assets that don't provide net benefits
- the extent to which the reallocation of customer-specific asset costs into the RAB is a material issue for consumers under the current arrangements
- whether the ability to reallocate assets into the RAB weakens NSP incentives to use prudential requirements or otherwise recover customer-specific asset costs from the connecting customer
- whether limiting the opportunities for NSPs to reallocate assets into the RAB would strengthen consumer protections and address any gaps in the existing framework
- whether limiting the opportunities for NSPs to reallocate assets into the RAB would strengthen incentives for NSPs to use prudential requirements and recover customer-specific asset costs from the connecting customer
- how opportunities to reallocate into the RAB should be limited, such as through an explicit restriction in the NER, through additional guidance to the AER in making determinations and obligations for NSPs, or an alternative method
- how assets subject to any tighter restrictions should be identified, including whether this should be based on a capital expenditure threshold, asset type, asset use case, or another criterion
- any risks, costs or unintended consequences that could arise from limiting the circumstances in which assets may be reallocated into the RAB and how these could be mitigated
- any alternative approaches to ensure that the broader consumer base does not bear the costs of customer-specific assets which do not eventuate (that is, are stranded assets) and therefore do not deliver a benefit to the broader consumers of the NEM.

Our questions are set out in the boxes below. Stakeholders are encouraged to support their views with evidence and examples.

Question 4: Do you consider there should be additional conditions or limitations on an NSP to reallocate the value of assets into their regulated asset base (RAB)?

- Do the existing safeguards adequately protect consumers from the reallocation of customer-specific asset costs? If not, why not?
- Would further limiting the circumstances in which customer-specific assets can be reallocated into the RAB improve consumer protections? What benefits, risks or unintended consequences could arise from doing so?
- If additional restrictions are warranted, how should they be implemented and how should they apply?

3.4 Gap 4 - Collection, sharing and publication of information on large loads

The proponent states there is currently no obligation for NSPs and AEMO to establish, maintain and publish information on prospective and existing large-load connections, unlike the obligations that apply in relation to large generator connections.

As a result, while NSPs and AEMO have visibility of enquiries and connection applications on their own networks, they lack a complete view of large-load developments across the NEM.

The resulting lack of visibility on large load connections across the NEM may reduce the accuracy of demand forecasting and network planning, potentially leading to inefficient investment decisions and higher costs for consumers.

As discussed in Chapter 1, the AEMC also intends to progress a number of rule change requests arising from its data centre advice to the ECMC. The Operational integration and visibility of large inverter-based loads rule change request proposes to establish reporting requirements and information reporting requirements across large inverter-based loads, networks and AEMO to manage large inverter-based load demand.[71] The AEMC notes that the issues raised in the Operational integration and visibility of large inverter-based loads rule change request may be relevant to those raised in Gap 4.

3.4.1 There is no public register for large loads

There is currently no dedicated public register for large loads published by AEMO or NSPs**.**

There are public registers for generation

At the transmission level, clause 5.18A.2 of the NER requires TNSPs to establish, maintain and publish a connections register of certain large generation connections (including bi-directional connections). The information published in the register includes, but is not limited to, details such as the location of the connection point, the person who is registered by AEMO as a Generator or Integrated Resource Provider in respect of the large generator connection at that connection point, the technology of the production units, aggregate nameplate capacity of all production units comprised in the large connection, connection status and an impact assessment of that large connection in accordance with clause 5.18A.3. The register currently applies to generating systems with a nameplate rating of 30 MW or greater and bidirectional units with a nameplate rating greater than 5 MW. The proponent considers that these TNSP registers for large generation connections enhance transparency regarding new generator connections.

The NER also contains requirements under clause 3.7F(g) for TNSPs to provide key connection information regarding valid connection enquiries and valid applications to connect, in accordance with the generation information guidelines. AEMO publishes this information on its generation information webpage.[72] This informs Registered Participants and other interested persons of the extent and nature of generating plant connected, or proposed to be connected, to the national grid.

There is no distribution clause equivalent to clause 3.7F(g) for distribution. That is, there is no requirement for DNSPs to provide key connection information regarding valid connection enquiries and valid applications to connect, in accordance with the generation information guidelines.

71 AEMO, *Operational integration and visibility of large inverter-based loads*, rule change request, 21 July 2026.

72 See AEMO's [Generation information] webpage.

At the distribution level, clause 5.18B.2 requires DNSPs to establish and publish a register of completed distribution connection resource projects. The information on the plant includes, but is not limited to:

- technology of each distribution connected unit comprised in the project (e.g. synchronous generating unit, induction generator, photovoltaic array, etc) and its make and model
- maximum power generation capacity of all distribution connected units comprised in the system
- contribution to fault levels
- the size and rating of the relevant transformer
- a single line diagram of the connection arrangement
- protection systems and communication systems
- voltage control and reactive power capability
- details specific to the location of a facility connected to the network that are relevant to any of the details above.

AEMO receives demand side participation information

Demand side participation information under rule 3.7D relates to arrangements involving the adjustment of non-scheduled load, the provision of unscheduled generation, or the provision of wholesale demand response.

Under Rule 3.7D, a Registered Participant must provide to AEMO (in accordance with the demand side participation information guidelines) demand side participation information or, if the Registered Participant has no demand side participation information to report in respect of the relevant period, a statement to that effect.

AEMO must publish, at least annually, an analysis of the reported volumes and types of demand response. This information must include information on the types of tariffs used by NSPs to facilitate demand response and the proportion of retail customers on those tariffs, and an analysis of trends, including year-on-year changes, in the information reported, in respect of each relevant category of Registered Participant.

3.4.2 Issues identified by the proponent

The proponent considers prospective and existing large-load connections can significantly affect how AEMO, NSPs and other market participants forecast demand and make network planning decisions.

While NSPs and AEMO have visibility of the enquiries and connection applications submitted to their own networks, they and other market participants may lack sufficiently complete and current visibility of large-load developments across the NEM.

Limited visibility of large load developments may make it harder to:

- forecast future electricity demand accurately, including:
    - identifying speculative, duplicative or dormant connection enquiries and applications
    - understanding whether multiple proposed developments are seeking connection in the same area or drawing on the same network capacity
- coordinate transmission and distribution planning activities
- efficiently allocate finite connection resources

Inaccurate forecasting and inefficient investment decisions can ultimately impose costs on consumers. As the volume and scale of data centre development increases, the magnitude of these costs may also increase.

The proponent considers that greater visibility of prospective and existing large-load connections could support more efficient planning and investment decisions by AEMO, NSPs and other market participants. This would support reliability and system security, and mitigate costs and risks for consumers, consistent with the NEO.

3.4.3 Proposed solution by the proponent

The proponent proposes to require DNSPs and TNSPs to regularly provide information about prospective and existing large loads, for a new public register that AEMO would host, by extending the requirement under clause 5.18A.2.

The requirement would apply to prospective and existing loads with a rated capacity of 5 MW or more, aggregating all connection points for the same facility or premises when applying the threshold.

For prospective loads, NSPs would be required to provide information, including the:

- name of proponent/applicant (and originating proponent where relevant), site and owner
- ANZSIC code (subdivision level)
- requested connection capacity and voltage
- relevant bulk supply point(s)
- requested and expected ramping rate and timeframe
- connection stage
- dates of contact, enquiry, application and withdrawal (where relevant)
- NSP treatment of the load for forecasting/planning purposes.

For existing loads, NSPs would be required to provide information, including the:

- name of proponent/applicant (and originating proponent where relevant), site and owner
- ANZSIC code (subdivision level)
- connection capacity and voltage
- relevant bulk supply point(s)
- expected and observed ramping rate and timeframe
- energisation of connection date.

The proponent acknowledges that in considering the creation of such a register, issues of confidentiality and competition are likely to arise. The proponent notes that the Rules will need to include clear requirements for the provision of information by connection applicants and NSPs. The proponent notes that the Rules should expressly prevent NSPs from giving contractual undertakings to connection applicants that would prevent them from providing information required for the register, or sharing information required by the AER or AEMO to perform their regulatory or market-support functions.

3.4.4 We are seeking your views on the extent of any perceived information gap and how it could be addressed

We are interested in stakeholders' views on the extent of the information gap and how it could be addressed. We seek stakeholders' views on:

- the extent to which there is an information gap regarding prospective and existing large-load developments, and the materiality of any impacts on planning, forecasting and investment decisions
- how any information-sharing framework should be designed and implemented, including whether amendments to the NER or alternative approaches would be more appropriate
- the information that NSPs, AEMO and other stakeholders would benefit from having access to, and the information that could reasonably be collected, shared or published
- whether information-sharing requirements for large loads should match those that currently apply for generation connections, or whether they should be stronger
- how any risks or unintended consequences could be mitigated, including confidentiality, risks associated with the publication of information, and how those risks could be managed
- the types of loads that should be subject to any information-sharing requirements, and any thresholds that should apply
- any alternative approaches to an information-sharing framework that could address the identified issues more effectively or proportionately.

Our questions are set out in the boxes below. Stakeholders are encouraged to support their views with evidence and examples.

Question 5: Do you consider that there is limited public information about large loads?

- To what extent is there an information gap regarding prospective and existing large load developments and how material is the impact it has on planning, forecasting and investment decisions?
- What information should be collected, shared or published to address any identified information gaps?
- How should any reforms to the collection, sharing or publication of information on large loads be designed and implemented?
- How should confidentiality, competition and other risks associated with the collection, sharing or publication of information be managed?

3.5 Gap 5 - Barriers to the use of funded augmentations

The proponent noted that large loads can necessitate significant shared transmission augmentations, particularly when they are geographically clustered. For example, if the network at a certain location can support at most a 20 MW load, a connection applicant (or a group of connection applicants) may seek to pay for the necessary augmentations so that the network can support a 50 MW connection. These augmentations may be known as 'funded augmentations'.

Funded augmentations may be located far from the connection point (commonly known as a 'deep' augmentation) or may already be a committed network project.

The proponent considers that the NER provides limited guidance for funded augmentations of the shared transmission network. It also considers that a 'first mover disadvantage' may deter connection applicants and networks from pursuing funded augmentations.

3.5.1 Current arrangements for funded augmentations

Rule 5.2A specifies a range of transmission connection services as negotiated or non-regulated services

Rule 5.3 of the NER provides for the connection of any plant to the transmission network~~.~~ The classification and contestability of different transmission services to connect the plant to the transmission network are detailed in rule 5.2A.[73] For example:

- works to construct a dedicated connection asset or a designated network asset may be provided by the Primary TNSP[74] as a non-regulated transmission service[75]
- construction and design of an identified user shared asset (IUSA) to connect the plant to the shared transmission network may be provided as either a negotiated transmission service or a non-regulated transmission service, subject to certain criteria.[76]

The table in clause 5.2A.4 of the NER covers many types of transmission connection services and augmentations. However, the NER does not define a 'shallow' or 'deep' augmentation.

Funded transmission augmentations are contemplated by rule 5.18 of the NER

Rule 5.18 of the NER relates to the construction of funded augmentations, including setting out a consultation process for TNSPs to construct 'funded augmentations' to their transmission network. The NER definition of a funded augmentation is:

> *A transmission network augmentation for which the Transmission Network Service Provider is not entitled to receive a charge pursuant to Chapter 6A and does not include an identified user shared asset or a designated network asset.*

The proponent considers this definition to be ambiguous and overly restrictive.[77]

Distribution connection applicants may be required to pay a capital contribution to pay for shared augmentations

For some distribution connections, clause 5A.E.1(c) of the NER requires DNSPs to seek capital contributions towards the costs of extensions or augmentations that may be necessary to provide a connection service. The AER's connection charge guidelines detail how DNSPs must calculate capital contribution amounts using a 'cost-revenue-test'.[78] The cost-revenue-test calculates capital contribution amounts by:

- adding the incremental costs incurred by the DNSP for any standard control connection services used solely by the connection applicant
- adding the incremental costs incurred by the DNSP for any standard control connection services that are not used solely by the connection applicant
- subtracting the incremental DUOS revenue expected to be received from the new connection.[79]

73 Rule 5.2A does not apply to connection and access to the declared transmission system of an adoptive jurisdiction, such as those in Victoria.

74 The Primary TNSP is the TNSP who operates the largest transmission network in a participating jurisdiction, excluding TNSPs for declared transmission systems (currently only in Victoria).

75 NER, clause 5.2A.4(a), row 8 and 9 of the table.

76 NER, clause 5.2A.4(a), rows 2, 4, 5, 6 and 7 of the table and paragraphs (b)-(d) of the same clause, which stipulates that if the capital cost of the IUSA is expected to be $10 million or less, then the Primary TNSP must provide the design, construction and ownership of the IUSA as a negotiated transmission service.

77 Rule change request, p. 24.

78 AER, Connection charge guidelines, p. 10.

79 Ibid. See sections 5.1 to 5.5 of the AER's connection charge guidelines for more information as to how DNSPs must calculate capital contributions.

The AER's connection charge guideline for distribution contains a 'pioneer scheme' that may refund first-movers

Clause 5A.E.1(d) requires that if a connection asset ceases to be dedicated to the exclusive use of the retail customer within 7 years after its construction or installation, then the DNSP must refund the retail customer. The DNSP may recover the amount from new users of the asset. The AER's connection charge guideline refers to this arrangement as a 'pioneer scheme' and details how refund amounts should be calculated and charged to new connection applicants.[80]

3.5.2 The proponent identified two main barriers to funded augmentations

The proponent considers that the NER is unclear on cost recovery arrangements for funded augmentations

In its rule change request, the proponent considers that the clustering of large loads could necessitate significant shared transmission augmentations.[81] However, it noted that rule 5.18 of the NER is limited in scope and only sets out a process to give notice of a funded augmentation proposal to other parties.[82]

Further, the proponent considers that the NER definition of 'funded augmentations' is ambiguous and overly restrictive. It explains its view that TNSPs are not necessarily bound to progress projects considered in a revenue determination, and that TNSPs may still be able to, or 'entitled' to, roll a portion of funded augmentation capex into their regulated asset base.[83]

Funded augmentations have rarely been used due to a potential 'first mover disadvantage'

The proponent also notes that it understands the use of funded augmentations under rule 5.18 has been rare, potentially due to a 'first-mover disadvantage' where an asset could be paid for by the 'first' connection, but used by subsequent connections at no cost to them.[84]

3.5.3 Proposed solutions by the proponent

To encourage the use of funded augmentations by connecting parties and reduce the regulatory barriers it perceives, the proponent suggests:[85]

- amending NER rule 5.18 (and chapter 5 more broadly) to ensure that the rules for funded augmentations and related guidance are fit for purpose and support greater use of funded augmentations, particularly for clustered connections
- amending the definition of 'funded augmentation' so that it applies to a broader set of circumstances
- for transmission connections, providing for a mechanism (such as a funding pool or a 'pioneer scheme', similar to the mechanism that exists in distribution (see section 3.5.2)), whereby a new connection that contributes to a funded augmentation could be compensated over time as subsequent connections materialise, to overcome the 'first mover disadvantage'.
- strengthening or expanding upon an existing principle in schedule 5.11(6) of the NER (see section 3.7.1) to ensure that negotiated costs are subject to adjustment over time to compensate for the 'first mover disadvantage' for any relevant augmentations

80 Ibid., chapter 6.

81 Rule change request, p. 23.

82 Ibid.

83 Ibid., p. 24, footnote 7.

84 A 'first mover disadvantage' refers to any scenario where parties who have not contributed to the construction costs of a shared public good nevertheless receive benefits from that public good. These 'free' benefits disincentivise parties from funding the construction of that public good.

85 Rule change request, pp. 24-25.

- consider guidelines to ensure that assets are appropriately sized to achieve efficient outcomes
- potentially extending the above proposed solutions to funded augmentations of the shared distribution network.

3.5.4 We are seeking your views on whether there are barriers to the use of funded augmentations

The Commission is interested in stakeholders' views on whether the NER should provide more guidance on funded augmentations. We are also interested in stakeholder views on several related issues, such as:

- how an NSP should determine whether a particular shared augmentation is required to be built to establish a connection for a large load, or whether an augmentation is being voluntarily funded by existing or prospective network customers
- the service classification of funded transmission augmentations (that is, whether they should be a prescribed transmission service, negotiated transmission service or a non-regulated transmission service), how a TNSP should negotiate or recover its costs and from whom
- in circumstances where a connection applicant may voluntarily seek to pay to 'bring forward' the timing of an existing major transmission project to benefit their connection, whether such 'bring forward' costs should be classified as a funded augmentation
- interactions with downstream or inter-regional pricing of any funded augmentations (for example, where a funded augmentation in a transmission network benefits distribution or transmission users in other networks), and whether costs or benefits are appropriately passed on to those users in other networks.

We welcome stakeholder views on any of these topics above, as well as answers to the specific consultation questions below.

Question 6: Do you consider there are barriers for connection applicants to fund 'deep' shared augmentations?

- Have you ever been involved in discussions regarding a potential funded augmentation under rule 5.18 or otherwise? If so, what factors influenced your decision to pursue or not pursue a funded augmentation of the shared transmission or distribution network?
- Do you agree with the proponent that the 'first mover disadvantage' and the lack of clarity in the NER are barriers to funding augmentations of the shared network? If so, do you have a view on what the definition of 'funded augmentation' should be amended to, or what particular aspects the NER should provide better clarity on?
- Do you consider that a mechanism to compensate for the 'first mover disadvantage', such as a pioneer scheme, is an effective way to promote funded augmentations? If so, what is your view on the details of how such a mechanism should work?
- Do you consider that the proponent's suggested solutions should be extended to distribution networks for shared distribution augmentations?

3.6 Gap 6 - Jurisdictional scheme costs can only be recovered from distribution-connected customers

The NER does not contain a mechanism for transmission-connected customers to contribute to jurisdictional schemes. . The proponent considers that with the increased costs being recovered via jurisdictional schemes, this may result in certain customers, such as those connected at the distribution level, bearing a disproportionately large portion of the jurisdictional scheme costs compared to those connected at the transmission level.

3.6.1 There is no mechanism under the NER for TNSPs to recover jurisdictional scheme amounts from transmission-connected customers

Clause 6.18.7A provides a framework for DNSPs to recover jurisdictional scheme amounts from distribution customers. Under that framework, DNSPs recover approved scheme costs through distribution service charges, subject to the scheme meeting jurisdictional requirements and oversight by the AER.

Chapter 6A does not contain an equivalent framework for transmission networks. As a result, there is currently no mechanism under the NER for TNSPs to recover jurisdictional scheme amounts from transmission-connected customers.

3.6.2 Issues identified by the proponent

Customers with large loads that connect to the transmission network are not currently required to contribute to jurisdictional schemes. The proponent considers that historically with the majority of customers being distribution connected, this was not a material issue. The proponent considers that with the increase in costs being recovered via jurisdictional schemes, combined with the increase in transmission connected loads, equity concerns will grow if the framework continues to allow jurisdictional scheme costs to be recovered solely from distribution connected customers.

The proponent considers smaller customers would bear costs that large customers do not (exacerbating existing inequities, particularly where jurisdictional scheme costs rise due to large load connections). This which may distort investment and connection decisions, incentivising connection to transmission networks to avoid jurisdictional scheme charges that are imposed on customers connecting to distribution networks.

The proponent also identified a need to address this issue before individual states derogate from the NER, to create a consistent and equitable framework and avoid inequitable outcomes. It noted that South Australia has derogated from the NER to enable transmission-level cost recovery for the jurisdictional scheme, the Firm Energy Reliability Mechanism.

3.6.3 Proposed solution by the proponent

The proponent proposes to insert a new rule in Chapter 6A, analogous to clause 6.18.7A, to facilitate the pass-through of jurisdictional scheme amounts to TNSPs and their customers.

The proposed rule would:

- allow jurisdictions to allocate costs to particular connection classes (e.g. to exclude DNSPs from ‘double dipping’) and/or for costs to be recovered via certain tariff structures (e.g. $/MW capacity charges)
- enable jurisdictional scheme amounts to be isolated and not recovered from customers in another jurisdiction (to prevent inter-jurisdictional cross-subsidisation of scheme costs), so

that customers in one jurisdiction do not fund another jurisdiction's scheme unless the relevant scheme provides otherwise

- enable the AER to determine whether schemes proposed to it by jurisdictions meet the criteria set out in the NER (this would be analogous to the Rule 6.18.7A(f)-(x) process set out in the distribution rules).
- the same scheme could be both a distribution and transmission jurisdictional scheme, recovered across both distribution and transmission connected loads. Where this occurs, the AER should have an oversight role to ensure the same scheme costs are not recovered more than once.
- the proponent proposes that existing distribution jurisdictional schemes will not automatically become transmission jurisdictional schemes, but it should be administratively simple for jurisdictions to nominate a distribution scheme to become a transmission scheme if they so choose. A jurisdiction could be required to inform the AER if the jurisdiction develops a transmission jurisdictional scheme. If the AER determines that the scheme meets the relevant criteria set out in the NER, the AER could then publish details of the scheme (consistent with current practice).[86]

The proponent considers that, as part of this new rule, a new transmission service charge category may be required for jurisdictional schemes to pass through costs directly to TNSP customers, including large loads.

The proponent considers that the purpose of this additional category would be to enable TNSPs to recover jurisdictional scheme amounts directly from their connected customers on a cost-reflective basis, in proportion to the volume of electricity consumed and/or requested capacity.

The proponent also suggests considering whether the charge should be a required transmission service applying to both prescribed transmission service and negotiated transmission service customers, to avoid a distortion in cost recovery that would occur if directly connected transmission customers could avoid contributing to jurisdictional scheme cost recovery by negotiating a negotiated transmission service. The proponent's intent is that costs recovered under the jurisdictional scheme would not duplicate cost recovery under any other mechanism.

3.6.4 We are seeking your views on the recovery of jurisdictional scheme amounts from customers

We are interested in stakeholders' views on recovering jurisdictional scheme amounts from customers who connect to the transmission network.

We seek your input on:

- whether jurisdictional scheme amounts should also be recovered from transmission-connected customers
- how any framework for recovering jurisdictional scheme amounts from transmission-connected customers should be designed and implemented, including whether a new rule in Chapter 6A is the most appropriate mechanism or whether an alternative approach would be preferable
- if a new rule in Chapter 6A were to be introduced, whether a new transmission service charge category is required and, if so, whether it should apply to both prescribed and negotiated transmission service customers

86 Rule change request, pp. 26-28.

- the most appropriate basis for recovering jurisdictional scheme amounts from transmission-connected customers
- how any framework or amending rule could prevent distribution customers paying twice through both distribution and transmission charges
- how any framework or amending rule could prevent jurisdictional scheme costs being collected across interconnectors
- any alternative approaches that could address the identified issues more effectively or proportionately

Our questions are set out in the boxes below. Stakeholders are encouraged to support their views with evidence and examples.

Question 7: Do you consider that the costs of jurisdictional schemes should be recovered from transmission customers?

- Should the NER enable jurisdictional scheme amounts to be recovered from transmission customers? Why or why not?
- How should any transmission-level jurisdictional scheme framework be implemented?
- What issues could arise from introducing a transmission-level jurisdictional scheme framework, and how could these be addressed?

3.7 Gap 7 - Guidelines for transmission connection policies and charges

The proponent has identified that there is currently no consolidated guidance for transmission connection pricing in the NER. The NER and AER guidelines set out principles and methodologies for determining distribution connection charges, taking into account the costs of any necessary augmentations or extensions to the shared network. In comparison, the proponent considers the NER requirements for transmission charges are high-level and principles-based, and notes that there is no AER guideline for transmission connection services or charges.[87]

The proponent considers that the relative lack of detail or prescription for transmission connections may increase the risk that consumers inappropriately bear the cost of augmentations resulting from large connections. To address this, it suggests creating a new AER guideline for transmission charges that is based on the existing connection charge guideline, while considering how best to adapt it for transmission connections and networks.

3.7.1 Current arrangements for connection policies and charges guidelines

In its rule change request, the proponent has identified that there is currently no consolidated guidance for transmission connection pricing in the NER. In this section, to assist stakeholders in answering the questions in section 3.7.4, we have provided a brief summary of existing rules and guidelines that set out how connection policies and charges should be determined.

NER schedule 5.11 provides for negotiating principles for negotiated transmission services

Rule 5.2A of the NER provides the framework for transmission network connection and access (except for connection and access to the declared transmission system in Victoria).[88] Rule 5.2A

87 Except for Victoria, where the AER is required to approve Negotiated Transmission Service Criteria that apply to the TNSP, as part of its five-yearly transmission determination. However, these criteria are generally very similar to the principles set out in Schedule 5.11 of the NER.

88 Ibid.

details the classification and contestability of different transmission services that may be required to connect a plant.

If a connection applicant seeks access to negotiated transmission services, clause 5.2A.6(a) requires that the TNSP and the connection applicant must, in negotiating pursuant to rule 5.3 and other relevant rules, negotiate in accordance with the principles detailed in schedule 5.11 of the NER. This schedule contains 13 principles that govern how TNSPs should set prices for negotiated transmission services. For example, principle 2 provides that:

> 2 Subject to paragraphs (3) and (4), the price for a *negotiated transmission service* should be at least equal to the avoided cost of providing it but no more than the cost of providing it on a stand-alone basis.

and principle 6 states that:

> 6 The price for a *negotiated transmission service* should 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 which case such adjustment should reflect the extent to which the costs of that asset is being recovered through charges to that other person.

Note that principle 6 may provide for a cost-sharing arrangement (or ‘pioneer scheme’) to address the ‘first mover disadvantage’ discussed in section 3.5.2.

Rule 5.3AA sets out access arrangements and principles for some distribution connections

Rule 5.3AA applies to Distribution Connected Resource Providers, electing non-registered DER providers, and HVDC links (schedule 5.3a plant). The price for the connection service provided by the DNSP must be negotiated in good faith to reflect any augmentations or extensions required to be undertaken on all affected transmission networks and distribution networks, and must pass through payable TUOS were it not for the proposed connection (see section 3.1.1).

Connection charge principles and the AER’s connection charge guideline apply to distribution retail customers

Under clauses 5A.E.1 and 5A.E.3, connection charges levied on retail customers must be determined in accordance with several principles relating to capital contributions to cover the costs of any required augmentations or extensions.[89] The NER also requires the AER to develop and publish a connection charge guideline, with the objective of ensuring that connection charges:

- are reasonable, taking into account the efficient costs of providing the services and the revenue a prudent operator would require to provide connection services
- provide a user-pays signal to reflect the efficient cost of providing connection services
- limit cross-subsidisation of connection costs between different classes of retail customer
- if the connection services are contestable, are competitively neutral.[90]

Furthermore, clause 5AE.3(c) requires that the guidelines must set out (among other things):

- a method for determining charges, capital contributions, prepayments or financial guarantees, and the circumstances under which a DNSP may receive them

89 NER, clause 5A.E.1(b)-(c).

90 NER, clause 5A.E.3(b).

- principles for fixing a threshold below which retail customers are exempt from paying connection charges for an augmentation
- a method for calculating refunds for when an extension is used within 7 years of its installation to connect other premises.

The AER's connection charge guideline[91] requires connection applicants (where chapter 5A of the Rules apply) to pay to the DNSP a connection charge, which is comprised of:

- charges for all relevant alternative control connection services[92]
- capital contributions for any standard control connection service, if the incremental cost of providing standard control connection services for that connection exceeds the estimated incremental revenue from the connection applicant paying for standard control connection services[93]
- any pioneer scheme charges for network extensions, to refund existing customers within the pioneer scheme[94]
- prepayments and security fees, where applicable.[95]

3.7.2 Issues identified by the proponent

The proponent considers that there is a lack of detail on transmission connection charges and that there is a mismatch in the level of detail on connection charge guidance between distribution and transmission connections. It states that:[96]

> The distribution connection charge guidelines set out much more explicit requirements on [DNSPs]. In particular, the distribution guidelines require [DNSPs] to use unit rates to calculate and allocate the cost of shared network assets to new customers.
>
> In contrast, any upfront contribution by a transmission connection applicant toward deeper transmission augmentations (required at the time of connection or subsequently) depends on a negotiation between the parties, subject to the bounds set by Schedule 5.11.

The proponent considers that a lack of specificity in the NER or in guidelines may lead to inconsistent approaches among TNSPs, and gives the example of Principle 2 (see section 3.7.1) as potentially being read in different ways. It contends that any inconsistency in interpreting these negotiation principles increases the risk that certain consumers inappropriately bear the costs or risks of augmentations triggered by new connections.[97]

3.7.3 Proposed solution by the proponent

The proponent considers that more explicit guidance or prescription should be given regarding transmission connection charges. The proponent considers the NER should provide TNSPs more explicit guidance on pricing connections, potentially through an AER published guideline similar to the distribution connection charge guideline or through amendments to Schedule 5.11 (noting Victoria's unique framework may require the AER to update its approach to the negotiated transmission service criteria).

91 AER, Connection charge guidelines for electricity customers.
92 Ibid., chapter 4.
93 Ibid., chapter 5.
94 Ibid., chapter 6.
95 Ibid., chapter 10.
96 Rule change request, p. 29.
97 Ibid.

It considers that providing more explicit guidance and prescription regarding connection pricing will increase certainty and consistency of implementation across TNSPs, reducing the risk of inefficient cross-subsidisation between consumers.

The proponent noted that certain aspects of the AER's connection charge guideline, such as unit rates,[98] may be difficult to replicate for a transmission network due to differences between transmission and distribution.[99] Nevertheless, it suggested that the guidelines could require TNSPs to calculate a $/MW or $/km estimate that reflects the cost of necessary transmission augmentations, together with an adjustment mechanism for differences between estimated and actual costs.

While the proponent noted its preference for more prescriptive approaches in a new AER guideline, if this approach is unworkable, the proponent considers that the negotiating principles should provide more explicit guidance around ensuring pricing appropriately captures the full scale of augmentations needed to support a new load. In its view, these principles should avoid cross-subsidy and ensure existing consumers do not bear any current or future pricing risks from stranded assets.[100] It noted that any new guidance for transmission connection services could also incorporate the proponent's other suggestions on prudential requirements and funded augmentations.

3.7.4 We are seeking your views on this issue

We seek your views on whether you consider there would be benefits from greater guidance on transmission connection policies and charges. In considering potential policy solutions, the Commission will also consider whether any aspects of the AER's connection charge guidelines for distribution should be applied to any new transmission rules or guidelines.

Question 8: Do you consider that there should be more explicit guidance on how TNSPs determine or negotiate prices for negotiated transmission services?

- Do you agree with the proponent that the relative lack of detail for transmission connection services may increase the risk of inefficient cross-subsidisation? Why or why not?
- Do you support the proponent's proposal for the AER to develop and publish a new guideline for transmission connection services, similar to its existing connection charge guidelines for distribution?
- If so, should any new guidance prescribe methodologies for how transmission service charges are calculated (similar to how the AER's connection charge guideline details the calculation of 'unit rates'), or is a more principles-based approach preferable?
- Are there any aspects of the guidance provided for distribution connections that should be adapted for transmission to reduce the risk of inefficient cross-subsidisation?

98 In the AER's connection charge guideline, unit rates reflect the average cost of adding a unit of capacity to the shared network for a particular area of the network. See section 5.2 of the AER's connection charge guideline.

99 Rule change request, p. 30.

100 Ibid.

4 Making our decision

When considering a rule change proposal, the Commission considers a range of factors.

This chapter outlines:

- issues the Commission must take into account
- the proposed assessment framework
- decisions the Commission can make
- rule-making for the Northern Territory.

We would like your feedback on the proposed assessment framework.

4.1 The Commission must act in the long-term interests of consumers

The Commission is bound by the National Electricity Law (NEL) to only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective.[101]

The NEO is:[102]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system; and
>
> (c) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

The targets statement, available on the AEMC website, lists the emissions reduction targets to be considered, as a minimum, in having regard to the NEO.[103]

4.2 We must also take these factors into account

The Commission must take into account the form of regulation factors and any other matter the AEMC considers relevant in making or revoking a Rule that specifies an electricity network service as a direct control network service or a negotiated network service, or confers a function or power on the AER to specify an electricity network service as a direct control network service or a negotiated service under a network revenue or pricing determination.[104] The AEMC will consider the application of the form of regulation factors as part of the rule change process, particularly given that the rule change request raises issues related to the service classification of distribution and transmission services.

The Commission must take into account the revenue and pricing principles set out in section 7A of the NEL in making certain rules.[105] The AEMC will consider the application of the revenue and

101 Section 88 of the NEL.

102 Section 7 of the NEL.

103 Section 32A(5) of the NEL.

104 Section 88A of the NEL.

105 Section 88B of the NEL.

pricing principles as part of the rule change process, because the rule change request raises issues in relation to safeguards regarding cost reallocation and determining the rolling of certain types of expenditure into the regulated asset base.

The Commission may only make a Rule that has effect with respect to an adoptive jurisdiction if satisfied that the proposed Rule is compatible with the proper performance of AEMO's declared network functions.[106]

4.3 We propose to assess the rule change using these three criteria

4.3.1 Our methods to analyse the proposed rule

Considering the NEO and the issues raised in the rule change request, the Commission proposes to assess this rule change request against the set of criteria outlined below. These assessment criteria reflect the key potential impacts – costs and benefits – of the rule change request. We consider these impacts within the framework of the NEO.

The Commission's regulatory impact analysis may use qualitative and/or quantitative methodologies. The depth of analysis will be commensurate with the potential impacts of the proposed rule change. We may refine these methodologies as this rule change progresses, including in response to stakeholder submissions.

Consistent with good regulatory practice, we also assess other viable policy options - including not making the proposed rule (a business-as-usual scenario) and making a more preferable rule - using the same set of assessment criteria and impact analysis methodology where feasible.

4.3.2 Assessment criteria and rationale

The proposed assessment criteria and rationale for each are as follows:

- **Outcomes for consumers** – The relevant frameworks should create incentives and regulations for NSPs and connecting customers so that they do not make decisions that, as a byproduct, negatively impact other consumers in the NEM. We will consider how different types of customers and consumers are accounted for, so that the costs associated with connecting large loads are not inappropriately borne by other consumers.
- **Safety, security and reliability -** We will consider whether potential changes to the NER would continue to contribute to the provision of reliable, secure and safe provision of energy at efficient cost, to benefit consumers over the long term. Efficient investment in new generation, load, storage, networks and other system capabilities would be promoted by ensuring:
  - parties that are best able to carry and manage certain risks and costs, bear those risks and costs
  - that we minimise any distortion of incentives to locate in optimal areas of the electricity network
  - all relevant parties are able to effectively coordinate to plan their networks and investments.
- **Principles of market efficiency -** The relevant frameworks should promote efficient planning and investment of the power system by:
  - delivering productive, dynamic and allocative efficiency in the investment and planning timeframes

106 Section 91(8) of the NEL. Section 111 of the *National Electricity (Victoria) Act 2005* (Vic), inserted by section 57 of the *National Electricity (Victoria) Amendment (VicGrid Stage 2 Reform) Act 2025* (Vic) deals with superseded references to AEMO that relate to AEMO's Victorian network functions.

- allocating risk to parties best suited to manage risk, taking into account different approaches to risk management between different types of stakeholders
- increasing information transparency and reducing information asymmetry
- promoting price discovery and encouraging competition through effective signals, incentives and suitable pricing methods for different kinds of connection services.

We note that the rule change request and the proponent use the words 'equitable' and 'fair' when discussing its identified issues, proposed solutions or potential benefits. Equity and fairness are broad terms that encompass a diverse range of interrelated and overlapping concepts, such as inequality, protections for vulnerable customers and social justice.

Equity (and other factors) are considered in our decision-making, provided the rule or recommendation contributes to achieving the national energy objectives. Equity should be considered where equitable outcomes would improve or maintain efficiency, and where consideration of distributional impacts may inform the design of appropriate protections for certain types of consumers. We seek to deliver equitable outcomes to the extent that those outcomes align with the NEO, as described above in our 'Outcomes for consumers' criterion.

We seek stakeholder views on how equity-related factors should be considered in our decision-making, noting that the Commission can only make a rule that contributes to achieving the NEO.

For more information on how we consider equity, refer to section 4.1.6 of How the national energy objectives shape our decisions.

Question 9: Assessment framework

Do you agree with the proposed assessment criteria? Are there additional criteria that the Commission should consider or criteria included here that are not relevant?

4.4 We have three options when making our decision

After using the assessment framework to consider the rule change requests, the Commission may decide:

- to make the rule as proposed by the proponent[107]
- to make a rule that is different to the proposed rule (a more preferable rule), as discussed below, or
- not to make a rule.

The Commission may make a more preferable rule (which may be materially different to the proposed rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule is likely to better contribute to the achievement of the NEO.[108]

4.5 We may make a different rule to apply in the Northern Territory

Parts of the NER, as amended from time to time, apply in the Northern Territory, subject to modifications set out in regulations made under the Northern Territory legislation adopting the NEL.[109]

107 The proponent describes its proposed rule in each of its identified gaps in chapters 5 and 6 of its rule change request.

108 Section 91A of the NEL.

109 National Electricity (Northern Territory) (National Uniform Legislation) Act 2015 (**NT Act**). The regulations under the NT Act are the National Electricity (Northern Territory) (National Uniform Legislation) (Modification) Regulations 2016.

The proposed rule would amend provisions in NER chapters 5 and 10, among others, that apply in the Northern Territory.[110]

Test for scope of "national electricity system" in the NEO

Under the NT Act, the Commission must regard the reference in the NEO to the "national electricity system" as a reference to whichever of the following the Commission considers appropriate in the circumstances having regard to the nature, scope or operation of the proposed rule:[111]

1. the national electricity system
2. one or more, or all, of the local electricity systems[112]
3. all of the electricity systems referred to above.

Test for differential rule

Under the NT Act, the Commission may make a differential rule if it is satisfied that, having regard to any relevant MCE statement of policy principles, a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.[113] A differential rule is a rule that:

- varies in its term as between:
  - the national electricity systems, and
  - one or more, or all, of the local electricity systems, or
- does not have effect with respect to one or more of those systems

but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s. 91(8) of the NEL.

A uniform rule is a rule that does not vary in its terms between the national electricity system and one or more, or all, of the local electricity systems, and has effect with respect to all of those systems.[114]

110 Under the NT Act and its regulations, only certain parts of the NER have been adopted in the Northern Territory. The version of the NER that applies in the Northern Territory is available on the AEMC website at: https://energy-rules.aemc.gov.au/ntner.

111 Clause 14A of Schedule 1 to the NT Act, inserting section 88(2a) into the NEL as it applies in the Northern Territory.

112 These are specified Northern Territory systems, listed in schedule 2 of the NT Act.

113 Clause 14B of Schedule 1 to the NT Act, inserting section 88AA into the NEL as it applies in the Northern Territory.

114 Clause 14 of Schedule 1 to the NT Act, inserting the definitions of "differential Rule" and "uniform Rule" into section 87 of the NEL as it applies in the Northern Territory.

Abbreviations and defined terms

ACS	Alternative control service
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AI	Artificial intelligence
ANZSIC	Australian and New Zealand Standard Industrial Classification
CER	Consumer energy resources
Commission	See AEMC
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DNSP	Distribution network service provider
DUOS	Distribution use of system
ECMC	Energy and Climate Change Ministerial Council
EII Act	Electricity Infrastructure Investment Act 2020 (NSW)
ESOO	Electricity Statement of Opportunities
GW	Gigawatt
HVDC	High Voltage Direct Current
IUSA	Identified user shared asset
MCE	Ministerial Council on Energy
MW	Megawatt
MVA	Megavolt ampere
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NSP	Network service provider
OIV	Operational integration and visibility of large inverter based loads
Proponent	The proponent of the rule change request, the Hon Chris Bowen MP
RAB	Regulated asset base
REGO	Renewable Electricity Guarantee of Origin
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
SCS	Standard control service
TNSP	Transmission network service provider
TUOS	Transmission use of system
TWh	Terawatt hour