31 March 2023

[redacted]

Jessica Robinson
Director, IPART
[redacted]

Also submitted via online portal to IPART
cc: [redacted]

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Dear Ms Grigg and Ms Robinson,

Ausgrid response to draft Ministerial Statement of Expectations and draft Terms of Reference for protecting NSW customers of embedded networks

Ausgrid welcomes the opportunity to respond to the Office of Energy and Environment's (**OECC**) Draft Ministerial Statement of Expectations for protecting NSW customers of embedded networks (**draft SoE**) and the Independent Pricing and Regulatory Tribunal's (**IPART**) associated draft Terms of Reference (**draft ToR**).

We support the draft SoE that seeks to introduce further regulation and oversight of embedded networks in NSW. As we noted in our submission to the Parliamentary Inquiry (**Attachment A**), the current regulatory framework for embedded networks in NSW does not serve the long-term interests of customers. Our concerns are broader than improving fairness in regulated pricing, extending to safety, technical and consumer protection regulatory gaps.

We support the two 'expectations' relevant to the electricity sector and refer you to **Attachment A** for more details.

Ausgrid agrees that embedded network customers should have equivalent customer protections as on-market customers, which is not currently the case in NSW.

Attachment A outlines the regulatory gaps that impact electricity embedded network customers, despite them having an electricity retail contract with an Australian Energy Regulator (**AER**) authorised electricity retailer. It is common for these customers to be adversely affected in terms of reliability standards, connections standards, billing information, outage notifications, guaranteed services levels and payments, and appropriate life support customer protections.

When implementing the 'expectation' that embedded network customers have equivalent customer protections to on-market customers, we encourage the NSW Government and IPART's review to consider the safety and technical gaps outlined in **Attachment A**. Unlike embedded network operators, DNSPs must comply with a range of detailed safety obligations, audits, reporting and compliance obligations for voltage frequency and disturbances and report any safety incidents (when they occur).

Importantly, whether an embedded network is classified as a ‘distribution system’ or as an ‘electricity system’ will have important implications for customer protections, reliability and guaranteed services levels as well as reporting and monitoring conditions. Some of these consumer protections and safety regulations may require amendment for them to apply to embedded networks.

We recommend the OECC consider a state-based licensing regime with licence conditions proportionate to the size and type of embedded network, and that would enable data collection on embedded networks and enhanced customer protections such as reliability standards and guaranteed service levels.

Ausgrid supports IPART’s draft ToR however encourages IPART consider additional matters to pricing, including safety, technical, licencing and customer protection frameworks.

We consider IPART’s draft ToR ‘considerations’ to be sufficiently broad to be able to consider a suitable regulatory framework for embedded networks to the benefit of embedded network customers. However, as noted above, the review should be broader than pricing elements and include safety, technical, licencing and customer protection frameworks as outlined in **Attachment A**.

For example, this attachment explains the need to distinguish between different types and sizes of embedded networks and regulate them accordingly to address the safety and technical regulatory gaps. With the increasing trend of high voltage residential mixed use embedded networks in NSW, action is needed to ensure these regulatory gaps do not result in worse safety outcomes. As seen in South Australia where, despite their sole residential mixed-used embedded network being licensed, there was a major safety incident with two contractors hospitalised, one of whom was in ICU.

We encourage IPART, as part of this review, to speak with the AER about any data they may have on high voltage residential mixed use embedded networks.

Ausgrid supports the proposal for authorised electricity retailers to comply with the AER’s Default Market Offer (DMO) and recommends that the NSW Government publicly support dedicated embedded network tariffs in NSW

As part of our 2024-29 Tariff Structure Statement (**TSS**) (**Attachment B** page 15) and TSS Explanatory Statement (**Attachment C** (pages 21-25)), Ausgrid is proposing new tariffs that would apply to embedded network operators. These tariffs would apply from 1 July 2024 and are designed to reduce the tariff arbitrage that currently exists for embedded network operators (as compared to customers that are not located in an embedded network). We understand there are reasons why an apartment complex, office building or industrial estate might choose to connect as an embedded network, such as to enable innovation. But in our view, tariff arbitrage should not be one of them.

To minimise network bill impacts, we propose to introduce the new tariffs over a five-year transition period that would be completed by 2029. We have consulted extensively on our proposed embedded network tariffs, and we believe that they will achieve the appropriate balance between fairness and cost recovery principles. **Attachment C** provides more information on the proposed tariffs and our consultation process. We note that Endeavour Energy is also proposing embedded network tariffs for the 2024-29 regulatory period.

We recommend that IPART’s review into electricity pricing for embedded networks consider Ausgrid’s and Endeavour’s proposed embedded network tariffs, and how this would impact a maximum retail price for these customers.

We would welcome the opportunity to meet and discuss our submission with the OECC and IPART. Please contact [redacted]

Regards,

[redacted]

[redacted]
Chief Customer Officer

Attachments:

- Attachment A: NSW DNSP's submission to the 2022 Embedded Network Parliamentary Inquiry 2022
- Attachment B: Ausgrid's 2024-29 Tariff Structure Statement (page 15)
- Attachment C: Ausgrid's 2024-29 Tarif Structure Statement Explanatory Statement (pages 21-25)

24 June 2022

Mr Ray Williams MP

Committee Chair

Parliament of New South Wales

[redacted]

NSW DNSPs response to the Legislative Assembly Committee on Law and Safety Inquiry on embedded networks in New South Wales

Dear Mr Williams MP,

Ausgrid, Endeavour Energy and Essential Energy (NSW distribution network service providers (**DNSPS**)) thank the Legislative Assembly Committee (the **Committee**) for the opportunity to provide a submission on the Law and Safety Inquiry into embedded networks in New South Wales (the **Inquiry**).

DNSPs consider that the regulatory framework that applies to embedded networks in NSW is no longer fit for purpose. Several recent independent reviews of embedded networks both in Victoria and nationally, have identified numerous gaps in the regulatory framework for embedded networks ranging widely from technical, billing and even safety issues. Broadly speaking, these reviews determined that the existing regulatory regime for embedded networks required reform.

The existing regulatory framework was established at a time when there were relatively few embedded networks in NSW, and these were mostly, what are now considered, micro embedded networks for small-scale retirement villages or caravan parks. At the time, the embedded network regulatory framework was broadly considered fit for purpose in addressing a specific defined need.

However, more recently the historically 'typical' embedded network types have moved away from being a limited number of small scale retirement villages or caravan parks arrangement. Embedded networks are now proliferating in number and size, and are dominated by strata residential buildings, shopping centres and other large 'mixed use' developments, which are often large precincts comprising potentially hundreds or thousands of individual customers. This dramatic growth in the number and scale of embedded networks in NSW from the original intent of the framework designed for caravan parks and small retirement villages has meant that identified gaps (and corresponding harms) in the regulatory framework are being amplified over time, a trend which will continue if not addressed.

This regulatory framework scope-creep continues as embedded network developers are starting to request NSW network business to provide high voltage connections over low voltage connections as their embedded network developments increase in scale.

Please see **Attachment A** for our joint submission. It outlines key deficiencies in the existing regulatory framework for embedded networks in NSW and provides our recommendations for the Committee for consideration, including to:

1. Consider NSW-specific measures that may be required to address gaps in the consumer protection framework for customers served by embedded networks.
2. Clarify the circumstances and thresholds under which an embedded network (be it an 'electrical installation' or other category of network infrastructure) requires additional regulation and licensing in the form of conditions for consumer protections, reliability, guaranteed service

levels, reporting and monitoring, technical, safety and/or price regulation, for example as occurs in South Australia or with water embedded networks in NSW (also known as private water networks).

3 Clarify that under the *Electricity Supply Act 1995* (NSW) (**ESA**), the mode of connection for an embedded network (i.e. whether it will be high voltage or low voltage) will be determined by the DNSP, having regard to network safety considerations. The former typically being used for industrial sites where work, health and safety provision apply.

4 Consider policy options identified in the AEMC and Victorian Government reviews and apply a cost-benefit assessment of each.

5 Consider measures to improve the visibility of resources within embedded networks. This information could be reported directly to the Australian Energy Market Operator (**AEMO**) by embedded network operators and accessible to all market participants.

6 Clarify what constitutes a 'distribution system' and what constitutes an 'electrical installation' for regulatory purposes.

A potential regulatory and policy pathway forward for the Inquiry to consider could be to:

1 Retain the existing regulatory settings for traditional embedded networks such as small networks servicing caravan parks or retirement villages with fewer than 30 residential or small business customers.

2 Implement stronger regulation of larger embedded network operators through licensing. The AEMC and AER have recommended greater alignment of consumer protections for embedded network customers with those of standard supply customers. For NSW it may also include closely aligning safety and reliability obligations for large embedded networks with those applying to DNSPs and use the SA licensing approach and NSW approach for private water networks under the Water Industry Competition Act as a model.

3 Restriction or bans on certain types of embedded networks where they are not appropriate due to scale. For example, the Victorian Government has decided to ban new embedded networks. Instead NSW could determine that certain types of new embedded networks of a certain size or type should be restricted or banned. This could include banning residential or mixed use HV networks and limiting HV embedded networks to industrial sites only.

We welcome the opportunity to discuss any aspect of this submission with the Committee.

Please contact the following with any questions:

- Ausgrid: [redacted]
- Endeavour Energy: [redacted]
- Essential Energy: [redacted]

Yours sincerely,

[redacted]

Chief Customer Officer

Ausgrid

[redacted]

Chief Financial Officer

Endeavour Energy

[redacted]

Executive General Manager, Corporate Affairs

Essential Energy

Attachment A: NSW distribution businesses

Submission to the Legislative Assembly Committee on Law and Safety Inquiry on embedded networks in New South Wales

24 June 2022

Contents

1 Executive Summary

Ausgrid, Endeavour Energy and Essential Energy (NSW distribution network service providers (**DNSPS**)) welcome this opportunity to provide a joint submission to the Legislative Assembly Committee on Law and Safety (the **Committee**) Inquiry into embedded networks in New South Wales (the **Inquiry**).

The Inquiry is timely given the proliferation of embedded networks in NSW over the past decade and the rapid pace of the energy market's transition.

The regulatory framework for embedded networks in NSW no longer serves or protects energy consumers within embedded networks. Several recent independent reviews of embedded networks both in Victoria and nationally, identified regulatory framework gaps ranging widely from technical, billing and even safety issues and determined that the existing regulatory regime for embedded networks required reform.

The existing regulatory framework was established when there were relatively few embedded networks in NSW – they were mostly micro-embedded networks for small-scale retirement villages or caravan parks. When limited to just micro-embedded networks for small-scale retirement villages only, then the embedded network regulatory framework is broadly considered to be fit for purpose.

However, more recently the 'typical' embedded network is now large-scale retirement villages, strata residential buildings, shopping centres and other large 'mixed use' developments, which are often large precincts comprising potentially hundreds or thousands of individual customers. For example, since 2015, the number of embedded networks in Ausgrid's distribution area has grown 8-fold from around 100 for many years, to around 800.

This dramatic growth in the number and scale of embedded networks in NSW represents a departure from the original intent of a framework designed for caravan parks and small retirement villages. It also means that identified gaps (and corresponding harms) in the regulatory framework are being amplified over time. This trend is continuing and is now progressing to expand to high voltage (**HV**) mega embedded networks – a trend which will continue if not addressed by this review.

The key deficiencies in the regulatory framework include:

1 **Gaps in the customer protection framework.** Many of protections that apply to distribution-connected customers do not apply or do not apply in the same way to embedded network customers. In its 2017 and 2019 reviews of the national regulatory framework for embedded networks, the Australian Energy Market Commission (**AEMC**) identified numerous gaps in the customer protection framework for embedded network customers – including: reliability standards, connection standards, billing information, outage notifications, guaranteed service levels and protections for life support customers.[1] However, the AEMC's recommendations for greater alignment of embedded network customer protections with those applying to distribution-connected customers are on hold with Energy Ministers and there are no known plans to implement them.

2 **Lack of clarity around classification and regulatory treatment of embedded networks**. The *Electricity Supply Act 1995* (NSW) (**ESA**) and Service & Installation Rules currently distinguish between 'distribution systems' and 'electrical installations'. This distinction is critical because the ESA confers substantial powers and imposes significant obligations on 'network operators' (including operators of distribution systems i.e. DNSPs) and exempts them from various burdens when installing, operating and carrying out works. This is particularly relevant

[1] See: AEMC, Review of regulatory arrangements for embedded networks, Final Report, 28 November 2017, Sydney (**AEMC 2017 Final Report**); AEMC, Updating the regulatory frameworks for embedded networks, Final Report, 20 June 2019 (**AEMC 2019 Final Report**).

for safety regulations, public road consents, property rights, access rights and obtaining planning approvals. However, the ESA and Service & Installation Rules are currently unclear on this distinction between 'distribution systems' and 'electrical installations', and on the circumstances in which an 'electrical installation' requires additional regulation given its size and scope. This has direct and important implications for consumer protections, reliability and guaranteed service levels as well as reporting and monitoring conditions. Additionally, there is no requirement in NSW to licensee embedded networks to provide comparable protections to customers like there is in South Australia, or set parameters for when they are or are not allowed like in Victoria. The NSW DNSPs consider that greater clarity is now required given the growth in embedded networks in NSW over the past decade like it has done for water embedded networks (also known as private water networks) via the *Water Industry Competition Act 2006* (**WIC Act**). This Act imposes obligations on water embedded networks to ensure that the operators are licensed and must provide an array of customer protections including splitting out the retail function from the network function. However, does not confer the same powers given to the public water utility for matters such as land acquisition and compliance.

3 **Safety risks for embedded network customers and the general public**. The AEMC reviews have also noted that safety regulations often apply inconsistently to embedded networks and distribution systems. In NSW, where an embedded network is classified as an 'electrical installation' under the ESA, the operator will not be subject to the same safety obligations as a distribution system operator. This creates safety risks for customers and the general public, particularly in the case of larger embedded networks (e.g. those in 'mixed use' developments). Of particular concern are HV embedded network installations, since these carry a higher likelihood of catastrophic consequences to both life and property from close contact. For example, the only HV mixed use with residential embedded network in South Australia had a major safety incident in 2019 resulting in two contractors being hospitalised with severe burns.[2]

4 **Limited visibility of embedded network operations**. In order to support efficient dimensioning and maintenance of distribution systems, it is important for DNSPs to have visibility of load, generation and storage resources connected to their networks. This is important both to maximise the efficiency of distributed resources and to support the safety and reliability of the distribution system. While important steps have been taken to improve visibility of distribution-connected resources, DNSPs continue to have limited visibility of operations and energy resources within embedded networks. With growing levels of behind the meter distributed energy resources such as rooftop solar, this could have implications for how NSW DNSPs manage their network during times of system constraint.

5 **Potential for uneven sharing of network costs**. Where there are a large number of customers connected to an embedded network, those customers currently pay a much smaller share of fixed network costs compared to distribution-connected customers (assuming the embedded network operator passes through that lower amount, which it may not). As such, the costs of running the distribution network are not shared equitably between customers within embedded networks and those outside embedded networks. Ausgrid is currently working to address this inefficiency and will consult on a new tariff assignment policy that seeks to address this cross subsidy between network users. This results in other customers paying a higher than otherwise proportion of the fixed-shared costs of the network, to the benefit of the embedded network customers (or often the embedded network owner). As a shared community asset, this is often viewed as unfair by our customers.

[2] 'Two suffer burns in accident at Tonsley precinct', *The Advertiser*, 7 February 2019.

6 **Customers are not receiving access to retail choice or comparable regulated outcome**. The AEMC and AER have identified ‘significant practical barriers’ to customers in embedded networks accessing retail choice or comparable regulated outcomes. Whilst access to retailer choice in and of itself does not guarantee improved customer outcomes (given the range of regulated solutions also available to policy makers), we would nonetheless encourage close consideration from regulatory bodies to ensure customers connected to an embedded network are ‘no worse off’ relative to normal distribution-connected customers. Where embedded network customers are not receiving adequate service levels, options could be explored which include regulated pricing, similar to a regulated default market offer type construct.

The NSW DNSPs consider that all regulatory reform options should be considered as part of this Inquiry – including those arising out of the AEMC and Victorian Government reviews,[3] and the approach taken for water embedded networks in NSW. The expected costs and benefits of each option should be assessed by the Committee, having regard to the potential role of electricity embedded networks in the future energy system and the need to maintain appropriate regulatory safeguards.

At a minimum, the Committee should consider:

- Providing greater clarity around the regulatory treatment of embedded networks in NSW – including the circumstances in which an ‘electrical installation’ will require additional regulation and licensing given its size and scope, for example to align with the approach taken in NSW for private water networks (water embedded networks);
- Improving protections for customers connected to embedded networks, and potentially aligning these with protections available to distribution-connected customers;
- Enhancing safety regulations for embedded networks; and
- Improving visibility of operations and energy resources within embedded networks.

The NSW DNSPs’ key recommendations are:

1 Consider NSW-specific measures that may be required to address gaps in the consumer protection framework for customers served by embedded networks.

2 Clarify the circumstances and thresholds under which an embedded network (be it an ‘electrical installation’ or other category of network infrastructure) requires additional regulation and licensing in the form of conditions for consumer protections, reliability, guaranteed service levels, reporting and monitoring, technical, safety and/or price regulation, for example as occurs in South Australia.

3 Clarify that under the ESA, the mode of connection for an embedded network will be determined by the DNSP, having regard to network safety considerations.

4 Consider policy options identified in the AEMC and Victorian Government reviews, and apply a cost-benefit assessment of each one.

5 Consider measures to improve the visibility of resources within embedded networks. This information could be reported directly to the Australian Energy Market Operator (**AEMO**) by embedded network operators and accessible to all market participants.

6 Clarify what constitutes a ‘distribution system’ and what constitutes an ‘electrical installation’ for regulatory purposes.

[3] The State of Victoria Department of Environment, Land, Water and Planning, Embedded Networks Review, Final Recommendations Report, January 2022.

A potential regulatory and policy pathway forward for the Inquiry to consider could be to:

1 Retain the existing regulatory settings for traditional embedded networks such as small networks servicing caravan parks or retirement villages with fewer than 30 residential or small business customers.

2 Implement stronger regulation of larger embedded network operators through licensing. The AEMC and AER have recommended greater alignment of consumer protections for embedded network customers with those of standard supply customers. For NSW it may also include closely aligning safety and reliability obligations for large embedded networks with those applying to DNSPs and use the SA licensing approach and NSW approach for private water networks under the WatIC Act as a model.

3 Restriction or bans on certain types of embedded networks. For example, the Victorian Government has decided to ban new embedded networks. Instead NSW could determine that certain types of new embedded networks of a certain size or type should be restricted or banned. This could include banning residential or mixed use HV networks and limiting HV embedded networks to industrial sites only.

For embedded networks that fall within category 2 or 3 above we recommend that IPART license and regulate these categories of embedded network like wat they do for the embedded water network industry. Safety, technical and performance requirements for these categories of embedded networks should mirror the obligations imposed on DNSPs. This will help ensure that customers receive standardised protections, safety, technical and performance standards regardless of whether they are connected to an DNSP or an embedded network.

We would be happy to discuss any aspect of this submission with the Committee.

2 Introduction

The Committee has been asked to inquire into and report on embedded networks in NSW, with particular reference to:

- The current legal framework regulating embedded networks;
- Changes to the legal framework proposed by the AEMC in its 2019 review on updating the regulatory frameworks for embedded networks;
- The effect of embedded networks on NSW residents and businesses, including any health or safety concerns;
- Policy and legal solutions to address the effect of and concerns about embedded networks, including to address any gaps in the regulatory framework or safety concerns raised by NSW residents and businesses; and
- Any other related matters.

As the DNSPs for NSW, we are uniquely positioned to comment on these issues given our central role in the supply chain and interface with embedded networks.

Embedded networks play a complimentary role to distribution networks and are our customers as well. As such, our interest is to ensure that there is sufficient clarity in the regulatory treatment of embedded networks and appropriate protections for embedded network customers. This is particularly important at a time of transition in the energy market.

This review is timely, for two reasons:

1. The 'typical' embedded network use case has moved away from small scale retirement village or caravan park arrangements (micro embedded networks of fewer than 30 customers) and is now dominated by strata residential buildings, shopping centres and other large 'mixed use' developments, which are often large precincts comprising potentially hundreds or thousands of individual customers. The rapid growth in the scale of embedded networks far exceeds what was contemplated when current NSW legal frameworks were established. It continues to exceed those bounds with NSW DNSPs beginning to see new embedded network connection applications comprising HV connections, multiple buildings and thousands of customers.
2. The energy market transition is now gathering pace, with implications for the role of networks including licensed networks and embedded networks.

Each of these points is discussed briefly below.

2.1 Expansion in embedded network types combined with rapid growth in the number and scale of embedded networks

The regulatory frameworks governing embedded networks – including frameworks for exemption from registration and other regulatory obligations – were established at a time when embedded networks were mostly limited to caravan parks, residential parks and retirement villages of 30 customers of less. At the time, the embedded network regulatory framework was broadly considered fit for purpose in addressing a specific defined need for the relatively few embedded networks operating in NSW at that time.

The embedded network types later grew to include some strata apartment buildings as embedded networks became an increasingly common method for developers to build medium- to high-density dwellings.

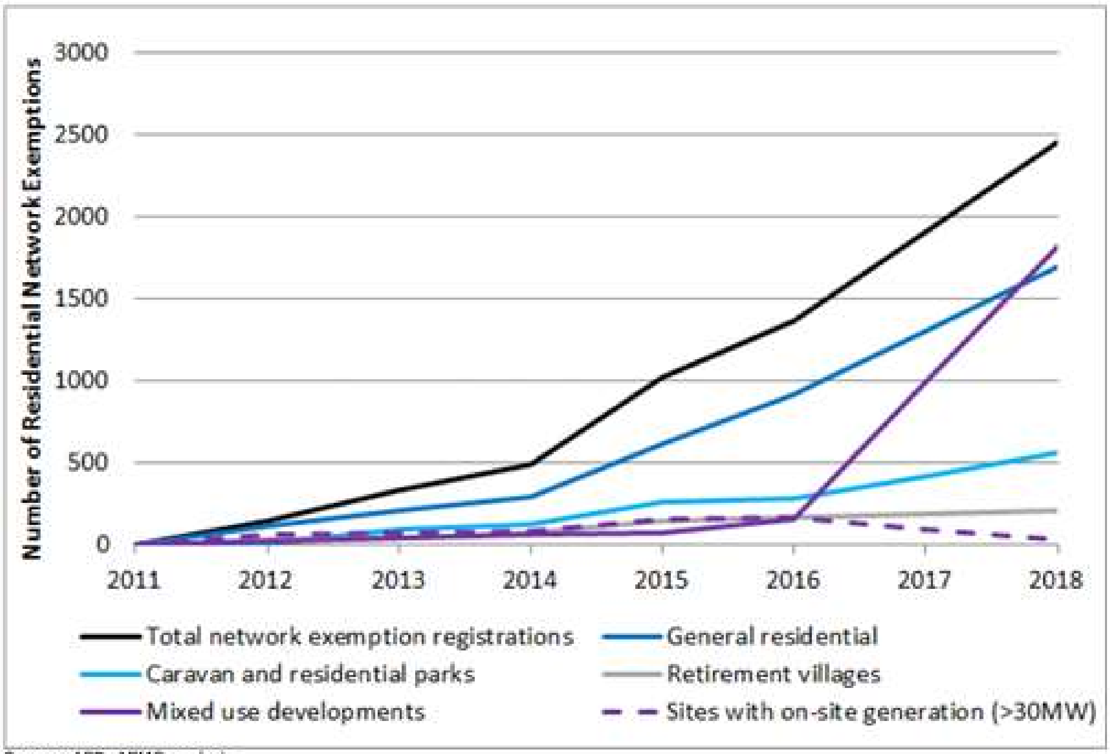
Over the past decade, there has been a rapid increase in the number of embedded networks. Between 2014 and 2018, the number of residential network exemptions recorded by the AER more than quadrupled – from around 500 to around 2,500 – across the NEM (**see Figure 1 below**).[4]

This growth was initially driven by general residential developments, such as new apartment buildings. However, over the past five years there has been dramatic growth in the number of network exemptions for 'mixed use developments'. These 'mixed use' developments are often large precincts combining residential, shopping centres, commercial and community usage, in some cases with significant generation and storage behind the parent meter. Prior to 2016, there were very few of these 'mixed use' developments holding network exemptions. However, 'mixed use developments' were the largest category of network exemptions by 2018, overtaking general residential developments and far outstripping the traditional small-scale caravan park, residential park and retirement village embedded network types.

Of note, pre-2016 the mixed use developments were typically for commercial use only (i.e. shopping centre and small business sites or mixed use industrial sites) that did not include residential customers. These types of customers typically have greater agency to engage with embedded networks than a residential customer and can advocate for more beneficial outcomes.

For example, a large supermarket chain could have sufficient economies of scale to justify investing in the metering infrastructure required to leave an embedded network. Whereas an equivalent cost on a residential customer would be prohibitive.

Figure 1: Residential network exemptions

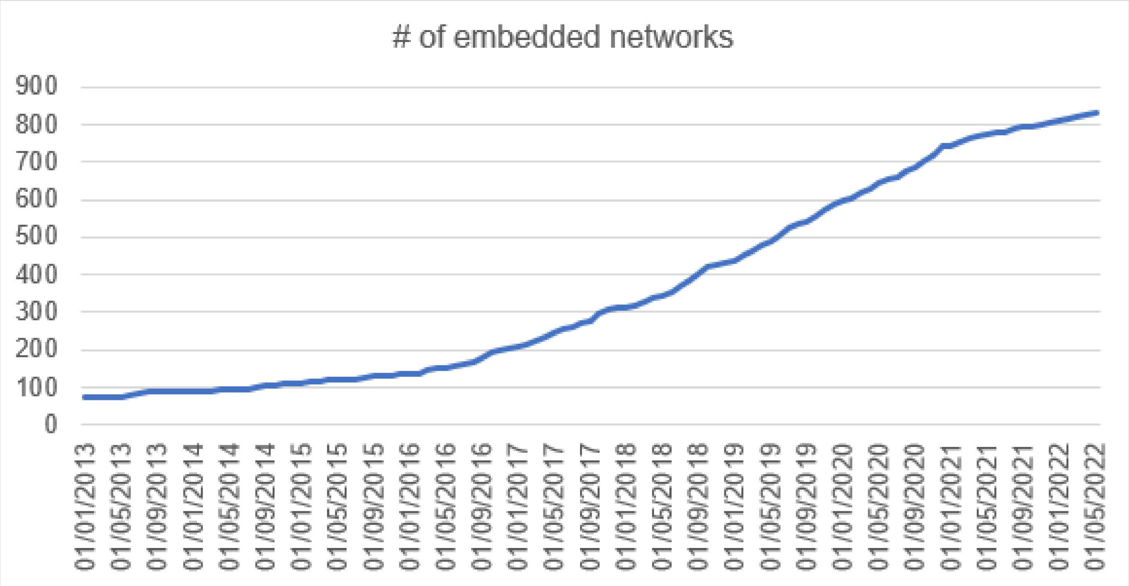


Source: AER, AEMC analysis.

[4] AEMC 2019 Final Report, ii.

The NSW DNSPs have a similar growth trajectory within their distribution areas. For example, Ausgrid has seen the number of embedded networks in its distribution area grow 8-fold from around 100 in 2015 to around 800 today (**see Figure 2 below**).

Figure 2: Number of embedded networks in Ausgrid distribution area showing a stable number of embedded networks that increase 8-fold in under 5 years



In the same time period, the number of embedded networks on the Essential Energy network service area has rapidly grown at an annualised rate of approximately 14% and as at June 2022 numbers 72 embedded networks.

Due to limited visibility of embedded network operations in NSW as there is no NSW registration or licensing requirement for them, NSW DNSPs are unable to identify the specific types of embedded networks that have been driving this growth.

2.2 The energy market transition

The energy market transition is rapidly gathering pace. Various factors are reshaping the energy supply chain, including developments in technology, shifting community sentiment around climate action and ageing of legacy infrastructure.

Of particular importance to this review is the growth of distributed energy resources (**DER**) and the changing role of networks. DER include solar PV installations, small-scale battery storage, electric vehicles and smart devices offering demand response capability. DER growth means that our role as DNSPs is changing. DNSPs will increasingly be used as platforms to connect these distributed resources, rather than just a conduit for delivery of centralised generation.

From a DNSP perspective, the market transition creates a need to more closely monitor the network and its capacity to accommodate distributed resources in our role as distribution system operators. With greater visibility of distributed energy resources, DNSPs can proactively plan investment needed to support the additional DER on the network and capacity needed to support them.

From a customer perspective, the transition potentially creates many more opportunities for participation in the energy market – including opportunities to produce, store and consume energy and to participate in demand response. However, a customer's ability to actively engage with new energy services depends on having access to information and markets for these services. There is also a need to ensure that customer protection frameworks keep pace with the expansion of markets for new energy services.

3 Gaps in the current legal framework for embedded networks

In the AEMC's 2017 Final Report, the AEMC found that the regulatory framework for embedded networks was no longer fit for purpose in the face of the change in embedded network use case, combined with the growth in the number of embedded networks.[5] The AER has subsequently agreed with this finding noting that 'embedded networks pose potential harms to consumers given the way they are set up' and 'are likely to be exacerbated in a post-2025 market, whereby consumers in embedded networks are unlikely to have access to or control over how they access new technologies and service models.[6]

NSW DNSPs agree with these observations. At a national level, the rules relating to consumer protection, network price regulation and retail contestability have failed to keep pace with the change in embedded network types and scale, combined with the rapid growth in the number of embedded networks. At the state level, there is a lack of clarity around the regulatory treatment of large-scale embedded networks in particular, and significant gaps in the application of safety regulations.

3.1 Gaps in the consumer protection framework for customers served by embedded networks

A number of protections apply to customers that are directly connected to a distribution system by a DNSP. These include protections around reliability and safety under the ESA and DNSP licences, as well as protections that must be afforded by DNSPs to their customers under the National Energy Customer Framework.

Some of the key protections for distribution-connected customers include:

- Network reliability standards and customer service standards imposed under DNSP licences;[7]
- Payments to customers when a DNSP fails to comply with reliability or service standards under guaranteed service level schemes;[8]
- Regulatory oversight of network performance – including requirements to report regularly to IPART on performance against reliability standards;[9]
- Obligations to provide connection services;[10]
- Deemed standard connection contracts governing the relationship between DNSPs and customers;[11]
- Requirements to publish certain information relating to connection services and the customer's rights and obligations;[12]
- Restrictions around interruption of supply, and requirements to notify customers in advance of any planned interruption;
- Strict rules around disconnection of supply;
- Additional protections for customers relying on life support equipment; and
- Retailer of last resort (**RoLR**) arrangements.

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[5] See, e.g. AEMC 2017 Final Report, i and iv.
[6] AER, Retailer authorisation and exemption review: Issues Paper, April 2022, 31.
[7] For example: Ausgrid distributor licence issued under the ESA, cls 4, 5 and 6.
[8] For example: Ausgrid distributor licence issued under the ESA, cl 6.
[9] For example: Ausgrid distributor licence issued under the ESA, cl 7.
[10] NERR, s 79(4); NERL, s 66.
[11] NERR, s 81; NERL s 71(1).
[12] NERR, r 80.

Most of these protections do not apply to customers within embedded networks. In particular, these customers do not have any assurance around the reliability or performance of the embedded network, nor is there any regulatory scheme for compensation in the event or poor network performance.

Further, rules relating to service interruptions, including requirements to notify customers of a planned interruption do not apply to embedded network operators. Indeed, many embedded network customers are not even aware that they are an embedded network customer. This means that they are not able to make informed choices about their energy usage or advocate for their choices.

A number of these gaps in the customer protection framework were identified in the AEMC 2019 Final Report. The AEMC observed:[13]

> *While embedded network customers do benefit from some consumer protections imposed by the AER as conditions of exempting embedded network operators from registering as a network service provider and being authorised as a retailer, these consumer protections are more limited than those applicable for standard supply arrangement customers. Consumer protection gaps exist in areas such as de-energisation and re-energisation obligations, obligations to provide connection services, life support arrangements, information provision and retailer of last resort arrangements. There are no reliability standards or guaranteed service level payments for outages that apply to customers in embedded networks, as well as gaps in safety obligations in some jurisdictions. It is also more difficult for embedded network customers in some jurisdictions to access concessions and ombudsmen schemes.*

The AEMC also noted that the application of safety rules to embedded networks in some jurisdictions was unclear.[14] The issue of safety regulations is discussed further below.

The AEMC recommended changes to the National Energy Retail Law (**NERL**) and National Energy Retail Rules (**NERR**) to address some of these gaps. The AEMC's recommendations included changes to the NERL and NERR that would align the consumer protections for embedded network customers with those of standard supply customers. This reflects the position of the AEMC that embedded networks should be included in the national framework and that the existing protections could be applied without alteration. This position was adopted by the AEMC in the AEMC 2017 Final Report, and further reinforced in the final recommendations provided in the AEMC 2019 Final Report.[15] However the recommendations have not yet been enacted in legislation by Energy Ministers and we understand that there are no current plans to do so.

NSW DNSPs generally support changes to the NERL and NERR to better align protections for embedded network customers with those of standard supply customers. However, we note that the gaps in the customer protection framework are unlikely to be fully addressed through amendments to the NERL and NERR, as recommended by the AEMC given that a number of the key protection mechanisms for consumers exist in state legislation and/or instruments issued under state legislation (e.g. service standards applicable under DNSP licences).

The Energy & Water Ombudsman NSW (**EWON**) reports that it has received numerous complaints from embedded network customers in recent years, highlighting gaps in the customer protection framework.[16] EWON points to confusion among small business and residential customers regarding the regulatory framework, as well as inconsistencies in protections available. EWON considers that the growth of the embedded network industry has caused the regulatory system to 'become unwieldly'. For example, EWON notes that the ESA gives all residential and small business customers the right to complain to EWON, but because operators are not required to be EWON members, EWON's dispute

[13] AEMC 2019 Final Report, iii at [18].

[14] AEMC 2019 Final Report, v.

[15] see AEMC 2019 Final Report, chapter 4.

[16] See: https://www.ewon.com.au/page/publications-and-submissions/reports/spotlight-on/embedded-networks.

resolution powers are limited to, at best, negotiating an outcome if the operator is open to engaging with EWON.

We would encourage the Committee to consider additional NSW-specific measures that may be required to supplement any changes to the NERL and NERR. Possible NSW-specific measures to address gaps in the customer protection framework are discussed in section 4 below.

3.2 Lack of clarity around classification of embedded networks for regulatory purposes

The ESA and Service & Installation Rules currently distinguish between 'distribution systems' and 'electrical installations'. The Service & Installation Rules also refer to the concept of a 'customer installation' which has the same meaning as an 'electrical installation'.

The distinction between a 'distribution system' and an 'electrical installation' is critical because the ESA confers substantial powers and imposes significant obligations on 'network operators' (including operators of distribution systems (DNSPs)) and exempts them from various burdens when installing, operating and carrying out works. This is particularly relevant for safety regulations, public road consents, property rights, access rights and obtaining planning approvals. The same rights and obligations do not apply to owners and operators of electrical installations.

Under the ESA, a key point of delineation between a 'distribution system' and an 'electrical installation' is a 'connection point'. The ESA defines a 'distribution system' as the electricity power lines, structures and associated equipment used to convey and control the conveyance of electricity up to the connection point for the premises of a wholesale or retail customer.[17] An 'electrical installation' is defined as the wiring and electrical equipment used to convey and control the conveyance of electricity 'within premises to which electricity is supplied from a distribution system' – in other words, the equipment beyond the connection point.

NSW DNSPs understand that, under these definitions, a traditional embedded network (e.g. a caravan park or retirement village network) would not be a 'distribution system' and would likely be classified as an 'electrical installation'. This means that an operator of a small scale embedded network of say 30 residential customers or less in a caravan park or retirement village would not be subject to the same regulatory obligations as a distribution system operator. Among other things, the operator of such a network would not require a distribution licence under the ESA.

However, the position with respect to larger embedded networks is less clear. In particular, it is unclear to what extent an 'electrical installation' may extend beyond a customer's premises and traverse public lands. To the extent that an embedded network does traverse public lands (including public roads), it is unclear whether it would meet the definition of an 'electrical installation'. In such cases, the embedded network would appear to be in a regulatory 'no man's land'.

One example of this lack of clarity is in the definition of a 'connection point'. The ESA definition of a 'distribution system' suggests that a connection point need not be on the customer's premises – the 'distribution system' is defined as extending up to the connection point for the premises, *whether or not the connection point is on the building or land comprising the premises*.[18] However, under the ESA definition of 'connection point', this point is to be determined by reference to the Service & Installation Rules. The Service & Installation Rules state that, except for HV connections, a connection point must be on 'relevant land', meaning 'land to which the customer concerned or the electrical installation owner has a legal right of access for the purpose of constructing or maintaining the electrical installation'.[19] Thus, the ESA appears to contemplate a connection point being outside

[17] *Electricity Supply Act 1995* (NSW), s 12A.

[18] *Electricity Supply Act 1995* (NSW), s 12A.

[19] Service and Installation Rules of New South Wales (October 2019), r 1.9.

the land comprising the customer's premises whereas the Service & Installation Rules suggest a 'customer installation' is in a particular place.

This is one example of where the regulatory framework is unclear on the classification and treatment of embedded networks. On one view of the ESA and Service & Installation Rules, a large embedded network traversing public land could be an 'electrical installation'. However, on another reading of the regulatory framework, some large embedded networks would sit in regulatory 'no man's land' – neither a 'distribution system' nor an 'electrical installation'.

There is also no distinction under the regulatory framework between traditional embedded networks which clearly satisfy the definition of an 'electrical installation' (e.g. a caravan park or retirement village network) and much larger embedded networks (e.g. multi-building residential strata developments). These larger embedded networks can have very different characteristics to traditional embedded networks – including their size, load / generation profiles, connection type and the extent to which they traverse public land.

To address these issues, the ESA is likely to require amendment to clarify what constitutes a 'distribution system' and what constitutes an 'electrical installation'. At a minimum, this is likely to mean adopting more consistent definitions of a 'connection point', 'distribution system', 'electrical installation' and 'customer installation'. To the extent that some embedded networks do not meet these amended definitions, a new category of network installation may need to be created to fill this regulatory gap.

The ESA should also clarify the circumstances and thresholds under which an embedded network (be it an 'electrical installation' or other category of network infrastructure) requires additional regulation and licensing in the form of conditions for consumer protections, reliability, guaranteed service levels, reporting and monitoring, technical, safety and/or price regulation. This may be, for example, where an embedded network reaches a particular size or extends beyond a customer's premises.

NSW DNSPs understand that in some other jurisdictions, additional regulation and/or licencing obligations apply to certain types of embedded network operators. For example, in South Australia, certain HV embedded networks will be classified as 'distribution networks' and therefore require a licence under Part 3 of the *Electricity Act 1996* (SA). As part of issuing a licence to a HV embedded network operator, the South Australian energy regulator (**ESCOSA**) may impose conditions including in relation to safety, connection policies and customer protection mechanisms. There is currently one licenced HV embedded network operator in South Australia – for the Tonsley Innovation District.

Similar issues have been addressed in the water sector in NSW through the imposition of licence requirements for embedded network operators. Under the WIC Act, water embedded network operators are now required to hold a licence, which may be subject to conditions. This may include conditions to ensure that the licensee has, and continues to have, the capacity (including technical, financial and organisational capacity) to carry out the activities authorised by the licence. IPART is responsible for monitoring compliance with these licence conditions.

The WIC Act separates out water embedded networks by scale and type. For example water embedded networks with fewer than 30 residential or small business customers connected to the network do not require a license from IPART. Water embedded networks with 30 or more residential or small business customers must have a licensed operator and a licensed retailer. This means the licensed operator is responsible for compliance with the license conditions for operating and maintaining the network allowing for more direct understanding of roles and responsibility for customer protections. It also allows a community to retain their embedded network licensed operator but change their licensed retailer.

This could work in NSW for electricity embedded networks by requiring the electricity embedded network operator arm to hold a license from IPART and the licensed retailer arm to hold a retailer authorisation from the AER. This promotes competition in the embedded network market, as customers within embedded networks could seek another authorised retailer to provide them with services as a collective or individually.

The WIC Act provisions also include obligations on water embedded networks to seek approval from IPART before it can be built from a design perspective and 'last resort' provisions in the event that a licensed operator fails. The operator licenses are not tied to specific infrastructure but instead the same licensee can be registered to multiple sites subject to IPART's approval.

We would encourage the Committee to consider options for clarifying the regulatory obligations that apply to embedded network operators under the ESA. This may include expanding licensing obligations to cover embedded network operators – similar to the approach adopted for HV embedded networks in South Australia and for water infrastructure in NSW under the WIC Act. This Act imposes obligations on water embedded networks to ensure that the operators are licensed and must provide an array of customer protections including splitting out the retail function from the network function. However, does not confer the same powers given to the public water utility for matters such as land acquisition and compliance. We support the Inquiry and IPART taking a similar approach for electrical embedded networks in NSW.

3.3 Application of safety regulations

As the number and scale of embedded networks grows, it is critical that the application of safety regulations is appropriately updated. DNSPs are subject to strict regulations to protect the safety of our workers and customers. NSW DNSPs recognise that safety regulations need not apply in the same way to small-scale embedded networks (e.g. traditional caravan park or retirement village models). However, certain larger embedded networks – including those that traverse public lands – may need to be subject to a stricter safety regime. A similar approach is used for water embedded networks in NSW as outlined in section 3.2.

Embedded networks are typically only subject to general workplace health and safety laws, which operate in limited contexts. These laws are not designed to comprehensively address the risks to members of the public created by electricity networks when operated in areas more accessible to the general public.

Of particular concern are HV embedded network installations. Recently, NSW DNSPs have seen developers start to apply for HV embedded network connections. This reflects how the scope of embedded networks have changed from caravan parks and retirement villages of fewer than 30 customers to increasingly larger embedded networks for 'mixed use' developments. HV installations carry a higher likelihood of catastrophic consequences from close contact when compared to low voltage (**LV**) installations. The risk to the general public increases when HV installations are situated in close proximity to residential developments.

Regrettably, some safety incidents have occurred at HV embedded network sites in other jurisdictions. For example, in South Australia, the only HV mixed use residential embedded network has a safety incident in 2019 resulting in two employees of the embedded network being hospitalised for severe electrical burns, and one being placed in an induced coma due to the extent of their burns.[20]

In section 4 we discuss policy options to address the safety risks posed by larger embedded networks. These include applying stricter safety regulation to these larger embedded networks and/or restricting the size and scope of embedded networks that can be operated without meeting higher safety standards.

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[20] 'Two suffer burns in accident at Tonsley precinct', *The Advertiser*, 7 February 2019.

3.4 Determining the appropriate mode of connection to the distribution system

A related issue arises in relation to the mode of connection to the distribution system. Historically, smaller scale embedded networks (e.g. traditional caravan park or retirement village models) have been accommodated through LV connections to the distribution system. However, as noted above, NSW DNSPs have started to see developers request HV embedded network connections, which NSW DNSPs reject and request one or more LV connections unless there are extenuating circumstances.

In some cases there will be a choice to be made between a single HV connection or multiple LV connections for a large development. The choice between these options will have implications for network safety.

NSW DNSPs consider that, in such cases, the DNSP (i.e. distributor) should have discretion to decide on the appropriate mode of connection, having regard to safety considerations.

We consider this is currently reasonably clear on the face of the ESA and Service & Installation Rules. In particular, the following sections of the ESA provide a broad discretion to determine suitability of an electricity connection:

- Section 26(2) states that the type, construction and route of a service line and its point of connection are to be determined by the distributor;
- Section 26(3) states that a distributor may require premises to be provided with more than one point of connection if the distributor considers it necessary to avoid interference with the supply of electricity to or from any other premises; and
- Section 24(2) states that a distributor may refuse to provide a customer connection service to a person who fails to comply with a requirement under Division 4 of the ESA (which includes section 26 of the ESA).

Moreover, rule 7.4.3 of the Service & Installation Rules expressly provides that a distributor will nominate the supply voltage:

> *The electricity distributor will nominate the supply voltage during negotiations. Consult with the electricity distributor for its likely range of voltage conditions and install suitable equipment accordingly.*

Although we consider this to be reasonably clear under the current ESA and Service & Installation Rules, there appears to be some uncertainty among embedded network operators regarding their ability to request an HV connection. We would therefore recommend clarifying that under the ESA, the mode of connection for an embedded network will be determined by the licensed DNSP having regard to network safety considerations.

3.5 Limited visibility

In order to support efficient dimensioning and maintenance of distribution systems, it is important for DNSPs to have visibility of load, generation and storage resources connected to their networks. This is important both to maximise the efficiency of DER on their networks and to support the safety, security and reliability of their distribution system.

There has been growing recognition of the need for visibility of DER in recent years, as more generation and storage moves behind the meter. For example, in 2018 the AEMC (at the request of the COAG Energy Council) made a rule for AEMO to establish a register of distributed energy resources in the national electricity market, including small scale battery storage systems and rooftop solar.[21] The register is intended to give DNSPs and AEMO visibility over where distributed energy resources are connected to assist in planning and operating the power system as it transforms.

While important steps have been taken to improve visibility of DER, DNSPs continue to have limited visibility of operations and energy resources within embedded networks. Again, this is of greater concern in relation to larger embedded networks that are likely to have larger amounts of generation and storage resources connected.

As one example of this lack of visibility, EWON notes that there continues to be limited information available on the number of customers connected to embedded networks. EWON recommends that the AER be more proactive in collecting data regarding the number of customers covered by network and retail exemptions and ensure these numbers are reported publicly on a regular basis – or change the public register so that customer numbers are included in the details on a registered exemption.[22]

NSW DNSPs would support improving the visibility of both customer numbers and distributed energy resources within embedded networks. This information could be reported directly to AEMO by embedded network operators and accessible to all market participants.

3.6 Unfair sharing of fixed network costs

The rules that apply to the determination of network tariffs can restrict the ability of DNSPs to fairly apportion fixed network costs between embedded network customers and standard supply customers. This issue has not been particularly significant with relatively small embedded networks, but it becomes more significant as more customers are connected to an embedded network.

The regulatory framework for determining network tariffs is fundamentally designed to support 'postage stamp' or 'uniform' pricing. Under 'postage stamp' pricing all customers of a certain type (e.g. residential) pay the same share of fixed network costs regardless of the network assets used to supply the individual. Specifically, the National Electricity Rules (**NER**) require that tariff classes be constituted with regard to the need to group customers together on an economically efficient basis and to avoid unnecessary transaction costs. Customers with similar connection and usage profiles must also be treated on an equal basis.[23]

Typically, a DNSP's fixed costs will be shared equally among all customer connection points within a tariff class. For an embedded network with a single parent connection point and multiple customers behind the parent connection point, the total amount of fixed costs apportioned to that connection point will be the same as for a connection point serving a single customer. This means that for an embedded network with multiple customers, the contribution of each customer to fixed network costs will be much smaller than the contribution of a single standard supply customer. In effect, standard supply customers will cross-subsidise those customers connected to embedded networks.

The scale of the cross-subsidy increases significantly as the size of an embedded network grows.

This gives rise to both equity and efficiency concerns. From an equity perspective, standard supply customers will be paying more in fixed network costs simply because they are not connected to an embedded network. This results in other customers paying a higher than otherwise proportion of the fixed-shared costs of the network, to the benefit of the embedded network customers (or often the embedded network owner). As a shared community asset, this is often viewed as unfair by our customers.

[21] *National Electricity Amendment (Register of Distributed Energy Resources) Rule 2018*. See: https://www.aemc.gov.au/rule-changes/register-of-distributed-energy-resources#:~:text=as%20it%20transforms.-,On%2013%20September%202018%20the%20AEMC%20made%20a%20final%20rule,storage%20systems%20and%20rooftop%20solar.

[22] See: https://www.ewon.com.au/page/publications-and-submissions/reports/spotlight-on/embedded-networks.

[23] See NER, rr 6.18.3(d) and 6.18.4(a)(2).

From an efficiency perspective, the cross-subsidy could lead to development of embedded networks purely on the basis of an artificial cost advantage – and in circumstances where it would not otherwise be efficient. An embedded network should be utilised where it is the most practicable model (e.g. caravan parks) and offers a cost-service quality mix that is more attractive to customers, rather than implemented to exploit pricing inefficiencies or inconsistent regulations and regulatory gaps.

NSW DNSPs acknowledge that tariff structure issues are likely to be best addressed through the NER and AER approval of tariff structure statements.

However, this again illustrates the strain on regulatory arrangements posed by rapid growth in the number and size of embedded networks.

3.7 Embedded network customers not receiving access to retailer choice or a comparable regulated alternative

The AEMC reviews and the Victorian Government review each raised concerns that embedded network customers may not have access to retailer choice.[24] This is at least partly due to inadequate regulation of embedded network operators, and retailers needing to accommodate unregulated bespoke arrangements for individual embedded networks.

Currently, bespoke embedded network tariffs and embedded network arrangements require retailers to operate manual processes to manage transactions with large numbers of exempt network service providers. These network tariff structures and billing arrangements make it costly for NEM retailers to serve embedded network customers because they must adapt product offerings and implement manual processes to manage transactions with large numbers of exempt network service providers. In the AEMC 2017 Final Report, the AEMC found that the costs and risks related to network billing act to deter NEM retailers from serving embedded customers.

Whilst access to retailer choice in and of itself does not guarantee improved customer outcomes given the range of regulated solutions that are also available to policy makers, we would nonetheless encourage close consideration from regulatory bodies as to ensure customers are 'no worse off' relative to a normal distribution connected customers. Where embedded network customers are not receiving adequate service levels, options could be explored which include regulated pricing, similar to a regulated default market offer type construct.

In its recent review of retailer authorisation and exemption arrangements the AER similarly observes that, in practice, consumers in an embedded network often have limited retailer choice.[25] This is due to the way the network may have been wired or metered, or because energy retailers may not want to sell to a consumer inside an embedded network. The AER notes that conversions into embedded networks can lead to customer harm if occupants are not properly informed of the limitations imposed on their access to retail competition and alternative supply options. The AER identifies this as a key challenge for the energy sector transformation, as it means that customers within embedded networks may face barriers to engaging with new energy services. This challenge will become more acute if embedded networks are allowed to become larger and more numerous.

[24] AEMC 2017 Final Report, 25; AEMC 2019 Final Report, i-v; The State of Victoria Department of Environment, Land, Water and Planning, Embedded Networks Review, Final Recommendations Report, January 2022, 42-46, 75-76.

[25] AER, Retailer authorisation and exemption review: Issues Paper, April 2022, 31.

4 Policy solutions

The AEMC and Victorian Government reviews identified various policy solutions to address the regulatory challenges raised by the rapid growth of embedded networks.

Broadly, these policy solutions fall into three categories:

1. **Status quo**. It is recognised that current regulatory settings may be appropriate in some cases. For example, existing regulatory settings may be largely appropriate for traditional embedded networks such as small networks servicing caravan parks or retirement villages with fewer than 30 residential or small business customers.
2. **Stronger regulation of embedded network operators – particularly for large embedded networks and those traversing public land**. In particular, the AEMC and AER have recommended greater alignment of consumer protections for embedded network customers with those of standard supply customers. It may also be appropriate to more closely align safety and reliability obligations for large embedded networks with those applying to DNSPs and use the SA licensing approach and NSW approach for private water networks under the WIC Act as a model.
3. **Restriction or bans on certain types of embedded networks**. In some cases, it may be necessary to impose restrictions or bans on certain types of embedded networks. Notably, the Victorian Government has decided to ban new embedded networks. Alternatively, certain types of new embedded networks such as those of a certain size or type may be restricted or banned. This could include banning residential or mixed use HV networks and limiting HV embedded networks to industrial sites only.

For embedded networks that fall within category 2 or 3 above we recommend that IPART license and regulate these categories of embedded network like wat they do for the embedded water network industry. Safety, technical and performance requirements for these categories of embedded networks should mirror the obligations imposed on DNSPs. This will help ensure that customers receive standardised protections, safety, technical and performance standards regardless of whether they are connected to an DNSP or an embedded network.

Some brief commentary on the policy options coming out of the AEMC and Victorian reviews is set out in **Appendix A**.

We would encourage the Committee to consider all policy options and apply a cost-benefit analysis to each option for consultation. This assessment should have regard to both the potential role of embedded networks in the future energy system and the need to maintain appropriate regulatory safeguards and customer protections.

Appendix A: Recommendations from AEMC and Victorian Government reviews

AEMC recommendations

(a) Registration and exemption

The AEMC has recommended that, rather than requiring exemptions from normal registration requirements, additional categories of registration be created for embedded network operators and retailers.

The AEMC proposed that two new roles be created:

1 Embedded Network Service Providers (**ENSPs**), which will be required to **register with AEMO** and will be subject to many of the existing regulatory requirements placed on DNSPs; and

2 Off-market retailers, which will be required to obtain an **authorisation from the AER** and will be subject to most requirements that existing authorised retailers are subject to, including being subject to the NERL compliance framework applicable to NEM retailers.

(b) Consumer protections in the NERL and NERR

Under the AEMC recommendations, customers in new embedded networks will be retail customers, supplied by either an authorised on-market NEM retailer or an authorised off-market retailer. Where customers are supplied by an authorised off-market retailer, almost all the existing consumer protections under the NERL and NERR should apply.

New Retailer of Last Resort (**RoLR**) arrangements would also apply in embedded networks where the retailer at the parent connection point would become the RoLR in the event of the failure of an off-market retailer.

(c) Market and system integration

The AEMC has recommended extending the application of the NER metering framework, noting that this is key to providing customers in embedded networks improved access to retail choice and important consumer protections relating to metering data.

The AEMC's specific recommendations in this respect include:

- <u>Metering framework:</u> apply the metering framework set out in Chapter 7 of the NER to embedded networks by requiring the off-market retailer to appoint a metering coordinator (**MC**), other than where a large customer at an off-market child connection point has appointed their own metering coordinator. In turn, as required under Chapter 7 of the NER, the metering coordinator will be required to appoint a metering provider (**MP**) and a metering data provider (**MDP**) who will have the same responsibilities at an off-market child connection point as they would have in relation to a standard supply customer's connection point or an on-market child connection point.
- <u>Market interface:</u> require ENSPs to apply to AEMO for national metering identifiers (**NMIs**) for all child connection points; register the NMI for connection points with AEMO through Market Settlement and Transfer Solutions (**MSATS**); and maintain information in the metering register. This will allow off-market child connection points to be 'discoverable'.
- <u>B2B:</u> ENSPs and off-market retailers should become B2B parties and be permitted to use B2B communications if they acquire accreditation with AEMO.

(d) Network billing

The AEMC recommended that, for 'on market' customers of ENPSs, ENSPs:

- Be required to set network charges at a level no greater than the amount that the customer would have paid had it been directly connected to the LNSP's distribution network to which the embedded network is connected (the 'shadow price');
- Be required to use standardised processes and data formats to bill retailers these charges for on-market customers; and
- Will not be permitted to charge residential customers for any infrastructure costs associated with their internal embedded network. If mutually agreed, an ENSP may levy charges from large customers and/or large corporate entities for the internal network.

(e) Connection of retail customers

Obligations would be imposed on ENSPs to provide customer connection services under the NERL and Chapter 5A of the NER in a similar manner to DNSPs. However, unlike for DNSPs, it is proposed that a single connection policy covering all ENSPs will be established by the AER. There will be obligations in place that require connection charges levied by ENSP to be reasonable and provisions that allow any disputes raised in this regard to be resolved by the AER.

(f) Connection of registered participants

While the ENSP will be required to meet certain obligations in establishing a connection agreement, the ENSP is not under any obligation to agree to connect a registered participant. The Commission considers there may be valid reasons why an ENSP may not wish to connect a registered participant, such as lack of network capacity or site characteristics.

Embedded networks that connect a registered embedded generator will not be eligible for a network exemption. ENSPs will be required to negotiate performance standards as part of establishing a connection agreement with a registered participant. AEMO will have an advisory role on the acceptability of some negotiated access standards. The ENSP will also have an obligation under Chapter 5 of the NER to consult the relevant DNSP prior to entering into or modifying a connection agreement with a registered participant. The ENSP and relevant DNSP will both be included in the information flow under the compliance framework for performance standards under Chapter 4 of the NER.

(g) Jurisdictional regulations

The AEMC also observes that to provide a complete set of consumer protection and safety regulations to consumers in embedded networks, there are state and territory functions that need to be considered.

Relevant state and territory regulations include:

- Network reliability protections including guaranteed service level schemes (as noted above, these apply as conditions of DNSP licences in NSW);
- Safety requirements and monitoring regimes; and
- Technical regulation, such as equipment and performance standards.

Given the importance of network reliability in particular, the AEMC has given consideration as to how jurisdictional frameworks might be amended to extend protections for existing DNSP customers to those of ENSPs. This could involve amending existing jurisdictional regulations for DNSPs in order to capture customers at child connection points, as opposed to treating parent connection points as only being single customers, and extending guaranteed service level schemes to cover ENSPs.

Recommendations of the Victorian Government review

On 14 January 2022, the final report in the Victorian Government's Embedded Networks Review was published. This report followed on from the Government's decision to ban new embedded networks, and included a series of recommendations relating to the implementation of the ban. Some of the key recommendations from this review are set out below.

Number	Recommendation	Rationale for recommendation
1	Implementation of ban on new embedded networks	• The Victorian Government's commitment to ban embedded networks in new apartment buildings (allowing limited exemptions) should be implemented via amendments to the General Exemption Order (**GEO**). • Changes to the GEO should include a new renewable energy condition requiring at least 50% of electricity at the site to be met from on-site renewable sources.
2	Additional conditions for legacy (existing) local energy networks	• Stakeholders broadly supported this recommendation to ensure that operators selling electricity in local networks are adequately equipped to provide this essential service.
3	Introducing licensing framework for new local energy networks	• Stakeholders noted that the introduction of licensing would support the long term effect of the embedded networks ban and eliminate disparities between conditions and regulatory obligations placed on licensed energy retailers and exempt sellers.
4	Applying the Local Energy Service (**LES**) licensing framework to legacy (existing) local energy networks	• Stakeholders were generally pleased at this recommendation ensuring all sites being brought under the new framework to ensure equity and fairness for all Victorian energy consumers.
5	Reviewing the broader licensing and exemptions framework	• Any review should also consider whether it is appropriate to extend these reforms to small business customers and the feasibility of extending the LES licensing regime to other exempt entities, such as commercial sites, industrial sites and business parks.
6	Enhancing consumer protections	• All local energy network customers (e.g. social housing, retirement villages and residential parks) should have access to customer protections which are equal or equivalent to those provided to on-market customers. • Aligning consumer access to rebates and concessions for both embedded network customers and on-market customers.
7	Enhancing the Essential Services	• Strengthen compliance, monitoring and enforcement of the state energy regulator to enforce an exempt person's compliance with

Number	Recommendation	Rationale for recommendation
	Commission's (**ESC**) enforcement powers and information about local energy network	exemption conditions. • Strengthen information gathering powers.
8 and 9	Access to competitive retail offers	• Embedded network customers noted that access to competitive retail offers and being able to exercise their choice of retailer is a consumer right. • Greater sense of control for embedded network customers to improve ongoing relationship with provider. • Customers should not be required to pay for the infrastructure upgrade and it should fall to embedded network operators. • Address lack of business-to-business arrangements and a dearth of suitable energy-only plans offered by on-market retailers for embedded network sites.
10	Improved information disclosure	• Commercial agreements and decisions around the ownership of an embedded network's infrastructure and assets are made long before new lot owners and tenants take possession or occupy the site. As a result, prospective customers have very little, if any, influence over the design (including technology offerings) and operation of the embedded network. • A lot owner and occupant's understanding of the commercial contracts and ownership arrangements associated with the embedded network infrastructure and assets is also often quite limited, making it difficult for them to negotiate a better deal. • In relation to information disclosure, prospective purchasers are at an even greater disadvantage than tenants, because there is no obligation to disclose information relating to an embedded network to a prospective purchaser.
11 and 12	Planning and building requirements (amendments to Victorian building and planning legislation)	• Panel uncovered a range of issues that are having a detrimental effect on owners and occupants in apartment buildings, some of which lie outside of the Panel's remit. One of the most significant issues is that embedded networks are often established in new residential sites with very little regard for the likely impact for consumers.
13	Bundled services and other fees and charges	• Some services that are common in apartment buildings, such as bulk hot-water, bulk heating/cooling, unmetered gas cooktops and solar PV, are often bundled together with electricity embedded networks and are provided by the same third-party service provider. As a result, customers may be unable to decipher how much they are paying for each service.

Number	Recommendation	Rationale for recommendation
14	Mitigating disruption of supply due to failure of a local energy network	• As an essential service, disruption to electricity and other bundled service supply should be minimised to the fullest extent possible, regardless of where people live.
15	Giving voice to energy consumers in local energy networks	• Reflects the ESC's approach in its published vulnerability strategy, *Getting to Fair: Breaking Down Barriers to Essential Services.* • The purpose of the strategy is to ensure the ESC is supporting consumers who are at risk or experiencing vulnerability to access essential services, noting that legislation requires the Commission to consider vulnerable and low-income consumers in its decision-making.
16	Transitional arrangements	• It is vital that affected stakeholders have a clear understanding of the key changes, including their rights and obligations as well as the sequencing and timelines for the reforms coming into effect.

Tariff Structure Statement Compliance Document

January 2023

Ausgrid

Contents

1. Introduction and overview

The National Electricity Rules (**NER**) specify that Ausgrid's Tariff Structure Statement (**TSS**) must comply with the pricing principles for direct control services. The network pricing objective, as specified within the NER, requires that our tariff charges should reflect our efficient costs of providing these services to customers using these tariffs. The efficient costs of a distributor are determined by the Australian Energy Regulator (**AER**) during the five-year regulatory reset process.

Our TSS demonstrates how Ausgrid's network tariffs for the 2024-29 period will comply with the requirements of the NER, the AER's Export Tariff Guidelines and the AER's final decision for the 2024-29 period. For more information on the considerations that Ausgrid applied when designing the tariff structures for the 2024-29 period, see the associated detail in our TSS Explanatory Statement.

For ease of reference we have included a compliance check list as an appendix to this document.

2. List of tariff classes and allocations

This chapter sets out the tariff classes into which retail customers for direct control services will be divided during the 2024-29 period.[1] It also sets out the principles governing the assignment or re-assignment of retail customers to tariff classes, including the process for assessment and review of these tariff class assignments.[2]

2.1 Tariff classes

Part of the process of tariff design is to establish the tariff classes into which we will assign customers. Each of the proposed tariff classes contain at least one tariff.

We define tariff classes on the basis of several attributes, principally, the nature of the customer's connection to our network and whether or not their supply is metered.

Table 1 sets out our standard control tariff classes for the 2024-29 period. These are the same tariff classes we adopted in the 2019-24 period.

Table 1 Our standard control tariff classes

Tariff class	Customer type	Connection characteristics
Low Voltage	Residential Small to medium businesses Larger commercial and light industrial	Any separately metered low voltage (230V or 400V) connection, as measured at the metering point
High Voltage	Industrial	Any high voltage (typically 11kV) connection, as measured at the metering point
Sub-transmission	Industrial	Any sub-transmission (33kV, 66kV or 132kV) connection, as measured at the metering point
Unmetered	Unmetered (e.g. public lighting)	Any unmetered low voltage connected, as defined by Ausgrid in consultation with AEMO[3]
Transmission-connected	Industrial	Any transmission network connection

In addition, Ausgrid also proposes to adopt the following three tariff classes for alternative control services:

- Public lighting;
- Type 5 and 6 metering; and

[1] NER, clause 6.18.1A(a)(1).

[2] NER, clauses 6.18.3 and 6.18.4.

[3] NER, clause S7.4.3 (item 5) sets out eligibility requirements for Type 7 unmetered connections

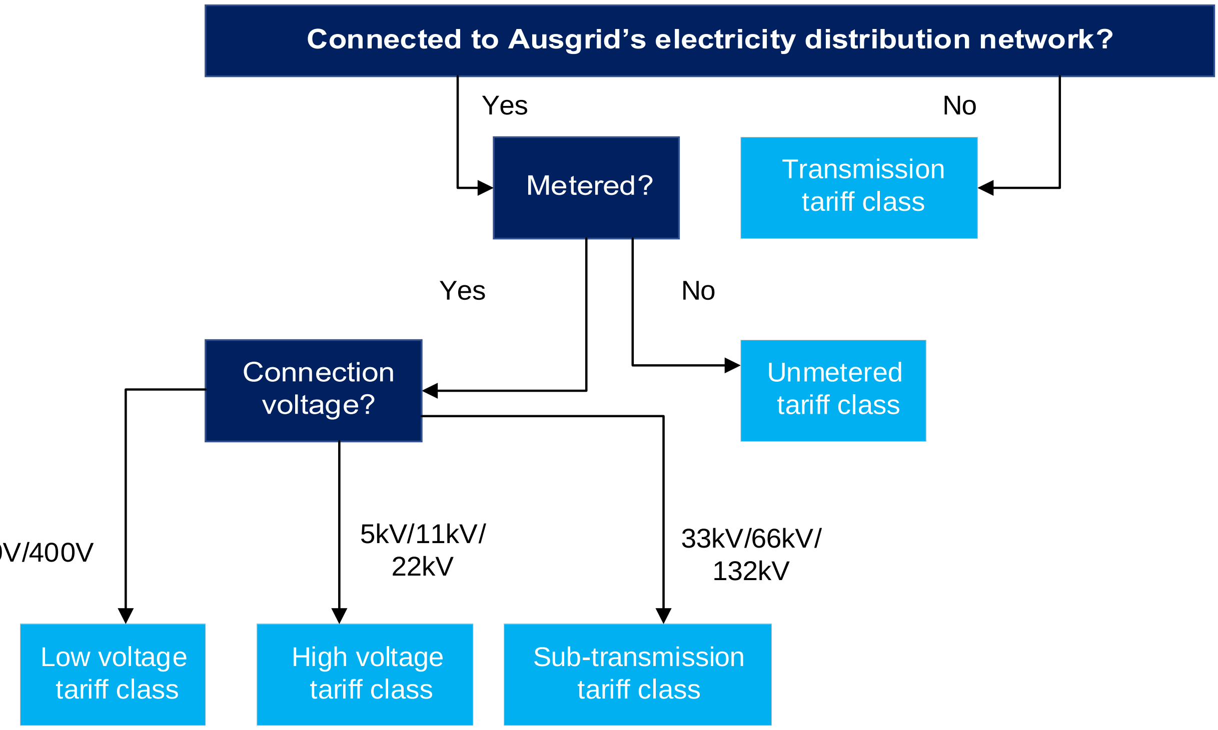
• Ancillary network services.

Alternative network control services are discussed more in Chapter 7.

2.2 Assignment of customers to tariff classes

Our policies and procedures for assigning customers to standard control tariff classes is summarised in Figure 1 below. Our policies and procedures for subsequently assigning customers to tariffs within each tariff class is set out in Chapter 5.

Figure 1: Overview of our tariff class assignment process



Consistent with Figure 1, we propose that the AER determine the below procedures for assigning and reassigning retail customers to tariff classes.[4]

Assignment of existing retail customers to a tariff class at the start of the 2024-29 period

1. Our retail customers will be assigned to the tariff class to which Ausgrid was charging them immediately prior to 1 July 2024 if:

   a. They were an Ausgrid retail customer prior to 1 July 2024; and
   b. They continue to be an Ausgrid retail customer as at 1 July 2024.

[4] NER, clause 6.12.1(17).

Assignment of new retail customers to a tariff class during the 2024-29 period

2. If, after 1 July 2024, Ausgrid becomes aware that a person will become a retail customer, then Ausgrid must determine the tariff class to which the new customer will be assigned.
3. In determining the tariff class to which a retail customer or potential retail customer will be assigned, or reassigned, Ausgrid must take into account one or more of the following factors:
   a. The nature and extent of their usage or intended usage of distribution services;
   b. the nature of their connection to the network; and/or
   c. Whether remotely-read interval metering or other similar metering technology has been installed at the retail customer's premises as a result of a regulatory obligation or requirement.
4. In addition to the requirements under point 3 above, Ausgrid, when assigning or reassigning a retail customer to a tariff class, must ensure:
   a. Retail customers with a similar connection and distribution service usage profile should be treated on an equal basis, subject to subparagraph 4b; and
   b. Retail customers connected to a regulated stand alone power system (SAPS) should be treated no less favourably than retail customers connected to the interconnected national electricity system.

Reassignment of existing retail customers to another existing or a new tariff class during the 2024-29 period

5. Ausgrid may reassign a retail customer to another tariff class if the existing retail customer’s connection characteristics have changed such that it is no longer appropriate for that retail customer to be assigned to the tariff class to which the retail customer is currently assigned, or a retail customer no longer has the same or materially similar connection characteristics as other retail customers in the retail customer’s existing tariff class. In determining the tariff class to which a retail customer will be re-assigned, Ausgrid must take into account points 3 and 4 above.

Objections to proposed tariff class assignments and reassignments

6. Ausgrid must notify a customer’s retailer in writing of the tariff class to which the retail customer has been assigned or reassigned, prior to the assignment or re-assignment occurring.
7. A notice under point 6 above must include advice informing the customer’s retailer that they may request further information from Ausgrid and that the retail customer may object to the proposed reassignment. This notice must specifically include:
   a. A written document describing Ausgrid’s internal procedures for reviewing objections;
   b. That if the objection is not resolved to the satisfaction of the customer’s retailer under Ausgrid’s internal review system within a reasonable timeframe, then, to the extent that resolution of such disputes is within the jurisdiction of the Energy and Water Ombudsman of NSW, or like officer, the customer’s retailer is entitled to escalate the matter to such a body; and
   c. That if the objection is not resolved to the satisfaction of the customer’s retailer under Ausgrid’s internal review system and the body noted in clause 7b above, then the customer or its retailer is entitled to seek a decision of the AER via the dispute resolution process available under Part 10 of the National Electricity Law (**NEL**).

8. If, in response to a notice issued in accordance with point 7 above, Ausgrid receives a request for further information from a customer's retailer, then it must provide such information within a reasonable timeframe. If Ausgrid reasonably claims confidentiality over any of the information requested by the customer's retailer, then it is not required to provide that information to the customer's retailer. If the customer's retailer disagrees with such confidentiality claims, it may have resort to the dispute resolution procedures referred to in point 7 (as modified for a confidentiality dispute).
9. If, in response to a notice issued in accordance with point 7 above, a customer's retailer makes an objection to Ausgrid about the proposed assignment or reassignment, Ausgrid must reconsider the proposed assignment or reassignment. In doing so Ausgrid must take into consideration the factors in points 3 and 4 above and notify the customer's retailer in writing of its decision and the reasons for that decision.
10. If a customer's retailer's objection to a tariff class assignment or reassignment is upheld by the relevant body noted in points 7b and 7c above, then any adjustment which needs to be made to tariffs will be done by Ausgrid as part of the next annual review of prices.

If a customer's retailer objects to Ausgrid's tariff class assignment, Ausgrid must provide the information set out in point 7 above and adopt and comply with the arrangements set out in points 8, 9 and 10 above in respect of requests for further information by the customer's retailer and resolution of the objection.

3. Approach to setting tariffs and the basic export level, pricing principles

3.1 Long run marginal cost for import energy

Clause 6.18.5(f) of the NER requires that our tariffs are based on the long run marginal cost (**LRMC**) of providing network services to our customers. The LRMC is an estimate of our future costs of expanding (or contracting) our network to allow for one additional (or one fewer) unit of use of the network. Customer demand during peak network demand periods is a key driver of the costs of our network, and so the LRMC reflects the cost to supply one additional unit of capacity (in kW or kVA) at peak times. By setting tariffs with reference to the LRMC of the network, we promote efficient use of our network based on tariffs that are aligned with the underlying cost of network usage. In addition to managing peak network demand, customer export of energy onto the grid is also becoming an increasing driver of costs. We outline our LRMC approach for customer exports later in this chapter.

In May 2022 we engaged Houston Kemp who worked with Ausgrid network planners on inputs for the calculation of LRMC. This project determined the LRMC in areas of the network where demand is growing and an estimate of LRMC in areas where demand is falling. The average incremental cost (AIC) approach was used to calculate LRMC in areas where demand is growing and the perturbation approach in areas where demand is falling. An estimate was used to calculate the LRMC in areas where demand is falling. The AIC value sets the upper range and the perturbation value sets the lower range of Ausgrid's estimate of import services LRMC. The lower range is based on an upgrade to a zone substation and should be considered a single point estimate. Further justification for using the upper range values (instead of lower range) is explained in the Houston Kemp report (Attachment 8.7).

We note that the LRMC has declined for all distribution tariff classes in the current regulatory period. This reflects the changes in the demand outlook over this period. A spreadsheet model has been provided with this TSS (Attachment 8.4) which provides the full details of our import LRMC calculations. The capital costs, operating costs, and peak demand assumptions in this model align with table 7.7 of our reset RIN attachments. Appendix B to this document provides detailed information on these items as required by AER Regulatory Information Notice (RIN 4.11).

Table 2. Comparison of LRMC between regulatory control periods ($, real FY24)

Tariff class	2019-24 period per kW pa[5]	2024-29 period per kW pa (upper estimate)	Percentage change
Low voltage / Unmetered	$65.9	$40.0	-39%
High Voltage	$42.2	$15.0	-64%
Sub-transmission	$7.5	$3.1	-58%
Transmission	0	0	0

[5] Excludes LRMC-based repex

3.2 Stand alone and avoidable costs

The NER require Ausgrid to ensure that the revenue recovered for each tariff class lies between:

- An upper bound, representing the stand alone cost of serving the retail customers who belong to that class; and
- A lower bound, representing the avoidable cost of not serving those retail customers.[6]

Therefore, the stand alone and avoidable costs for a tariff class must be set between the costs necessary to only supply that tariff class (i.e. a stand alone price) and the costs that could be avoided if that tariff class were not supplied at all. This ensures that tariffs cannot be set below the incremental cost to supply these customers and do not exceed the cost of only supplying these customers. These approaches are used to calculate the revenues for each standard control service tariff class. The costs are compared with the weighted average revenue derived from Ausgrid's proposed tariffs.

Our stand alone and avoidable cost estimates are prepared using building block costs from the post-tax revenue model. The avoidable costs include scalable operating costs for assets and customer services. Stand alone costs also include the indirect component for operating costs and the return on capital expenditure. The stand alone and avoidable costs estimates are provided separately for the low voltage, unmetered, high voltage, and sub-transmission tariff classes.

Attachment 8.10 is the model that calculates the stand alone and avoidable distribution cost as a percentage of revenue. The Ausgrid distribution revenue for the first year of the next regulatory period is within the stand alone and avoidable cost boundaries for each tariff class, as shown in Table 2.

Table 2 FY25 distribution revenue by tariff class with stand alone and avoidable costs

Tariff class	Avoidable cost	Indicative FY25 distribution revenue	Stand alone cost
Low voltage	$251,017,570	$1,433,864,565	$1,475,002,205
High voltage	$10,645,071	$55,401,769	$956,220,852
Sub-transmission	$8,075,016	$41,055,959	$396,833,087
Unmetered	$1,016,389	$9,121,381	$1,225,001,024

3.3 Side constraints

In respect of pricing side constraints, Ausgrid, under the Rules is limited to the annual movement of revenue recovery between tariff classes. A tariff class cannot face increases that are more than 2% higher than the average increase for all tariffs. The side constraint applies to Distribution Use of System (**DUOS**) only and the tariff class as a whole, and not to individual tariffs, tariff charging components or individual customer outcomes. We also note that the side constraint does not apply to the first year of a regulatory period.

[6] NER, clause 6.18.5(e).

Compliance with this side constraint is a matter for our Annual Pricing Proposals and is not discussed in detail in this TSS. However, in years 2-5 of the 2024-29 period, we will ensure that the annual increase of each tariff class is not more than 2% above the average DUOS price increase overall. We have also ensured that the indicative prices for years 2-5 provided with this TSS comply with the side constraint derived from our proposed revenue paths and forecast CPI.

3.4 Approach to setting consumption-based prices

The network pricing objective as specified within the NER[7] requires that our tariffs and charges should reflect our efficient costs of providing standard control services. Our prices for the 2024-29 period are set to recover total efficient cost. Our approach to setting distribution tariffs is as follows:

1. **Set prices for cost reflective tariff components**
   We currently reflect LRMC in the demand, capacity, and peak period tariff charging components. Ausgrid's long-run marginal costs will continue to be signalled in our peak demand/capacity components and where relevant in the peak energy charges, as per the AER's 2019 decision for the 2019-24 period. For flat tariffs we will reflect the upper LRMC value in the variable energy rate.
2. **Allocate residual distribution revenue to tariff classes**
   Allocation of residual network revenue occurs based on the contribution to system demand by each tariff class, and the extent that each tariff class uses network assets. For example, the low voltage tariff class receives a larger distribution cost allocation (than a high voltage and sub-transmission connections) given a low voltage connection uses more network assets. The residual revenue share outcomes for the low voltage and unmetered tariff classes are projected to be largely stable in the next period. We propose a gradual reduction in residual revenue recovery for the sub-transmission tariff class and an increase for the high voltage tariff class. These changes reflect a long-term transition to a cost reflective revenue recovery for all tariff classes.
3. **Allocate residual distribution revenue to tariff charging components**
   We will continue to reduce the proportion of residual costs recovered from non-peak energy charges, as per the AER's 2019 decision for the 2019-24 period. Residual revenue recovery will gradually increase on existing demand, capacity, and fixed charge components.
4. **Provide an incentive for cost reflective tariffs for small customers**
   Our residential and small business cost reflective tariffs will be set to create a small incentive for customers (via their retailer) to move to these tariffs. This will be achieved by continuing to allocate less residual revenue to the cost reflective demand tariffs (EA116 and EA256). As more customers move to cost reflective tariffs, the amount of residual revenue allocated to these tariffs will increase. This will help avoid bill impacts for customers who remain on flat tariffs, and who would have been progressively assigned more residual revenue as part of a diminishing customer base.
5. **Stand alone and avoidable costs**
   We will ensure the distribution revenue for each tariff class lies between stand alone and

[7] NER, clause 6.18.5(a)

avoidable costs, and that the year-on-year price change for years 2 to 5 is within the side constraint for each tariff class.

Further, the AER's determination decision for the 2019-24 period required that we gradually reduce the difference in residual revenue recovery across residential and small business tariffs. We propose to continue to progress these changes in the next regulatory period.

This section outlines the proposed recovery of residual costs, where we plan to gradually increase or decrease the recovery of residual costs on certain tariffs. For the avoidance of doubt, these rebalancing changes are intended to be achieved over the course of the regulatory control period. Rebalancing may or may not occur in each regulatory year.

3.5 LRMC for export energy

Our small customer export tariff (EA960) is based on the LRMC of providing export services.[8] Consistent with both the NER and the AER's export tariff guidelines, we assume that the total efficient costs of export services is the LRMC.

In Ausgrid's network, the cost drivers for export services are typically voltage related. This means that marginal expenditure typically occurs on low voltage distributors. To reflect this we developed an LRMC estimate based on 16 case studies of low voltage distributors. The 16 case studies are representative of typical distributors that supply most export customers, with a range of customers served and existing penetration of export customers.

We have applied our export growth forecasts, based on AEMO's step-change forecast, to each of these case studies and identified when we would need to build additional hosting capacity. We have built both an average incremental cost and a perturbation LRMC model, with both returning similar results (see Table 3 below).

Table 3 LRMC estimates of export services

$2024	Average incremental cost (lower estimate)	Perturbation (upper estimate)
Central estimate $/kW	$16.6/kW	$21.6/kW
Corresponding export tariff c/kWh	0.91c/kWh	1.18c/kWh

The small customer export tariff will apply the export charge from 10am to 3pm every day. This reflects the time of greatest utilisation of export services and the time of day that drives demand for network hosting capacity.[9]

Over 5 hours every day, the LRMC of exports (based on our central estimates of the case studies) is between 0.91c/kWh and 1.18c/kWh. We note the LRMC of exports has a wide range over our sample of 16 distributors, including variation within four distributors supplied by the same zone

[8] NER, clause 6.18.5(f)

[9] NER, clause 6.18.5(f)(2)

substation. With around 50,000 distributors across our network, and significant variation within local areas it is not practical to calculate locational LRMC estimates to apply to tariffs.[10]

3.6 Approach to setting export prices

We must base all our tariffs on LRMC.[11] For export tariffs, we have estimated that the LRMC is ($, real FY24):

- 0.91c/kWh to 1.18c/kWh for exports between 10am and 3pm; and
- -1.17c/kWh to -2.19c/kWh for exports between 4pm and 9pm everyday

Under the AEMC's access and pricing rule change we can only apply a LRMC based charge for exports above the basic export level.

Ausgrid is providing a 2,500 kWh per annum[12] basic export level between 10am and 3pm, available on our export tariff to residential and small business customers. All exports outside of 10am and 3pm are either free or rewarded, so no free export allowance applies.[13]

Our preference is to apply the basic export level as an energy measure, because it is easier for customers to understand.[14] Our basic export level is consistent with the NER requirements for all distribution businesses to include a basic export level to all export tariffs for the next two regulatory periods.[15]

Consistent with the AER's export tariff guidelines and the NER, we have calculated our 2,500 kWh per annum basic export level by:

1. Analysing the intrinsic hosting capacity of our network.[16] We analysed 16 real, representative low voltage distributors on our network and calculated how much export they could handle before needing significant investment.[17] Rooftop solar capacity was added to individual customers until the export levels required material investment by Ausgrid to manage voltage.
2. Forecast use of the network to accept exports from embedded generation.[18] Our forecast use of the network is consistent with our rooftop solar and battery estimates used throughout our regulatory reset documents. It is based on the AEMO's step-change forecast.

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[10] Balancing NER, clauses 6.18.5(f)(3) and 6.18.5(f)(1).

[11] NER, clause 6.18.5(f)

[12] Applied in retailer billing as 6.85 kWh per number days in the billing period. For example, a 30-day billing period has a basic export level of 205.5 kWh. The first 205.5 kWh exported in the that month (and within the charging window) will not be charged.

[13] NER, clause 11.141.12(a) states that 'A Distribution Network Service Provider must not charge…'. Neither the NER nor the AER's export tariff guidelines define charge, we have interpreted charge in this context to exclude rewards or negative charges.

[14] We are also limited in how we can apply a basic export level by our billing system.

[15] NER, clause 11.141.12(a)

[16] The AER's export tariff guidelines defines the intrinsic hosting capacity as NER, clause 11.141.13(b)(1)(i).

[17] Consistent with NER, clause 11.141.13(b)(1)(i) very small investments were disregarded. We note minimal was not defined. The minimum investment in our sample was $20,000 on a distributor supplying 58 customers, equivalent to $345 per customer served.

[18] NER, clause 11.141.13(b)(1)(ii).

We found that 75% of our distributors could handle all forecast PV customers installing 3 kW solar system. We consider this 75% percentile as suitable as it balances the risk of:

- Ausgrid exhausting its intrinsic hosting capacity without signalling to customers the costs of their export decisions; and
- Charging too many customers for exports where we have sufficient intrinsic hosting capacity in the forecast period.

Our analysis of existing export customers found a significant majority of customers with 3 kW of export capacity export less than 625 kWh in any quarter, making 2,500 kWh per annum an appropriate energy measure for 3 kW of rooftop PV capacity.

We note that 3 kW is not our basic export level, as customers with 3 kW solar system self-consume a significant proportion of their generation. Under our basic export level of 2,500 kWh per annum, customers that set their inverters to a maximum of 1.37 kW exports between 10am and 3pm can avoid all export charges.

Under the NER, cost reflective tariffs are LRMC based tariffs adjusted to recover total efficient costs, in a manner that minimises distortions from a purely LRMC tariff.[19] The AER's export tariff guidelines limit the NER's definition of total efficient costs to refer to directly attributable costs incurred from:

- the date of the access and pricing rule change taking effect; or
- the first day of a network's upcoming regulatory control period.

Using the latter definition and the AER's guidance on export tariff total efficient costs, we estimate our operating and returns on capital for attributable costs is around $5 million per year. We expect revenue recovery for the small customer export tariff will be around $1.5 million per annum.[20]

For the introduction of the export tariff, we have decided that it will be based only on the long-run marginal cost of providing export services after applying a basic export level. We have made this decision, in accordance with the NER:

- Distribution businesses have significant discretion on the 'total efficient costs' under the NER,[21] and we have decided that the 'total efficient costs' are limited to the chargeable long-run marginal costs for export services, for the introduction of the tariff; and
- From 1 July 2025, customers will be assigned to the small customer export tariff,[22] and many export customers with older inverters connected to generation have limited ability to mitigate their exports,[23] supporting a lower cost recovery to manage customer impacts.

The decision to set tariffs equal to LRMC (for exports we can charge) for the introduction of the tariff is a key component of our export tariff transition strategy. Ausgrid will reassess the customer

[19] AEMC, *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014,* 27 November 2014, p 25.

[20] This is based on 2025-26 where all small customers with sufficient metering will be assigned the small business export tariff.

[21] AEMC, *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014,* 27 November 2014, p 158.

[22] NER, clause 6.18.5(h)(ii)

[23] NER, clause 6.18.5(h)(iii)

impacts on how we recover export costs in future years, including when the requirement for a basic export level expires in 2034.

3.7 Impact on retail customers

Distributors must consider the impact on retail customers of changes in tariffs from the previous regulatory year by having regard to the pricing principles, customer choice, and the availability of price signals. This TSS demonstrates our compliance with the pricing principles (Chapter 3), the opt out options available for small customer tariffs (Chapter 4), and the time periods in which price signals are available for customers to respond to (Chapter 4).

An extensive bill impact analysis is provided as Attachment 8.3 to this TSS. Our pricing reforms have been developed while considering this analysis and the feedback from our customer and industry stakeholders.

3.8 Tariffs reasonably capable of being understood by customers

Our pricing reforms for 2024-29 period are strongly motivated by the desire of customers and stakeholders for a simple and easily understood tariff structure. Our streamlining reforms include removal of some existing tariffs and simplifying charging components. These reforms have the additional benefit of streamlining our tariff assignment procedure (Chapter 5). Further information is in Chapter 3 of the TSS Explanatory Statement (Attachment 8.2).

3.9 Embedded network tariffs

We propose to assign embedded networks (**EN**s) using above 160 MWh per annum to separate tariffs. Our proposal includes a tariff for:

- ENs connected to the low voltage network using between 160 and 750 MWh per annum (for ENs currently on the LV 160-750 MWh tariff);
- ENs connected to the low voltage network using more than 750 MWh per annum (for ENs currently on the LV >750 MWh tariff); and
- ENs connected to the high voltage network (for ENs currently on the HV Connection tariff).

The tariffs we currently assign EN customers to result in lower network bills than those in our residential and small business rates. This means that a development's choice to connect to our network as an EN instead of connecting each individual energy user may be partly driven by a reduction in the total network bill (known as tariff arbitrage). The NER require that recovery of residual cost should not distort LRMC. Without the proposed changes our business tariffs could potentially distort price signals to customers, by creating an inefficient incentive (via tariff arbitrage) for new embedded networks.

These proposed tariffs would have the same fixed and energy charges as the equivalent medium or large business tariff, but they would include an increased capacity charge. In response to stakeholder feedback we will introduce the capacity charge uplift over five years, resulting in the tariffs reaching the proposed level by July 2029 (instead of a one-off increase in July 2024). This achieves an appropriate balance between managing bill impacts across the EN customer segment and achieving greater fairness for our other customers.

3.10 Utility-scale storage tariffs

We will introduce a suite of utility scale storage tariffs on 1 July 2024, with a storage tariff available within the low voltage, high voltage and sub-transmission tariff classes. The storage tariffs are based on the National Electricity Objective and the network pricing objective[24] guided by the NER pricing principles.

Our storage tariffs are LRMC based

The sub-transmission storage tariff has LRMC based charging components: [25]

- Critical peak energy – this charge is based on the LRMC of an overload that would shorten the life of a sub-transmission network asset and that could have been avoided by the storage customer, bringing forward $30 million in replacement expenditure by 5-years. This reflects that overloads above the N reliability measure have a meaningful impact on the asset lives of our network infrastructure. The reward is based on the estimated value of unserved energy for other customers when a storage customer can support the network to avoid an outage to prevent an overload.
- Peak usage – this charge is based on the standard LRMC of load for the sub-transmission network, it applies when local assets are within 5 MW of our N reliability level. This considers that only when a flexible storage asset's usage drives the network to near capacity is it likely that the storage customer's network use could drive augmentation expenditure. For the purposes of the tariff, we have assumed peak typically occurs 10 hours a year.
- Off-peak usage – at all other times we consider the LRMC of network usage is zero.

The N measure will vary by where in the network the flexible storage asset is located[26] and the LRMC applied is based on usage of the local network at that time.[27]

The high voltage storage tariff has two LRMC based charging components:

- Critical peak energy – this symmetrical charge/reward is based on the standard LRMC of load for the high voltage network. We have applied the LRMC over a 40-hour window, assuming with our critical peak events we can capture all storage customer activity that drives augmentation expenditure.
- Off-peak usage – we apply no LRMC to usage outside of the peak usage.

The low voltage storage tariff has three LRMC based charging components:

- Critical peak energy – this symmetrical charge/reward is based on the standard LRMC of load for the low voltage network. We have applied the LRMC over a 40-hour window, assuming with our critical peak events we can capture all storage customer activity that drives augmentation expenditure.
- Critical peak export– this symmetrical charge/reward is based on the standard long-run marginal cost of exports for the low voltage network. We have applied the LRMC over a 44-hour[28] window, assuming with our critical peak events we can capture all storage customer

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[24] NER, clause 6.18.5(a)

[25] NER, clause 6.18.5(f)

[26] NER, clause 6.18.5(f)(3)

[27] NER, clause 6.18.5(f)(2)

[28] On a postage stamp basis, we have found that high voltage impacts our average low voltage customer for 44 hours per year. This figures varies significantly across the network, however it is consistent in approach with our long-run marginal cost of exports.

activity that drives augmentation expenditure. We have included a 44 kWh/year basic export level to allow 1 kWh/hour of free exports. We have set the basic export level at the minimum level possible because there is no available intrinsic hosting capacity when a peak export event occurs[29].

- Off-peak usage – we apply no long-run marginal cost to usage outside of the peak usage.

The storage tariffs recover more DUOS than the storage customers' avoidable costs

Storage assets have relatively low avoidable and stand alone costs:

- The avoidable distribution cost of a flexible storage customer located in our network will typically be near zero. The flexible storage customers' flexibility allows it to operate in a way that drives no additional costs to our distribution network.[30]
- The stand alone distribution costs of a flexible storage customer are also typically low. Utility scale storage facilities can connect to either the transmission or the distribution network. This suggests that the distribution assets required to exclusively serve a storage facility could in many circumstances be minimal.

We consider that it is important that the total efficient costs allocated to flexible storage customers are between the avoidable and stand alone costs. This ensures that the total efficient costs are:

1. Consistent with the guidance on how to interpret NER, clause 6.18.5(g)(1) provided by the AEMC in its 2014 final determination.[31]
2. Flexible storage customers will connect to Ausgrid's assets where we have spare capacity removing the need for other networks to augment their networks to support flexible storage customers.
3. Flexible storage customers will contribute to Ausgrid's residual cost recovery, reducing the network costs allocated to all other customers.

The storage tariff design minimises distortions to efficient network use

We expect that storage customers will have high price elasticity of demand. This means that allocating cost recovery to variable usage charges may have significant distortions on efficient network usage.[32] Therefore, to comply with the NER we will only allocate residual DUOS to the annual fixed charge component.

Storage tariffs requires dynamic flexible connection agreements to manage customer impacts

Storage customers present a novel challenge for managing customer impacts. We currently only have low voltage storage assets connected to our network (these assets are Ausgrid owned). For new customers, including all high voltage and sub-transmission customers the customer impacts

[29] We consider an economically efficient level would be zero, but as the NER require a basic export limit to be set over the transitional period, we have adopted the lowest level practical.

[30] Any storage customers operating to provide network support at the low voltage or high voltage network may have a negative avoidable cost, that is without the storage customer Ausgrid would incur costs it must recover from the broader customer base.

[31] AEMC, *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014,* 27 November 2014, p 158.

[32] NER, clause 6.18.5(g)(3).

on those customers are managed by the customers' ability to decide not to connect assets to our network or by operating these assets dynamically to reduce their exposure to these network tariffs.[33]

The main challenge is ensuring existing customers without highly elastic demand and the ability to connect to other networks are not able to access this tariff. We consider that there is a risk that the tariff is below the typical avoidable costs of existing, non-flexible network customers. If typical network customers were able to access the tariff the customers may be recipients of economic cross-subsidies. Therefore, we have decided to limit access to the tariff to storage customers. This manages the customer impacts to our broader customer base, by significantly reducing the risk of cross-subsidisation.[34]

Storage customers can understand the tariff

We have consulted with storage customers on the storage tariff. These customers are highly engaged in energy markets, working primarily in wholesale and FCAS markets. Given the type and nature of utility scale storage customers we consider that the tariff is capable of being understood by customers that seek to connect to the Ausgrid network.[35]

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[33] NER, clause 6.18.5(h)(2).

[34] NER, clause 6.18.5(h).

[35] NER, clause 6.18.5(i).

4. Explanation of tariff structures and charging parameters

In this chapter, we firstly set out the main tariffs to apply over the 2024-29 period, grouped by tariff class. We then set out the tariffs that we will withdraw at the start of the 2024-29 period and reassign any remaining customers to other tariffs. At the end of this chapter, we set out the trial tariffs to apply in 2024-25. An indicative pricing schedule for our tariffs in 2024-29 is set out in Attachments 8.15 and 8.17.

4.1 Peak tariff charging window from 1 July 2027

The peak charging windows (for energy, demand and capacity components) in the tables in this chapter may shift from 3-9pm to 4-10pm on 1 July 2027. The trigger event for this change will be the occurrence of a network system demand peak occurring after 9pm on any day prior to 1 March 2027. The time of the network system demand peak will be determined according to the approach used in Table 5.3.1 of the annual Regulatory Information Notice submission.[36]

Further information on this proposal can be found in section 3.4 of Attachment 8.2.

4.2 Low voltage customer tariffs

The tariffs structures and charging parameters for the low voltage customer tariff class are set out in the tables below. Tariffs in this tariff class comprise residential and business customer tariffs, as well as primary and secondary tariffs.

[36] This can be found in the Category Analysis RIN document.

Residential and small business customers – primary tariffs

Table 4 Residential customer primary tariffs

Tariff name	Tariff code	Components	Measurement	Charging parameter
Residential flat	EA010 (closed)	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Energy	cents / kWh	Charged applied to all energy consumed
Residential TOU	EA025	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Peak energy	cents / kWh	Charge applied to energy consumed between 3-9pm each day during Summer (November to March) and Winter (June to August) months
		Off-peak energy	cents / kWh	Charged applied to energy consumed at all other times
Residential demand (introductory)	EA111	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Peak energy	cents / kWh	Charge applied to energy consumed between 3-9pm each day during Summer (November to March) and Winter (June to August) months
		Off-peak energy	cents / kWh	Charged applied to energy consumed at all other times
		Peak demand	cents / kW / day	Charge applied to the customer's highest kW demand in any half-hour period between 3-9pm during Summer (November to March) and Winter (June to August) months, resetting monthly
Residential demand	EA116	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Peak energy	cents / kWh	Charge applied to energy consumed between 3-9pm each day during Summer (November to March) and Winter (June to August) months
		Off-peak energy	cents / kWh	Charged applied to energy consumed at all other times
		Peak demand	cents / kW / day	Charge applied to the customer's highest kW demand in any half-hour period between 3-9pm during Summer (November to March) and Winter (June to August) months, resetting monthly

Table 5 Small business customer primary tariffs

Tariff name	Tariff code	Components	Measurement	Charging parameter
Small business flat	EA050	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Energy	cents / kWh	Charged applied to all energy consumed
Small business TOU	EA225	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Peak energy	cents / kWh	Charge applied to energy consumed between 3-9pm working weekdays during Summer (November to March) and Winter (June to August) months
		Off-peak energy	cents / kWh	Charged applied to energy consumed at all other times
Small business demand (introductory)	EA251	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Peak energy	cents / kWh	Charge applied to energy consumed between 3-9pm working weekdays during Summer (November to March) and Winter (June to August) months
		Off-peak energy	cents / kWh	Charged applied to energy consumed at all other times
		Peak demand	cents / kW / day	Charge applied to the customer's highest kW demand in any half-hour period between 3-9pm on working weekdays during Summer (November to March) and Winter (June to August) months, resetting monthly
Small business demand	EA256	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Peak energy	cents / kWh	Charge applied to energy consumed between 3-9pm working weekdays during Summer (November to March) and Winter (June to August) months
		Off-peak energy	cents / kWh	Charged applied to energy consumed at all other times
		Peak demand	cents / kW / day	Charge applied to the customer's highest kW demand in any half-hour period between 3-9pm on working weekdays during Summer (November to March) and Winter (June to August) months, resetting monthly

Residential and small business customers – secondary tariffs

The following tables set out the secondary tariffs available to residential and small business customers. These comprise of export pricing and controlled load tariffs.

Secondary tariffs apply in addition to the customer's primary tariff. The tariff assignment policy – including whether these tariffs are opt-in or apply by default to certain customers – is set out in Chapter 5.

Table 5: Export pricing

Tariff name	Tariff code	Components	Measurement	Charging parameter
Small customer export tariff	EA960	Energy (charge)	cents / kWh	Charge applies to energy exported above the Basic Export Limit between 10am-3pm each day
		Energy (reward)	cents / kWh	Reward (credit or payment) applies to energy exported between 4-9pm each day. No Basic Export Limit applies before the application of energy rewards.

Table 6: Controlled load tariffs

Tariff name	Tariff code	Components	Measurement	Charging parameter
Controlled load 1	EA030	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Energy	cents / kWh	Charged applied to all energy consumed Supply is usually available for at least 6 hours in any 24-hour period, from midnight to midnight
Controlled load 2	EA040	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Energy	cents / kWh	Charged applied to all energy consumed Supply is usually available for at least 16 hours duration within any 24-hour period, from midnight to midnight, with more than 4 hours between 7am-5 pm.

Medium business customer tariffs

The following table sets out the tariff structures and charging parameters for our medium business customer tariffs in the 2024-29 period. It includes our new tariffs to apply to embedded network customers.

Table 7: Medium business customer tariffs

Tariff name	Tariff code	Components	Measurement	Charging parameter
FY25: LV 60-160 MWh[37] FY26: LV 80-160 MWh FY27, 28, 29: LV 100-160 MWh	EA302	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Peak energy	cents / kWh	Charge applied to energy consumed between 3-9pm on working weekdays during Summer (November to March) and Winter (June to August) months
		Off-peak energy	cents / kWh	Charged applied to energy consumed at all other times
		Peak capacity	cents / kW / day	Charge applied to the customer's highest kW of demand during any half-hour period between 3-9pm on working weekdays in the previous 12 months
LV 160-750 MWh (system)	EA305	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Peak energy	cents / kWh	Charge applied to energy consumed between 3-9pm on working weekdays during Summer (November to March) and Winter (June to August) months
		Off-peak energy	cents / kWh	Charged applied to energy consumed at all other times
		Peak capacity	cents / kVA / day	Charge applied to the customer's highest kVA of demand during any half-hour period between 3-9pm on working weekdays in the previous 12 months
LV 160-750 MWh (embedded network)	EA314	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Peak energy	cents / kWh	Charge applied to energy consumed between 3-9pm on working weekdays during Summer (November to March) and Winter (June to August) months
		Off-peak energy	cents / kWh	Charged applied to energy consumed at all other times
		Peak capacity	cents / kVA / day	Charge applied to the customer's highest kVA of demand during any half-hour period between 3-9pm on working weekdays in the previous 12 months

[37] The name of tariff EA302 changes over the regulatory control period in line with our proposed assignment policy transitional arrangements on who is eligible for this tariff. This is explained in Chapter 5.

Tariff name	Tariff code	Components	Measurement	Charging parameter
LV >750 MWh (system)	EA310	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Peak energy	cents / kWh	Charge applied to energy consumed between 3-9pm on working weekdays during Summer (November to March) and Winter (June to August) months
		Off-peak energy	cents / kWh	Charged applied to energy consumed at all other times
		Peak capacity	cents / kVA / day	Charge applied to the customer's highest kVA of demand during any half-hour period between 3-9pm on working weekdays in the previous 12 months
LV >750 MWh (embedded network)	EA315	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Peak energy	cents / kWh	Charge applied to energy consumed between 3-9pm on working weekdays during Summer (November to March) and Winter (June to August) months
		Off-peak energy	cents / kWh	Charged applied to energy consumed at all other times
		Peak capacity	cents / kVA / day	Charge applied to the customer's highest kVA of demand during any half-hour period between 3-9pm on working weekdays in the previous 12 months
LV storage (import)	EA962	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Off-peak energy	cents / kWh	Charge applied to energy consumed outside critical peak periods
		Critical peak energy	cents / kWh	Charge applied during locational critical peak load events
		Critical peak export	cents / kWh	Reward applied during locational critical peak voltage events
LV storage (export)	EA963 Secondary tariff to EA962	Critical peak energy	cents / kWh	Reward applied during locational critical peak load events
		Critical peak export	cents / kWh	Charge applied during locational critical peak voltage events 1 kWh/hour basic export level applies given all exports drive costs when this tariff applies.

4.3 High voltage customer tariffs

The tariffs structures and charging parameters for the high voltage tariff class are set out in the table below.

Table 8: High voltage customer tariffs

Tariff name	Tariff code	Components	Measurement	Charging parameter
HV connection (system)	EA370	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Peak energy	cents / kWh	Charge applied to energy consumed between 3-9pm on working weekdays during Summer (November to March) and Winter (June to August) months
		Off-peak energy	cents / kWh	Charged applied to energy consumed at all other times
		Peak capacity	cents / kVA / day	Charge applied to the customer's highest kVA of demand during any half-hour period between 3-9pm on working weekdays in the previous 12 months
HV connection (embedded network)	EA365	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Peak energy	cents / kWh	Charge applied to energy consumed between 3-9pm on working weekdays during Summer (November to March) and Winter (June to August) months
		Off-peak energy	cents / kWh	Charged applied to energy consumed at all other times
		Peak capacity	cents / kVA / day	Charge applied to the customer's highest kVA of demand during any half-hour period between 3-9pm on working weekdays in the previous 12 months
HV storage tariff (import)	EA340	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Off-peak energy	cents / kWh	Charge applied to energy consumed outside critical peak periods
		Critical peak energy	cents / kWh	Charge applied during locational critical peak load events
HV storage tariff (export)	EA341 Secondary tariff to EA340	Critical peak energy	cents / kWh	Reward applied during locational critical peak load events

4.4 Sub-transmission customer tariffs

The tariff structure and charging parameter for the sub-transmission tariffs is set below.

Table 9: Sub-transmission customer tariff

Tariff name	Tariff code	Components	Measurement	Charging parameter
ST connection (system)	EA390	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Peak energy	cents / kWh	Charge applied to energy consumed between 3-9pm on working weekdays during Summer (November to March) and Winter (June to August) months
		Off-peak energy	cents / kWh	Charged applied to energy consumed at all other times
		Peak capacity	cents / kVA / day	Charge applied to the customer's highest kVA of demand during any half-hour period between 3-9pm on working weekdays in the previous 12 months
ST storage (import)	EA380	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Critical peak energy	cents / kWh	Charge applied to energy consumed that exceeds the N reliability measure of local network assets.
		Peak energy	cents / kWh	Charge applied to energy consumed that is between the N reliability measure and 5 MW below the N reliability measure.
		Off-peak	cents / kWh	Charge applied to energy consumed at all other times.
		Locational TUOS demand	cents / kW / month	Charge applied to the customer's average kW during the half-hour period with the maximum monthly kW recorded at the transmission network connection point(s) supplying the storage customer.
ST storage (export)	EA382 Secondary tariff to EA380	Critical peak energy	cents / kWh	Reward applied to energy exported that is supporting the network to avoid exceeding the local network assets N reliability measure
		Peak energy	cents / kWh	Reward applied to energy exported that is supporting the network reduce overall load between the N reliability measure and 5 MW below the N reliability measure.
		Off-peak energy	cents / kWh	Reward applied to energy exported at all other times

4.5 Unmetered customer tariffs

The tariffs structures and charging parameters for this tariff class are set out in the table below.

Table 10: Unmetered customer tariffs

Tariff name	Tariff code	Components	Measurement	Charging parameter
Public lighting	EA401	Energy	cents / kWh	Charge applied to all energy assumed to be consumed based on device type
Constant unmetered	EA402	Energy	cents / kWh	Charge applied to all energy assumed to be consumed based on device type
EnergyLight	EA403	Energy	cents / kWh	Charge applied to all energy assumed to be consumed based on device type

4.6 Transmission-connected customer tariffs

There is one tariff that will apply to all transmission-connected customers in the 2024-29 period. The tariff structure and charging parameter for this tariff is set out in the table below.

Table 11: Transmission-connected customer tariff

Tariff name	Tariff code	Components	Measurement	Charging parameter
Transmission-connected	EA501	Fixed	cents / day	Access charge reflecting a fixed amount per day
		Peak energy	cents / kWh	Charge applied to energy consumed between 3-9pm on working weekdays during Summer (November to March) and Winter (June to August) months
		Off-peak energy	cents / kWh	Charged applied to energy consumed at all other times
		Peak capacity	cents / kVA / day	Charge applied to the customer's highest kVA of demand during any half-hour period between 3-9pm on working weekdays in the previous 12 months

4.7 Tariffs to be withdrawn at the start of the 2024-29 period

We propose to withdraw the following tariffs on 1 July 2024 and re-assign any customers on these tariffs to the relevant tariff listed in the tables above. Our tariff re-assignment policy is set out in Chapter 5.

Table 12: Tariffs to be withdrawn on 1 July 2024

Tariff name	Tariff code
Residential transitional TOU	EA011
Residential TOU demand	EA115
Small business transitional TOU	EA051
Small business TOU demand	EA255
Transitional 40-160 MWh	EA316
Transitional 160-750 MWh	EA317
LV Connection (standby)	EA325
HV connection (standby)	EA360
HV connection (substation)	EA380
ST connection (substation)	EA391

Refer to our 2019-24 TSS for the tariff structures and charging parameters for these tariffs

4.8 Trial tariffs for the first year of the regulatory period

In 2024-25, we will offer the following trial tariffs:

1. A flexible load tariff – to test how to implement and the size of the market for prices that only signal costs during critical system events;
2. A stand alone power systems tariff – to test the ability of energy-based charges to optimise customer use of stand alone power systems;

We have included completed AER sub-threshold tariff notifications for each of the proposed trial tariffs in Attachment 8.16.

We intend to test innovative tariff throughout the 2024-29 period. Under the current rules, the expanded threshold for sub-threshold tariffs of up to 1% of revenue from a sub-threshold tariff and up to 5% of revenue from all sub-threshold tariffs will expire for Ausgrid at the end of the 2024-29 period.[38]

We expect to modify and add trial tariffs each year of the 2024-29 regulatory period.

[38] NER, clause 11.141.8(b).

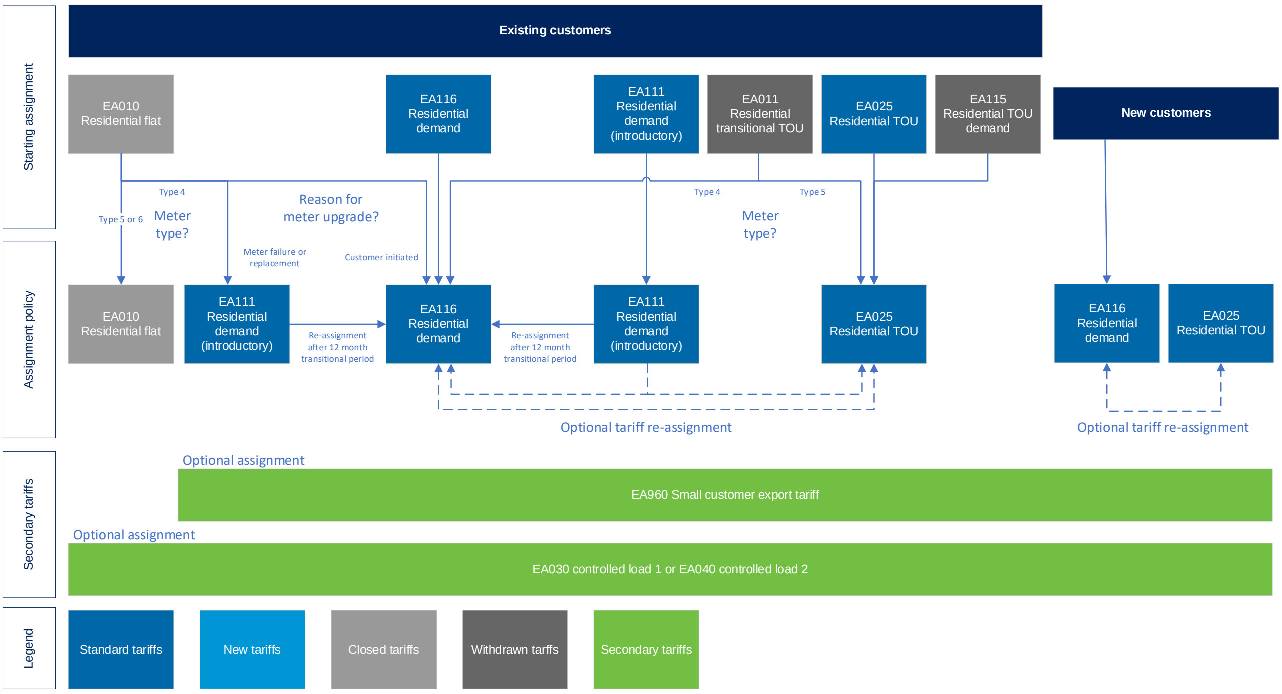
5. Tariff assignment procedures

This chapter sets out the tariff assignment and re-assignment policies to apply to retail customers for standard control services over the 2024-29 period. The tariff assignment and reassignment policies for tariffs within each tariff class are outlined in turn, starting with the Low voltage tariff class. Tariffs for alternative control services are covered in Chapter 7.

5.1 Low voltage customer tariffs – residential customers

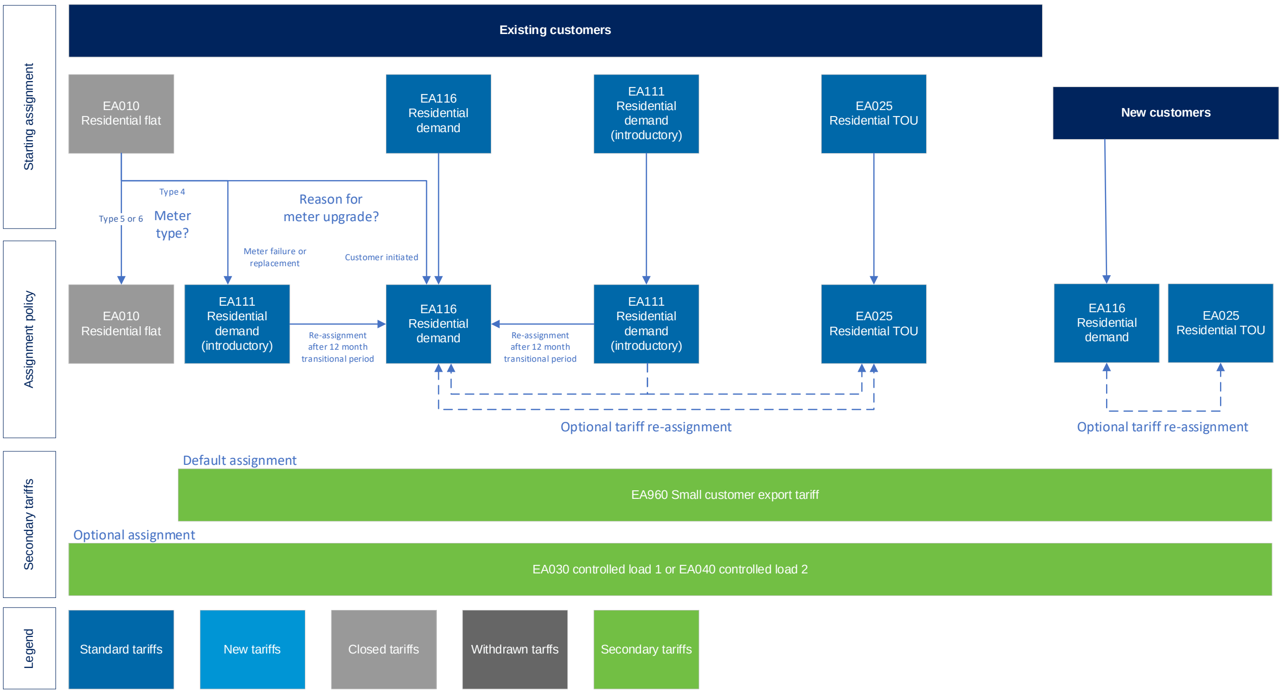
In the first year of the 2024-29 period, we propose to withdraw some residential tariffs and reassign those customers to our main standard tariffs. This is part of our plans to simplify our overall tariff offering. In addition to these changes, in the first year we propose to introduce export pricing as opt-in for residential customers.

Figure 2: Low voltage (residential customer) tariff assignment policy – to apply to regulatory year 2024-25



From the second year (2025-26) we propose to adopt the same tariff assignment policy for residential customers in all remaining years of the regulatory control period. From this year onwards, we also propose to modify our tariff assignment policy for export pricing so it applies by default to any residential customers assigned to cost reflective network tariffs.

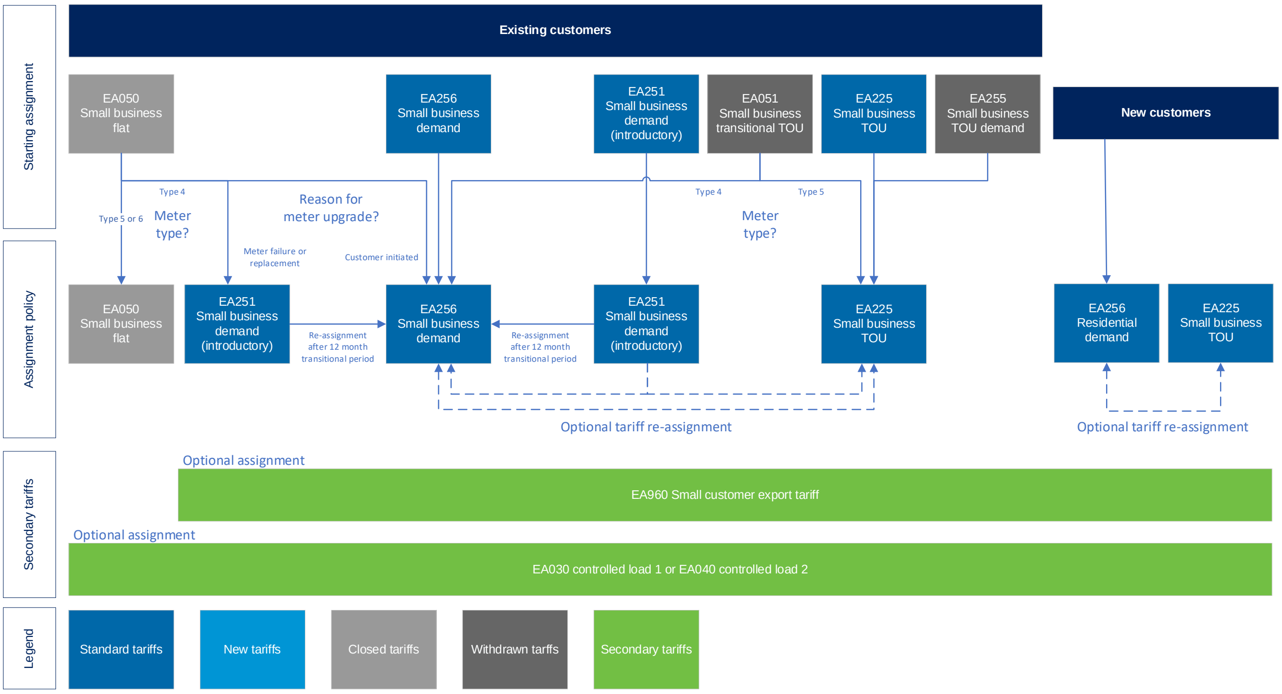
Figure 3: Low voltage (residential customer) tariff assignment policy – to apply from 1 July 2025



5.2 Low voltage customer tariffs – small business customers

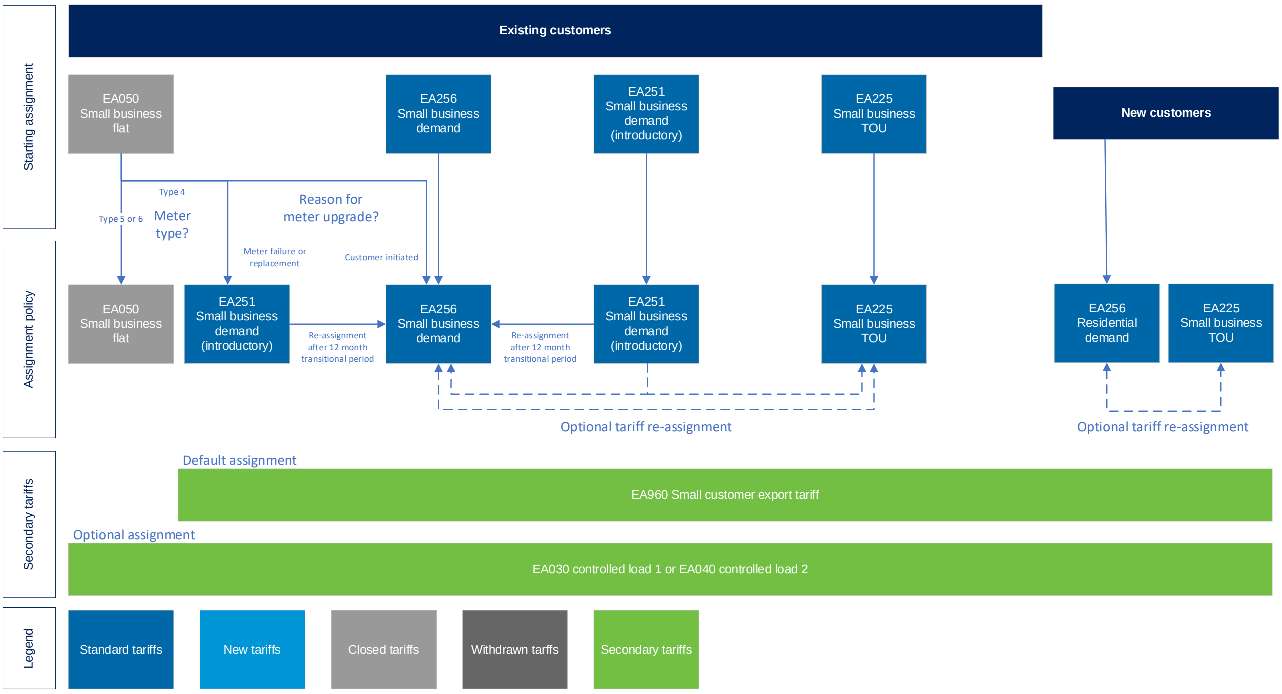
Our tariff assignment policy for small business customers is largely the same as our assignment policy for residential customers. In the first year of the 2024-29 period, we propose to withdraw several small business tariffs with few customers and reassign those customers to our main standard tariffs. In addition to these changes, we propose to introduce opt-in export pricing for small business customers.

Figure 4: Low voltage (small business) tariff assignment policy – to apply to regulatory year 2024-25



From the second year (2025-26), the tariff reassignments from withdrawn tariffs will be complete, and we propose to adopt the same tariff assignment policy for small business customers in all remaining years of the regulatory control period. From this year onwards, we also propose to modify our tariff assignment policy for export pricing so it applies by default to any small business customers assigned to cost reflective network tariffs.

Figure 5: Low voltage (small business) tariff assignment policy – to apply from 1 July 2025

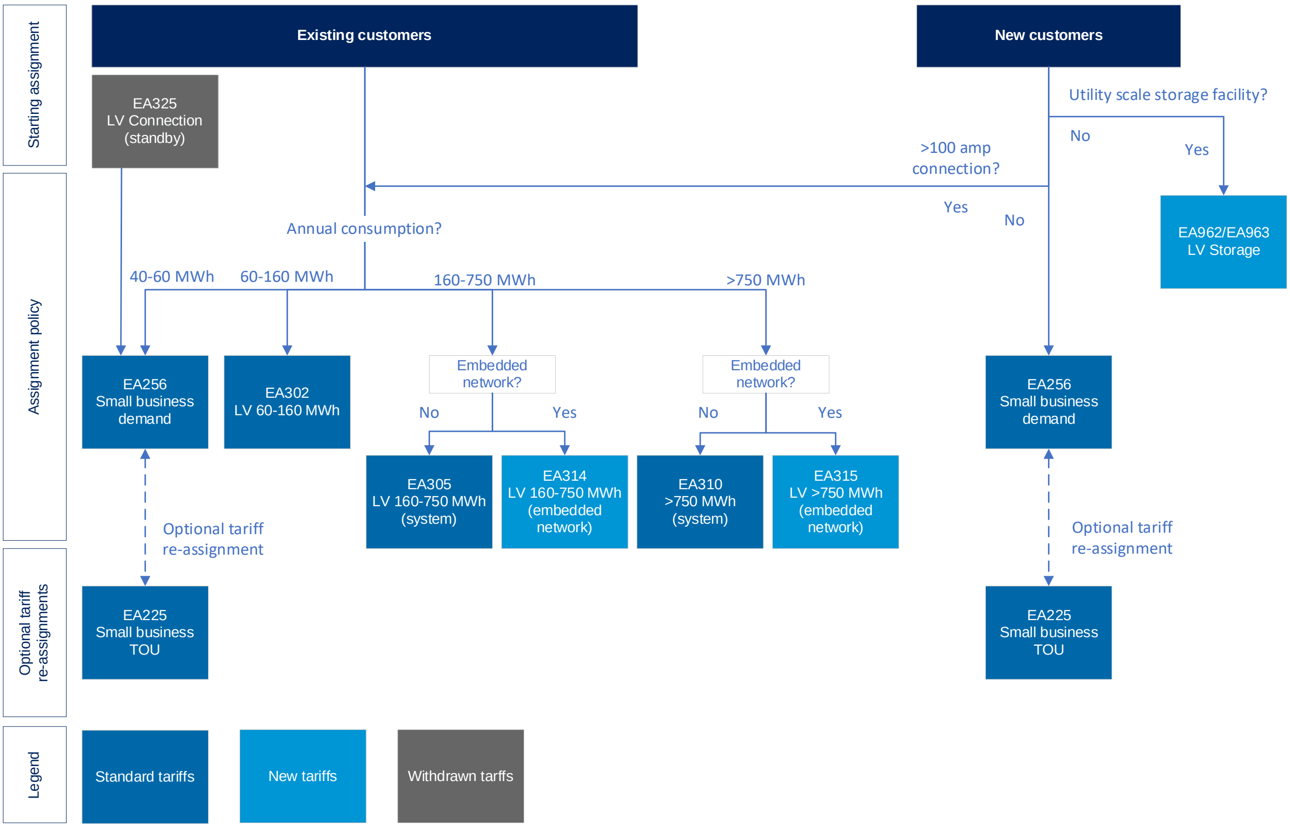


5.3 Low voltage customer tariffs – medium business customers

We are proposing to make several changes to our medium business customer tariff assignment policies. In the first year of the 2024-29 period, we propose to withdraw one medium business tariffs with few customers and reassign those customers to one of our main demand tariffs.

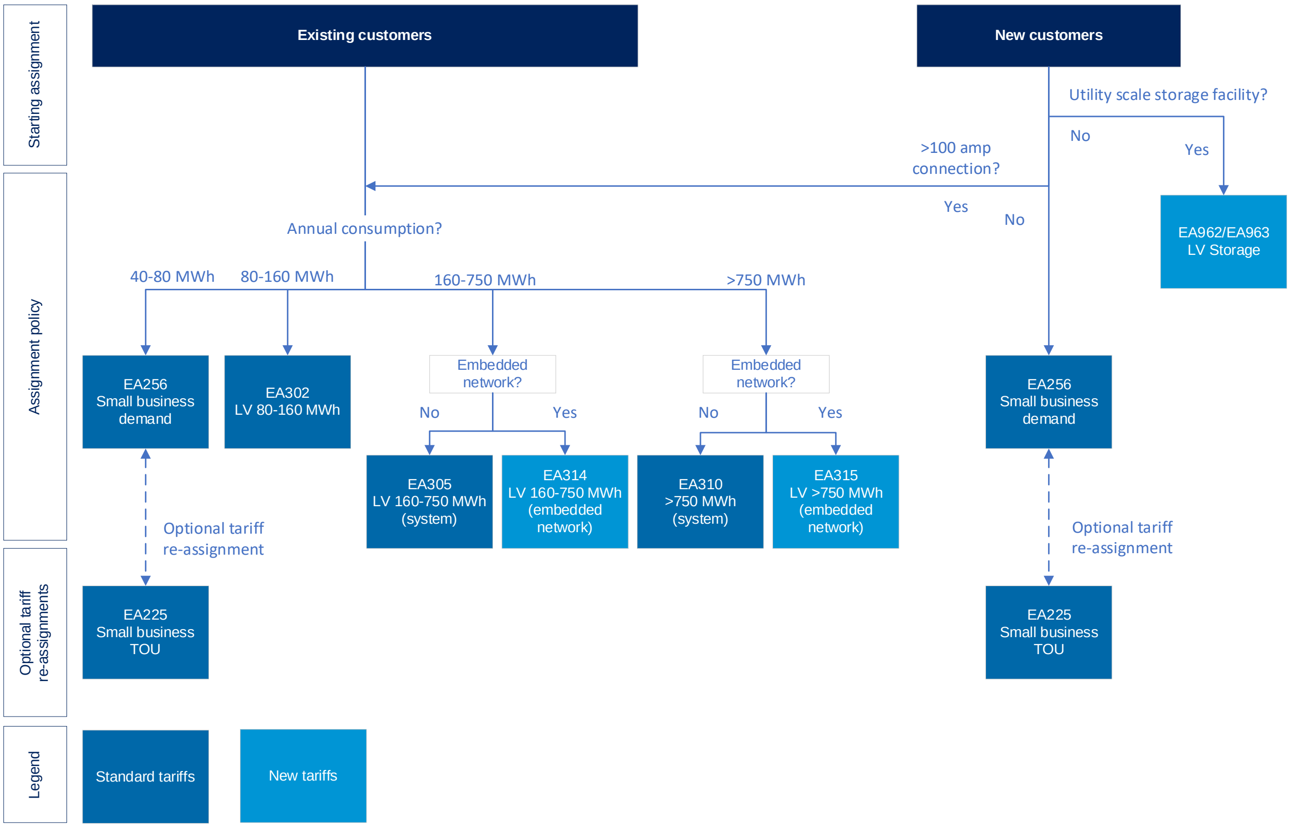
We are proposing to change the way new business connections are assigned by including connection size. We are also proposing to broaden our demand tariff eligibility to medium business customers with lower levels of annual consumption. In addition, we are also proposing to introduce new embedded network tariffs and utility scale storage tariffs. Further information is in Chapter 3 of Attachment 8.2.

Figure 6: Low voltage (medium business) tariff assignment policy – to apply to regulatory year 2024-25



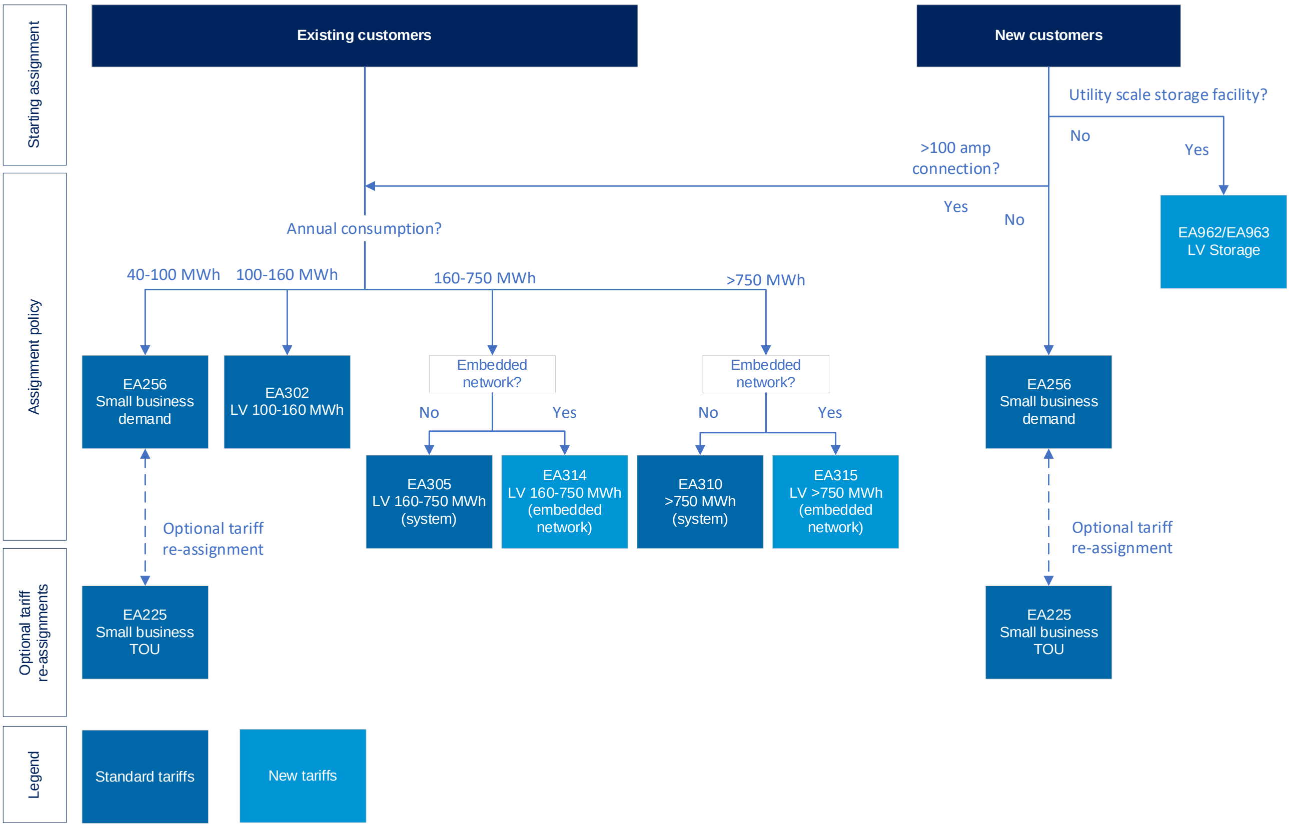
We are broadening the eligibility of small business demand and time of use tariffs over the first three years of the regulatory control period. In the second year, we propose to increase the eligibility threshold from 60 to 80 MWh annual consumption.

Figure 7: Low voltage (medium business) tariff assignment policy – to apply to regulatory year 2025-26



In the third year, we propose to complete our transition and increase the eligibility threshold from 80 to 100 MWh annual consumption for small business demand and time of use tariffs. No other tariff assignment policy changes occur in this year.

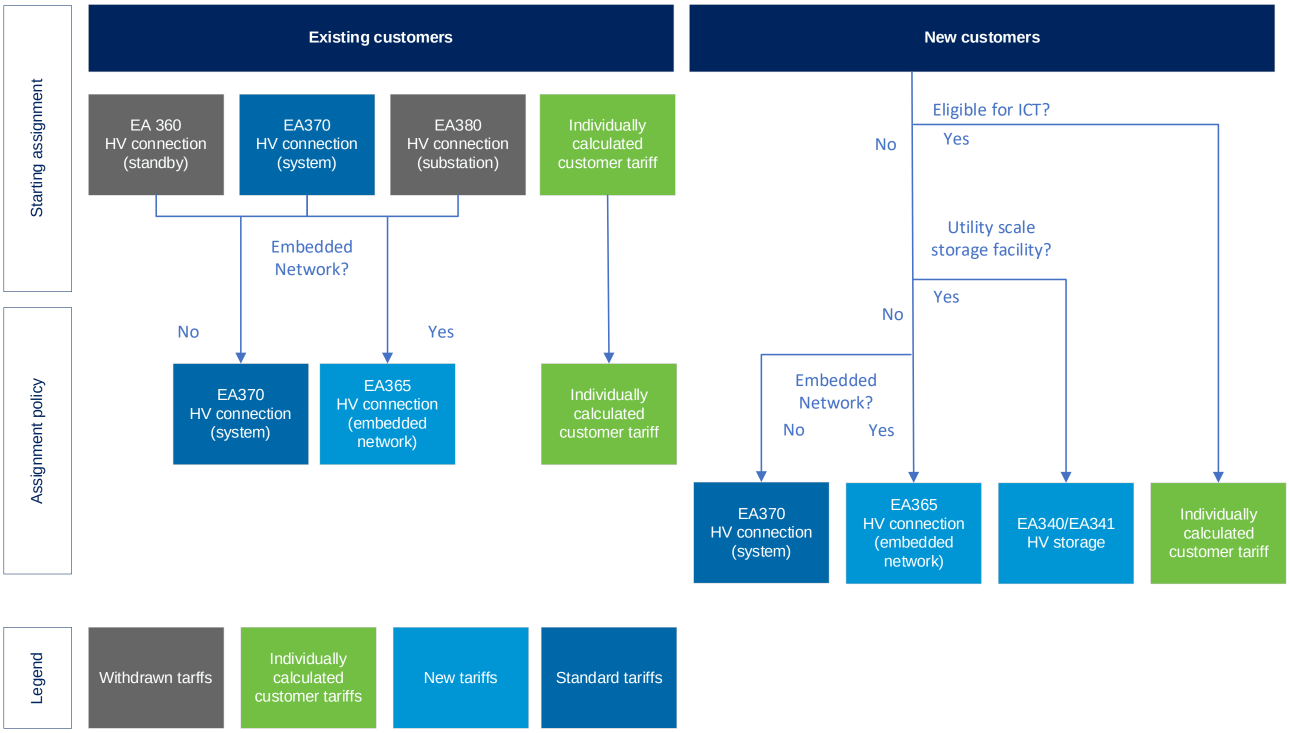
Figure 8: Low voltage (medium business) tariff assignment policy – to apply from 1 July 2026



5.4 High voltage customer tariffs

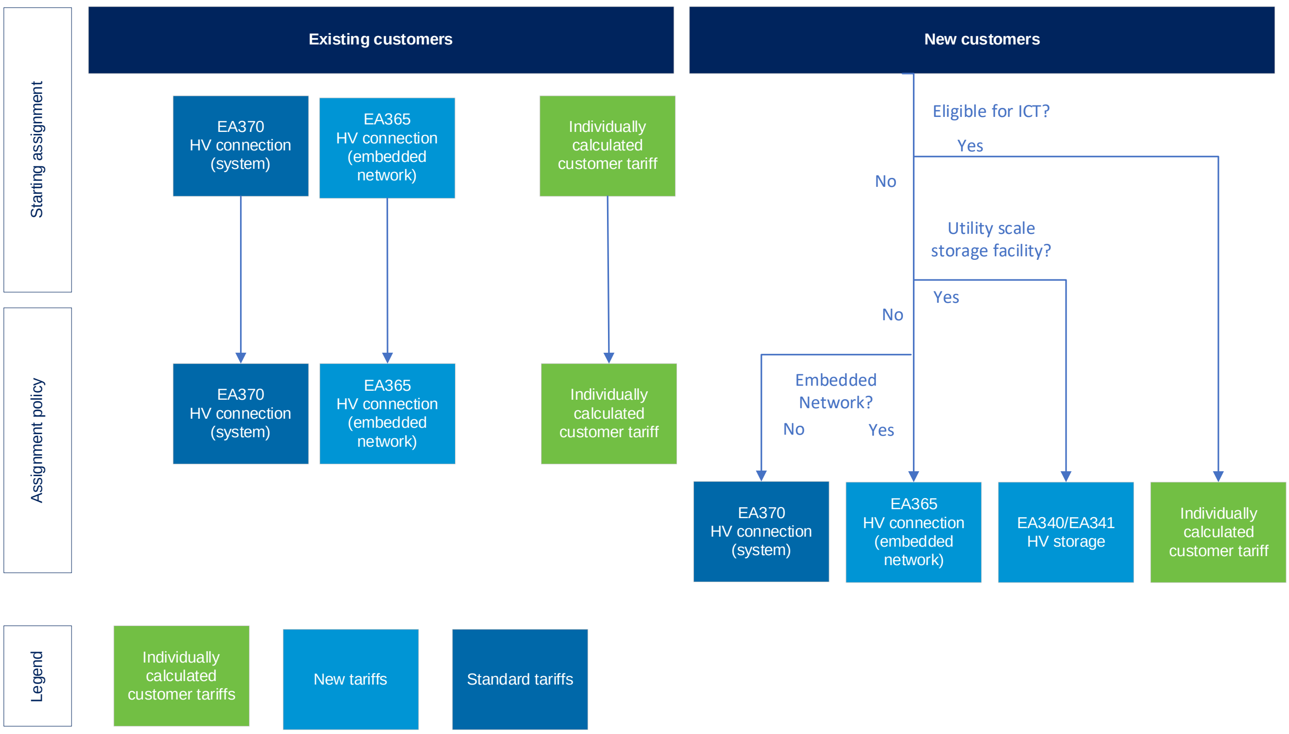
In the first year of the 2024-29 period, we propose to withdraw several high voltage tariffs with few customers and reassign those customers to our main standard tariffs. This is part of our plans to simplify our overall tariff offering. In addition to these changes, we propose to introduce a new tariff to apply to embedded networks connected to our high voltage network, and a utility scale storage tariff.

Figure 9: High voltage customer tariff assignment policy – to apply to regulatory year 2024-25



After the tariff simplification and introduction of an embedded network tariff in the first year, we do not propose to make any further changes to our tariff assignment policies for high voltage customers over the 2024-29 period.

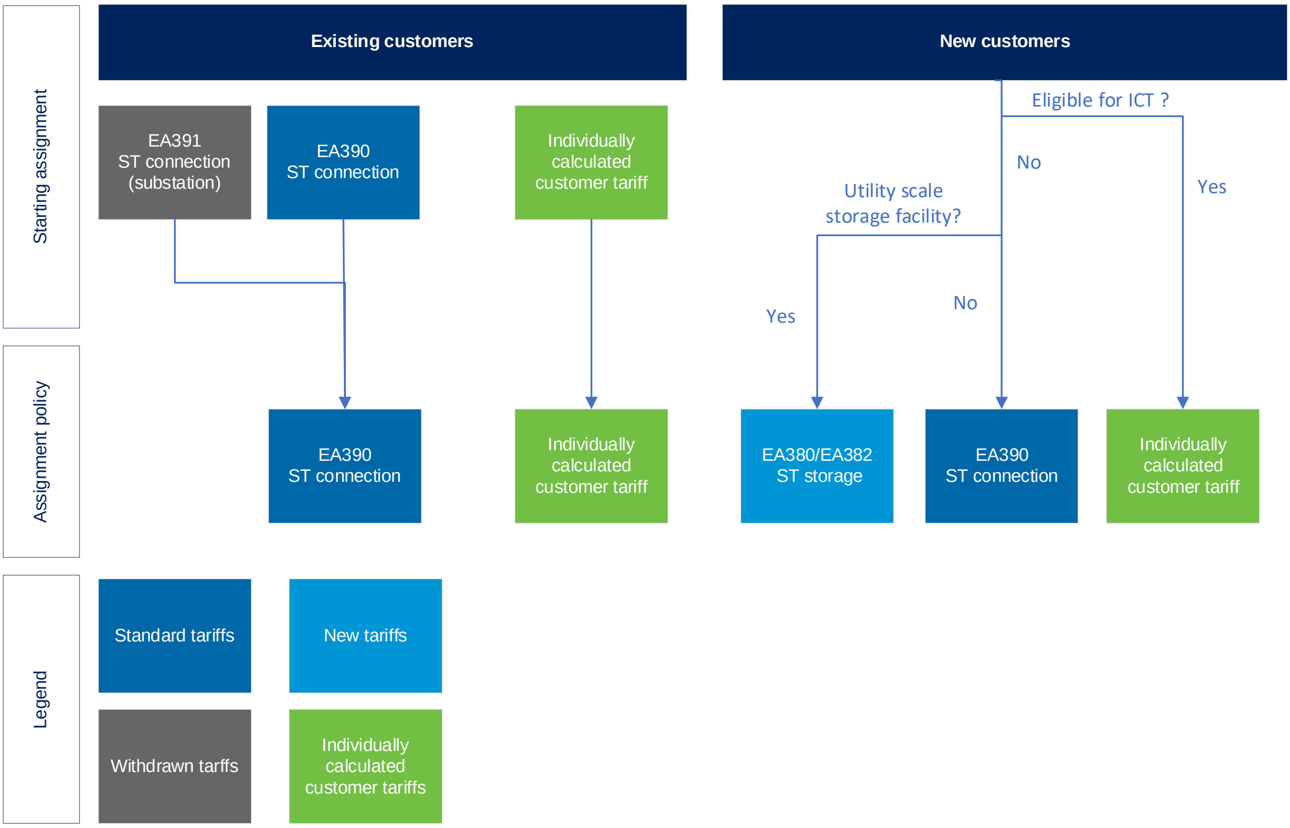
Figure 10: High voltage customer tariff assignment policy – to apply from 1 July 2025



5.5 Sub-transmission customer tariffs

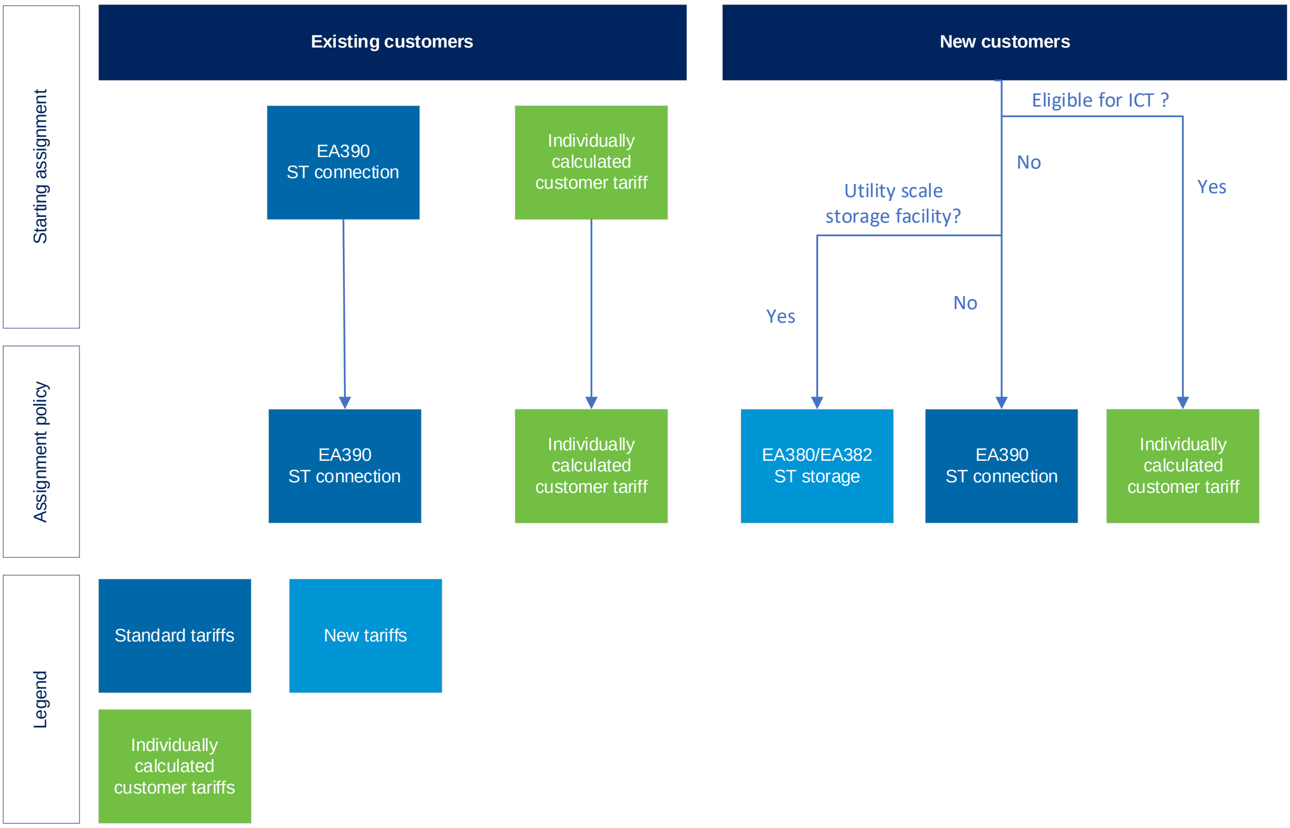
In the first year of the 2024-29 period, we propose to withdraw one tariff with few customers and re-assign those customers to our main standard tariff. This is part of our plans to simplify our overall tariff offering. We also propose to introduce a utility scale storage tariff.

Figure 11: Sub-transmission customer tariff assignment policy – to apply to regulatory year 2024-25



After the tariff simplification in the first year, we do not propose to make any further changes to our tariff assignment policies for sub-transmission connected customers over the 2024-29 period.

Figure 12: Sub-transmission customer tariff assignment policy – to apply from 1 July 2025



5.6 Unmetered customer tariffs

We have made no changes to our tariff assignment policy for unmetered tariffs from the 2019-24 period, and propose no changes for the new regulatory control period unless changes are required to meet NER or AEMO requirements.

Unmetered tariffs apply to network customers that are not required to install a meter to measure the flow of electricity in a power conductor and accordingly there is a requirement to determine by other means the energy data that is deemed to flow in the power conductor.

Table 13: Unmetered tariffs

Tariff name	Tariff code
Public lighting	EA401
Constant unmetered	EA402
EnergyLight	EA403

5.7 Transmission-connected customer tariffs

We have one standard transmission connected tariff (EA501) for customers directly connected to our transmission network. Some customers are also eligible to be assigned to our individually calculated customer tariffs.

5.8 Individually calculated customer tariffs

Customers currently on a published NUOS tariff that have network usage that is greater than 10 MW or 40 GWh per annum over a period of a full year will be reassigned to an Individually Calculated Tariff (**ICT**). Individually calculated tariffs can also be offered to customers expected to satisfy the threshold criteria in the near future and/or customers requiring non-standard connection. ICTs apply to customers assigned to the high voltage, sub-transmission or transmission tariff classes.

Ausgrid will conduct an ICT eligibility assessment in September in the financial year preceding the financial year from which the ICT will apply. This gives Ausgrid sufficient time to calculate an appropriate distribution loss factor for the tariff as distribution loss factors are required to be submitted to the AER and AEMO by late February.

Ausgrid can reassign customers on ICTs whose network usage is expected to permanently fall below 10 MW or 40 GWh per annum over a period of a full financial year, to an appropriate listed tariff unless provided otherwise in the connection agreement with this customer. This reassignment will be notified to the customer by 30 September in the financial year preceding the financial year from which the ICT will cease to apply.

5.9 Green hydrogen exemptions

The NSW Government's Hydrogen Strategy was released in October 2021 to support development of a commercial green hydrogen industry in NSW. The strategy will require a 90% reduction in network charges for eligible green hydrogen facilities. The Electricity Supply Act 1995 has been amended to give effect to these changes and supporting regulations are expected to be released in 2023. We will comply with these regulations and ensure that the reduction in network charges is applied to eligible facilities.

6. Export tariff transition strategy

Ausgrid considers that export services, like consumption services, are a standard service available to almost all our customers. The AEMC's removal of the prohibition on export charges allows distribution businesses to improve the efficiency of our prices by signalling the costs of both consumption and export services to the customers using these services. We will introduce our small customer export tariff (EA960) for residential and small business customers on the timeline allowed by the AEMC. The rule change has also enabled us to create and new innovative tariff structure for storage tariffs that includes export pricing.

6.1 Overview of proposal

In the 2024-29 period, we will base our small customer export tariff on the LRMC (and LRMC savings) of chargeable exports.[39]

We will transition customers to our small customer export tariff (EA960) over two-years:

- From 1 July 2024 our small customer export tariff is available to all residential and small business customers on demand or TOU tariffs on an opt-in basis; and
- From 1 July 2025, we will assign by default all residential and small business customers with demand or TOU tariffs, and all new connections and meter upgrades to our small customer export tariff.

Our assignment policy does not allow customers to opt-out of the small customer export tariff from 1 July 2025. This ensures that customers are paying for the Ausgrid services they use. Similarly, we do not allow customers to opt-out of consumption charges. As our export pricing structure includes charges and rewards, customers who respond to these price signals (e.g. by installing a battery or adopting behavioural changes to shift their consumption profile) will have the opportunity to reduce their exposure to export charges and increase the opportunity to receive export rewards. Further, we expect it is likely our export charges for the 2024-29 will be lower than the feed-in tariffs customers receive from retailers. Therefore, in practice, it is likely customers will perceive these export charges as a reduction in their feed-in tariff, rather than a charge to export.

The revenue recovered for the export tariff will be lower than the attributable costs of export services.[40]

Additionally, our suite of storage tariffs each have export components:

- The sub-transmission storage tariff (EA380/EA382) and high voltage storage tariff (EA340/EA341) reward customers when they export into the Ausgrid network during critical peak energy events; and
- The low voltage storage tariff (EA962/EA963) rewards storage customers for providing network support during critical peak energy events and charges storage customers for load during critical peak export events.

[39] That is exports above the basic export level in the charging window and all exports in the reward window.

[40] To clarify in terms of the NER, our allocation of total efficient costs to the small customer export tariff is lower than if we strictly adhered to the guidance provided by the AER. We consider that our allocation of total efficient costs remains consistent with NER, clause 6.18.5(g).

6.2 Customer consultation and tariff trials

Our export tariff transition strategy has been developed in consultation with our customers. We heard from:

- Voice of Community Panel (citizens jury) – who provided support for a flexible two-way pricing mechanism to optimise electricity supply and demand;[41]
- Ausgrid Pricing Working Group (customer advocate group) – who helped Ausgrid develop our export tariff strategy and provided strong and varied feedback on the export tariff proposal; and
- Submissions – we received feedback on our export tariff transition strategy through submissions to our Pricing Directions Paper.

We have supported the customer consultation with extensive modelling and a tariff trial. Since 1 July 2022, Ausgrid has trialled a residential two-way tariff (EA959/EA960). In this process we have learnt how to implement an export tariff without incurring additional expenditure.

Our modelling found that most residential export customers will see network bill decreases.[42]

6.3 Export tariff transition strategy

We expect that our export tariffs will change in future regulatory periods in response to:

- The forecast costs and savings from exports;
- The customer impacts of changes to export tariffs; and
- The regulatory requirements of export tariffs.

Our best forecasts are that exports are expected to drive substantial future costs on our network. We expect to progressively exhaust intrinsic hosting capacity in many parts of our network. We consider it is important to signal our best estimate of the costs of exports to signal to customers the costs and benefits of changing behaviours and Customer Energy Resources (**CER**) investment.

There is significant uncertainty on the future of CER, particularly if CER will respond to the introduction of a network price signal:

- Customers may respond to our price signal by reducing exports in the charging window and increasing exports in the reward window, which could reduce our future costs of hosting exports on our network. Similarly, responses to changing load charging windows could similarly reduce our future costs of hosting exports on the network.
- Customers may consider the export tariff does not significantly change their export or investment decisions and may continue to increase exports during our export charging window. This could maintain or even increase our future cost of hosting exports.

Our future export tariffs will significantly depend on how export behaviour changes. We consider that network prices are an important factor in export behaviour, but customer energy decisions will be based on a much wider range of factors including costs of electrical technology, wholesale and retail costs, and environmental factors.

Between 2025-26 and 2028-29, we consider we could have justified recovering approximately $5 million per year under the AER's export tariff guidelines. Our indicative DUOS prices show we

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[41] Ausgrid Community Panel Report, *Voice of Community Panel Report,* 2022, Recommendation 9

[42] Relative to not being assigned an export tariff.

will be below this recovery level in the 2024-29 period. In future regulatory periods, we expect to recover a greater proportion of our export costs from export tariffs. The transition will depend on how much we spend on export hosting capacity, LRMC, retailer responses to the export structure, and regulatory requirements.

The amount of expenditure we incur expanding hosting capacity in this and future regulatory periods will influence the revenue recovery from export tariffs. Higher expenditure will increase our need to recover revenue from export tariffs. The LRMC will change overtime. The long-run marginal cost is forward looking and our allowed revenue is based on past and present expenditures. If the LRMC falls after we have invested to expand hosting capacity, LRMC based tariffs will recover less revenue. To ensure export customers recover a fair amount of the costs for our investments in expanding hosting capacity we may need to recover costs in other ways.

Until 2034 we are required to include a basic export level.[43] The basic export level in this regulatory period removes the price signal from around 70% of exports that drive our future network costs. Reducing or removing the basic export level will allow greater cost recovery and reduce inefficient signals that may drive inefficient network use and investment.

We will continue to consult with our stakeholders on export tariffs and their evolution in our network.

[43] NER, clause 11.141.13

7. Alternative control services

Ausgrid provides three categories of alternative control services: public lighting, type 5 and 6 metering and ancillary network services. Each alternative control service category is its own tariff class. These services are subject to different pricing mechanisms than standard control service network tariffs and operate under a price cap mechanism as decided in our final framework and approach.[44] Attachment 8.11 contains the indicative pricing schedule 2024-29 for ACS.

7.1 Public lighting

Provision of public lighting services in NSW is governed by the Public Lighting Code.[45] Our services include:

- Condition monitoring and maintenance planning;
- Luminaire cleaning and inspection;
- Lamp replacement and disposal;
- Luminaire replacement and refurbishment;
- Outage detection; and
- Inspection, test, repair and replacement of equipment.

We recover our costs through three charging structures:

- For lighting installed after July 2009, a capital charge for luminaires, brackets, smart controllers and poles where the pole is a dedicated lighting pole. This is an annual charge per asset;
- For lighting assets installed before July 2009, a total capital charge relating to all pre-July 2009 installed public lighting assets for each customer, mainly local councils, per annum; and
- A maintenance charge which is an annual charge per luminaire, and connection type where the connection is underground.

The post-2009 capital charges are levied according to the type of luminaire, bracket or pole, and whether it is located on a minor or major road. The maintenance charges also vary depending on the lighting technology, i.e. LED or traditional/legacy, and whether it is located on a minor or major road.

7.2 Type 5 and 6 metering

Ausgrid provides basic metering services to customers in our network area. While customers can switch to an advanced meter through their retailer, many customers still retain their basic Ausgrid meter. As customers transition to advanced meter offerings, they cease to receive an Ausgrid provided regulated metering service. Accordingly, our role in providing metering services is declining as the transition to advanced meters occurs.

The cost of providing these services are not uniform for all customers because:

- If their meter was installed before 30 June 2015, Ausgrid funded the cost of the meter; and

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[44] AER, Framework and Approach for Ausgrid, Endeavour Energy and Essential Energy: Regulatory control period commencing 1 July 2024, July 2022, 39.

[45] https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/public-lighting-code

- If their meter was installed after that date, the customer paid for the meter upfront.

To reflect this difference, our current metering pricing includes two charges – a capital charge that reflects the cost of funding the meter, and a non-capital charge which reflects the cost of delivering meter reading, testing and maintenance services.

We apply these charges so that customers who paid for their own meter upfront via their retailer only pay the non-capital charge, while customers with an Ausgrid funded meter may pay both charges. The charges are per meter per year, and by customer type as defined by the network tariff.

7.3 Ancillary network services

To recover our costs associated with ancillary network services, we levy fees on the requesting party. The fees that we charge may be either of the following:

- a fixed fee — applied to services where delivery involves a consistent level of effort each time and are based on the average time required to deliver a service and hourly labour rates; and
- a quoted fee — applied to services where the delivery time varies significantly, depending on size and complexity of the work involved and are based on estimated time required to deliver the service and hourly labour rates.

One fee, material sales, is based on the cost of the materials plus a margin.

7.4 Consistency with the NER

The prices we have proposed reflect the efficient cost of providing each service.

Price changes in each year of the regulatory period are defined by the relevant control mechanism, which we will apply at each annual pricing proposal.

A. Appendix: Compliance checklist

This TSS is a requirement of the NER. The below table outlines requirements from version 193 of the NER and where we have addressed these rule requirements within this TSS.

NER reference	Requirement(s)	Relevant section of Ausgrid's submission
6.8	Regulatory proposal and proposed tariff structure statement	
6.8.2	Submission of regulatory proposal, tariff structure statement and exemption application	
6.8.2(a), (b)	A *Distribution Network Service Provider* must, whenever required to do so under paragraph 6.8.2(b) (i.e. at least 17 months before the expiry of a distribution determination that applies to the Distribution Network Service Provider), submit to the *AER* a *regulatory proposal* and a proposed *tariff structure statement* related to the *distribution services* provided by means of, or in connection with, the *Distribution Network Service Provider's distribution system*.	This TSS
6.8.2(c)(7)	A *regulatory proposal* must include a description (with supporting materials) of how the proposed *tariff structure statement* complies with the *pricing principles for direct control services* including: i) a description of where there has been any departure from the pricing principles as set out in paragraphs 6.18.5(e) to (g) of the NER; and ii) an explanation of how that departure complies with clause 6.18.5(c) of the NER.	TSS Chapter 3 and TSS Explanatory Statement
6.8.2(c1)(2)	The *regulatory proposal* must be accompanied by an overview paper in reasonably plain language which includes: i) a description of how the *Distribution Network Service Provider* has engaged with relevant stakeholders including *distribution service end users* or groups representing them and (in relation to the *tariff structure statement*) *retailers* and *Market Small Generation Aggregators* in developing the *regulatory proposal* and the proposed *tariff structure statement* including the *export tariff transition strategy*; ii) the relevant concerns identified as a result of that engagement; and iii) how the *Distribution Network Service Provider* has sought to address those concerns.	2024-29 Regulatory Proposal - Overview
6.8.2(c1)(5)	The *regulatory proposal* must be accompanied by an overview paper in reasonably plain language which includes a description of the key risks and benefits for *distribution service end users* of the *regulatory proposal* and the	2024-29 Regulatory Proposal - Overview

NER reference	Requirement(s)	Relevant section of Ausgrid's submission
	proposed tariff structure statement including the *export tariff transition strategy*;	
6.8.2(d1)	The proposed *tariff structure statement* must be accompanied by an *indicative pricing schedule*.	Attachments 8.15 and 8.17 indicative pricing schedules
6.8.2(d2)	The proposed *tariff structure statement* must comply with the *pricing principles for direct control services*.	TSS Chapter 3
6.8.2(e)	If more than one *distribution system* is owned, controlled or operated by a *Distribution Network Service Provider*, then, unless the *AER* otherwise determines, a separate *tariff structure statement* are to be submitted for each *distribution system*.	Not applicable
6.8.2(f)	If, at the commencement of this Chapter, different parts of the same distribution *system* were separately regulated, then, unless the *AER* otherwise determines, a separate *tariff structure statement* are to be submitted for each part as if it were a separate *distribution system*.	Not applicable
6.18	Distribution Pricing Rules	
6.18.1A	Tariff Structure Statement	
6.18.1A(a)(1)	A *tariff structure statement* must include the *tariff classes* into which *retail customers* for *direct control services* will be divided during the relevant *regulatory control period*.	TSS Chapter 2
6.18.1A(a)(2)	A *tariff structure statement* must include the policies and procedures the *Distribution Network Service Provider* will apply for assigning *retail customers* to tariffs or reassigning *retail customers* from one tariff to another (including any applicable restrictions).	TSS Chapter 5
6.18.1A(a)(2A)	A *tariff structure statement* must include a description of the strategy or strategies the *Distribution Network Service Provider* has adopted, taking into account the pricing principle in clause 6.18.5(h), for the introduction of *export tariffs* including where relevant the period of transition (*export tariff transition strategy*);	TSS Chapter 6
6.18.1A(a)(3)	A *tariff structure statement* must include the structures for each proposed tariff.	TSS Chapter 4
6.18.1A(a)(4)	A *tariff structure statement* must include the *charging parameters* for each proposed tariff.	TSS Chapter 4
6.18.1A(a)(5)	A *tariff structure statement* must include a description of the approach that the *Distribution Network Service Provider* will take in setting each tariff in each *pricing proposal* during the	TSS Chapter 3

NER reference	Requirement(s)	Relevant section of Ausgrid's submission
	relevant *regulatory control period* in accordance with clause 6.18.5 (pricing principles). Note: Under clause 11.141.13(a), a *tariff structure statement* of a *Distribution Network Service Provider* applicable during the tariff transition period for the *Distribution Network Service Provider* must also include, for each proposed *export tariff*, the basic export level or the manner in which the basic export level will be determined and the eligibility conditions applicable to each proposed *export tariff*.	TSS Chapters 5 and 6 (for export tariff eligibility conditions)
6.18.1A(b)	A *tariff structure statement* must comply with the *pricing principles for direct control services*.	TSS Chapter 3
6.18.1A(e)	A *tariff structure statement* must be accompanied by an *indicative pricing schedule* which sets out, for each tariff for each *regulatory year* of the *regulatory control period*, the indicative price levels determined in accordance with the *tariff structure statement.*	Attachments 8.15 and 8.17 indicative pricing schedules
6.18.3	Tariff Classes	
6.18.3(b)	Each customer for *direct control services* must be a member of 1 or more *tariff classes*.	TSS Chapter 2
6.18.3(c)	Separate *tariff classes* must be constituted for *retail customers* to whom *standard control services* are supplied and *retail customers* to whom *alternative control services* are supplied (but a customer for both *standard control services* and *alternative control services* may be a member of 2 or more *tariff classes*).	TSS Chapter 2
6.18.3(d)	A *tariff class* must be constituted with regard to: 1. the need to group *retail customers* together on an economically efficient basis; and 2. the need to avoid unnecessary transaction costs.	TSS Chapter 2
6.18.4	Principles governing assignment or re-assignment of retail customers to tariff classes and assessment and review of basis of charging	
6.18.4(a)	In formulating provisions of a distribution determination governing the assignment of *retail customers* to *tariff classes* or the re-assignment of *retail customers* from one *tariff class* to another, the *AER* must have regard to the following principles:	Noted
6.18.4(a)(1)	*retail customers* should be assigned to *tariff classes* on the basis of one or more of the following factors: i) the nature and extent of their usage or intended usage of *distribution services*; ii) the nature of their connection to the *network*;	TSS Chapters 2 and 5

NER reference	Requirement(s)	Relevant section of Ausgrid's submission
	iii) whether remotely-read interval metering or other similar metering technology has been installed at the *retail customer's* premises as a result of a *regulatory obligation or requirement*.	
6.18.4(a)(2)	*retail customers* with a similar *connection* and *distribution usage* profile should be treated on an equal basis, subject to subparagraph (3A).	TSS Chapters 2 and 5
6.18.4(a)(3A)	*retail customers connected* to a *regulated SAPS* should be treated no less favourably than *retail customers connected* to the interconnected national electricity system.	TSS Chapter 2 (FY25 trial tariffs)
6.18.4(a)(4)	a *Distribution Network Service Provider's* decision to assign a customer to a particular *tariff class*, or to re-assign a customer from one *tariff class* to another should be subject to an effective system of assessment and review. Note: If (for example) a customer is assigned (or reassigned) to a *tariff class* on the basis of the customer's actual or assumed *maximum demand*, the system of assessment and review should allow for the reassignment of a customer who demonstrates a reduction or increase in *maximum demand* to a *tariff class* that is more appropriate to the customer's *load* profile.	TSS Chapter 2
6.18.4(b)	If the *charging parameters* for a particular tariff result in a basis of charge that varies according to the *distribution service* usage or load profile of the customer, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged.	TSS Chapters 2, 4 and 5
6.18.5	Pricing principles	
6.18.5(a)	Network pricing objective The *network pricing objective* is that the tariffs that a *Distribution Network Service Provider* charges in respect of its provision of *direct control services* to a *retail customer* should reflect the *Distribution Network Service Provider's* efficient costs of providing those services to the *retail customer*. Note: Charges in respect of the provision of direct control services may reflect efficient negative costs.	TSS Chapter 3
6.18.5(b)	Application of the pricing principles Subject to paragraph 6.18.5(c), a *Distribution Network Service Provider's* tariffs must comply with the pricing principles set out in paragraphs (e) to (j).	TSS Chapter 3

NER reference	Requirement(s)	Relevant section of Ausgrid's submission
6.18.5(c)	A *Distribution Network Service Provider's* tariffs may vary from tariffs which would result from complying with the pricing principles set out in paragraphs (e) to (g) only: (1) to the extent permitted under paragraph (h); and (2) to the extent necessary to give effect to the pricing principles set out in paragraphs (i) to (j).	TSS Chapter 3
6.18.5(d)	A *Distribution Network Service Provider* must comply with paragraph (b) in a manner that will contribute to the achievement of the *network pricing objective*.	TSS Chapter 3
6.18.5(e)	Pricing Principles For each *tariff class*, the revenue expected to be recovered must lie on or between: (1) an upper bound representing the stand alone cost of serving the *retail customers* who belong to that class; and (2) a lower bound representing the avoidable cost of not serving those *retail customers*.	TSS Chapter 3
6.18.5(f)	Each tariff must be based on the *long run marginal cost* of providing the service to which it relates to the *retail customers* assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to: (1) the costs and benefits associated with calculating, implementing and applying that method as proposed; (2) the additional costs likely to be associated with meeting demand from *retail customers* that are assigned to that tariff at times of greatest utilisation of the relevant service; and (3) the location of *retail customers* that are assigned to that tariff and the extent to which costs vary between different locations in the *distribution network*.	TSS Chapter 3
6.18.5(g)	The revenue expected to be recovered from each tariff must: (1) reflect the *Distribution Network Service Provider's* total efficient costs of serving the *retail customers* that are assigned to that tariff; (2) when summed with the revenue expected to be received from all other tariffs, permit the *Distribution Network Service Provider* to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the *Distribution Network Service Provider*; and (3) comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage	TSS Chapter 3

NER reference	Requirement(s)	Relevant section of Ausgrid's submission
	of the relevant service that would result from tariffs that comply with the pricing principle set out in paragraph (f).	
6.18.5(h)	A *Distribution Network Service Provider* must consider the impact on *retail customers* of changes in tariffs from the previous *regulatory year* and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the *Distribution Network Service Provider* considers reasonably necessary having regard to: (1) the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one *regulatory control period*); (2) the extent to which *retail customers* can choose the tariff to which they are assigned; and (3) the extent to which *retail customers* are able to mitigate the impact of changes in tariffs through their decisions about usage of services.	TSS Chapter 3, TSS explanatory statement and Attachment 8.3 bill impacts
6.18.5(i)	The structure of each tariff must be reasonably capable of: (1) being understood by *retail customers* that are or may be assigned to that tariff (including in relation to how decisions about usage of services or controls may affect the amounts paid by those customers) or (2) being directly or indirectly incorporated by *retailers* or *Market Small Generation Aggregators* in contract terms offered to those customers, having regard to information available to the *Distribution Network Service Provider*, which may include: (3) the type and nature of those *retail customers*; (4) the information provided to, and the consultation undertaken with, those *retail customers*; and (5) the information provided by, and consultation undertaken with, *retailers* and *Market Small Generation Aggregators*.	TSS Chapter 4 and TSS explanatory statement
6.18.5(j)	A tariff must comply with the *Rules* and all *applicable regulatory instruments*.	Noted
11.141	Rules consequential on the making of the National Electricity Amendment (Access, pricing and incentive arrangements for distributed energy resources) Rule 2021	
11.141.13	Basic export levels to be specified in tariff structure statements	

NER reference	Requirement(s)	Relevant section of Ausgrid's submission
11.141.13(a)(1)	For the purposes of new clause 6.18.1A(a), a tariff structure statement of a Distribution Network Service Provider that will apply during the tariff transition period for the Distribution Network Service Provider must include, in addition to the elements in new clause 6.18.1A(a): (1) for each proposed export tariff, the basic export level or the manner in which the basic export level will be determined; and (2) the eligibility conditions applicable to each proposed export tariff.	TSS Chapters 3 and 5

RIN obligations (26 October 2022)

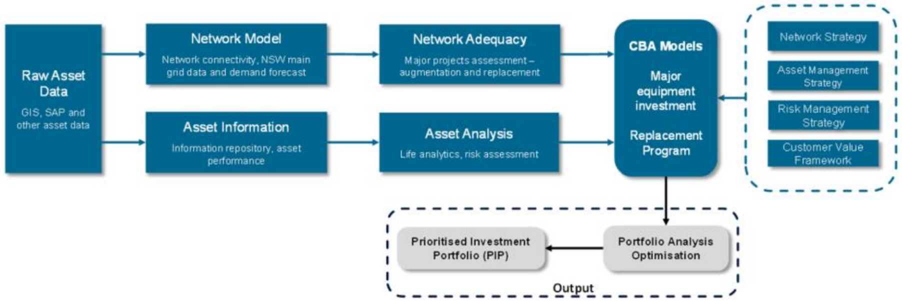
RIN reference	Requirement(s)	Relevant section of Ausgrid's submission
4	Supporting information requirements	
4.2.5(f)	Provide the models Ausgrid has used to: … calculate the long run marginal cost estimates in Ausgrid's proposed tariff structure statement;	Attachment 8.4 and 8.5 LRMC models
4.11	Proposed tariff structure statement	
4.11.1	Provide and describe the methodology and assumptions used to prepare the long run marginal cost estimates in Ausgrid's tariff structure statement.	Attachment 8.6 Houston Kemp LRMC paper
4.11.2	Describe the relationship between the expenditure, demand and other inputs (as appropriate) used in the model provided under this section and the expenditure, demand and other forecasts (as appropriate) provided as part of the building block proposal for the forthcoming regulatory control period.	TSS Appendix B RIN.11 Houston Kemp LRMC paper
4.11.3	If Ausgrid calculates the long run estimate cost estimates using a method different from the Average Incremental Cost method, Ausgrid must provide all inputs, definitions and sources for inputs, a description of the methodology, and calculations for every stage of the methodology in the in the materials submitted to the AER.	Attachment 8.6 Houston Kemp LRMC paper Attachment 8.4 and 8.5 LRMC models
4.11.4	Describe the methods and assumptions used to derive the disaggregated capex beyond the forthcoming regulatory control period. Provide any model(s) used to derive such capex.	TSS Appendix B Attachment 8.4 and 8.5 LRMC models
4.11.5	Describe the methods and assumptions used to derive the disaggregated opex beyond the forthcoming regulatory control period. Provide any model(s) used to derive such opex.	TSS Appendix B Attachment 8.4 and 8.5 LRMC models
4.11.6	Describe the methods and assumptions used to derive the disaggregated demand beyond the forthcoming regulatory control period. Provide any model(s) used to derive such demand.	TSS Appendix B Attachment 8.4 and 8.5 LRMC models

B. Appendix: Supporting information to LRMC inputs

<table>
<tr><th>4.11</th><th>RIN obligation</th><th>Responses</th></tr>
<tr><td>4.11.2</td><td>Describe the relationship between the expenditure, demand and other inputs (as appropriate) used in the model provided under this section and the expenditure, demand and other forecasts (as appropriate) provided as part of the building block proposal for the forthcoming regulatory control period.</td><td>The demand forecast is a critical set of information required to determine the need for investments to augment the network. This is combined with data that describes the performance of the existing network (i.e. asset life, asset capacity, connections, load transfer capabilities, failure rates, repair times, etc) in a model that forecast the performance of the current network to determine the level of supply risks posed to customers.

The model identifies and quantifies the risks (i.e. supply risks measured as expected unserved energy, safety risks, environmental risks, etc). The consequences of these risks are converted into economic impact measured in dollars and included as benefits in a Cost-Benefit Analysis, because the reduction of these risks is a benefit to the market (i.e Ausgrid and its customers).

Ausgrid applies Cost-Benefit Analysis to make capital investment decisions in network assets. This is the approach to determine if network augmentation investments are required at the subtransmission and distribution levels. These investment decisions are in-turn included in a Prioritised Investment Portfolio (PIP). A high-level description of the process and the relationships between demand, expenditure and other inputs is provided in the diagram below.


</td></tr>
</table>

4.11.4	Describe the methods and assumptions used to derive the disaggregated capex beyond the forthcoming regulatory control period. Provide any model(s) used to derive such capex.	Once the network constraint triggering network augmentation is identified, an Options Analysis is performed to identify the network solutions capable of resolving the constraint. Both network and non-network solutions or options are considered. Generally, the parameters considered to identify network options are capacity/size (MVA), site specific conditions (space available, access difficulties) and timeframe required to deliver the solution. Opportunities are also sought to improve network arrangement, potential for staging of investments and/or potential for implementing holistic solutions addressing multiple issues. Multiple options are considered at the initial stage, but as the assessment considers the magnitude of the investment or the ability to deliver the solution at the required time, some of the initial proposals are filtered and not pursued any further. After that, only few options are considered for comparison in an economic analysis, which is undertaken to determine the option that maximises the market benefit. In some cases, preliminary investigations are carried out to gain a better understanding (and refined cost estimates) of the feasibility of an option prior to economic analysis. All options require an estimation of the investment costs required to procure, install and commission new assets. Ausgrid's cost estimation is based on unit rates and building blocks of network assets that are updated regularly, based on previous projects undertaken in previous years, and consideration of market conditions (i.e. available suppliers, commodity prices, inflation, etc). The latest set of unit rates is uploaded in a cost estimation model (SAP Analytics Cloud or SAC) jointly developed by Ausgrid with consultants, which also take into consideration the typical construction timeframes to develop the cash flow of the proposed investment over the construction period.
4.11.5	Describe the methods and assumptions used to derive the disaggregated opex beyond the forthcoming regulatory control period. Provide any model(s) used to derive such opex.	Consideration is given to include a high-level estimate of preventative maintenance, including an allowance for regular inspections and to undertake a maintenance program. In general, a percentage relative to the capital cost of the asset is used to derive opex for network assets. This percentages are usually between 0.5% and 2%, depending on the network asset type. For instances, the lower value is usually assigned for underground cables because they are less prone than other assets to have breakdowns. These values are included in the economic analysis to determine the Net Present Value of the options in the Options analysis, but generally they are not material relative to the capex values.
4.11.6	Describe the methods and assumptions used to derive the disaggregated demand beyond the forthcoming regulatory control period.	Forecasted demand across the network is disaggregated into 3 voltage levels namely Low Voltage (LV), 11kV High Voltage (HV) and 33kV and above Subtransmission (ST), and segmented into the 25 area plans to facilitate the calculation of LRMC. Zone substation, subtransmission substation, and HV customer forecasted demand is produced as per methodology and assumptions outlined in Attachment 5.6.a - Maximum Demand Forecast.

	Provide any model(s) used to derive such demand.	For disaggregation to LV and 11kV HV demand: a) 11kV HV customer load at time of system peak for the latest processed year is extracted from metering interval data and aggregated by connecting zone substation b) Zone substation actual peak demand for the latest processed year is extracted from forecasting system c) The ratio of 11kV HV demand at a zone substation as a percentage of total the zone substation demand is calculated d) Zone substation forecast demand for each year is diversified to system peak e) 11kV HV ratio is applied to forecasted zone substation demand to calculate the forecasted HV demand f) Zone forecast demand minus the calculated forecast HV demand at the location is the residual LV forecast demand g) HV forecast demand and LV forecast demand for each zone substation and each year is aggregated by 25 area plans For disaggregation to ST demand: h) Forecast demand for subtransmission customers connected at 33kV and above is extracted from forecast system, diversified to system peak, and categorised by area plan i) Forecast demand in h) is adjusted for known major customer connections forecasted to occur at 33kV and above j) Forecast demand for each forecast year in i) is aggregated to ST forecast demand by 25 area plans

January 2023

Our TSS Explanatory Statement for 2024–29

Empowering communities for a resilient, affordable and net-zero future.

Ausgrid

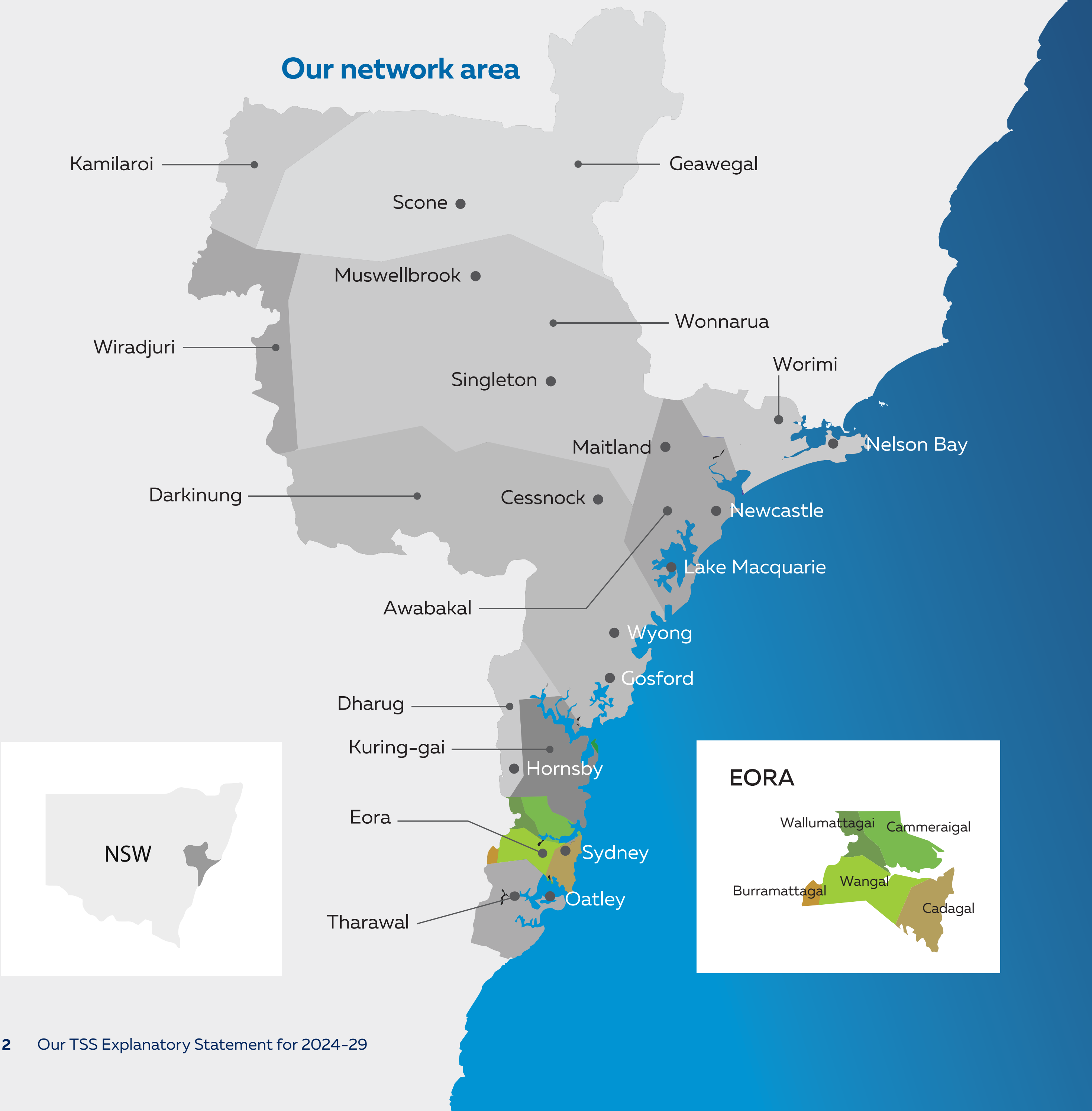
Acknowledgment of Country

We acknowledge the Traditional Custodians of the lands where the Ausgrid distribution network is located, and we pay our respects to the elders past, present and emerging.

As set out in our Reconciliation Action Plan, it is important that this recognition leads to industry wide support and understanding of the knowledge, stories, languages and experiences of Aboriginal and Torres Strait Islander peoples, as our way of paying respect, and contributing to, some of the oldest continuous cultures of the world.

Our network and operations span the traditional country of 17 languages, tribal and nation groups in Sydney, the Central Coast and Hunter regions of New South Wales. We want to lead and foster a workforce, and approach to our operations, that embraces the learnings, voices, cultures and histories of these Traditional Owners into our own organisation.

Our network area



Contents

Executive summary

As the provider of the poles and wires delivering electricity to homes and businesses across large parts of Greater Sydney, the Central Coast and the Hunter, Ausgrid plays a pivotal role in connecting communities and empowering the lives of over four million Australians. Our network provides a platform for customers to make choices based on what is important to them, be that affordability, decarbonisation, or other priorities. Because of this, we need a strong plan for our future network prices.

In 2019 we introduced new demand tariffs for households and small businesses, which offered our customers lower bills for spreading out the use of electrical appliances. Further pricing reform is required to support the evolving needs of our changing sector. We need to get ahead of the changes facing our customers, our industry, and our world. Rising temperatures and more frequent and severe bushfires, floods and storms mean the effects of climate change – and the need for a net zero future – are more apparent than ever before. New ways of living and working are leading to new patterns of energy use and customers are expecting individualised and affordable, zero emissions energy solutions. These changes create new opportunities for customers to be rewarded for using the network more flexibly. This improves utilisation of the grid, lowering the overall cost of the system.

1.1 Pricing reform is a significant opportunity

We want to maximise the opportunities for retailers and other partners, such as aggregators, to reward customers for their flexible use of the grid. We are building on reforms we have already introduced, such as trialling new incentives for customers to realise the shared value of rooftop solar, home batteries and electric vehicles. Digitisation will facilitate 'prices for devices', a future where retailers and aggregators leverage advanced computing to manage any network tariff complexity, so customers do not have to. Our data-driven initiatives, such as Project Edith[1] and our Customer Energy Resource (**CER**) integration strategy, are also showcasing the potential of new green technology solutions such as Virtual Power Plants to decarbonise the system at lowest cost.

Ausgrid remains committed to delivering options that cater for our diverse communities and customers who use our network. We appreciate that our customers' access to new technology will vary. We know customers and our partners expect an orderly transition that supports choice and involves solutions that set us on the right path for the long term. We will always balance innovative options with simple solutions and ensure customers are supported through change. We will continue building trust with the community through leadership and a clear commitment to support a fair, affordable, resilient and decarbonised system for the benefit of all.

We can only unlock these opportunities if we work together. Ausgrid is excited to collaborate with Governments, retailers and other partners to explore and communicate solutions, so all customers can benefit from the opportunities on offer, if they choose to do so.

Together we can improve the outcomes for NSW electricity customers and the communities we serve.

We have conducted extensive engagement with our communities, to guide and inform us as we develop our revenue, expenditure and pricing proposals for the 2024-29 period. This TSS Explanatory Statement provides information on our pricing reforms and tariff innovation to support our TSS compliance document.

1 Project Edith is an initiative that aims to showcase how the grid can facilitate technology and green energy solutions like Virtual Power Plants to participate in energy markets while responding to dynamic network pricing. See our website for more information.

1.2 Our proposed pricing reforms for 2024-29

We are developing a set of pricing reforms that respond to the changes and opportunities in the energy sector in the 2024-29 period, and what we are hearing from our customers and communities. Our key proposals are outlined in **Table 1** and discussed in detail in **Section 4** of this paper.

Table 1: Proposed pricing reforms from 1 July 2024

Reform	What and why	What has changed since the Pricing Directions Paper
Export tariffs	Introduce opt-in export pricing for small customers in July 2024, and make it the default assignment for new and existing[2] small customers on time of use (**TOU**) tariffs and demand network tariffs from July 2025. Our proposed tariff has a charge and a reward component. The proposed level of the charge is low, and we expect it to have minimal bill impacts over the 2024-29 period. We want to empower customers to use the network and maximise the value they get from self-generation, benefiting from being flexible, and facilitating the transition to net zero.	We have increased the reward price and lowered the export charge, in response to stakeholder feedback. We also consulted on not allowing customers to opt-out of the export tariff. We found support for reducing bill impacts for customers who don't have access to CER. This can be achieved by not allowing customer opt-outs of the export tariff.
Tariff streamlining	Withdraw 10 network tariffs that are very similar to other tariffs, or have few or no customers assigned to them. This will increase the likelihood of our tariff offerings being passed through by retailers or responded to by market aggregators.	We propose to retain our two introductory demand tariffs (EA111 and EA251), to introduce customers to this price signal over 12 months.
Embedded network pricing	Introduce 3 tariffs for embedded networks (**ENs**) with medium or large annual energy usage with a five-year transition period. These will be the default tariffs for new and existing ENs connected to our network from 1 July 2024.	Following feedback, we propose to introduce the tariffs over a five-year transition period.
Utility scale storage	Introduce tariffs for utility scale storage facilities connected at our sub-transmission, high and low voltage parts of our network. This will enable storage projects to connect to our network where there is existing capacity and reduce network charges for other customers by contributing to residual revenue.	We originally proposed to introduce trial tariffs for storage facilities. As a result of our consultation, we propose to introduce storage tariffs as part of our standard tariff offerings (instead of as a trial tariff). This will also ensure we are ready to support federal and state government community battery programs by having appropriate tariffs for proponents.
Business customer tariff assignment	Lift the lower usage threshold at which capacity charges apply from 40 MWh to 100 MWh. This change will align with the NSW ombudsman scheme and the National Energy Retail Law Regulation 2020 (NSW) definition of a small customer. It will also improve available options in our tariff assignment process for small business customers.	No changes to our proposal.

2 NER, clause 11.141.1 defines an existing CER customer as one that was connected as of 19 August 2021

Table 1: Proposed pricing reforms from 1 July 2024

Continued

Reform	What and why	What has changed since the Pricing Directions Paper
Controlled load	Change the switching times for controlled load devices to allow customers to use these devices during the daytime, when solar customers are exporting to the grid. This proposal will encourage soaking of solar exports during the day, improve network utilisation, and potentially reduce greenhouse gas emissions, improving pricing efficiency and supporting the transition to net zero.	No changes to our proposal.
Charging windows	Move our peak period window to later in the day for customers on TOU and demand/capacity network tariffs, and extend it to weekends for residential customers. These changes will ensure our peak charges accurately signal the periods when these customers' energy use imposes highest costs on the network, improving pricing efficiency and fairness.	No changes to our proposal.

To help implement these reforms we are proposing transitional arrangements, which mostly apply in the first year or first couple of years of the regulatory period, depending on the measure. By the end of the regulatory period, our overall tariff strategy will include the following core features:

- All customers with a smart meter are assigned to a cost reflective network tariff;
- Cost reflective tariffs are available for utility scale storage facilities;
- All customers on TOU, demand or capacity tariffs have simpler tariffs – with only two charging windows, peak and off-peak;
- All residential and small business customers are assigned to modest export pricing arrangements – incorporating both charges and rewards depending on the time of export; and
- All embedded network connections connected to the LV network (with annual consumption >160 MWh) or connected to the HV network are assigned to embedded network tariffs.

Introduction

As the provider of the network that delivers electricity to homes and businesses across large parts of Greater Sydney, the Central Coast and the Hunter, Ausgrid plays a vital role in connecting communities and empowering the lives of more than four million Australians.

How we charge customers for our network services can influence when and how customers use electricity and give them flexibility to choose what is important to them – for example, convenience, lower bills, or lower carbon emissions. Our pricing can also influence the costs we incur in providing our services, and how we recover those costs from different customers – for example, the extent to which our pricing reflects the higher or lower costs that patterns of electricity use impose on the network, or result in some customers paying or more or less than their fair share. Because of this, we are proposing a comprehensive plan for our future network prices, which takes into account customer and stakeholder views.

2.1 Purpose of this document

This TSS Explanatory Statement supports our TSS compliance paper and provides further detail on our pricing reform and pricing innovation proposals for 2024-29.

The sections that follow outline:

- The challenges and opportunities in the energy sector our proposed pricing reforms are responding to;
- How we have engaged with our communities to inform the development of our TSS;
- Our proposed pricing reforms for 2024-29, including how they meet our pricing principles and respond to what we are hearing in our engagement with our communities;
- Our proposed tariff innovation for 2024-29, including tariff trials to test and guide future pricing reforms; and
- Where we think our network tariffs are heading, as we look beyond 2030.

Throughout these sections, we provide and respond to the feedback we have received from stakeholders, either via submissions, Pricing Working Group (**PWG**) meetings, the retailer forum, or our meetings with customers.

2.2 Our current network prices

We have different network prices for our residential and small business customers and for our medium and large business customers.

For residential and small business customers, retailers package up our prices with the other costs of electricity supply – including wholesale, environmental and retail costs. Retailers' pricing structures might mirror the structure of our network prices, or have another structure entirely.

Historically, most of our residential and small business customers have been on network prices with a flat energy-based structure, which means they paid a fixed rate for every kWh of electricity they used. This is because older electricity meters only recorded the amount of energy used over time. However, this flat tariff structure:

- **Is not cost-reflective –** our costs are not driven by how much energy our customers use over time, but by how much energy our customers use **at the same time** (the peak demand on our network). Our costs are also expected to increasingly be driven by the amount of energy customers export to the grid at the same time.
- **Does not give customers much control over their bills –** with a flat energy-based structure, the only way customers can lower the network cost component in their bill is to lower their overall energy usage.

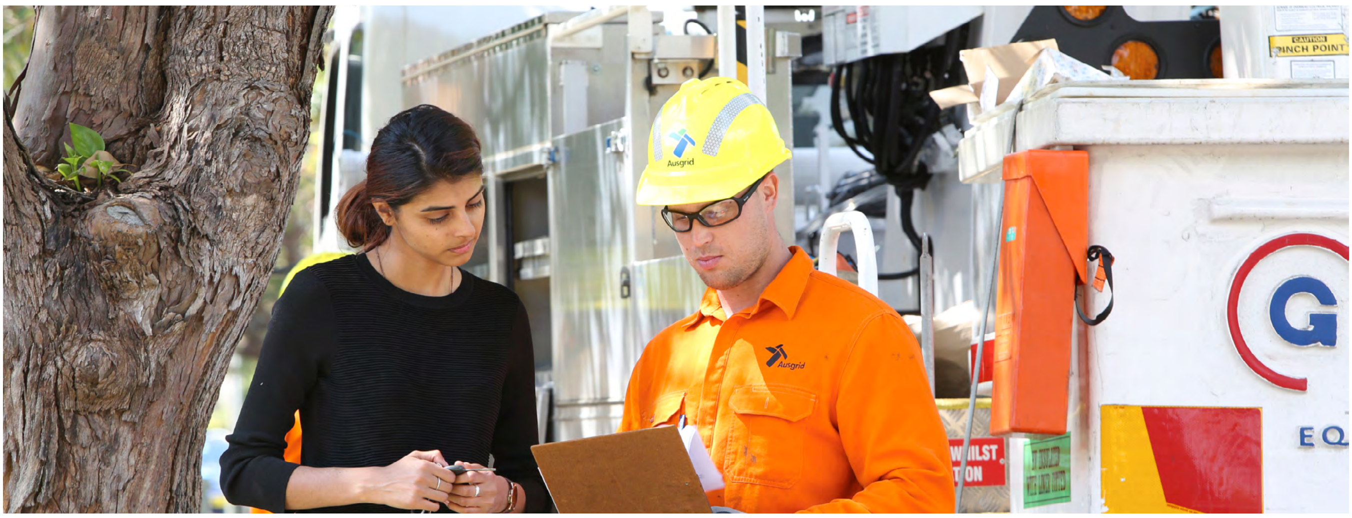
As metering technology has improved, we have implemented several pricing reforms to make our residential and small business tariffs more cost-reflective and give our customers more power to influence their bills. In 2003, we introduced TOU pricing for small customers with interval ready meters. These prices have a range of 'charging windows', so customers pay a higher rate for energy used during the periods of peak demand on our network. In 2019, we introduced demand pricing for new residential and small business customers with smart meters. These tariffs apply to a customer's metered peak demand that occurs over a month and within the peak period window.

If passed on by their retailer, our TOU and demand tariffs provide price signals to customers about how the timing of their energy use influences our network costs, and allow customers to lower their bills by shifting some of their energy use to when network demand is low. Importantly, if many customers respond to these price signals, these tariffs also help us control the growth in our network costs reducing the overall costs of providing the community with network services.

Going forward for the 2024-29 period, we are proposing to simplify the structure of our cost reflective network tariffs. The goal of these simpler tariff structures includes to encourage more retailers to reflect these cost reflective price signals into retail tariff structures. Retailers may also respond in other ways, such as through 'prices-for-devices' pricing (explained elsewhere in this paper). We expect different retailers to respond in different ways providing our end customers with choice on how they pay for their energy.

Almost half a million residential and small business customers are on our TOU tariffs, and more than 160,000 are on demand tariffs. This is nearly a third of all our residential customers and more than half of all our small business customers.

For large commercial and industrial customers, our network prices are typically itemised on their bill so they can see the contribution of our network prices to their overall electricity costs and are better able to respond to their price signals. Our existing tariffs for these customers include capacity charges, which are applied to the highest peak demand that occurs over 12 months that falls within the peak period window.



2.3 Stakeholder consultation

In this section, we provide an overview of our engagement on pricing reforms to date. What we are hearing through our engagement, and how we are proposing to respond, is included in the discussion of our proposed reforms and tariff innovation in **Section 3** and **Section 6**.

Pricing Working Group

We continue to work closely with our PWG to develop our proposed pricing reforms. The group's members include a range customer and electricity industry advocates, as well as energy retailers and aggregators. Ausgrid has met with the PWG 15 times in the last year and discussed a wide range of topics relevant to the changes and opportunities facing the energy sector, and how our tariff structures and policies could be reformed to respond to these trends and provide better outcomes for our customers.

For example, the diverse members of the group have provided their perspectives on our pricing principles, and the options for and trade-offs involved in introducing and designing export pricing, changing our charging windows and our controlled load tariffs, streamlining our residential and business tariffs, reforming our policies for assigning customers to these tariffs, and introducing EV charging tariffs. Representatives from the AER and the NSW Government also attended most of the group's meetings, to provide comments and observe. We greatly appreciate each member's insights, contributions and assistance in developing our initial pricing reform proposals.

Our September 2022 PWG meeting focused on our proposal for embedded network tariffs. The meeting was attended by embedded network operators, Energy & Water Ombudsman of NSW, Australian Energy Market Commission (AEMC), and NSW Government. As a result of this meeting we received several submissions on our embedded network proposal, and this feedback is summarised in **Section 3** and **Section 6**.

In our November 2022 PWG meeting we presented our export tariff and utility scale storage proposals. We thank our PWG for their insight and feedback as we have developed these proposals.

Voice of Community Panel

To help us understand the experiences and perspectives of our residential customers, we have established a Voice of Community Panel. The panel includes 45 randomly selected members of the public who represent the diverse range of households our network serves across the Hunter, the Central Coast and Greater Sydney.

The feedback we have received from the panel is helping us to test whether our proposed pricing reforms reflect our customers' expectations of fairness and value for money. It is also helping us to gauge the extent to which customer behaviour could be influenced by price signals and pricing reforms that aim to optimise electricity supply and demand, balancing time of use, time of export, and reliability.

In the Town Hall meeting on 15 October 2022 we heard further feedback from the community on our export tariff proposal. Stakeholders emphasised that more customer education was required, particularly on how the export tariffs contribute to their cost. This includes explaining that it is unlikely customers would be charged to export (by their retailer). Rather, it is much more likely that customers will experience export pricing by receiving a slightly lower retail feed-in tariff (or slightly higher feed-in tariff depending on the time of export). They are also being rewarded for shifting their usage and smoothing out load on the grid.

Large and medium business customers interviews

To better understand the perspectives of our large commercial and industrial customers, we interviewed representatives from several large businesses during March and again in September, 2022. In these interviews we found support for the proposed changes to the tariff charging windows and component structures, and for a price trajectory that is even across the 2024-29 regulatory period. We also held two forums for large customers in May 2022, to get their input and test our thinking on reforms, such as moving the peak period to later in the day and combining the existing shoulder and off-peak charging windows into a new off-peak window.

Small business interviews

In September 2022, we visited several small businesses in Lakemba, Cessnock, and Tuggerah and asked them for their views on our proposed pricing reforms. These interviews established that small businesses did not expect to be impacted greatly by our charging window or export tariff reforms. However, some small businesses seek a closer alignment of retail prices and charging components across residential and business tariffs.

Retailers and aggregators

During 2022 we invited retailers to 1 to 1 discussions on our reset, to attend our PWG meetings and two retailer forums. Unfortunately, there wasn't a strong interest in 1 to 1 discussions on the reset, and PWG meetings were not regularly attended by retailer representatives. Pleasingly we had more than 40 attendees at both retailer forum meetings to discuss our proposed pricing reforms. Overall, the feedback we received was relatively limited. We did receive one submission from an energy retailer - Red Energy - which raised a number of concerns with our proposed reforms. We have responded to this feedback in Chapter 3.

We are working with aggregators to trial innovative tariffs. Most recently, we have partnered with Reposit Power to develop and demonstrate dynamic network tariff models as part of Project Edith (see **Section 6.3**). In March and November 2022, we hosted roundtable discussions with representatives from more than 20 retailers and aggregators to discuss the potential of more dynamic network tariffs. We have also received valuable feedback on how we could make it easier for retailers to engage with our tariffs and pass our price signals on to our customers.

Pricing Directions Paper

We released a Pricing Directions Paper in early September 2022 which contained our proposed pricing reforms for the 2024-29 period. We have consulted extensively with our stakeholders, including our customers, retailers, industry and consumer associations, and our regulator, the AER. The consultation on our Pricing Directions Paper received a total of 18 submissions from the following organisations:

- Firm Power
- Compliance Quarter
- Uniting
- Shopping Centre Council of Australia
- Electric Vehicle Council
- NSW Caravan & Camping Industry Association
- Shell Energy
- Origin Energy
- Red Energy/Lumo
- Energylocals
- GoEvie
- Northern Beaches Council
- Willoughby Council
- City of Sydney
- Inner West Council
- City of Newcastle
- Public Interest Advocacy Centre (**PIAC**)
- Total Environment Centre (**TEC**)

The feedback we have received through this process is included throughout this TSS Explanatory Statement. We have also included the amendments we have made to our proposal in response to this feedback.

2.4 Our pricing principles

We need to continue reforming our pricing, to meet the challenges and capture the opportunities facing the energy sector and our customers. The next regulatory period is expected to include significant changes in the way customers use our network as a result of CER uptake and electric vehicle charging. However, our proposal positions us and our customers well to manage these changes and to adapt to a range of futures. We have developed a set of reforms to implement in the 2024-29 period, and will continue to undertake pricing innovation to inform further reforms in future periods.

Our TSS provides details of how our proposed prices comply with the National Electricity Rule (**NER**) pricing principles. To provide further strategic direction to our reforms, we have developed a set of Ausgrid pricing principles in consultation with our PWG. We consider our pricing reforms for 2024-29 effectively balance these three principles:

1. **Efficiency**: our prices should efficiently reflect the overall costs of operating the distribution network, and the costs associated with providing different network services at different times of the day and year. Efficient cost-reflective tariffs can signal to customers the costs of distributing electricity, enabling customers to decide whether the benefits they get from the electricity (consumed or self-generated) outweigh the costs.

2. **Flexibility**: our prices should reward customers for being flexible in when and how they use energy. Prices that encourage customers to consume energy at times of low network demand and export energy at times of peak network demand can improve the overall utilisation of the grid. This can reduce the need to augment the network and limit network charge increases for everyone in the long term. It also supports customer choice, facilitates innovation, and creates win-win outcomes across customer segments. In addition, our approach to price setting should be technology-neutral to promote innovation and remain relevant as technology evolves.

3. **Fairness**: our prices should recover our costs in a way that is fair and equitable to all customers. For example, they should not create an unfair burden on customers who have less ability to control their network charges, such as those renting and living in apartments, who may be unable to invest in CER, such as rooftop solar and battery storage systems. We should also consider customer impacts, and significant change should be supported by complementary measures to minimise these impacts if necessary.

Our Pricing Directions Paper consultation asked stakeholders for their views on our pricing principles. Northern Beaches, Newcastle and Willoughby Councils supported the proposed pricing principles. Northern Beaches and Willoughby Councils said that further information on how the approach will be implemented to ensure the proposed pricing is fair and equitable and does not discriminate between customers would be valued. We have provided further information on how we set prices in chapter 3 of our TSS compliance paper.

PIAC said that it considers fairness to be best expressed as an objective, rather than a pricing principle. We consider fairness to be a fundamental guiding consideration which is best expressed as a principle, rather than a destination (or objective) of itself. Further, PIAC indicated that flexibility should not imply that Ausgrid is seeking to provide retailers with flexibility in the tariffs they are exposed to. We generally agree, in the sense that retailers should only have very limited flexibility to move a customer onto a less cost-reflective network pricing structure. PIAC supports rewarding customers for being flexible in how and when they use energy, where they are able to choose to do so. We agree, on the condition that this flexibility is beneficial for both the customer and the network.

We have found it valuable to have a set of pricing principles developed in consultation with our PWG to guide our pricing reforms. We also recognise the importance of our proposed reforms being consistent with the pricing principles established in the NER. **Table 2** explains how our pricing principles align with the NER pricing principles.

Table 2: Alignment of our pricing principles with NER pricing principles[3]

Our pricing principles	Alignment to NER pricing principles	Rationale
Efficiency	NER, clause 6.18.5(e) – stand alone and avoidable cost principle	Efficient tariffs avoid cross-subsidies between groups of customers by recovering revenue no higher than the standalone cost, and no lower than the avoidable cost, of serving that tariff class of customers. Cross-subsidies reduce allocative efficiency leading to unnecessary additional cost.
	NER, clause 6.18.5(f) – long run marginal cost principle	Efficient tariffs are based on the long run marginal cost (**LRMC**) of providing the service to customers assigned to that tariff. This helps ensure we only make investments when customers value the product of that investment.
	NER, clause 6.18.5(g) – total efficient cost and minimising distortions principle	Efficient tariffs recover residual costs in a way which minimises the distortions to LRMC-based price signals.
Flexibility	NER, clause 6.18.5(f) – long run marginal cost principle	Tariffs (and rewards) that signal LRMC during peak times appropriately encourages customers to be flexible in when and how they use energy.
	NER, clause 6.18.5(i) – customer understandability principle	The NER now recognises that retailers may incorporate our network tariff structures directly or indirectly into their retail offerings (e.g. through 'prices-for-devices' tariffs). Offering a range of cost reflective tariffs (TOU or demand) ensures customers always have access to an option they can easily understand.
Fairness	NER, clause 6.18.5(e) – standalone and avoidable cost principle	Fair tariffs avoid cross-subsidies between groups of customers by recovering revenue no higher than the stand alone cost, and no lower than the avoidable cost, of serving that tariff class of customers. Cross-subsidies are unfair because it means one group of customers are paying the costs caused by another group of customers.
	NER, clause 6.18.5(h) – customer impact principle	Fair tariffs take into account the impact on customers from tariff changes, and may include transitional measures or enable customer choice, where desirable. Fair tariffs also take into account customers' ability to respond to tariff signals.
	NER, clause 6.18.5(i) – customer understandability principle	Fairness means at least one tariff option is always available that is reasonably capable of being understood by customers, if reflected directly into retail tariff structures.
	NER, clause 6.18.5(g) – total efficient cost and minimising distortions principle	Fair tariffs are ones where all customers contribute to the residual costs of funding the network and where sub-sets of customers cannot easily avoid contributing to these costs, which would shift the cost burden onto other customers.

3 There is also a general NER pricing principle that states tariffs must be compliant with the Rules and any applicable regulatory instruments, such as jurisdictional requirements. NER, clause 6.18.5(j) – Applicable regulatory instruments compliance principle.

2.5 Energy affordability and bill impacts

After a period when our customers saw their bills go down, a range of factors are now putting upward pressure on the costs of supplying electricity, and thus on its affordability for our customers. These factors are largely outside of Ausgrid's control or affect the non-network components of electricity bills. For example:

- **Rising interest rates** and higher inflation are increasing our network costs, as well as the overall cost of energy supply, while also increasing our customers' cost of living;
- **Disruptions in the energy supply chain** due to gas shortages and an aging fleet of coal fired power stations are driving up the generation component of bills; and
- **Significant investments** in transmission infrastructure are expected to increase the transmission component of bills.

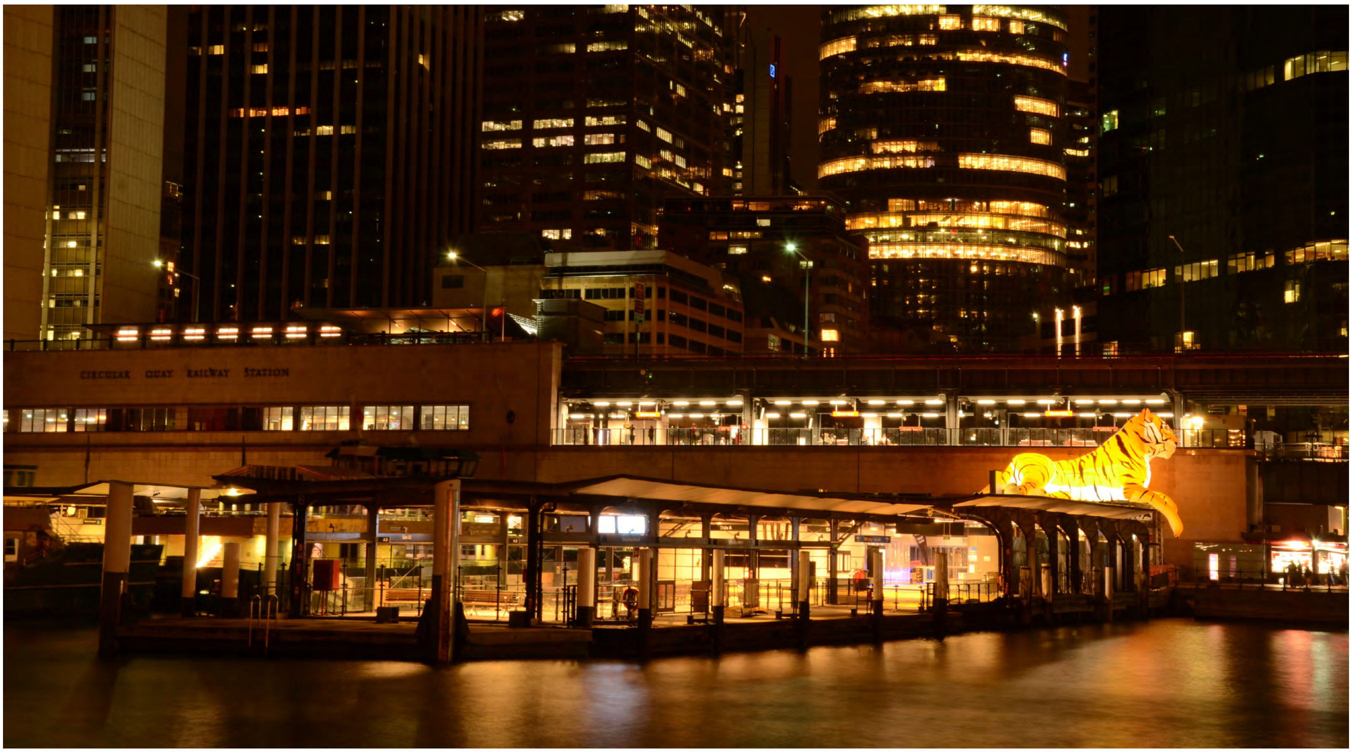
As explained in **Section 6**, in response to the changes and opportunities ahead for the energy sector, and to what we are hearing in our engagement with our customers and communities, we are proposing a number of key changes to reform our standard tariff offerings for the 2024-29 period. Many of our proposed pricing reforms also aim to support an affordable transition by giving our customers choice and control over their energy services and bills.

For example, our tariff assignment policy moves customers (with capable metering) to demand tariffs with the option to opt-out to TOU tariffs. Our 2024-29 Regulatory Proposal also sets out a range of responses to ensure customers pay no more than necessary for our network services, and facilitates an affordable transition to net zero.

In an environment of energy affordability challenges, we aim to provide a clear indication of the impacts of our proposal to the network component of customer bills. The bill impact analysis supporting this explanatory statement is based on an estimate of total network charges for the 2024-25 year. It includes our proposed distribution and transmission revenues, and an estimate of the TransGrid and NSW Climate Change Fund pass through recoveries reflected in our network prices. We have not included the NSW Roadmap scheme recoveries in our network bill impacts (**Attachment 8.3**) as this information has not been provided by the NSW Government.

The full details of the bill impacts (by tariff) are included in **Attachment 8.3**. We have also included the customer network bill impacts for each of the main pricing reforms within the relevant chapter of this explanatory paper:

- Introducing export pricing for residential and small business customers (**Section 3.1**);
- Introducing tariffs for embedded network operators (**Section 3.2**);
- Streamlining our existing tariff offerings (**Section 3.3**); and
- Simplifying and updating the charging windows for our existing tariffs (**Section 3.4**).



Proposed pricing reforms for 2024–29

In response to the changes and opportunities ahead for the energy sector, and to what we are hearing in our engagement with our customers and communities, we propose to reform our standard tariff offerings for the 2024–29 period.

We are proposing six main changes:

- **Introducing export pricing for residential and small business customers after a one-year transition period**, to reflect the increasing costs to support CER customers' exports and provide an incentive for CER customers to self-consume or time their exports to minimise these costs and maximise the benefits they receive;
- **Introducing tariffs for embedded network operators** that will better reflect the costs (over a transition period) that these business customers impose on our network, and ensure they make a fair contribution to residual costs;
- **Streamlining our existing tariff offerings and tariff assignment policies for our customers** to make it easier for retailers and market aggregators to respond to or pass through our price signals to our customers;
- **Simplifying and updating the charging windows for our demand, capacity and TOU tariffs** to make it easier for retailers to pass through our price signals to customers, and ensure customers know when demand on our network is highest;
- **Introducing pricing for utility scale storage facilities**, to enable directly connected batteries and other energy storage facilities connect to our network and create a level playing field for projects located in the distribution network; and
- **Updating our controlled load tariffs for residential and small business customers** to reflect changes in the times of day when demand on our network is lowest, and allow our 470,000 controlled load customers to operate their hot water systems during the day when solar energy production is highest.

We think our proposed reforms would make our tariffs more efficient, flexible, fair, and sufficiently cater for the anticipated electrification of transport. The sections below discuss each of the changes we are proposing in more detail and set out the questions we seek comments on.

In these sections, we explain our rationale with reference to our three pricing principles – efficiency, flexibility and fairness. We also link our rationale back to the NER requirements by providing a footnote reference to the relevant NER pricing principles throughout our reasoning.

3.1 Introducing export pricing

Background

In 2021, the AEMC changed the NER to recognise that exports onto distribution networks can reach or exceed the intrinsic hosting capacity and drive network costs. However, network providers were not able to signal the cost of providing export services to those that use this service. To address this, the NER now allow distribution networks to charge and provide rewards for exports.

This reform to the Rules stemmed from the Distributed Energy Integration Program (**DEIP**) Access & Pricing Workstream, co-ordinated by ARENA, which was a highly collaborative process between customer representatives, environmental representatives, market bodies, industry and government. It adopted a multi-stage process that started with establishing a user-centred vision and principles to guide CER integration reform, identified a range of CER access and pricing options, then analysed those options. This process was undertaken through a series of workshops, reports and discussions involving many stakeholders. The DEIP Access & Pricing Workstream resulted in a consumer group, environmental group and distributors proposing rule changes to the AEMC which created the DER Access, Pricing and Incentives rule change. This rule change made several changes to the rules – notably the removal of the ban on export charges and enablement of credits, to have two-way pricing. Our TSS proposal implements this reform.

When the volume of energy exported to the grid at the same time exceeds the intrinsic hosting capacity, customers with solar will experience reduced solar generation and export reliability. This is because when the network exceeds its intrinsic hosting ability, the voltage level exceeds the standards. This causes solar customers' inverters to curtail energy production, reducing their ability to export or self-consume solar energy until voltage returns to within the prescribed range. Alternatively, if we spend more money to manage these voltage swings by augmenting the capacity of our network so we can accept more exports, all customers may face higher prices.

We think the introduction of export pricing aligns with our pricing principles:

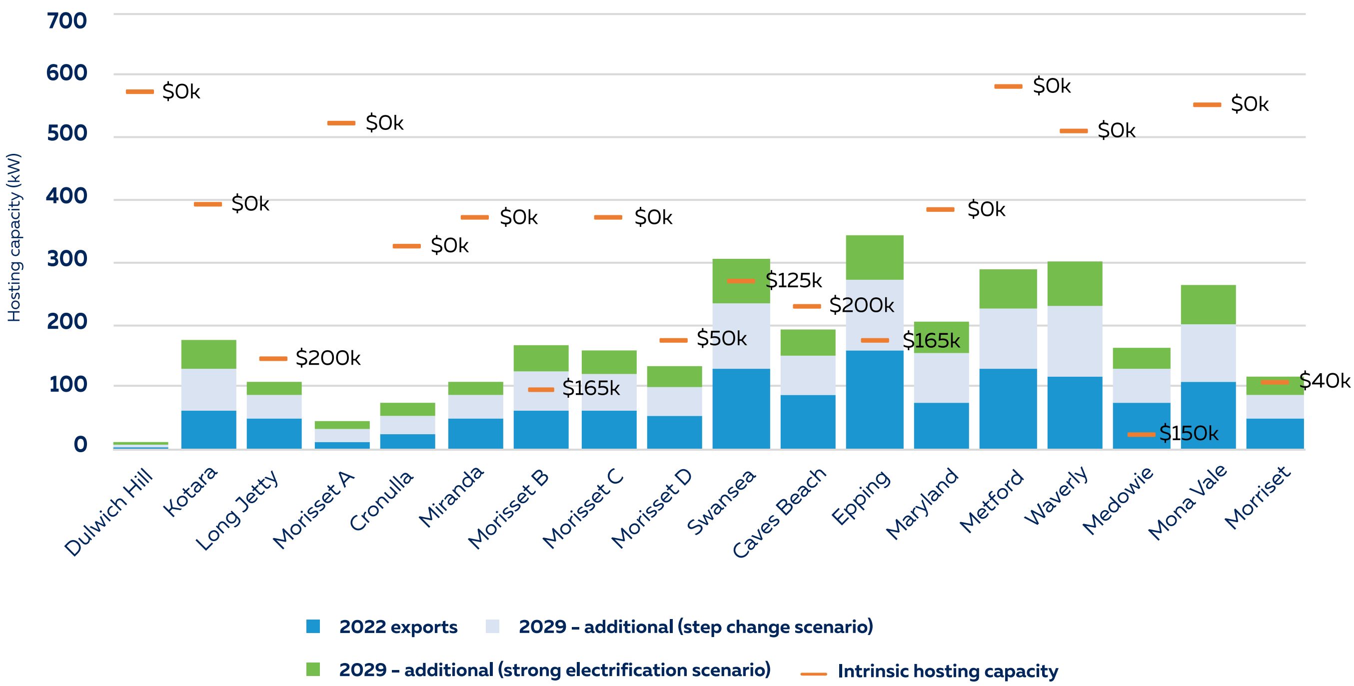
- **Export charges create more efficient outcomes.** By signalling the costs and benefits of exports, customers can make more informed decisions about the sizing of their CER like rooftop solar, when it is optimal to self-consume their generation, or invest in energy storage;[4]
- **Export charges can reward flexibility.** The flexibility principle builds on the efficiency principle as it involves sending efficient price signals that allow customers that can be flexible to save money. Customers who can self-consume their generation or move when they export (e.g. by installing western facing rooftop solar or batteries) will share in the benefits this provides our network through lower bills;[5] and
- **Export charges can create a fairer outcome.** Our fairness principle means our network charges minimise situations where some of our customers are paying more so we can supply other customers.[6] When we were able to accept all customers' exports without any additional network investment it was fair that customers exporting did not pay for exporting. However, as we incur costs to accept exports we are creating a situation where customers are receiving a service for less than it costs us to provide it.[7]

When assessing whether to introduce export pricing, we have considered the impact of CER on the grid now and into the future. Over the last few years we have made significant improvements in how we manage network voltage, including lowering the average voltage across much of our network. This creates some additional capacity for us to enable customer exports.

However, in parts of our network, we are reaching or have started to exceed the limits of the exports we can accept without augmenting the network (also known as the intrinsic hosting capacity). The following figure demonstrates how different export forecasts trigger CER investment, both in the next regulatory period and beyond. Network augmentation triggers include upgrades to overhead low voltage conductors, installation of new underground cables, installation of new distribution substations and network re-arrangement. If AEMO's Step Change scenario for CER uptake proves to be reasonably accurate, between 2024-29 we expect intrinsic hosting capacity to be exhausted in parts of the network. Across 16 sampled locations in the LV network, half are expected to require investment by 2050 under the Australian Energy Market Operator (AEMO) step change scenario. We have provided the details of this intrinsic hosting analysis in **Attachment 8.5**. This analysis shows it would be prudent to start sending our customers price signals about the costs and benefits their exports can have on grid costs.[8]

4 NER, clause 6.18.5(f) – Long run marginal cost principle
5 NER, clause 6.18.5(f) – Long run marginal cost principle
6 NER, clause 6.18.5(g) – Total efficient cost and minimising distortions principle
7 NER, clause 6.18.5(g) – Long run marginal cost principle
8 NER, clause 6.18.5(g) – Total efficient cost principle

Figure 1: Investment triggers to 2050 for 16 sample locations in the low voltage network (the dollars shown are the required investment real $, FY24)



Our proposed export tariffs

We propose to introduce an opt-in export tariff from 1 July 2024 and then move to a default assignment a year later. The export tariff would:

- **Have a Basic Export Level[9] (BEL) over the 2024-29 period.** Customers would not be charged for energy exports below this threshold. Our analysis indicates that 2,500 kWh per year is the appropriate level for the BEL for exports within the 10am to 3pm charging window. For practical reasons, it is important to align the duration the BEL is measured over with our billing period.[10] This ensures there is no need for ex-post adjustments;
- **Include both a charge component and a reward component.** Customers receive a payment or credit for the volume they export during the peak demand period (and no threshold applies to reward exports)
    - **Export charge component** of 1.18 cents per kWh (ex GST, FY24 $) of energy exported above the BEL between 10am and 3pm. This period is when total exports from our customers' rooftop solar systems are highest, and therefore when these exports are most likely to drive network costs;[11]
    - **Export reward component** of 2.19 cents per kWh (ex GST, FY24 $) of energy exported between 4pm and 9pm and in the peak period. This period is when total demand on our network is highest, and therefore when customer exports provide most benefit to the network;[12]
- **Applies to new and existing[13] residential and small business customers** on cost-reflective tariffs, regardless of where they connect to the network, and when they invest in CER. We believe this approach treats customers equally;
- **Be initially available on an opt-in basis only.** From 1 July 2024, only customers who choose to opt-in would receive the tariff as part of the first year transition period;[14] and
- **Become our default tariff in the second year of the period.** From 1 July 2025, all residential and small business customers on demand or TOU tariffs would be automatically assigned to the tariff.[15]

9 Required under the new export tariff transitional rule. NER, clause 11.141.12

10 Formally, we propose our BEL to be calculated as 6.85 kWh per number of days in the billing period. For example, a 30 day billing period has a BEL of 205.5 kWh.

11 NER, clause 6.18.5(f) – Long run marginal cost principle

12 NER, clause 6.18.5(f) – Long run marginal cost principle

13 The export tariff transitional rule defines an existing CER customer as one that was connected as of 19 August 2021.

14 NER, clause 6.18.5(h) – Customer impact principle

15 Under the new export tariff transitional rule, an existing CER customer cannot be assigned to an export tariff until after 30 June 2025. NER, clause 11.141.11(a)

When combined with the proposed BEL and the proposed reward component, we estimate that the export charge will have a minimal impact on the bills of CER enabled customers over the 2024-29 period.[16] We think even at a low price level, now is an appropriate time to introduce export pricing. This enables our customers to become familiar with export pricing structures without incurring meaningful cost impacts for this component.[17] Export charges are likely to be a much smaller portion of the bill than consumption charges. Putting these structures in place from FY25 will prepare Ausgrid and customers for subsequent regulatory periods and the continued shift to a decentralised and decarbonised energy system.

Our proposed charge is set lower than the rebate and achieves an appropriate balance of reward and charge across our customers with and without rooftop solar. Customers who export more energy are more likely to face a net charge, rather than reward. Our indicative estimates for FY26 show that our export/reward tariff will result in $1.5 million less distribution revenue recovered from non-solar customers than would be the case without our export pricing proposal.[18] This outcome was presented to our PWG in December 2022 and was a result of a scenario analysis that considered different charging windows and recovery of residual revenue. We may introduce a residual component in our future export tariffs but this currently does not form part of our proposal.

We do not propose to introduce export pricing for large commercial and industrial load customers in the 2024-29 period, other than for utility-scale battery customers as currently most of the CER exports to our network come from small customers. However, we may trial export pricing for large customers over this period, and these customers will be able to opt-in to these trials.

We note that our export pricing proposal may differ to the proposals of other NSW distributors. This is due to a number of reasons, including different CER penetration rates, customer usage profiles, and billing system capabilities.

16 NER, clause 6.18.5(h) – Customer impact principle
17 NER, clause 6.18.5(i) – Customer understandability principle

18 NER, clause 6.18.5(g) – Total efficient cost and minimising distortions principle

Why isn’t our export reward price higher?

During our consultation, stakeholders asked why our proposed export reward isn’t higher than the export charge. This feedback was triggered in part by an Ausgrid temporary trial tariff which has a large export reward component. Our pricing approach seeks to deliver fairness for customers with access to export-capable technology, such as rooftop solar, and customers that do not have this technology. In deciding what is fair, we have balanced the size of the reward for exporting customers, with the regulatory rules mandate that we give a free allowance for exporting electricity to the grid.

We want to ensure that we don’t create a cross subsidy at the expense of customers who aren’t export capable. This could occur if the export reward was higher than what we propose given our regulatory framework includes a revenue cap. We are also required to ensure LRMC is reflected in our prices and the LRMC values for these prices are very low.

Our TSS compliance paper also includes our basic export transition strategy and approach used to calculate the BEL and export LRMC.

Stakeholder feedback to the Pricing Directions Paper

Our Pricing Directions Paper consultation asked stakeholders about our proposal to introduce export pricing. In its submission, the TEC asked why the proposed reward component was not more generous for CER enabled customers. They suggested that the LRMC of consumption be used to determine the price for the reward component. We agree with this feedback and have moved the reward price from 1.85 to 2.19c/kWh which reflects the upper bound of our consumption LRMC. Our TSS compliance paper includes further information on how we calculate the LRMC of export services and the BEL. TEC also said that Ausgrid lacks a clear need for the introduction of export pricing. However, our analysis indicates that we will incur additional costs as customer export capacity increases, and this is reflected in a positive value for the export LRMC. We have provided further information on our export LRMC in our TSS.

City of Newcastle supported the proposed changes. The City of Sydney said that the proposed charge is unlikely to be sufficient for customers to invest in grid support solutions like west-facing solar panels or costly battery storage. It also suggested that the price signal may not be passed through by retailers, and if it was most customers would not know how to respond. At our council forum in September 2022, we also heard that the proposal is a good incentive for west facing panels and home storage, but the tariff cost impact is so negligible and obscure (behind retailer tariffs) that it may be ineffectual. However, in our large customer interviews, NSW Treasury (in its role of whole of government procurement) said that the proposed changes would impact the retail feed-in tariff that it receives across its portfolio of rooftop PV installations. We have considered this feedback and have decided to start the export reward period at 4pm, instead of 3pm. This will mean the rebate becomes a stronger price signal, is more likely to be passed through by retailers, and will encourage west facing solar investments and batteries.

Northern Beaches and Willoughby Councils supported the commencement of opt in from 1 July 2024, however, they also recommend that the mandatory roll-out is delayed for more than the proposed one-year interval to allow customers to be better prepared. Ausgrid has considered this feedback. A transition period would not provide any clear benefits to customers given the small impact the proposed changes will have on network bills (under current CER forecasts). Our export charge only applies above the free threshold and is lower than what was initially proposed in the Pricing Directions Paper. We consider this change suitably addresses stakeholders’ concerns on the introduction of export pricing.

Inner West Council said that export tariffs will penalise solar owners who invest in good faith to cut their energy bills and do their part for the environment. It recommended that the reduction to feed-in tariffs should be accompanied by reductions in consumption charges for solar customers. Ausgrid’s view is that the proposed export tariff will not create significant bill impacts for the majority of solar owners, on the assumption that future CER investment will not exceed the current forecasts. Our export tariff proposal provides bill saving opportunities for west facing solar panels and battery investments.

Our focus groups for culturally and linguistically diverse (**CALD**) stakeholders suggested that the proposed changes may be unfair for customers who had already invested in solar panels. We note that our export tariff becomes mandatory four years after the rule change was finalised. These stakeholders also considered that the proposal may be perceived as discouraging CER take up and customers should be informed early of these changes. At our Peak Group roundtable meeting we heard that if export tariffs are required to make a fair balance between solar and non-solar households, then the tariff must be mandatory. There may be a communication challenge if each network responds differently on export tariffs, and engagement with retailers was critical in passing through the price signal.

PIAC supported the proposal for the export tariff to be mandatory from 1 July 2025 and that it should not allow customer opt-outs. It also said that the BEL should be introduced on a more cost reflective basis. In particular, the tariff should be applied in network billing on a kilowatt (kW) basis, not as a kilowatt-hour (kWh) threshold. The reward should only be applied in locations where exports help avoid or delay network upgrades or reduce the need for load shedding. In response to the PIAC submission, we have balanced tariff simplicity and the cost of changing our billing systems with the potential efficiency benefit of billing based on kilowatts. We consider our proposed kWh export tariff sufficiently achieves the aim of charging the high export-capable customers more than those customers with only a small export capability. Therefore we consider it is a suitable pricing structure for our proposed export tariff. We are continuing to review our billing systems as we introduce more dynamic pricing signals over time, and if an efficient change to our systems could accommodate kW, we will engage further with stakeholders at that time.

Red Energy responded that the proposed export tariff will require IT changes, collateral changes and extensive training to their staff to be able to communicate the changes. It preferred that Ausgrid provide an opt-in export tariff that is consistently structured with other NSW networks for the 5-year period. We note in response that export pricing is being introduced across NSW and both Ausgrid and Essential Energy are proposing a mandatorily assigned export tariff in the next regulatory period. We also agree that the introduction of export tariffs will require an adequate retailer communication program.

Our engagement with PWG highlighted that introducing export pricing is a complex issue, which particularly concerns customers who have already invested in CER. The group suggested ways of improving our communication of the export tariff to customers, including the BEL. Some of the issues we explored were whether export prices should only be introduced for customers who have invested in CER, and whether the price signals provided should be on a locational basis, given different impacts of energy exports across different parts of our network.

PWG noted that the proportion of customers who have already invested in CER varies by location within our network area, and the intrinsic hosting ability of the network also varies by location. They suggested it may be more cost-reflective to apply the export tariff (including the level of the BEL) on a locational basis. While we agree there would be some benefits in introducing export pricing on a locational basis, we consider these are outweighed by the costs. In particular, we think it is more important to avoid the complexity of differentiated pricing for a relatively small component of the bills of our small customers, and to retain the simplicity of postage-stamp pricing for at least the 2024-29 period.

Our Voice of Community Panel recommended that recovering the costs associated with customers' exports by introducing a TOU export tariff takes into account network stability and cost. In particular, export services could be priced differently at different times of day, to reflect periods of peak demand (and peak exports). The panel also recommended we should allow CER customers to opt-in to this tariff initially, with a view to transitioning to all-in over the 2024-29 period.

In our engagement with our communities, we also discussed whether we should provide "grandfathering provisions", so that customers who invested in CER before the export was introduced are exempt from the tariff. Our Voice of Community Panel indicated a preference to avoid these provisions, and to treat all small customers in the same way. In line with this feedback, we propose to assign all residential and small business customers on demand and TOU tariffs to the export pricing structure from 1 July 2025.

Amendments since Pricing Directions Paper

Our September 2022 Pricing Directions Paper discussed whether the export tariff should be mandatory or whether opt-out should be allowed. A key consideration for allowing opt-out is the impacts on other customers. For example, under an opt-out scenario, customers with large solar systems are more likely to opt-out to avoid charges.[19] To overcome this challenge, we considered providing a greater incentive for these customers to encourage them to remain on the export tariff. However, this would reduce the cost reflectivity of the export tariffs and put a burden on customers without solar.

We consulted on whether customers should be able to opt-out of the export tariff. At our September 2022 Voice of Community meeting, participants supported mandatory export tariffs if the introduction included a community education campaign. The need for customer communication was highlighted given the potential complexity of a new, two-way pricing structure. The Voice of Community support was also based on the following considerations:

- Rooftop PV systems can be paid back in 4-5 years and customers will have had four years notice of these changes;
- The export charge is a small amount based on current CER forecasts and it includes a free threshold;
- The export tariff will reduce their feed-in-tariff, rather than be a standalone charge; and
- Only larger systems will see the biggest change and they shouldn't be the ones to opt-out.

Given this feedback we think our proposed approach of introducing mandatory export tariffs from 1 July 2025 could be more effective if it includes a customer education campaign. This is an initiative we seek to undertake in 2023.

Other changes since the Pricing Directions Paper include increasing the export reward price by:

- Basing the reward on the upper limit of the LRMC of consumption services; and
- Starting the reward period at 4pm instead of 3pm.

Our analysis shows that moving the reward window to 4pm is more likely to provide a stronger signal for investments in west facing rooftop solar and batteries. These changes to our export tariffs are discussed above in our stakeholder feedback section.

Bill impacts of the proposed export tariffs

We are proposing the introduction of an export pricing structure from 1 July 2024. From 1 July 2024, only customers who choose to opt-in would receive the tariff; and from 1 July 2025, all residential and small business customers on demand or TOU tariffs would be automatically assigned to the tariff. The proposed structure will:

- Include both a charge component and a reward component.
- Have a BEL of 2,500 kWh per annum over the 2024-29 period.

The FY25 bill impacts of adding on our proposed export tariff to small customer demand tariffs are presented in the table below. We note that in FY25 the export tariff is an opt-in option (before becoming mandatory in FY26).

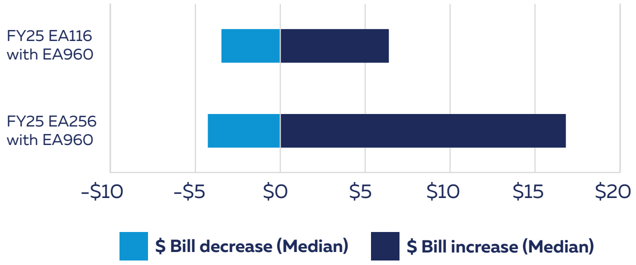
Introducing the export tariff (EA960) has led to relatively small bill impacts for small customers who have CER capability, as shown in **Table 3** and **Figure 2**.

Table 3: FY25 export tariff bill impact for customers on demand tariffs

Scenario	Sample customers with bill decrease	Sample customers unaffected	Sample customers with bill increase
Residential customer sample: FY25 EA116 with EA960	74%	8%	18%
Small business customer sample: FY25 EA256 with EA960	48%	13%	38%

19 NER, clause 6.18.5(g) – Total efficient cost and minimising distortions principle

Figure 2: FY25 export tariff median dollar impact



Detailed charts and analysis of export tariff bill impacts can be found in **Attachment 8.3**.

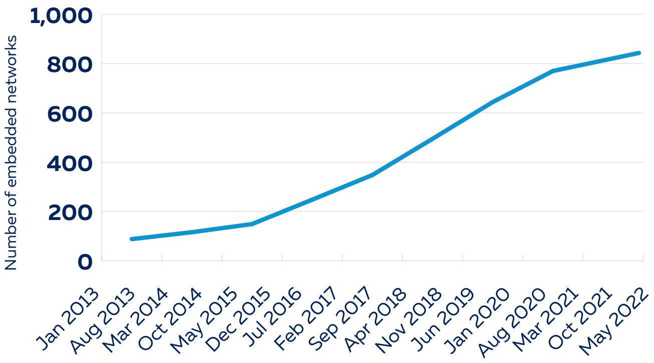
3.2 Introducing tariffs for embedded network operators

Background

Embedded networks (EN) are private electricity networks that supply multiple homes or businesses – for example, within developments such as apartment buildings, shopping centres, retirement villages, industrial estates or caravan parks. The EN operator typically connects to the distribution network via a single point, and purchases and on-sells energy to the customers located within its network.

As **Figure 3** shows, the number of ENs connected to our network has grown significantly over the past 10 years. There are more than 800 in our network with an additional 5-6 connecting each month.

Figure 3: Number of ENs connected to the Ausgrid network



A typical EN in our network has an average annual consumption of around 1,000 MWh, which is equivalent to about 200 households or 50 small businesses. Most ENs are connected to our low voltage network, although some are connected at higher voltage levels.

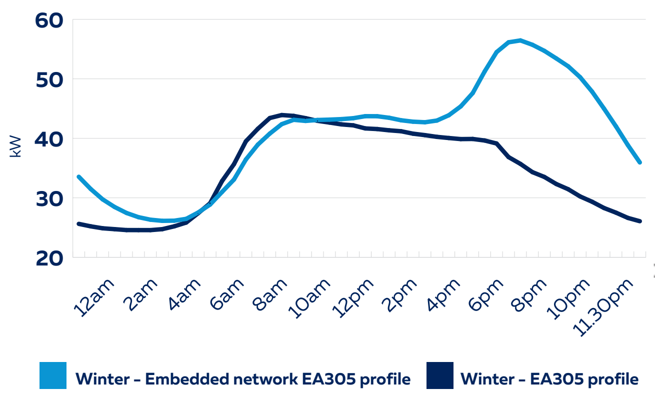
Currently, none of our tariffs are specifically designed for EN customers. Under our tariff assignment policies, most are assigned to a low voltage medium business network tariff (either EA305 or EA310). Those that connect to our high voltage networks are assigned to our high voltage large business network tariff (EA370).

We have reviewed what EN customers pay in network charges and compared their load profiles to those of other customers on the same tariff. This analysis suggests our current tariff arrangements for EN customers are not as efficient or fair as they could be.

To meet the requirement for distribution networks to assign customers to tariffs based on the nature and extent of their usage, we currently assign ENs to tariffs designed for medium or large businesses. However, the load profiles for ENs are different to the other customers on those tariffs.

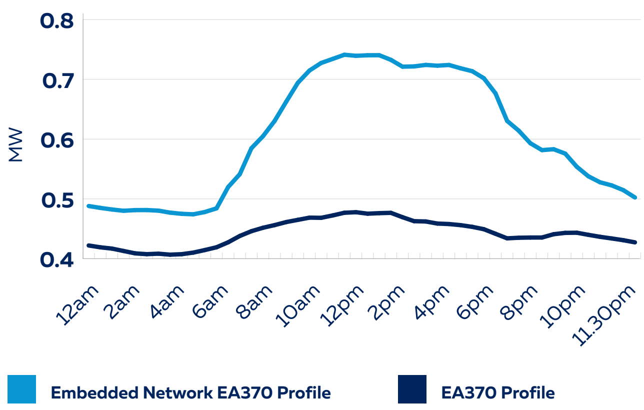
For example, **Figure 4** compares the winter profile of an average customer on our low voltage EA305 tariff (a medium business using between 160 and 750 MWh per annum) to the average winter profile of an EN assigned this tariff. It shows that the EN has a peakier load shape and a peak that occurs later in the day. This load shape is more closely aligned with a residential customer than a medium business customer.

Figure 4: Embedded network profile versus other customers on the same tariff (EA305)



Similarly, **Figure 5** compares the summer profile of an average customer on our high voltage EA370 tariff (a large business using a high volume of energy) to the average summer profile of an EN assigned this tariff. It shows that these profiles are very different. The average customer's profile is much flatter, which indicates a high utilisation of the network. The EN's load profile is more like that of a smaller business customer connected to the low voltage network (such as a customer assigned to EA305).

Figure 5: Embedded network profile versus other customers on the same tariff (EA370)



Given these load profile differences, we considered it was appropriate to take a closer look at the tariff arrangements for ENs. This review included analysing the network bills of these customer types connecting as an EN compared with individual customers connecting directly to our network (and instead faced residential and small or medium business tariffs, as relevant).

That network bill comparison analysis (see **Tables 3 and 4**) demonstrates the tariffs we currently assign EN customers result in lower network bills than those in our residential and small business rates. This means that a development's choice to connect to our network as an EN instead of connecting each individual energy user may be partly driven by a reduction in the total network bill (known as tariff arbitrage).

There are good reasons why a development (such as an apartment building or industrial estate) might choose to connect as an EN. But in our view, tariff arbitrage should not be one of them.[20] This is because the cost savings that accrue to ENs must be recovered from other customers. Tariff arbitrage may also encourage the growth of ENs in our area, which is a distortion of efficient price signals[21] and results in less equitable recovery of residual costs. The Rules require that recovery of residual cost should not distort price signals. Without this change our business tariffs could potentially distort price signals to customers, by creating an incentive for new embedded networks. Therefore, the tariff arbitrage opportunity represents an inefficiency. For these reasons, it is not consistent with the NER pricing principles.

20 NER, clause 6.18.5(g) – Total efficient cost and minimising distortions principle

21 NER clause 6.18.4(a)(2) – Retail customers with a similar connection and usage profile should be treated on an equal basis

Our Proposal

Our September 2022 Pricing Directions Paper proposes to introduce three EN tariffs from 1 July 2024 to better reflect the costs EN customers impose on our network and ensure they make a fair contribution to residual costs. These include a tariff for:

- ENs connected to the low voltage network using between 160 and 750 MWh per annum (for ENs currently on tariff EA305);
- ENs connected to the low voltage network using more than 750 MWh per annum (for ENs currently on tariff EA310); and
- ENs connected to the high voltage network (for ENs currently on tariff EA370).

These proposed tariffs would have the same fixed and energy charges as the equivalent medium or large business tariff, but they would include an increased capacity charge.[22] This is an efficient way to address the load profiles observed among ENs as this charging component is applied to the maximum peak demand over the prior 12 months.[23] A higher capacity charge scales better and is fairer and more practical across a wide range of EN customers compared to a higher fixed charge.

We considered including a higher fixed charge in these tariffs. However, there is limited information on the number of sub-metered customers within each EN in our network area, and therefore what the size of the fixed charge should be. A fixed charge applied on a postage stamp basis would not be an efficient way to recover network revenue and it would trigger a wide range of bill outcomes.[24]

The new tariffs would be applied to all connections within our network area that are identified as ENs in MSATS[25] and use above 160 MWh per annum[26]. This would allow small ENs such as caravan parks and small retirement villages to be exempt from the proposed changes.[27]

Importantly, the new EN tariffs would not result in Ausgrid earning more revenue because we are subject to a revenue cap. This ensures that any additional revenue earned from ENs is offset by lower charges for other customers.[28]

The following case studies compare the network charges currently paid by ENs with those paid by equivalent customers not in ENs, and the charges they would pay under our proposed EN tariffs. The case studies included a residential EN with 315 sub-metered customers (such as an apartment building) and a business EN with 35 sub-metered customers (such as an industrial precinct). They are based on actual ENs currently connected to our network and use FY21 consumption data and our FY22 prices.

The results of this analysis are summarised in **Table 3** and **Table 4**. They demonstrate that under our current tariffs, EN network charges are significantly less than the total charges their sub-metered customers would pay if they were billed individually. They also show the extent that our fully transitioned EN tariffs would reduce this difference.

Table 3: Comparative analysis of network charges for a residential EN with 315 sub-metered customers

	Normal customer billing (315 units on EA116)	Embedded network on EA310	With proposed embedded network tariff
Consumption per NMI, (kWh)	3,143	–	–
Total consumption, (kWh)	989,913	–	–
Fixed – network access charges	$45,480	$12,054	$12,054
Energy consumption charge	$22,176	$13,745	$13,745
Capacity charge	$100,268	$43,153	$64,730
Total network bill (per annum)	$167,924	$68,952	$90,529
Difference ($)		**-$98,972**	**-$77,396**
Difference (%)	–	-59%	-46%

22 NER, clause 6.18.5(i) – Customer understandability principle

23 Applied to peak demand occurring in the peak period window, 2pm-8pm on working weekdays.

24 NER, clause 6.18.5(h) – Customer impact principle

25 Market Settlements and Transfers System.

26 And are connected at low or high voltage.

27 NER, clause 6.18.5(h) – Customer impact principle

28 NER, clause 6.18.5(g) – Total efficient cost principle

Below is a summary of the charges for a business example – businesses on a street in an industrial precinct. The charges for the individual customer connections are compared to a single embedded network on EA310.

Our proposed fully-transitioned EN tariffs will close most of the tariff arbitrage opportunity. However, the EN will remain better off (by 8%) on the proposed tariff compared to what customers would pay under normal customer billing.

Table 4: Comparative analysis of network charges for business EN with 35 sub-metered customers

	Normal customer billing (35 customers)	Embedded network on EA310	With proposed embedded network tariff
Consumption per NMI, (kWh)	42,172	–	–
Total consumption, (kWh)	1,476,020	–	–
Fixed – network access charges	$25,984	$12,054	$12,054
Energy consumption charge	$42,898	$20,732	$20,732
Demand/Capacity charge	$84,802	$72,144	$108,216
Total network bill per annum	$153,684	$104,930	$141,002
Difference ($)	–	**$48,754**	**-$12,682**
Difference (%)	–	**-32%**	**-8%**

Stakeholder feedback on Pricing Directions Paper

Our Pricing Directions Paper consultation asked stakeholders for their views on our introduction of embedded network tariffs. We received submissions from several stakeholders on these issues. PIAC supported the proposed tariffs and the minimum threshold, however it said the proposal could go further toward cost reflective levels and include a "glide path" for the introduction.

Uniting (a non-for-profit organisation managing retirement villages) commented that our proposal should differentiate between residential and business embedded networks. We considered separate EN tariffs for residential and commercial embedded networks. However, as we do not have a clear indication of the different residential and business customer types within embedded networks, we are unable to introduce separate tariffs.

NSW Caravan and Camping Industry Association (**CCIA**) recommended that our proposal should exclude land lease communities as these organisations are prevented by legislation from making a profit from the sale of energy. They suggested that these embedded networks may be able to be identified from data via NSW Fair Trading. However, Ausgrid's proposal is not specifically seeking to target embedded networks based on their level of profitability, rather on the contribution they make to total efficient cost and residual network revenue. For this reason, we don't propose to create an exemption for land lease communities.

The Shopping Centre Council of Australia said that the proposed tariffs should only be introduced for residential ENs on the basis that commercial ENs are not creating a load profile problem. They also suggested that shopping centres be treated differently as some have paid capital contributions to Ausgrid. As the load profile analysis in **Figure 3** and **Figure 4** shows, commercial ENs on our high voltage tariff do have a different load profile to other customers on the same tariff. Our proposed tariffs seek to correct some, but not all of the imbalance observed between the network costs ENs pay and other network users.

GoEvie submitted that the proposal will make it harder to install EV charging stations in shopping centres. The electricity retailer Energylocals commented that the 30% average network bill impact was not an acceptable increase. Origin Energy commented that embedded networks create efficiencies that can be shared with customers. They also suggested that a grandfathering or transition arrangement be introduced to protect existing embedded networks. CCIA also supported a transitional arrangement for the proposed tariffs. We believe a grandfathering arrangement would not address the tariff arbitrage problem and create inequity between new and existing ENs. We have addressed the feedback on introducing a transitional arrangement in the next section.

The EV Council queried why Ausgrid was introducing tariffs specific to embedded networks, but not to EV charging stations. Our proposal is seeking to remove most of the tariff arbitrage opportunity that is currently available to the ENs located within our network. A tariff arbitrage problem does not exist for EV charging stations.

In its submission Compliance Quarter said that the Ausgrid proposal would stifle innovation. It also stated that the annual energy consumption is not correlated to the level of vulnerability of customers. It recommended that the AER commission an independent analysis of embedded network load profiles, any costs avoided by Ausgrid due to embedded networks, and the costs of "reverse retrofitting" embedded networks.

In our Pricing Directions Paper, we proposed to increase the capacity charge component and produce a 30% average network bill increase for the ENs assigned to the new tariffs. The PWG suggested that Ausgrid should go further toward removing the tariff arbitrage opportunity by increasing the capacity charge by a greater amount. We have considered this feedback and decided to not fully remove the tariff arbitrage opportunity given the range of network bill impacts experienced by each embedded network under the proposal (some have impacts of more than 30%). The PWG also considered whether specific exemptions should be created under the proposal, but concluded that this would not create an appropriate balance between efficiency and fairness.

Changes since our Pricing Directions Paper

Our Pricing Directions Paper proposed to introduce the EN tariffs in full on 1 July 2024 and without a transition period. In response to stakeholder feedback we have amended this proposal and will introduce the capacity charge uplift over five years, resulting in the tariffs reaching the proposed level by July 2029 (instead of a one-off increase in July 2024). This achieves an appropriate balance between managing bill impacts across the EN customer segment and achieving greater fairness for our other customers.[29]

Bill impacts for affected EN customers

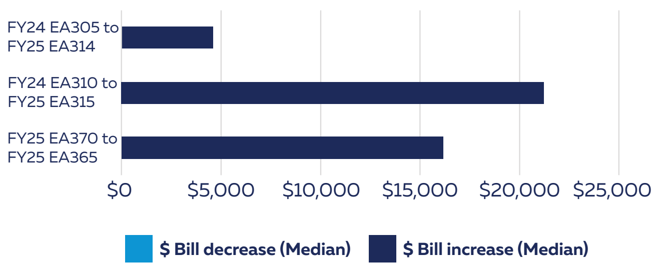
We estimate that our proposed five-year transition for EN tariffs will see a 5.7% per annum nominal increase for the affected ENs. These increases exclude other changes in the network revenue price paths in the 2024-29 period (such as inflation and interest rate impacts).

The FY25 bill impacts for EN customers currently on tariff EA305 (LV 160-750 MWh), EA310 (LV > 750 MWh) and EA370 (HV) are illustrated by **Table 5** and **Figure 6**.

Table 5: FY25 embedded network tariff bill impact

Scenario	No. of customers affected	Customers with bill decrease	Customers with bill increase
FY24 EA305 to FY25 EA314	359	0%	100%
FY24 EA310 to FY25 EA315	286	0%	100%
FY24 EA370 to FY25 EA365	29	0%	100%

Figure 6: FY25 embedded network tariff median bill impact



Detailed charts and analysis of EN tariff bill impacts can be found in **Attachment 8.3**.

29 NER, clause 6.18.5(h) – Customer impact principle

3.3 Streamlining our existing tariff offerings and tariff assignment policies

Background

In our engagement with our communities to date, we heard from retailers and aggregators that our tariff offerings and tariff assignment policies could be simplified. For example, the number of available tariffs makes it difficult to understand the differences between charging components and pass through our price signals in retail price offers. We also heard that some of our medium and large business tariff assignment policies could be improved, so that they are fairer for customers.

In response to this feedback, we want to streamline our tariffs and modify our tariff assignment policies for the 2024-29 period.[30] We are keen to simplify our tariffs where possible, particularly as we expect some parts of our tariff schedule may become more complex in the future as we explore more dynamic tariffs (see **Section 6.3**). We are proposing to make the following changes from 1 July 2024:

- Withdrawing some residential and small business tariffs that are very similar to other tariffs or have few customers assigned to them; and
- Withdrawing some medium and large business tariffs that have few customers assigned to them or were introduced as an interim measure.

In its submission Red Energy said that Ausgrid should pick one set of cost reflective windows to apply for the 2024-2029 period and that this should be an opt-in cost reflective tariff. It also said that Ausgrid should create the streamlined new seasonal peak tariff but allow retailers and their customers to transition to the new tariff over the 5-year period. If retailers choose not to adopt the streamlined tariff over the 5-year period, Ausgrid should be able to mandatorily reassign the remaining customers to the streamlined tariff in 5 years.

In response, we believe that our proposal does prioritise one set of cost reflective tariffs. In 2024-29 we propose to continue our assignment policy of moving small customers to demand tariffs when the meter is upgraded. We will also continue to allow flexibility by allowing small customers to opt-out of demand tariffs to a TOU based tariff.

Our proposal

We propose to withdraw two tariffs for residential customers and the equivalent tariffs for small business customers. These include our transitional TOU tariffs (EA011 and EA051) and our residential and small business TOU Demand tariffs (EA115 and EA255). **Table 6** shows the number of customers currently assigned to these tariffs, and the tariffs we propose to transfer these customers to. For further details on these tariffs please refer to our TSS for the 2019-24 period.

Table 6: Residential and small business tariffs we propose to withdraw from 1 July 2024

Tariff to be withdrawn	Number of customers affected	Reason for withdrawal	The tariff affected customers would be transferred to
Transitional TOU (EA011 and EA051)	170,000 residential 3,700 small business	The tariff structure is flat, so customers are not receiving cost-reflective price signals despite having a capable meter. This means they have no flexibility to manage their bills by responding to our price signals	Customers would be moved to a standard TOU tariff: • Those on Type 4 meters would move to EA116 or EA256 • Those on Type 5 meters would move to EA025 or EA225
Residential and small business TOU Demand (EA115 and EA255)	51 residential 23 small business	These tariffs have very few customers	Customers would be moved to a standard TOU tariff (EA025 or EA225)

30 NER, clause 6.18.5(i) – Customer understandability principle

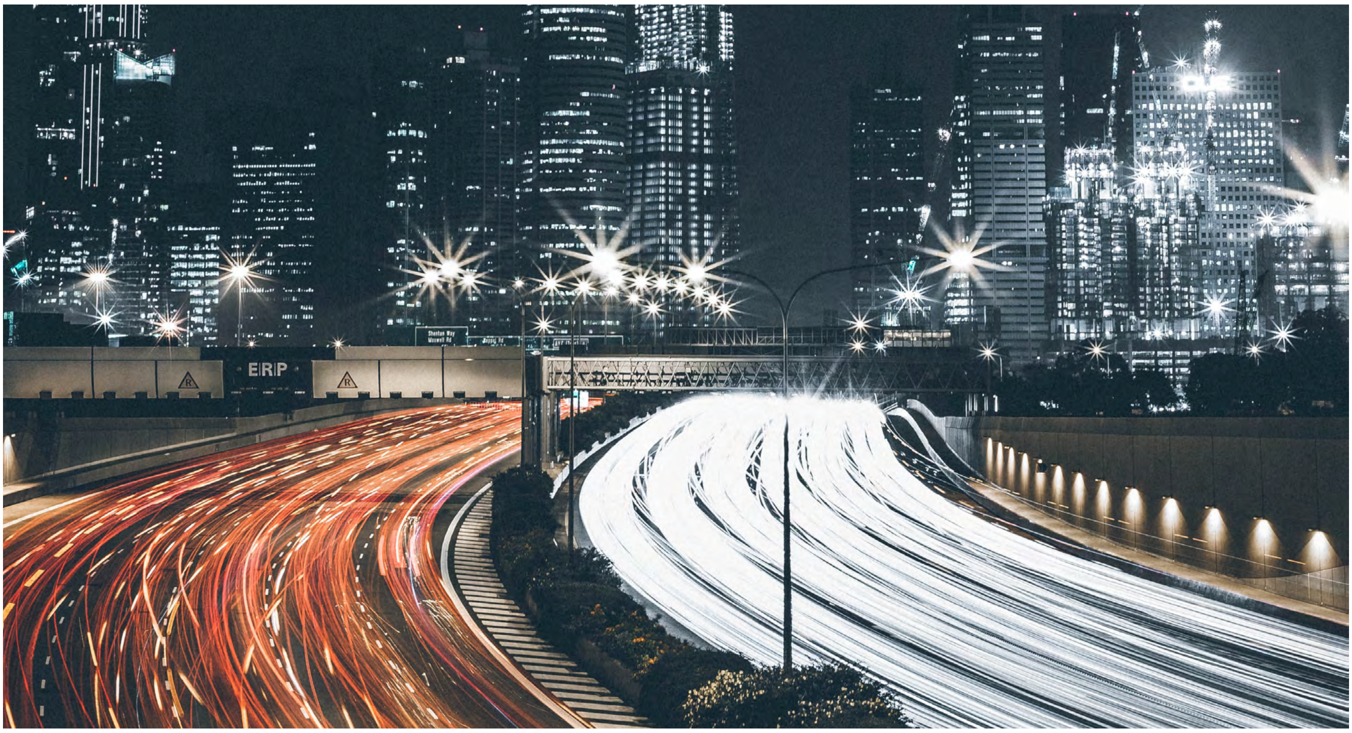
The transitional TOU tariffs (EA011 and EA251) were introduced in July 2018. Unlike standard TOU tariffs, these peak, shoulder, and off-peak rates are equal. This approach was intended to provide customers visibility of their consumption volumes within the TOU tariff structure, but without applying the actual TOU prices when calculating their network charges. We intended to transfer the customers to cost-reflective tariffs on 1 September 2019[31], but the 2019 regulatory decision prevented this from occurring.

Retailers have told us these tariffs are simply duplicating existing flat tariffs without providing any material benefit to customers. They are also not always passed through by retailers. Therefore, we propose to withdraw them and move customers assigned to them to our standard cost reflective tariffs. These tariffs are more cost-reflective and send price signals about the different costs of using the network at different times. This provides customers with flexibility to manage their bills by responding to our price signals.

The residential and small business TOU demand tariffs (EA115 and EA255) were introduced in 2019 as an option for TOU tariff customers who did not want to receive the full demand component rate. We propose to withdraw them as less than 100 customers have chosen to opt into them.

In our Pricing Directions Paper, we also proposed to remove our introductory demand tariffs (EA111 and EA251). We assign small customers with meter replacements (due to failures) to these tariffs for 12 months where they receive a small demand charge. At the end of the 12-month transitional period they are assigned to their respective "full" demand tariff. This introduces these customers to demand pricing as they are able to see the cost reflective structures on their electricity bill.

We received feedback from our engagement with AER staff in October 2022 that customers on flat tariffs who have meter upgrades should have a 12-month delay before moving to demand tariffs.[32] We are also aware that the AEMC's metering service consultation has recently considered a tariff transitional arrangement for customers who have their meter upgraded. In response to these developments, and in the context of a possible accelerated meter rollout, we propose to retain the existing introductory demand tariffs (EA111 and EA251) as they already provide a 12-month transition for customers to demand tariffs. We believe this is a better approach (than customers remaining on flat tariffs for 12-months) as they will have the opportunity to understand demand charges before receiving the full price signal.[33]



31 Ausgrid, Ausgrid - amendment to the revised TSS, Attachment A and AER, Ausgrid Distribution Determination 2019 to 2024 Attachment 18 Tariff Structure Statement, p 10.

32 NER, clause 6.18.5(h) – Customer impact principle

33 NER, clause 6.18.5(i) – Customer understandability principle

In its submission, PIAC supported the removal of introductory demand tariffs and that it does not support customer opt-outs of demand tariffs. We have considered this feedback and propose to retain introductory demand tariffs in the 2024-29 period. These tariffs will enable customers to become used to the structure of the demand charge, before receiving the full rate after 12 months. We also propose to continue to allow demand tariff customers to opt-out to TOU structures, as this is consistent with our pricing principle for customer flexibility.

In its submission City of Newcastle supported the withdrawal of the tariffs shown in **Table 7**. Red Energy agreed that the proposed charging and timing windows are simpler and easier for customers to understand. However, it said that the existing tariffs should be retained, but closed to new customers instead. Ausgrid supports a withdrawal of legacy tariffs (rather than closing to new customers) as it will avoid some customers being "left behind" and unable to access cost reflective price structures.

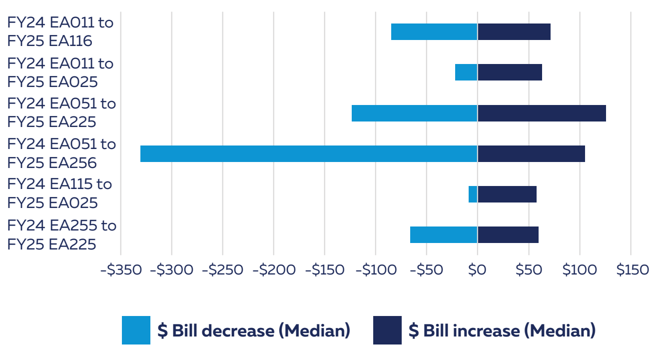
Residential and small business streamlining bill impacts

This section provides an overview of the first-year bill impact (FY25) of proposed tariff withdrawals. These changes are applicable for residential and small business customers currently assigned to transitional TOU tariffs (EA011 and EA051) and TOU Demand tariffs (EA115 and EA255). These network bill impacts include changes for inflation and regulated revenue paths. They also include the proposed changes in charging windows.

Table 7: FY25 Residential and small business bill impact – tariff streamlining

Scenario	No. of customers affected	Customers with bill decrease	Customers with bill increase
FY24 EA011 to FY25 EA116	104,003	37%	63%
FY24 EA011 to FY25 EA025	56,001	9%	91%
FY24 EA051 to FY25 EA225	1,135	23%	77%
FY24 EA051 to FY25 EA256	1,852	54%	46%
FY24 EA115 to FY25 EA025	99	15%	85%
FY24 EA255 to FY25 EA225	49	35%	65%

Figure 7: FY25 Residential and small business median bill impact – tariff streamlining



Detailed charts and analysis of tariff streamlining bill impacts can be found in **Attachment 8.3**.

Withdraw some medium and large business tariffs

We also propose to withdraw some medium business tariffs and the equivalent large business tariffs. These tariffs are listed in **Table 8**. As this table shows, few customers are currently assigned to some of these tariffs. Therefore, we expect the withdrawal of these tariffs would have little impact on customers. Removing these tariffs would make it easier for retailers to understand our tariffs.

The other tariffs – our transitional capacity tariffs (EA316 and EA317) - were introduced in 2018 as an interim measure to reduce bill impacts associated with the introduction of cost-reflective tariffs. We are already in the process of transitioning these customers, to meet our regulatory requirement to transfer customers on those tariffs to the cost-reflective equivalent tariff by 2024.[34] This process is on track, despite a postponement in 2020-21 due to the COVID-19 pandemic. We expect it to be complete by 1 July 2024.

Table 8: Medium and large business tariffs we propose to withdraw from 1 July 2024

Tariff	Customers	Why should this tariff be withdrawn	Tariff that customers will be transferred to
EA325 (LV Standby)	3		Demand tariff EA256
EA360 (HV Standby)	7	These tariffs have very few customers	High voltage tariff EA370
EA380 (HV Substation)	21		High voltage tariff EA370
EA391 (Substation)	0	This tariff has no customers	Not applicable
Transitional capacity (EA316 and EA317)	3,150 and 19	The AER requires us to transfer all customers from these tariffs by 30 June 2024	Equivalent cost-reflective tariffs (EA302 and EA305)

34 Ausgrid, Ausgrid - amendment to the revised TSS, 28 February 2019 and AER decision for the 2014-19 regulatory period (attachment 18, page 17).

Medium and large business streamlining bill Impacts

Almost all customers currently assigned to EA325, EA316 and EA317 are likely to benefit from the proposed tariff streamlining. Some customers transferred off network tariffs EA360 and EA380 may face bill increases.

We propose to manage any significant impacts for these customers with a capacity reset transition for the first six months of the regulatory period.

Table 9: FY25 medium and large business bill impact – tariff streamlining proposals

Scenario	No. of customers affected	Customers with bill decrease	Customers with bill increase
FY24 EA325 to FY25 EA256	2	100%	0%
FY24 EA360 to FY25 EA370	7	0%	100%
FY24 EA380 to FY25 EA370	19	0%	100%
FY24 EA316 to FY25 EA302	2,622	18%	82%
FY24 EA317 to FY25 EA305	9	0%	100%

Figure 8: FY25 medium and large business median bill impact – tariff streamlining

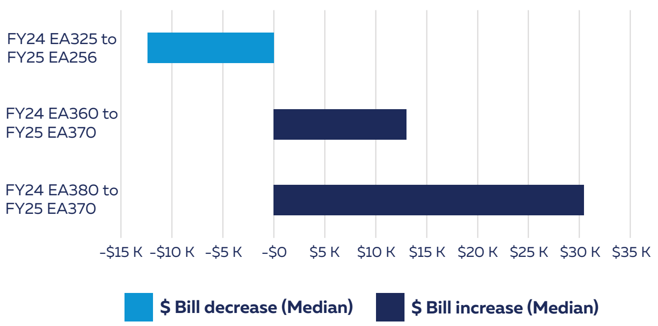
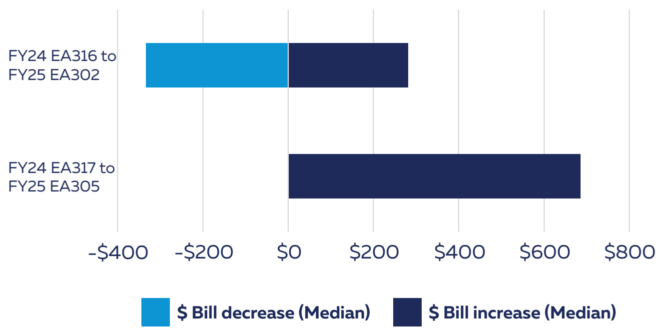


Figure 9: Withdrawal of transitional capacity tariffs, median bill impact



Detailed charts and analysis of tariff streamlining bill impacts can be found in **Attachment 8.3**.

Reform our small and medium business tariff assignment policies

Our PWG has provided strong support for our capacity component charges for medium to large business customers. However, in our consultations to date, retailers and customers have raised two concerns about the bill impacts for small and medium business customers, when we transfer them to another tariff in line with our current tariff assignment policies.

First, when a small business customer on our demand tariff (EA256) uses more than 40 MWh pa over a 2-year period, our policy is to transfer them to a medium business capacity tariff (EA302). This tariff has a different structure to the demand tariff, and this can create adverse bill impacts for customers who use the network infrequently (such as, currently, electric vehicle charging stations).

Second, when new business customers connect to our network, they do not have any existing metering data to guide us in assigning them to the most appropriate network tariff. Our current policy assigns them to a demand tariff if they have a single-phase connection, and to a capacity tariff if they have a three-phase connection. However, we understand that many small business customers (using less than 40 MWh pa) are on three-phase supplies. Under this policy, they are assigned to a capacity tariff that is likely to be inappropriate. In addition, under our existing assignment policies a new customer must wait 12 months before they can request a tariff transfer. For these reasons, we propose the following reforms to our tariff assignment policy:

- **Increasing the consumption threshold** for transferring existing customers from a demand tariff to a capacity tariff from 40 MWh pa to 100 MWh pa. This will align with the threshold at which the NSW ombudsman scheme and National Energy Retail Law (NSW) defines a small customer. It will also improve our annual review of tariff assignments by reducing the number of tariff transfers occurring. It will also enable customers using between 40 and 100 MWh per annum to be assigned to the business demand tariff EA256 (and to opt-out to a TOU tariff, should they choose to).[35] We propose to move the threshold to 100 MWh in 20 MWh steps over three years (FY25, FY26 and FY27) to limit rebalancing of tariff components and possible customer bill impacts.[36]
- When assigning new business customers to a tariff, we propose to **replace the "three-phase rule" with a "greater than 100 amp rule"** for assigning customers to capacity tariffs. This will ensure that smaller business customers who have three-phase supply sites are assigned to the business demand tariff (EA256) instead of the capacity tariff (EA302). These customers would still be able to opt-out of this demand tariff, and move to the business TOU tariff EA225.[37]

35 NER, clause 6.18.5(i) – Customer understandability principle

36 NER, clause 6.18.5(h) – Customer impact principle

37 NER, clause 6.18.5(h) – Customer impact principle

Stakeholder feedback on tariff streamlining

Our Pricing Directions Paper consultation asked stakeholders for their views on our changes to new and existing medium business customer tariff assignment. Northern Beaches and Willoughby Councils supported lifting the usage threshold from 40 to 100 MWh pa, as it would result in lower bills for business customers, including for councils.

In its submission, the EV Council said that the proposed reforms were moving slightly in the right direction. It recommended that new customers with greater than 100 amp connections be able to choose whether they receive a capacity, demand or TOU tariff. It also requested that the assignment threshold between demand and capacity tariffs be moved to 160 MWh per annum (instead of 100 MWh). GoEvie agreed with this position and also said that the 100 amp assignment threshold would create barriers to deploying higher power EV infrastructure.

We believe that 100 MWh per annum is an appropriate threshold to distinguish between small and large business customers as it aligns with the National Energy Retail Law Regulation (NSW) definition of a small customer. It also is the threshold below which the NSW energy ombudsman scheme applies. Our proposal is to apply demand tariffs to small customers and capacity-based tariffs to large customers as this reflects an appropriate balance between efficient, cost reflective pricing and fairness.

The 100 amp connection threshold is defined in the NSW Service and Installation Rules as the level above which an additional level of electrical compliance is required by both the accredited service provider and distribution network. It is also recommended by the AER in its connection charge guidelines.[38] All three NSW distributors use the threshold to identify larger loads that may require further investigation to maintain network reliability and safety.

The move to the 100 amp and 100 MWh thresholds will improve our tariff assignment policy by ensuring new business customers are more likely to be assigned to the correct tariff at the time of connection. Our analysis indicates that businesses who have greater than 100 amp electrical connections are likely to use more than 100 MWh per annum. On this basis it is an appropriate assumption for new business tariff assignment.[39]

If business customers who are assigned to capacity tariffs are allowed to opt-out to demand or TOU tariffs it will reduce the benefits of this cost reflective structure. Under our proposed system of assessment and review we will ensure than any businesses using less than 100 MWh (and on capacity tariffs) will be transferred to demand tariffs once they have 12 months of meter data.

38 AER Connection charge guidelines for electricity retail customers, June 2012.

39 NER, clause 6.18.5(h) – Customer impact principle

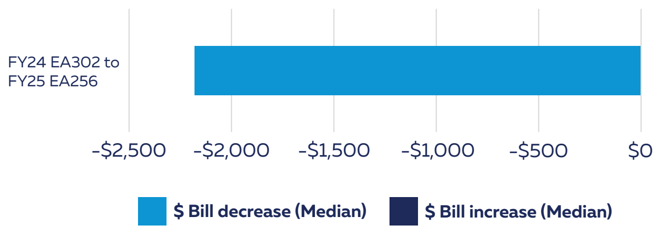
100 MWh threshold bill impacts

By July 2027 we propose to increase the threshold for assigning existing business customers to capacity tariffs to 100 MWh pa. In FY25 this means that existing capacity charge customers using between 40 and 60 MWh pa will be moved to demand tariffs. Eligible smaller business customers currently assigned to the capacity tariff (EA302) will be reassigned to the business demand tariff EA256 and benefit from bill reduction as shown in **Figure 10**.

Table 10: EA302 customers 40- 60 MWh bill impact

Scenario	No. of customers affected	Customers with bill decrease	Customers with bill increase
FY24 EA302 to FY25 EA256	13,154	100%	0%

Figure 10: EA302 customers 40-60 MWh median bill impact



Detailed charts and analysis of the bill impacts of these changes can be found in **Attachment 8.3**.

3.4 Simplifying and updating the charging windows

Residential and small business customers on our demand and TOU tariffs are charged more in summer and winter, when there is peak demand on our network. This is efficient because peak demand is a major driver of our network costs. Charging higher prices in peak demand periods signals these higher costs to customers, who can then make informed decisions about whether to consume energy when it is most convenient for them, or when it costs them less.[40] However, over the past four years, only around half of retailers have passed through our demand charges. This may be because our current charging windows are more complex than those of other distribution networks.

Our proposal

To improve the cost reflectivity of our price signals[41] and to increase the likelihood of customers receiving our price structures[42], we are proposing the following:

- Making the peak charging window consistent in summer and winter, and moving it to later in the day, so that from 1 July 2024 peak pricing applies from 3pm to 9pm in both seasons;
- Having the option to further move the peak charging window from 1 July 2027, so that peak pricing applies from 4pm to 10pm in both seasons;
- Extending the number of days per week that the peak charging window applies from five to seven for residential customers;
- Combining the off-peak and shoulder charging windows so that off-peak charges apply at all times in spring and autumn and outside of the peak charging window in summer and winter; and
- Removing the low season peak demand charge so that demand charges do not apply outside of the summer and winter periods.

The sections below discuss each of these changes in more detail. **Table 11** provides an overview of proposed charging windows for small customers and compares them to the existing charging windows.

40 NER, clause 6.18.5(f) – Long run marginal cost principle
41 NER, clause 6.18.5(f) – Long run marginal cost principle
42 NER, clause 6.18.5(i) – Customer understandability principle

Table 11: Comparison of current and proposed seasonal peak charging windows for our small customers

Time of use tariff	Current residential	Proposed residential	Current small business	Proposed small business
November to March (summer) and June to August (winter)	**Peak:** 2pm-8pm weekdays (summer) **Peak:** 5pm-9pm weekdays (winter) **Shoulder:** 7am-10pm all days except when peak applies **Off-peak:** 10pm-7am all days	**From 1 July 2024:** **Peak**: 3pm-9pm all days **Off-peak:** all other times **Option:** **From 1 July 2027:** Peak: 4pm-10pm all days **Off-peak:** all other times	**Peak:** 2pm-8pm weekdays **Shoulder:** 7am-10pm weekdays except when peak applies **Off-peak:** 24 hours on weekends and 10pm-7am weekdays	**From 1 July 2024:** **Peak**: 3pm-9pm weekdays **Off-peak:** all other times **Option:** **From 1 July 2027:** Peak: 4pm-10pm weekdays **Off-peak:** all other times
April, May, September, and October	**Shoulder:** 7am-10pm all days **Off-peak:** 10pm-7am all days	**Off-peak:** all times	**Shoulder:** 7am-10pm weekdays days **Off-peak:** 24 hours on weekends and 10pm-7am weekdays	**Off-peak:** all times

Demand tariff	Current residential	Proposed residential	Current small business	Proposed small business
November to March (summer) and June to August (winter)	**High season peak:** 2pm to 8pm weekdays (summer) **High season peak:** 5pm to 9pm weekdays (winter)	**From 1 July 2024:** 3pm-9pm all days **Option:** **From 1 July 2027:** 4pm-10pm all days	**High season peak:** 2pm to 8pm weekdays	**From 1 July 2024:** 3pm-9pm weekdays **Option:** **From 1 July 2027:** 4pm-10pm weekdays
April, May, September, and October	**Low season peak:** 2pm to 8pm weekdays	No demand charge	**Low season peak:** 2pm to 8pm weekdays	No demand charge

Note: For large business customers the peak window will also move to 3pm to 9pm. Capacity charges will continue to apply on working weekdays and energy charges in high season months. The shoulder and off-peak periods will also be combined for these customers.

Combining the peak charging window and the shoulder charging window

Shoulder period prices have historically played a role in keeping peak demand within the peak charging window. By providing a two-hour separation between evening peak and off-peak charges, they allowed demand to fall from peak levels before price-responsive demand was added to the network. However, retailers have told us that administering the existing shoulder charging windows for small customers involves an additional degree of complexity.

Our energy rates have been progressively reduced in the 2019-24 period, as per the AER's 2019 decision[43]. Most of our shoulder rates will soon be at similar levels to the corresponding off-peak rate, indicating limited gain in retaining a separate shoulder rate. This can be seen in the rates on our current network price list. Despite this trend there has been a decrease in peak events occurring outside the peak charging window. This means there would likely be little difference in an efficient price for a shoulder and an off-peak charge.

We also seek to encourage "solar soaking" load in the middle of the day to help accommodate more export capable devices in our network. Having lower energy rates in the middle of the day will help with this objective.[44]

Given the considerations described above, we propose to combine our existing off-peak and shoulder periods into a new off-peak period with a wider window. Our proposed change will have a minimal impact on customer bills, given the two charging rates are already approaching alignment.[45] We have provided the bill impacts for the first year in which these changes occur (FY25) in **Attachment 8.3**.

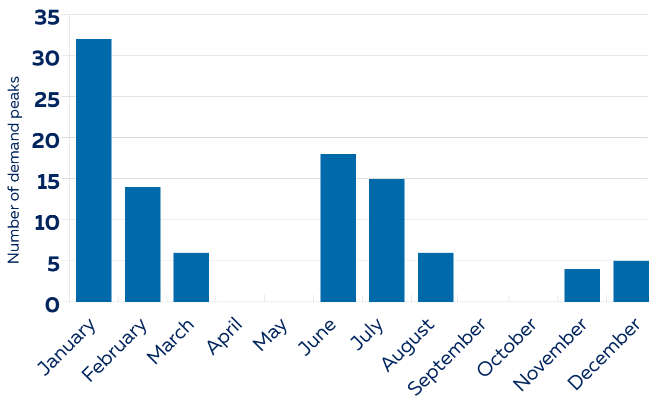
In its submission to our Pricing Directions Paper, the retailer Red Energy said that changes to network tariff structures can add to its operational and administrative costs. In response to this feedback, and a desire to minimise impacts on our retailers, we will continue to show the shoulder period component (with zero values) in the network billing files we send to our retailers.

Making seasonal peak charging window consistent in summer and winter and moving it to later in the day

Currently, our demand and TOU tariffs include higher charges at specified times of the weekday November to March (summer) and from June to August (winter). This is because, when we introduced these tariffs, the system wide demand on our network occurred almost entirely in these seasons.

We have reviewed the system-wide demand on the network over the past four years. As **Figure 11** shows, this seasonal pattern of demand has not changed. Therefore, we think it remains efficient and fair to charge customers more for using the network in those peak seasons than we do in the other months of the year. We also propose to withdraw low season demand charges which will remove demand-based charging from the April, May, September and October months.[46]

Figure 11: Count of top 100 system peak demands (2017-2021) by month



However, we propose to adjust the length and timing of the peak charging window so it is consistent in both seasons, and occurs later in the day. Currently, this window includes the six hours from 2pm to 8pm in summer, and the four hours from 5pm and 9pm in winter. We are proposing to change it to the six hours from 3pm to 9pm in both summer and winter from 1 July 2024.

43 Ausgrid, Revised Proposal – Attachment 10.01 Tariff Structure Statement, January 2019, p 6-7, and AER's final decision for the 2019-24 regulatory period (attachment 18, page 17).

44 NER, clause 6.18.5(f) – Long run marginal cost principle

45 NER, clause 6.18.5(h) – Customer impact principle

46 NER, clause 6.18.5(f) – Long run marginal cost principle

Our review of the timing of peak demand suggests that the benefits of maintaining the differences in these charging windows (in terms of improved cost reflectivity) are outweighed by the costs (in terms of increased complexity).[47] To address this, we think we should increase the length of the winter charging window to six hours. We consider this is more efficient than shortening the summer charging window to four hours because:

- The peak charging component is set to recover the LRMC of consumption services and residual revenue. Allocating this cost over a 4-hour period instead of a 6-hour period would result in a higher unit price (all other things being equal). This could exacerbate the bill impacts of customers who are unable to load shift during a 4-hour window.[48]
- If the peak price level were to become too high relative to other times of the day, it may lead to new demand peaks immediately after this charging window, as more customers delay using the network until the window closes. We want to avoid creating new demand peaks on our network, particularly as EV time-based charging becomes more common.[49]

We consider the proposed peak charging window of 3-9pm better matches the timing of peak demand than the current windows. Our analysis indicates that this change will significantly increase the number of peak demand events that fall within the peak window:

- Over the past 5 years, 92% of system-wide peaks have occurred in the proposed window of 3pm to 9pm, while only 83% have occurred in the current peak window; and
- Over the past 3 years, 82% of annual zone substation peaks have occurred in the proposed window, compared to 52% in the current peak window.

We are also aware that our review of an appropriate peak window must be forward looking and address expected demand profile changes in the 2024-29 period.[50] Our analysis indicates that the period of the day when there is peak demand will continue to shift to later over the 2024-29 period. **Figure 12** and **Figure 13** shows our forecast of the time of day that each zone substation will be at or near its peak demand in summer and winter in 2029, and largely within our proposed peak charging window of 3pm to 9pm.

47 NER, clause 6.18.5(f) – Long run marginal cost principle; NER, clause 6.18.5(i) – Customer understandability principle

48 NER, clause 6.18.5(h) – Customer impact principle

49 NER, clause 6.18.5(f) – Long run marginal cost principle

50 NER, clause 6.18.5(f) – Long run marginal cost principle

Figure 12: Forecast 2029 distribution of zone substation summer peak demands[51]

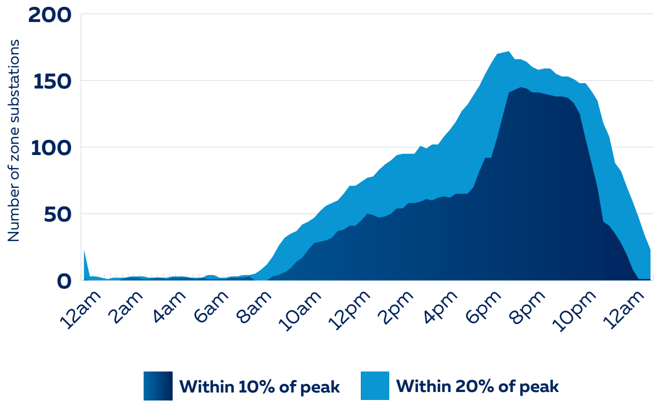
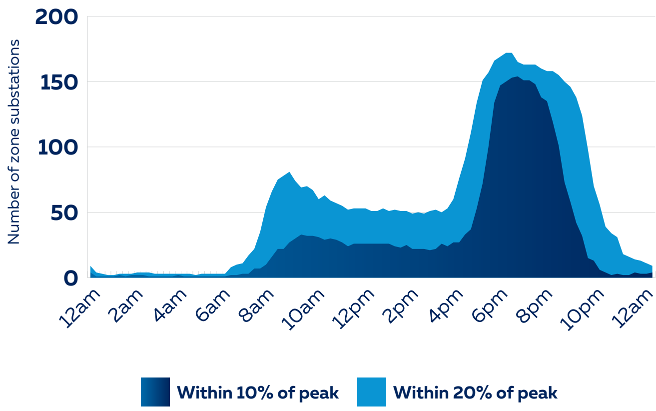


Figure 13: Forecast 2029 distribution of zone substation winter peak demands



Having the option to move the peak charging window again from 1 July 2027

As noted above, our proposed peak charging window from 1 July 2024 is based on our current forecast of the timing of peak demand over the 2024-29 period. However, the future is uncertain, and the ability to amend the TSS within-period is currently constrained under the Rules.

For example, the EV uptake rate and EV charging patterns over the period to 2029 are highly uncertain. If the take-up rate exceeds current expectations, the associated additional load could drive new evening demand peaks. We are less concerned of this occurring after 10pm given that other household load drops off significantly from this time.

Second, the increasing uptake of rooftop solar is reducing the demand on our network in the afternoon, when the volume of customer-generated energy typically peaks.

51 These two charts show a count of substations where forecast demand as a percentage of the zone substation's forecast peak is greater than 80%.

In locations where solar penetration is already high, high levels of customer exports and low levels of demand for imports is resulting in a lower 'minimum system load' in the afternoon than previously experienced overnight. If this continues, it could increasingly drive additional voltage management costs in the low voltage network in the future.

We seek AER approval for an option to move the peak charging window to 4pm to 10pm from 1 July 2027, which would help us address these issues if they eventuate: [52]

- Extending the window to 10pm would create an incentive for customers to move their EV charging activity to after this time, ensuring it does not coincide with other (non-EV-related) load. Existing loads typically decline rapidly around 10pm and we expect this pattern to continue, particularly in the residential segment; and
- Moving the start of the window back to 4pm could increase grid imports between 3pm and 4pm, and thus it could help moderate the impact on future minimum system load costs.

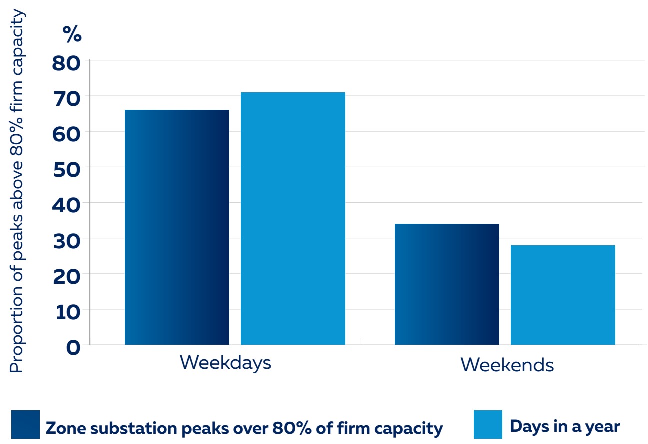
The trigger event for this option will be the occurrence of a network system demand peak occurring after 9pm on any day prior to 1 March 2027. The trigger will be determined using the half-hour interval that the maximum raw coincident system demand occurred. This data will be prepared on a similar basis to the approach used for table 5.3.1 of the annual Regulatory Information Notice submission.

Extending the peak charging window to weekends for residential customers

Currently, our peak charging windows apply only from Monday to Friday. This is because historically, the periods of peak demand across the whole network have occurred predominantly on working days. Of the top 160 coincident network peaks[53] in the last 5 years, only 14% occurred on weekends.

However, when we analysed the periods of peak demand in individual zone substation areas (we have around 190 zone substations with the necessary data), we found that these localised peaks are as common on weekends as on weekdays (see **Figure 14**).

Figure 14: Zone substation peaks by day of the week



Looking closer at this data, we found that localised peaks on the weekend are most common in highly residential areas or holiday areas. Weekend peaks are significantly less likely in predominantly commercial areas, and the probability of weekend peaks declines as the proportion of residential customers in these areas declines.

Given these findings, we are proposing to extend our peak charging window so that it applies on weekends as well as weekdays for residential customers only. This would improve the cost reflectivity of our peak pricing for these customers. [54]

This change would increase the total number of hours that the peak charging window applies per year for residential customers. Because the peak price level is set to recover the LRMC of meeting peak demand, increasing the hours over which it can be recovered would decrease in the price level (all other things being equal).

Stakeholder feedback on charging window changes

Our Pricing Directions Paper consultation asked stakeholders for their views on our proposed changes to the charging windows. In our interviews with large business customers (including Opal, Qenos, Woolworths and Telstra), we heard general acceptance of the move of the peak period to later in the day. This was because the load profiles of these businesses are generally flat and are not likely to create an impact to their network costs. City of Newcastle also supported moving the peak window to 4-10pm. However, Transport for NSW commented that this proposed option will reduce the length of the off-peak window and introduce uncertainty for their planned investments in electric buses. They prefer certainty for the full five-year regulatory period as it would remove a significant amount of risk. We note that while the peak window ends later in the day, the off-peak window will

52 NER, clause 6.18.5(f) – Long run marginal cost principle

53 The coincident network peak is the aggregate maximum demand that occurs across the Ausgrid network at the same point in time.

54 NER, clause 6.18.5(f) – Long run marginal cost principle

extend until 3pm the next day, (or 4pm if the trigger occurs) effectively increasing the time available for EV charging.

In its submission PIAC said that it did not support a consistent 6-hour window for summer and winter. It said that it is materially harder for households to respond to peak tariffs longer than 3 or 4 hours, and that most peaks in most parts of Ausgrid's network can be captured in a 4-hour period. As described above we have considered this trade off and are of the view that a lower peak price in a 6-hour window achieves a better balance (considering the efficiency, flexibility and fairness principles) than a higher price in a 4-hour window.

PIAC does not support moving the peak window to later if it is predicated on the increasing penetration of EVs. Our proposal to move the peak window to 3pm-9pm is not influenced by the expected take up of EVs. Our historical analysis of demand peaks (described above) shows that significantly more of the demand peaks seen in the last three years will be captured by the change to 3pm-9pm.

PIAC suggested that the expected future uptake of EVs could be managed by EV specific tariffs (and instead of having a trigger event for moving the peak period to 4pm-10pm). Ausgrid currently allows small customer EV charging to occur on its controlled load tariffs, and we will continue this arrangement in the 2024-29 period. EV specific tariffs face a barrier as distribution networks do not have visibility of EV ownership. We also consider that our proposed tariff structures provide suitable cost reflective incentives for EV charging.

PIAC said it has not seen sufficient evidence for extending the residential peak windows to weekends. It said this proposal would limit the capacity of households across Ausgrid's entire network to manage their exposure to peak pricing in the interest of capturing the peak period of a relatively small portion of the network. Our analysis (described above) does show that zone substations with predominantly residential loads are triggering peaks on weekends.

Red Energy said that making the new seasonal peak charging windows more cost reflective will ensure that the price signals for the use of the network are more accurate. However, it considers that there is little benefit in changing the timing windows twice within the 5-year period as customers need consistency to make meaningful changes to their consumption profile. Given the reasons outlined above, we are of the view that the peak charging window trigger is a prudent initiative given the uncertainty on EV take up in the next regulatory period.

Red Energy also said that Ausgrid should create the streamlined new seasonal peak tariffs but allow retailers and their customers to transition to the new tariffs over the 5-year period. If retailers choose not to adopt the streamlined tariff over the 5-year period, Ausgrid should be able to mandatorily reassign the remaining customers to the streamlined tariff in 5 years. We consider that the Red Energy proposal would result in an unnecessary delay in moving customers to cost reflective price signals, and it is worthwhile to commence the changes at the start of the next regulatory period.

Bill impacts of FY25 charging windows and price updates

This section provides an overview of the bill impacts on customers who will remain on their existing demand, TOU or capacity tariffs in FY25. These impacts are partly due to the the changes in charging structures, and also due to the assumed revenue path and CPI assumptions for FY25.

Table 12 and **Figure 15** illustrate the network bill impacts of residential and small business demand tariffs.

Table 12: FY25 demand and TOU tariff bill impact - combined factors

Scenario	No. of customers affected	Customers with bill decrease	Customers with bill increase
FY24 EA025 to FY25 EA025	399,890	12%	88%
FY24 EA116 to FY25 EA116	338,783	5%	95%
FY24 EA225 to FY25 EA225	72,527	19%	81%
FY24 EA256 to FY25 EA256	28,535	18%	82%

Figure 15: Demand and TOU tariff median bill impact - combined factors

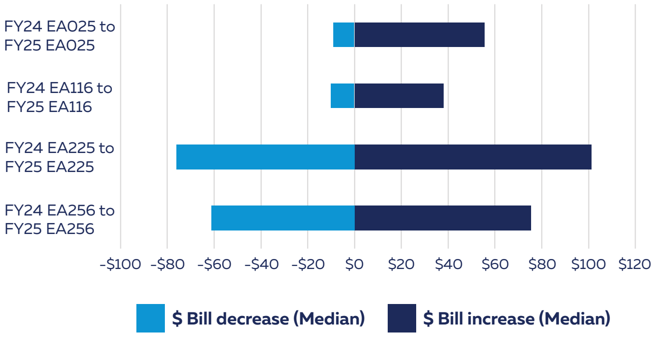
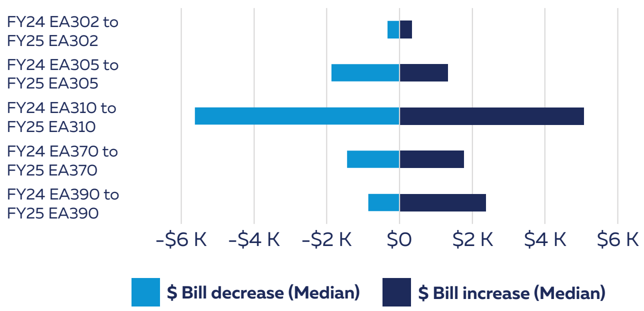


Table 13: FY25 capacity tariff bill impact – combined factors

Scenario	No. of customers affected	Customers with bill decrease	Customers with bill increase
FY24 EA302 to FY25 EA302	14,919	15%	85%
FY24 EA305 to FY25 EA305	7,340	11%	89%
FY24 EA310 to FY25 EA310	2,734	3%	97%
FY24 EA370 to FY25 EA370	291	16%	84%
FY24 EA390 to FY25 EA390	77	47%	53%

Figure 16: FY25 demand tariff median bill impact - combined factors



Detailed charts and analysis of export tariff bill impacts can be found in **Attachment 8.3**.

3.5 Utility scale storage tariffs

Background

We expect to see significant investment in storage by our customers in coming years. AEMO forecasts embedded storage (battery) installations in NSW to grow from 180 MW in 2021-22 to 2,382 MW in 2028-29 under the Step Change scenario.[55]

While we are starting to see the take up of behind-the-meter storage, we have not yet seen utility scale storage facilities connect to our network. We currently have no existing large storage customers apart from the Ausgrid community battery trial. Most utility scale storage customers currently connect to the transmission network, partly driven by lower prices relative to existing network tariffs. We seek to promote efficient levels of utility scale storage connecting to our distribution network in the 2024-29 period and beyond.[56] The connection of utility scale storage to our network – with appropriate network price signals – promotes an efficient, flexible and fair outcome to all our customers by:

- Encouraging storage to charge during periods of low demand and high voltage, thereby providing voltage support to the network, reducing the amount of rooftop solar exports being curtailed by our customers and reducing the costs of voltage management; and
- Encouraging storage to export during periods of peak demand, which can avoid us needing to augment our networks.[57]

There has been a growing debate on introducing new and innovative network tariffs to support the integration of storage into the grid:

- Each of the Victorian DNSPs proposed to the AER, in their 2021-26 TSS process, to exempt utility scale batteries from their network tariffs if operated to the net benefit of their customers.
- The AEMC reviewed the transmission and distribution network charging arrangements in its *Integrating Energy Storage Systems* into the National Electricity Market rule change review.[58]

In its review the AEMC only made a minor amendment to the distribution pricing rules, instead noting it considered further work was required on how network costs are recovered from storage.[59] In the Victorian TSS process, the AER did not accept the distributors' proposals to exempt storage from network tariffs. It instead preferred to maintain the status quo for the second round of TSS's, for consistency with the network tariff arrangements of other DNSPs outside Victoria.[60]

55 AEMO, 2022 ISP – Inputs, assumptions and scenarios workbook, June 2022.

56 NER, clause 6.18.5(g) – Minimizing distortions principle

57 NER, clause 6.18.5(f) – Long run marginal price signals

58 AEMC, Final rule determination – Integrating energy storage systems into the NEM, December 2021.

59 AEMC, Final rule determination – Integrating energy storage systems into the NEM, December 2021, p.65.

60 AER, Final decision – Victorian DNSPs – Distribution determination 2021 to 2026 – Attachment 19 TSS, April 2021, p.18.

The AER also stated:

> We anticipate specific pricing for grid-scale batteries may be a feature of the pricing reforms in the third round of tariff structure statement assessments, given the nature of the policy and regulatory reforms currently underway. As more grid-scale batteries are integrated into distribution networks, electricity distributors are likely to identify innovative ways to reflect the locational and dynamic costs of serving customers. This may result in alternative pricing structures, particularly if they are associated with differentiation in the use of network services by customers currently in the same tariff class.[61]

Given the significant storage forecasts expected over the 2024-29 period, we consider it is important that we develop efficient, flexible and fair network charging arrangements for storage. We also understand each NSW distributor is proposing specific arrangements for storage in its TSS proposal.

Our proposal

We propose to introduce three new opt-in storage tariffs on 1 July 2024. The three tariffs differ by voltage level of connection. Each tariff has a separate tariff code and tariff structure for when storage is importing (versus exporting). The three tariffs are:

- Local network support service tariff for low voltage storage (EA962/EA963);
- High voltage network storage tariff for high voltage storage (EA340/EA341); and
- Sub-transmission storage tariff (EA380/EA382).

The eligibility and specific design of these tariffs is explained below.

Our storage tariffs will be available to customers that use the network to store electricity for export at a later time, from the same connection point. Electricity imported at the connection point can only be used to power the storage facility or be stored for subsequent discharge of electricity. Electricity exported at the connection point may only be sourced from stored energy via electricity previously imported at the connection or pre-existing at time of connection. For example, storage connected with solar PV or with an additional load behind the same connection point would not be eligible.

We may publish further requirements in our ES7 Network Price Guide to ensure we are consistent with the implementation of the AEMC's integrating energy storage systems rule change.

61 AER, Final decision – Victorian DNSPs – Distribution determination 2021 to 2026 – Attachment 19 TSS, April 2021, p.19.

Utility scale storage only connections have unique characteristics which we consider warrant specific tariff arrangements. These are: [62]

- Highly flexible and price responsive forms of demand – this means highly cost reflective tariffs can be applied with minimal customer impacts because the load can respond to these efficient price signals.
- Connections where the investment decision is primarily driven by energy cost considerations – this supports the application of locational price signals to these tariffs. Locational price signals are efficient and supported by the NER, but not applied to other customers because of customer impact considerations and the cost of calculating and conveying locational price signals.
- Largely new forms of investment – this also means there are fewer customer impacts because we are establishing the pricing signals before many customers have made the decision of where to connect and what their business operation looks like. It avoids uneconomic pricing signals which could result in new storage connections choosing to instead connect to the transmission network or without regard to local network constraints because of the manner we collect residual network costs.

Stakeholder feedback to the Pricing Directions Paper

Our Pricing Directions Paper explained our current community battery tariff trials and asked stakeholders for their views on what innovative tariff trials we should introduce for energy storage in the 2024-29 period:

- City of Newcastle supported the tariff trials and the continued use of a critical peak pricing tariff for community batteries as a trial tariff;
- Shell Energy responded that Ausgrid should introduce a utility scale storage tariff in the 2024-29 period to ensure large batteries aren't disincentivised from connecting at the distribution level. Ausgrid's current distribution tariff for sub-transmission connections was considered uneconomic for batteries, and a tariff with rates similar to the Ausgrid transmission tariff would be more appropriate; and
- Firm Power stated that trial tariffs are "unbankable" to the investment community given that distributors update their sub-threshold applications annually. The submission said a large-scale storage tariff should recognise the benefits that batteries provide and not have capacity or fixed charge components, and be exempt from receiving the NSW Climate Change Fund levy.

Amendments since Pricing Directions Paper

In light of the feedback we received from storage proponents on the "unbankable" nature of trial tariffs, we propose to introduce storage tariffs as standard tariffs in the 2024-29 period. Starting with the design of our community battery tariff trials, we have reviewed and refined our proposed storage tariff structures. The proposed storage tariffs and their charging components are outlined in the TSS compliance paper.

We have developed LRMC based price structures for storage. The three tariffs all use a critical peak pricing approach to best match network costs to network prices. We consider that locational critical peak pricing best signals to customers the time and location that network usage (both imports and exports) drives network costs.

For our critical peak charges, we have applied energy charges over demand based rebates to signal network costs. The strength of energy charges for critical peak prices is that the signal to support the network, or avoid harming the network, is equal across the high load or high export event. Demand charges could drive storage assets to only support the network for 30-minutes (the minimum interval required to maximise reward payments), with little incentive to provide further network support.

Each of our peak energy and peak export critical peak events are locational. [63] That is the peak energy or peak export event will reflect the locational conditions of the storage asset. We do this in different ways for the low and high voltage tariffs, and the sub-transmission tariff:

- We will call critical peak events for the low voltage and high voltage tariffs. We will provide notification to retailers and, at customers request, directly to customers. We have designed critical peak events to be locational, based on the most local constraints we can measure and bill for the assets. Until we complete our billing system transformation we will apply the critical peak charges on a network-wide basis.
- We will use virtual metering for the sub-transmission tariffs. The sub-transmission storage customers will, given their size, have visibility of the local network's use and will be provided with an N level, reflective of the available capacity at that location in the network. The virtual meter will automatically allocate import and export to off-peak and near N components.

In each tariff we will set the distribution use of system charges equal to the long-run marginal cost at the time that activity drives future costs. The LRMC applied to each tariff depends on the network location and the event type.

62 NER, clause 6.18.5(f) – Long run marginal cost principle; NER, clause 6.18.5(h) – Customer impact principle; NER, clause 6.18.5(g) – Minimizing distortions principle.

63 NER, clause 6.18.5(f)(3) – long run marginal cost principle – locational consideration

Table 14: How long-run marginal cost is reflected in the tariff charging components

Event	How LRMC is reflected in the tariff charging components
Local network support service tariff (LV) – critical peak energy events	The low voltage consumption LRMC is applied as a charge for imports and a reward for exports during peak energy events.
Local network support service tariff (LV) – critical peak export events	The low voltage LRMC, developed for our export tariff, is applied as a reward for imports and a charge for exports during peak export events.
High voltage network storage tariff – critical peak energy events	The high voltage consumption LRMC is applied as a charge for imports and a reward for exports during peak energy events.
Sub-transmission storage - critical peak energy events	A bespoke LRMC is charged to use above the N reliability measure that reflects bringing forward the replacement of a sub-transmission substation by 5 years, the potential costs of overloading network assets. A reward applies when the customer avoids the network exceed the N reliability measure reflecting the value of otherwise unserved energy from an outage that would have likely occurred if the storage facility did not provide network support.
Sub-transmission storage tariff – peak energy	The sub-transmission consumption LRMC is applied as a charge for imports during peak energy events, when the local network assets are operating up to 5 MW below the N reliability measure. We do not include an export reward for this component.

Ausgrid recovers NSW jurisdictional schemes (such as the Climate Change Fund) through volumetric energy charges for all customers. For our low and high voltage storage tariff, the off-peak usage charges will include recovery of the jurisdictional schemes. For our sub-transmission storage tariff, we will ensure only the net energy consumed on-site is levied the jurisdictional schemes.

We are required under the NER transitional rules to include a basic export limit (that provides a free level of export) for any tariff involving export pricing. The policy rationale for the basic export limit is that a distribution network's intrinsic level of CER export hosting capacity should be provided without charge. However, that rationale does not apply in this circumstance. A peak export charge should only apply when voltages on our network are forecast to exceed Australian standards, a situation that indicates network hosting capacity is exhausted. In this situation there should be no unused intrinsic hosting capacity available to the storage customer. We have included a 1 kWh per event BEL for the low voltage storage tariff export charges. This is the lowest BEL we can practically apply.

Storage customers are unique in terms of their total efficient costs. By applying and responding to efficient network price signals, storage assets have relatively low avoidable and standalone costs:

- The avoidable cost of a flexible storage customer located in our network will typically be near zero. In some cases, where flexible storage customers support the network the avoidable costs are negative as their network use delays or avoids future augmentation expenditure.
- The standalone costs of a flexible storage customer are also typically very low. Flexible storage customers are primarily focused on wholesale and ancillary service markets, therefore their standalone cost is the cost of the storage connecting anywhere with access to the NEM. At larger scales the standalone costs are best represented by the prices offered to flexible storage customers by Transgrid, which we understand is significantly lower than our prevailing tariffs.

We consider that it is important that the total efficient costs allocated to flexible storage customers are between the avoidable and standalone costs. This ensures that storage customers are not creating or receiving an economic cross subsidy.

Our tariffs ensure storage customers contribute to Ausgrid's residual cost recovery, reducing the network costs allocated to all other customers. We are attempting to ensure that residual cost recovery does not deter customers from connecting to the network. In this sense we are aiming to maximise residual revenue recovery by encouraging storage facilities to operate in our network.

To comply with the NER and improve pricing efficiency, we will only allocate residual DUOS to the annual fixed charge (NAC). We expect that flexible storage customers will have a high price elasticity of demand. This means that allocating cost recovery to variable usage charges may have significant distortions on efficient network usage.

Similarly, the demand charge for the sub-transmission storage tariff will recover transmission use of costs (**TUOS**). We have developed a charge that will accurately reflect individual sub-transmission storage customer's impact on TUOS charges set by Transgrid. This ensures that the broader customer base will not see increases in the TUOS components of their bills due to the sub-transmission storage customer.

Given the type and nature of large-scale storage customers we consider that our suite of storage tariffs is very capable of being understood by its future customers.

We have consulted with storage proponents. These customers are highly engaged in energy markets, working primarily in wholesale and ancillary service markets. We consider that the customer impacts for our suite of storage tariffs are acceptable:

- Apart from the Ausgrid funded community battery trial customers, we have no existing storage customers. Therefore, potential customers can choose not to connect to the Ausgrid network and avoid our storage tariffs.
- Storage customers can avoid the highest charges, and accrue payments, by responding to the critical peak price events. The low voltage and high voltage tariffs create the potential for a responsive battery to avoid network charges when there are sufficient high load and high voltage network events.

3.6 Updating our controlled load tariffs

Our controlled load tariffs make supply available to residential and small business customers at a very low cost per kWh for a specified number of hours a day, in particular to heat electric hot water systems.

In return, we can control when we make this supply available, to help us manage system demand peaks. Historically, these peaks have occurred during the day and early evening, so our controlled load tariffs have specified that supply will be available within certain windows (mostly overnight).

Currently, almost half a million customers are assigned to these tariffs (mostly residential customers). We estimate that the associated controlled load reduces our system demand peaks by 300 MW in winter and 100 MW in summer.[64]

However, the number of customers on controlled load tariffs has been slowly decreasing by about 1% per year, as electric hot water systems are replaced with gas and solar thermal alternatives. This trend may continue if more customers with rooftop solar seek to move their hot water load to their primary meter, so they can benefit from offsetting their consumption with locally generated energy.

Our proposal

To stem this decline, we want to update our controlled load tariffs to make them more attractive to customers, while continuing to maximise the benefits for the network. The proposed switching times shown in Table 15 are currently available only as an option for our retailers. We propose to make it the default arrangement from 1 July 2024.

Table 15: Proposed changes to controlled tariffs in current period

Tariff	Default arrangements 2019-24	Proposed arrangements
EA030 controlled load 1 (suitable for large hot water systems)	Supply is usually available for up to 6 hours duration from 10pm to 7am	Supply is usually available for at least 6 hours in any 24-hour period, from midnight to midnight
EA040 controlled load 2 (suitable for smaller hot water systems)	Supply is usually available for 16 hours a day including more than 6 hours between 8pm and 7am and more than 4 hours between 7am and 5pm	Supply is usually available for at least 16 hours duration within any 24-hour period, from midnight to midnight, with more than 4 hours between 7am and 5pm

64 Ausgrid Demand Side Participation submission to AEMO.

We think that these changes will improve the relevance of our controlled load tariffs as the uptake of rooftop solar continues to increase over the 2024-29 period. As daytime wholesale energy prices continue to decline, moving more of the controlled load window to these times is expected to reduce retail prices for customers. This will mean we can continue using controlled load to manage system demand peaks while also helping to 'soak up' some of the abundant solar export energy available in the afternoon and reduce the impact on the low voltage network.

We will continue to work with retailers and metering providers to allow greater scope for optimisation by retailers for customers with smart meters, within the nominated tariff times. Ausgrid is currently undertaking a flexible load tariff trial (for EVs) with at least 22 hours of supply availability per day. In future years we also intend to trial a tariff that allows EV charging from power poles. Further tariff trials being considered include helping solar customers self-consume on controlled load tariffs (which is not currently possible) and testing critical peak pricing as an alternative. We also intend to trial other tariffs, where control of the load is shared on a dynamic basis for the mutual benefit of customer and network.

Stakeholder feedback to the Pricing Directions Paper

Our Pricing Directions Paper consultation asked stakeholders for their views on our proposed changes to controlled load switching times. Red Energy preferred that the current control load tariffs remain in place as the proposed changes will create additional costs for retailers to comply with the changes but only result in a marginal difference. We are of the view that the proposed changes will provide clear benefits to reducing emissions and to the low voltage network (as described earlier in this section). This was demonstrated by Ausgrid's successful solar soak trial for controlled load (in which AGL and EnergyAustralia participated).

PIAC responded that controlled load tariffs and associated enabling technology should support different usage applications including EVs, heat pumps, pool pumps and batteries. We note that Ausgrid currently allows EVs, pool pumps, and householder appliances to be connected to controlled load circuits (and controlled load tariffs). The device must be permanently connected to the controlled load circuit to be eligible.

Our proposal for amending controlled load switching times has not changed since the Pricing Directions Paper.

Impact of pricing on network investments

Cost-reflective network tariffs can encourage customers to use energy in ways that place less pressure on the network. This can reduce the need to augment the network and limit network charge increases for everyone in the long term. To what extent depends on how retailers package up the network tariff with the cost of energy and what other information or tools they make available to improve a customer's awareness, understanding and ability to adapt to tariffs.

Our demand forecasts look at historic trends, economic outlook and population growth to anticipate the likely load on the network. This in turn informs the investments we make to ensure we can meet customers' anticipated demand. With customers increasingly investing in smarter, more flexible assets such as electric vehicles, home batteries and home automation, we anticipate that if we get it right and work collaboratively with customers and retail partners, cost-reflective network tariffs can have a larger impact on the usage patterns we see on the network and minimise the network investments we need to make. This is particularly important as government looks to incentivise the electrification of transport and other sectors, bring on additional load and distributed generation as we work to a Net Zero future.

We have included with this submission a report by Houston Kemp (**Attachment 8.7**) that describes how our tariffs can help manage customer usage profiles and future augmentation of the network. The focus of this analysis was to compare two scenarios of future EV charging; one with network price signals and one with uncoordinated charging (with no price signals). The results showed that network expenditure can be reduced via network tariff structures and price signals. Further, there are clear benefits in continuing to improve our cost reflective network tariffs and component structures for the 2024-29 period.

For the 2024-29 period we have included a response to anticipated EV load profiles in our tariffs, targeting what we consider is the factor that will have the most impact over this period. We will also continue to do trials and collaborate with customers and retailers over this period and strengthen our evidence base for the link between cost-reflective network tariffs and usage profiles.

Our TSS also includes analysis of the linkages between expenditure for increasing PV penetration and prices. Our export LRMC analysis is based on 16 case studies of low voltage distributors located throughout our network. The case studies were sampled to produce a range of different distributor types, such as regional and metropolitan locations, and areas with high or low CER penetration. This modelling shows a positive LRMC, meaning that over the long run, a kilowatt of investment in solar capacity triggers an associated cost. We have reflected these LRMC values in our proposed export tariff, to give a cost reflective price signal to CER customers. Further information on our export LRMC is provided in our TSS compliance paper.

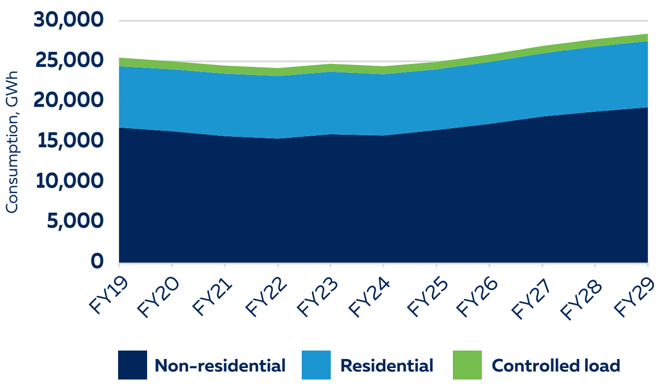
CER and underlying demand forecasts

5.1. Overview

This section explains how we have prepared the volume forecasts for the tariff charging components as part of Ausgrid's TSS for 2024-29. The energy volume forecast is prepared by combining an underlying econometric model projection with post-model adjustments for CER, energy efficiency, and major customer loads.

The following figure shows the overall energy consumption forecast to 2029. The decline in consumption due to COVID-19 starts to recover post-FY22 due to growth in customers, the general economy, EVs and major connections such as data centres. These factors are, to a degree, offset by projected energy conservation outcomes due to increasing solar penetration, the impacts of the NSW Energy Savings Scheme and improvements in building and electrical appliance efficiency.

Figure 17: Overall consumption forecast

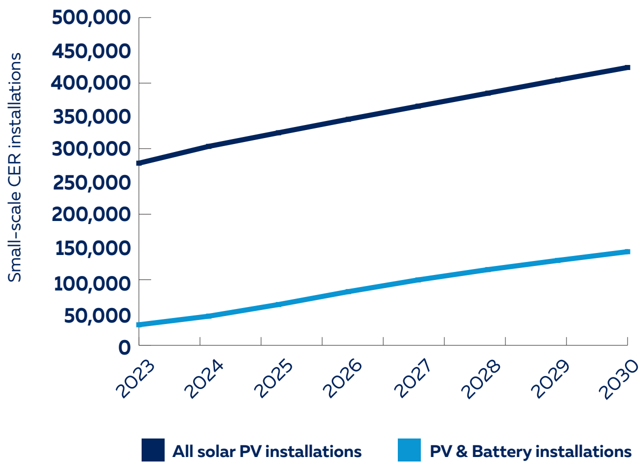


5.2 Growth in customer uptake of CER

Rooftop solar and battery uptake

The number of residential and small business customers generating electricity through their rooftop solar systems has been growing over the past 15 years. We are expecting to see strong growth over the 2024-29 period, both in the number of customers with solar in our network and the average system size. We are also starting to see growth in small residential and business customers installing batteries (see **Figure 18**). We expect that the installed capacity of batteries on our network will grow to 1.7 GWh by around 2030.

Figure 18: Ausgrid network area small-scale CER installed capacity (Ausgrid projection)



We use an in-house CER model to forecast the behind-the-meter consumption from rooftop solar and batteries. By 2029, we expect rooftop solar uptake will nearly double in our network area; and the number of batteries will increase around eight-fold. The resulting behind-the-meter (self) consumption is expected to increase from 670 GWh in FY22 to 1,590 GWh in FY29.

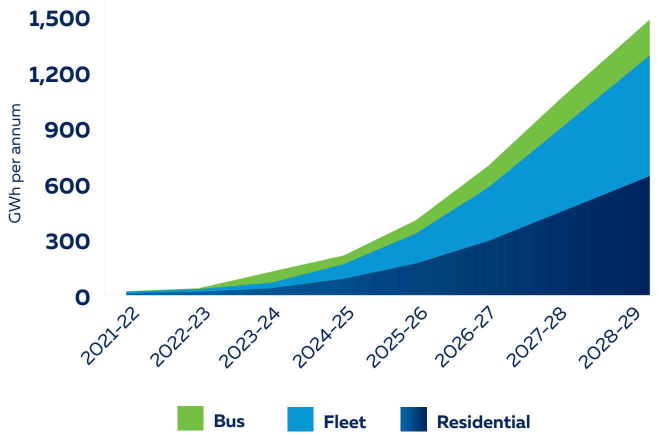
Forecast growth in EV uptake

We expect to see significant growth in the number of customers owning EVs in our network area over the 2024-29 period and beyond. Charging EVs can use a lot of electricity over a very short period. For example, we are already seeing on the market:

- Commercial chargers with up to 350 kW capacity; and
- Home smart chargers with a typical capacity of 7 kW chargers.

We engaged with Evenergi to develop an EV model which forecasts EV consumption for electric buses, public charging stations, business fleets and residential charging. A strong uptake in energy for EV charging is expected in the next regulatory period, increasing from 20 GWh in FY22 to 1,500 GWh in FY29 (see **Figure 19**).

Figure 19: Forecast electric vehicle energy consumption in Ausgrid's network



Source: Ausgrid/Evenergi modelling

Our forecasts for EV, rooftop solar and battery uptake are aligned to the 2022 AEMO Integrated System Plan (ISP) and use the Step Change scenario as the base case.

5.3 Energy consumption forecast

Establishing the baseline for the current year

This first year of the energy volume forecast (or "baseline") establishes the starting point of the projection. Several underlying factors have influenced our forecast of the remaining months of the current (FY23) year. The lingering impacts of COVID-19 lockdowns have led to stronger than expected energy consumption in the residential sector, as many workers delay their return to the office. However, total network energy use is still below trend due to the impact of the two lockdown periods on businesses in 2020 and 2021.

In preparing the first year volume forecasts (for FY23), the following factors have been taken into account:

- **Abnormal year-to-date weather:** Australia has entered a third year of the "la nina" weather pattern. This results in cooler and wetter weather which supresses energy consumption. In summer 2021/22, the impact of 'la nina" was calculated to be 230 GWh, reducing the consumption from what would be an average summer. The forecast assumes a similar impact in summer 2022/23.
- **Underlying energy growth:** Total energy consumed (weather corrected) has grown in the July to September 2022 period by 4.7% compared to the same period last year. This reflects the recovery from the COVID-19 lockdowns in the same period in 2021. We assume that the recovery will continue until December 2022 after which it will align with the same level of (weather corrected) consumption in the same period last year.

The table below shows that our resulting baseline forecast for FY23 energy consumption has 1.0% decline in residential consumption and 3.8% growth in non-residential consumption. The overall volumes are expected to grow by 2.0% in FY23.

Table 16: Volume forecast for FY23 compared to FY22

Consumption, GWh	FY22	FY23	Change
Residental	7,811	7,737	-0.9%
Controlled Load	981	960	-2.1%
Non-residential	15,433	16,008	3.7%
Total	24,225	24,706	2.0%

Underlying energy consumption

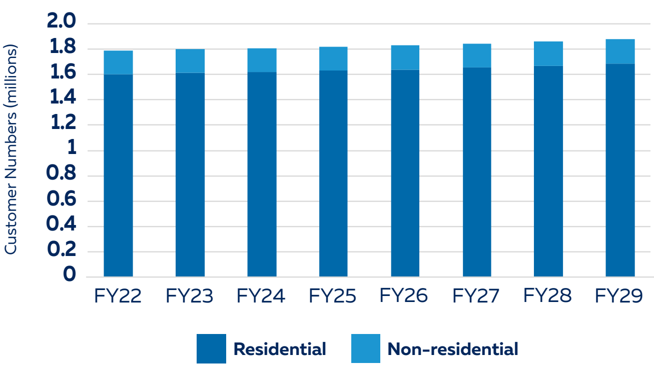
We use an established econometric model which defines the relationship of energy consumption with a number of economic indicators. The residential and business segments use underlying energy consumption or 'electricity services' data from 2003 as the dependent variable. Electricity services is weather corrected consumption data that has the impacts of CER and energy efficiency initiatives removed. The historical electricity services for residential and non-residential customers are modelled against the separate independent variables. These independent variables are underlying drivers of the forecasts and include new connection numbers, gross state product (**GSP**), a 3-year rolling electricity price index, and residential household disposable income (**RHDI**).

The results of the historical trend analysis establish the elasticity values which can be used in the projection model.

To produce the 2024-29 forecast of underlying energy we use the GSP and RHDI forecasts from the step change scenario in AEMO's Electricity Statement of Opportunities (**ESOO**) 2022. The GSP and RHDI forecasts are expected to increase steadily in the forecast period, whereas the electricity prices see a considerable increase in FY22 and FY23, followed by a period of volatility to 2029.

The residential model is calculated on a per customer basis. We therefore need a residential customer forecast to calculate the total residential consumption over the forecast term. To forecast these customer numbers, the Housing Industry Association's (**HIA**) dwelling starts forecast is used until FY25, followed by the household projections of NSW Department of Planning and Environment. Our current forecast of customer numbers for 2024-29 are shown in **Figure 20** below.

Figure 20: Customer Number Forecast to 2029 Post model adjustments



Post model adjustments

Post model adjustments are modelled separately before being applied to underlying energy consumption forecasts. They allow adjustments for items whose trends cannot be fully captured by the econometric model. These post model adjustments include:

- Forecast rooftop solar, batteries and electric vehicles;
- Estimated energy efficiency improvements for household appliances and buildings; and
- Major customer loads (such as new data centres and rail projects).

The energy efficiency forecast is aligned with AEMO's ESOO 2021 forecast inputs, with 2 exceptions. These are the NSW Energy Savings Scheme (**ESS**) and Peak Demand Reduction Scheme (**PDRS**) with forecasts in line with the latest developments in these areas.[65] The overall energy efficiency impact is expected to increase by 2,760 GWh between FY22 and FY29.

Figure 21: Residential post model adjustments (incremental to FY23)

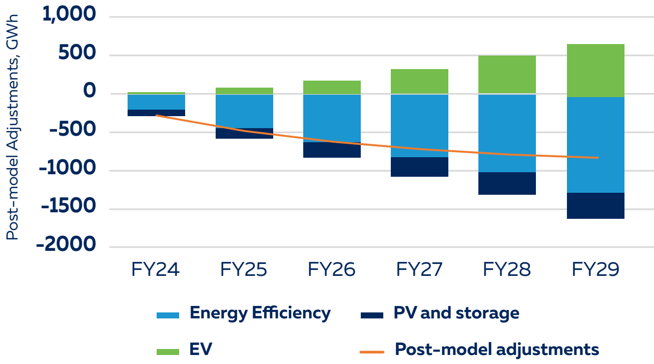
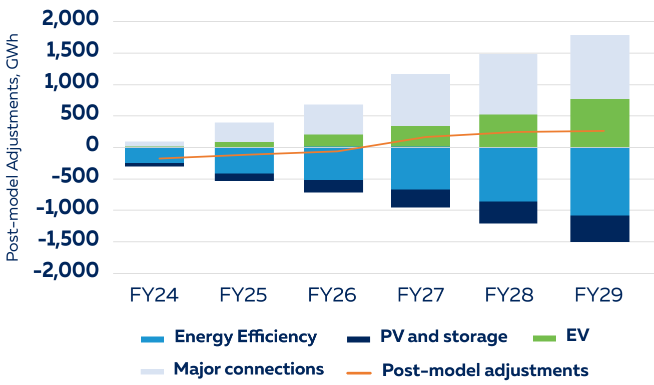


Figure 22: Non-residential post model adjustments (incremental to FY23)



65 Common Capital report

Final energy consumption forecast

The final energy consumption forecast is produced by combining the modelled forecast and the post-model adjustments. The residential energy consumption is expected to increase by 1.2% per annum and the non-residential energy consumption is expected to increase by 3.9% per annum between FY24 and FY29. Controlled load is expected to decline in line with the recent trends by 1.3% per annum.

Figure 23: Residential projection

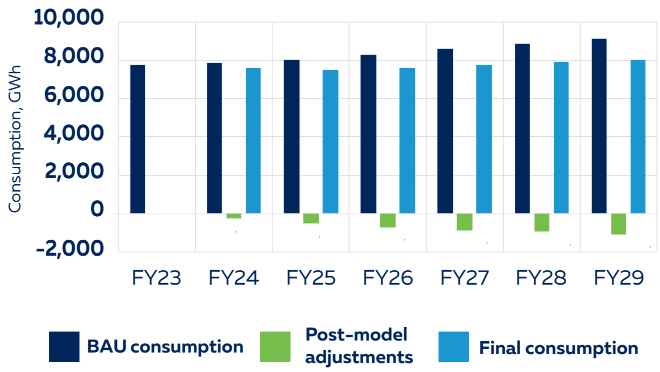
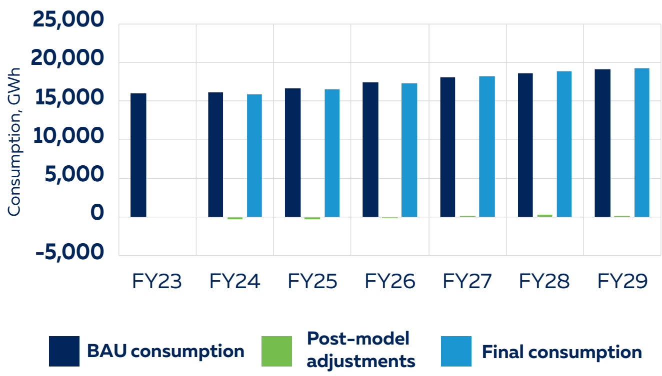


Figure 24: Non-residential projection



Our total energy usage to FY29 is expected to decrease by 0.8% between FY19 and FY24, followed by an increase of 2.9% per annum between FY24 and FY29.

The final volume forecast for residential and non-residential segments are distributed across tariffs based on historical trends and changes in tariff assignment policies. The detailed forecast by tariff and tariff component can be found in **Attachment 8.3**.

5.4. Tariff and tariff component allocation

Our proposed tariff assignment policy will see small customers with meter upgrades assigned to demand tariffs (after the one-year assignment to introductory demand tariffs, if applicable). New small customers will be immediately assigned to demand tariffs. The customer bill impacts of moving to cost reflective tariffs are presented in **Attachment 8.3**.

The rate at which smart meters are installed is an important factor in tariff assignment and revenue recovery for the 2024-29 period. Our forecasts for each tariff depend on the number of customers that have smart meters. We still have around 1 million customers with basic meters.

We note that in November 2022 the AEMC published its draft report on its review of the regulatory framework for metering arrangements. The report recommends a target of 100% uptake of smart meters by 2030 in the NEM jurisdictions. It also says that legacy accumulation and manually read interval meters are to be progressively retired by the DNSPs under a legacy meter retirement plan, and retailers are required to replace the retired meters within a set time frame.

Our smart meter forecast assumes that 90% of our customers will have a smart meter installed by 2032. We believe that this timeframe is a prudent projection given the AEMC metering review is still underway and the details of the legacy retirement plan are still to be finalised.

We are responding to challenges and seizing opportunities

The energy sector – and energy customers – around the world are experiencing a period of profound change. The impacts of climate change – and the importance of transitioning to net zero emissions – are more apparent than ever before. New ways of living and working are leading to new patterns of energy use and customers are expecting individualised and affordable, zero emissions energy solutions. These changes create new opportunities for customers to be rewarded for using energy more flexibly, improving the utilisation of the grid, and lowering the overall cost of the system.

In the 2024-29 period, we want to build on the pricing reforms we have already introduced to maximise the opportunities for retailers and other partners, such as aggregators, to reward customers for their flexible use of the grid. We also want to continue trialling innovative tariffs, for example to provide new incentives for customers to realise the shared value of rooftop solar, battery storage and EVs. This innovation is critical to help us prepare for the future, from a distribution network to distribution system operator and offer more dynamic network prices (see **Section 6.3**).

In developing our pricing reform and tariff innovation proposals for 2024-29, we need to respond to three main changes in our operating environment:

- New government policies to drive the transition to a net zero economy;
- Expected growth in our customers' uptake of CER – such as rooftop solar, battery storage and EVs – to support the transition to net zero as well as control their own energy costs; and
- Upward pressures on energy bills.

In this section, we outline how we see the role of the distribution network changing to facilitate these priorities, support the transition to net zero and enable greater customer choice.

6.1 New government policies to drive the transition to net zero

While Australia has been transitioning towards a cleaner and more sustainable energy system for some time, the pace and urgency of change is picking up. Federal and state governments are implementing policies that commit to net zero by 2050 and facilitate the electrification of the economy needed to achieve this ambition.

Electricity Infrastructure Roadmap

The NSW Government's Electricity Infrastructure Roadmap (Roadmap) aims to deliver significantly more renewable generation capacity by 2030. It includes projects to provide 12 GW of renewable generation capacity and 2 GW of large-scale storage, which will be located in Renewable Energy Zones across NSW.

The government requires Ausgrid and the other NSW distributors (Endeavour Energy and Essential Energy) to pass through a range of costs associated with implementing the Roadmap to our customers from 1 July 2023. We understand that we are to include these in our prices as two new jurisdictional schemes; one scheme will pass through costs known as 'contribution determinations'. The other scheme will pass through costs of administering exemptions for entities from paying Roadmap costs, as nominated by NSW Government.

We propose to pass through the Roadmap costs to our distribution customers via their energy charges. This aligns with the approach used to pass through the NSW Climate Change Fund (CCF), where costs are passed through as an energy usage charge to all distribution network customers. Under a similar approach, we estimate that every $100 million of Roadmap costs we pass through would result in a $21 per annum bill increase for the typical residential customer.

Our Pricing Directions Paper consultation asked stakeholders how we should pass through Roadmap costs to our customers. PIAC said that Roadmap costs would be more appropriately recovered through TransGrid, or from the NSW Government budget. Where Roadmap scheme costs continue to be recovered by DNSPs, PIAC recommends that the wholesale energy related portion of scheme costs should be recovered through volumetric charges and that network-related costs be recovered via demand charges. The costs of new transmission should ideally be recovered from the new entrant generators.

Ausgrid has considered this feedback and recommends that the total Roadmap pass through cost is recovered using energy charges and not peak demand charges. This is because we have more than 900,000 customers on accumulation meters and these meters measure energy and not peak demand.

Hydrogen Strategy

The 2021 NSW Hydrogen Strategy is expected to result in a significant number of green hydrogen electrolysers connecting to our network in the Hunter region. The strategy requires:

- Distributors like Ausgrid to provide these green hydrogen producers a 90% reduction off their network charges;
- Green hydrogen producers to be located in parts of the network where there is spare capacity; and
- Network or market operators to be able to direct the electrolyser to turn off during peak events, or in response to dynamic price signals.

Our Pricing Directions Paper consultation asked stakeholders how we should set prices for green hydrogen electrolysers. PIAC said that the decision to discount network tariffs for hydrogen producers is not consistent with Ausgrid's pricing principles, the NER network pricing principles, or the long-term interests of energy users. However, in the absence of a change to this policy, it said the 10% of network costs should be recovered via a fixed charge. An additional critical peak charge should apply to any demand triggering the need for network upgrades.

In response, we will incorporate the 90% network charge reduction into our individually calculated network tariffs. This will enable us to comply with the scheme regulations which are expected to be released in early 2023.

Electric Vehicle Strategy

The NSW Government's 2021 Electric Vehicle Strategy provides $500 million in tax cuts and incentives to increase uptake of EVs over the next four years. It includes $171 million to build a road network of ultra-fast charging stations. In October 2022 the NSW Government announced it is investing $39.4 million in the first round of Fast Charging Grants to co-fund 86 new fast and ultra-fast EV charging stations, each with four to 15 bays. The recipients are Ampol, BP, Evie Networks, Tesla, the NRMA and Zeus Renewables.

> We expect significant growth in EV ownership in our network area over 2024-29 and beyond. The time of day when customers charge their vehicles will be crucial, in addition to the location where this occurs – for example, at home, at a public charging station, or in an area of the network with a lot of solar generation.

Price signals can play an important role in encouraging customers to charge their EVs at times when electricity is abundant. We note that an increasing number of retailers[66] are offering EV pricing products, and our cost-reflective network tariffs have a role to play in supporting these offerings. It's also important that our tariffs send efficient price signals about the different costs of charging EVs at different times, so this growth does not drive significant increases in our long run costs.

Residential EV charging

EV specific tariffs for households face a barrier as distribution networks do not have visibility of EV ownership. However our proposed cost reflective tariffs for the 2024 - 29 period incentivises EV charging to occur outside of peak periods, in particular:

- Our residential demand and TOU tariffs signal the higher costs of charging in the evening peak period and encourage charging outside peak times when network demand is low. Our proposed changes to the charging windows for these tariffs (**Section 3.4**) will strengthen these signals (without these changes we are more likely to incur new demand peaks).
- Similarly, our solar customers already have strong incentives to charge EVs during the day, using their own generation, to avoid all network (and retail) variable charges. Our proposed export tariffs (**Section 3.1**) and the combined shoulder and off-peak energy charge will add to these incentives.

We also note that Ausgrid currently allows small customer EV charging via its controlled load tariffs. This provides a cost effective option for EV owners who are willing to use a secondary circuit for their charging. We will continue to offer this option in the 2024-29 period.

Public EV charging

New EV charging stations typically have a lower utilisation of the network and can therefore experience a higher cost per unit of energy than other customers on the same tariff. In September 2021, we engaged with PWG to test a proposal to introduce separate medium business tariffs for EV charging stations. The meeting was attended by the Electric Vehicle Council, the AER, NSW Government, and customer representatives. Most stakeholders indicated that Ausgrid should not embed cross subsidies in our pricing to overcome transitional technology challenges. However our proposed reform of raising the threshold at which capacity tariffs apply (**Section 3.3**) will go a long way in addressing the feedback from the EV industry.

We recognise that we may need further tariff reforms in the future, as the impact of EV charging increases. We are currently trialling a new flexible load tariff for residential customers, which we plan to extend to EV charging from our power poles.

Stakeholder Feedback

Our Pricing Directions Paper consultation asked stakeholders for their views on whether we should introduce EV tariffs. Northern Beaches and Willoughby Councils do not support the introduction of EV specific tariffs as it may delay EV uptake in its community and delay its transition to net zero.

PWG raised the concern that some EV households in our network may not have cost reflective tariffs. We agree that this is possible as there is no trigger for an EV household to have a meter upgrade if it uses slow AC charging. However if the household decides to invest in fast charging (with a wall charger or three phase supply) they are likely to have a meter upgrade and receive demand tariffs. We propose to engage with EV vendors and retailers on this question, to inform them and our customers of the opportunities available under our tariff assignment policy for EV owners.

In its submission PIAC did not consider the proposed demand and TOU tariffs suitable for enabling efficient integration of EV home charging. It supports technology specific tariffs for EVs and EV charging stations and also said that separate metering could support EV charging in apartment buildings. Ausgrid currently allows small customer EV charging to occur on its controlled load tariffs (which are separately metered), and we will continue this arrangement in the 2024-29 period. We consider that our proposed tariff structures provide suitable cost reflective incentives for EV charging for both households and public charging stations.

66 Emodi, N.V.; Dwyer, S.; Nagrath, K.; Alabi, J. Electromobility in Australia: Tariff Design Structure and Consumer Preferences for Mobile Distributed Energy Storage. Sustainability 2022

City of Newcastle said that Ausgrid should align its existing network tariffs with retailer EV pricing products, in particular the use of time-based price signals which will encourage EV smart chargers to be programmed when to operate. It also noted that lifting the assignment threshold to 100 MWh should go part way in addressing the feedback from the EV industry. It supports consideration of further pricing reforms in future, as the impact of EV charging increases.

GoEvie responded that Ausgrid should introduce a specific tariff for the EV public fast charging industry. The submission says that such a tariff would not create a cross-subsidy as EV charging structure provides network benefits such as increased network utilisation and stability, more solar soaking load, and network support via load control. It also said that residential and small business charges should be more closely aligned.

We believe that our proposed amendments to our tariff assignment policy for medium businesses (**Section 3.3**) will provide an appropriate balance between fairness and the need to reflect cost reflective price signals.

6.2 Becoming a Distribution System Operator

Energy Security Board Reforms

The Energy Security Board (**ESB**) has been tasked with developing reforms to the design of the NEM to ensure it is fit-for-purpose in an energy system with high levels of renewables.

In August 2021, the ESB recommended market reforms to Energy Ministers, including to efficiently and safely integrate the distribution connected resources into markets at all levels. As part of this, the ESB recommended that the NEM becomes a two-sided market, in which customers' rooftop solar, batteries and other CER participate in the wholesale market through Virtual Power Plants (**VPPs**). CER is becoming increasingly sophisticated, which is giving households and businesses the opportunity to actively manage their energy consumption and bills.

In its final advice to ministers in 2021,[67] the ESB proposed that distribution network service providers assume the role of distribution system operators (**DSOs**) and work in co-ordination with AEMO to manage local and whole of system issues in highly distributed and renewable energy systems. As part of its advice to ministers, the ESB proposed that "support[ing] more dynamic network tariff designs that will result in automated responses from DER and flexible load" [68] should be one of the key responsibilities of the DSO.

Ausgrid's DSO vision

Ausgrid has taken up this challenge. We see our role as a DSO as dynamically managing network capacity and operating the network to maintain an efficient, safe, and reliable service while optimising value to our customers, the energy system and supporting the renewable energy transition. In addition to uplifting our ability to dynamically manage the network as energy flows become more complex and playing a larger role in supporting the end-to-end security of the system in partnership with AEMO, we are also evolving our network services to support two-sided markets.

Technology offers the opportunity to move beyond static and average network prices and accounting for differences in location and time. That is creating new opportunities for how we think about network pricing and share value with our customers.

67 ESB Post 2022 market design final advice to energy ministers Part B (released 26 August 2021).

68 Ibid p 70

Sometimes, however, our current network tariffs can distort market participation by over or under stating the cost of network use and not rewarding beneficial behaviour. In addition, static measures to manage network capacity, such as limits at the time of connection, can reduce allocative efficiency. We see our services evolving in two key ways to address this:

- Developing dynamic access and connection solutions that provide a range of options for customers in line with their individual needs (but still retaining cost reflective and efficient pricing principles); and
- Improving system affordability for all our customers through encouraging efficient two-way utilisation of the network through dynamic network pricing.

Importantly, we see the role of the DSO is to support customers to participate in local and wholesale markets as they evolve, not to run local energy markets. Similarly, the DSO's role is to support retailers and aggregators by providing a flexible and reliable network service that they can use to aggregate and orchestrate customer resources in commercial products for their customers.

In the 2024-29 period, we want to build on the pricing reforms we have already introduced to maximise the opportunities for retailers and other partners, such as aggregators, to reward customers for their flexible use of the grid. We also want to continue trialling innovative tariffs, for example to provide new incentives for customers to realise the shared value of rooftop solar, battery storage and EVs. This innovation is critical to help us prepare for the future, from a distribution network to DSO and offer more dynamic network prices (see **Section 6.3**).

Our 2024-29 regulatory proposal includes an overview of the activities we are planning on taking to support the net zero transition over the next regulatory period, including foundational investments in systems to enable more flexible connections and more dynamic pricing.

While the dynamic pricing structure offers greater flexibility to DNSPs and supports value for customers, there is diversity in customer participation. Customers are likely to range from those that are extremely involved, or 'active' in the market to those that are content with a static tariff structure. Therefore in the future we need to have a range of tariff options for customers, depending on their preferences. It will continue to remain important that we cater for all customers, and to apply our pricing principles (fairness, efficiency and flexibility) to achieve this goal.

Our Pricing Directions Paper consultation asked stakeholders for their views on how we are using our tariffs to support the transition to net zero. Northern Beaches and Willoughby Councils responded that the proposed pricing reforms, particularly those that will help reduce bills to customers, improve customer benefits from their CER investments and reduce emissions. City of Newcastle said it supports implementation of dynamic access and connection solutions that improves system affordability for Ausgrid customers.

6.3 Leading pricing innovation

Our proposed tariff innovation and tariff trials for 2024-29 aim to improve our customers' opportunities to benefit from their CER investments, to share those benefits across our customers, and to build our capability to unlock new opportunities that will emerge from expected market changes over the coming years. Across the 2024-29 period, we propose to focus our tariff innovation on providing our customers and retailers with new choices and more opportunities to respond to incentives to efficiently utilise the network. Together with our proposed pricing reforms, this innovation improves our ability to facilitate and support the transition to net zero.

Ausgrid is committed to tariff innovation. We are continuously researching new ideas and ways for tariffs to better serve our customers. However, changing our tariffs can have a significant impact on our customers, our network and the broader energy system. For this reason, we take a staged approach to evolving our tariffs that generally involves:

1. **Concept development.** We research and develop new ideas and ways for tariffs to better serve our customers through desktop studies or small trials.
2. **Tariff trials.** The NER allows distribution networks like Ausgrid to add new tariffs each year if they do not recover more than 1% of our revenue each or 5% of our revenue combined. These are known as sub-threshold tariffs, or trial tariffs. This provision allows us to implement innovative tariffs alongside our regulated tariffs, testing our capabilities and customer interest.
3. **Pricing reform.** Ultimately the insights from our tariff trials and broader modelling informs the tariff reforms we include in our TSS proposal. Once approved by the AER, these tariffs become our standard tariff offerings. For example, in 2019 we introduced residential demand tariffs and residential TOU demand tariffs through TSS proposal and approval process.

During the energy transition the focus of our tariff innovation will be to learn what customers and retailers want, understand what drives efficient network use, and test our capabilities to operate new tariffs.

Our Pricing Directions Paper consultation asked stakeholders for their views on how quickly we should introduce innovative tariffs. PIAC said that EV tariffs should be introduced at the earliest opportunity. Firm Power stated that Ausgrid should move quickly to introduce a standard tariff for large batteries. Our proposal for utility scale storage tariffs is presented in the earlier section.

Dynamic cost-reflective pricing trials

We are currently undertaking a trial, known as Project Edith, as a proof of concept and proof of capability that we can send, and customers (through aggregators) can respond to dynamic network prices. Dynamic network prices allow customers, aggregators and virtual powerplants to get more cost-reflective price signals that vary by forecast network use. This gives customers greater opportunities to trade on energy markets and enables price responsive network support.

In many ways, Project Edith reimagines the role and flexibility of network pricing. It is iteratively trialling new dynamic pricing approaches alongside dynamic operating envelopes. We started the first of these trials in June 2022. It involves a weather-based price based on our residential TOU tariff:

- During the winter peak charging window of 5pm to 9pm, the peak charge will apply if the forecast temperature is below 10°C. Customers exporting electricity during this time will receive payments.
- During the summer peak charging window of 2pm to 8pm, the peak usage charge and export reward applies if the forecast temperature is above 26°C.
- Between 10am and 2pm, when we see the most solar exports, an export charge will apply if cloud cover is less than 50%, and customers can import electricity for free.
- An off-peak import charge will apply at all other times.

The weather-based inputs act as a simple proxy for network congestion. We are progressively adding capabilities to set prices based on network congestion directly. This will result in even greater granularity in time and location, further increasing the cost-reflectivity of the price signals and facilitating greater market participation of CER while efficiently managing network capacity.

Project Edith is currently a small-scale trial with a single aggregator partner representing less than 300 participating customers. Having successfully engaged stakeholders to consider Project Edith as a viable option for facilitating two-sided markets, we are now preparing to expand the trial to additional aggregators, to grow customer numbers and continue to demonstrate and validate the dynamic pricing concept.

Our Pricing Directions Paper consultation asked stakeholders for their views on how we can continue to build and test dynamic network pricing through the 2024-29 period. In its submission PIAC supported Ausgrid building its capability to effectively implement dynamic network pricing in the 2024-2029 period, including through tariff trials. City of Newcastle supported the continued use and implementation of Project Edith.

Learnings from current tariff trials

Ausgrid commenced three sub-threshold tariffs on 1 July 2022:

1. Residential two-way tariff
2. Residential flexible load tariff
3. Community battery tariff

We will look to modify these tariffs and expect to trial an additional tariff in 2023-24 to learn more for future tariff development, both internally and with our peer distribution businesses around the world. If we submit a revised TSS, we will provide further information on what we learn in the coming months.

The residential two-way tariff has helped Ausgrid design the export tariff included in our TSS. The key learnings have been:

- Energy based BEL - in developing our trial tariff, we found our billing system will not allow us to pair a demand measure BEL (e.g. 3 kW) with a usage charge (e.g. c/kWh exported). This led to our inclining block energy based BEL and usage charge, which we prefer given solar feed-in tariffs are predominately energy based.
- Charging windows need to reflect network conditions – the export charging windows for the trial tariff are based on our current summer peak window but applied all days, year-round. We have found that this does not reflect our network costs where most of our export customers are located. We have refined our export charging windows to reduce how often we reward exports when exports are driving voltage constraints.
- Residual costs in export tariffs distort customer decisions - the trial tariff artificially increased the peak usage charge and the export reward, by recovering additional residual costs from consumption and refunding those residual costs in the export reward. This approach has made our trial tariff lucrative for customers investing in batteries and driven additional cycling of batteries in response to our tariff. This has informed our decision to base export charges and rewards on the LRMC of exports on our network.

We have more limited learnings from our residential flexible load tariff. Our retailer partner ceased recruiting new customers due to high wholesale prices in 2022 making customer participation a challenge. Our community battery tariff applied to its first customers in December 2022. The process of connecting customers has influenced our storage tariffs. We have found that the costs of installing local use of system metering likely outweigh the network benefits of providing additional incentives for storage customers to consume local generation.

New trial tariffs

In 2024-25 Ausgrid proposes to introduce the following sub-threshold tariffs:

1. **Standalone power system tariff –** from 2023 Ausgrid is installing standalone power systems on the edge of our network. The main cost driver for a standalone power system is energy consumed, rather than peak demand. Therefore, we are trialling an energy-only tariff to better reflect the LRMC for standalone power systems and to incentivise lower energy use by SAPS customers.

2. **Flexible load tariff –** we will offer a flexible load tariff where instead of interrupting customer supply we will apply a critical peak price. We have heard from numerous retailers that they do not want to interrupt their customers, supply in our interruptible load tariff and would like to give the customers an opportunity to opt-out. It will be available to small business customers via a participating retailer.

Contact us

All correspondence in relation to this document should be directed to:
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