# Attachment 7.2

Tariff structure explanatory statement

30 November 2023

PowerWater

# Contents

# Abbreviations

The following table provides a list of abbreviations and acronyms used throughout this document. Defined terms are identified in this document by capitals.

| Term | Definition |
|---|---|
| ACS | Alternative Control Services |
| AEMC | Australian Energy Market Commission |
| AER | Australian Energy Regulator |
| AIC | Average Incremental Cost |
| Capex | Capital Expenditure |
| CER | Consumer Energy Resources |
| CPI | Consumer Price Index |
| CT | Current Transformer |
| DER | Distributed Energy Resources |
| DOEs | Dynamic Operating Envelopes |
| EV | Electric Vehicle |
| F&A | Framework and Approach |
| FRC | Full Retail Contestability |
| HV | High Voltage |
| LRMC | Long Run Marginal Cost |
| LV | Low Voltage |
| MWh | Megawatt hours |
| NER | National Electricity Rules |
| NT | Northern Territory |
| NTESMO | Northern Territory Electricity System and Market Operator |
| Opex | Operating Expenditure |
| pa | Per annum |
| PV | Photovoltaic |
| SAC | System Availability Charge |
| TOU | Time of Use |

| Term | Definition |
|---|---|
| TSS | Tariff Structure Statement |
| VT | Voltage Transformer |

# Overview

We set network tariffs each year to collect the revenue allowance set by the AER. In the current regulatory period, we started a journey to improve the fairness of our tariffs to better reflect each customer's share of network costs. For the 2024-29 period, we are continuing this journey by improving customer segmentation across tariffs and trialling new tariffs that improve network utilisation.

Customers are central to our plans. We have submitted our Revised Regulatory Proposal to the Australian Energy Regulatory (**AER**) for the 2024-29 regulatory period, from 1 July 2024 to 30 June 2029. Our Revised Regulatory Proposal details the proposed expenditure, revenue and tariffs for the regulated electricity networks in Darwin-Katherine, Alice Springs and Tennant Creek. At the same time, we also submitted a proposed Tariff Structure Statement (**TSS**).

The TSS describes how our network tariffs are structured and the arrangements for assigning and reassigning customers to these tariffs. This Explanatory Statement supports our proposed TSS and provides the reasons behind our proposed tariff structures. It also includes information on how we have taken account of customer and stakeholder feedback.

Customers have told us they want to be able to continue connecting renewables to the grid, and that we should be more innovative in how we manage our networks. They expect us to support emerging technologies such as electric vehicles and battery storage, while making certain vulnerable customers are not disadvantaged. Most importantly, they expect us to do our part to keep energy costs affordable, and provide better information on how they can manage their electricity bills.

We need to ensure our network charging structures are fit-for-purpose for all customer types so we can best support their long-term interests. This means designing tariffs that recognise the unique characteristics of our networks and our customers' needs - now and into the future.

Cost-reflective network tariffs provide customers with greater visibility on how their usage impacts the costs of operating our networks. It also allows customers to alter their consumption or export behaviour in return for lower network charges. However, for most of our customers, changes in our tariffs currently have no impact on their retail bills. This is because electricity retail prices charged to residential and commercial customers (those consuming less than 750 megawatt hours (**MWh**) of electricity per annum (**pa**)) are regulated by the Northern Territory (**NT**) Government through the Electricity Pricing Order (Pricing Order) made by the Treasurer under the *Electricity Reform Act 2000.*

Technological changes and the increasing shift to renewable energy is changing the way our customers use our networks. Our proposed TSS aims to evolve tariff structures to keep pace with the changing energy market, particularly the increasing volume of consumer energy resources (**CER**) being connected to and exporting into our networks. Our proposed TSS also considers the feedback from our customer and stakeholder engagement.

We are not proposing to introduce any mandatory export tariffs in the 2024-29 TSS period. Instead, we propose to take a staged approach to introducing two-way pricing and will undertake further engagement with retailers and the government to develop and test innovative tariffs through opt-in trials. This will allow us to better understand the customer experience and available network benefits of two-way pricing in a Northern Territory context prior to their potential deployment in any future TSS. Our proposed tariff trials for 2024-29 period aim to improve our customers' benefit realisation from their investments in renewable technologies, and to build our network capability to unlock new opportunities that will emerge from market changes in the coming years.

We will continue the tariff reform journey we started, which involves assigning customers with smart meters onto cost reflective time of use tariffs to enable them, and us, to better utilise the networks and send the right signals to use energy at times of excess system capacity. Our proposed changes seek to reduce future costs through tariff structures that encourage customers to shift consumption to periods when the networks have spare capacity, or to when minimum demand is driving network costs. The key proposed changes commencing 1 July 2024 are outlined in Table OV.1 and are discussed in more detail throughout this Explanatory Statement.

*Table OV.1: Overview of proposed changes in 2024-29 TSS*

| Change | What | Why |
|---|---|---|
| **Transition to two-way pricing** | Introduction of export tariff trials to help inform our tariff strategies and explore more complex, innovative tariffs in a controlled manner. | Our proposed export tariff trials aim to allow us to develop and refine alternative approaches and provide proof of concept to build retailers' and consumers' understanding and trust. These trials can also provide an evidence base for considering future reform of the Pricing Order. |
| **Improve the cost reflectivity of our energy charges through time-of-use tariffs based on the season and time of day when energy is consumed** | A key strategic change we are proposing in the 2024-29 regulatory period, is the refinement of time-of-use pricing for customers who have interval or smart meters and consume less than 750 MWh pa. This includes:<br>• Tightening the peak period to align with the time and seasons when our network experiences the highest demand.<br>• Introducing a free period from 9am and 3pm every day of the year to encourage energy use where there is abundant energy produced by PV generating units in our networks. | This reflects our analysis which shows that peak demand is continuing to shift further into the evening, when the network cannot rely on PV generating units to help meet underlying demand. It also reflects our desire to have the off-peak period cover the window of system minimum demand arising from more solar energy.<br>The change would provide a simpler signal to customers (if the pricing order protections are reviewed) for times when the network is experiencing peak demand in the evening, and when there is ample capacity to meet demand in the middle of the day. |
| **Remove demand charges for customers consuming less than 750 MWh pa with smart meters** | For the new tariffs that apply to customers with smart meters consuming less than 750 MWh pa, we are proposing to remove the demand charge and instead apply the time of use energy charges outlined above. | We consider the change would provide a simpler signal to customers (if the Electricity Pricing Order protections are reviewed) for times when the network is experiencing peak demand in the evening, and when there is ample |

| Change | What | Why |
|---|---|---|
| | | capacity to meet demand in the middle of the day. |
| **Major customer seasonal demand charge** | For major customers consuming above 750 MWh pa or connected to the HV network, we will continue to apply an annual peak demand charge. However, this charge will be applied as an 'On' season, from 1 October to 31 March, and an 'Off' season from 1 April to 30 September each year. | The purpose of this change is to ensure that:<br>• Maximum demand charges send a long-run marginal cost (LRMC)-based price signal for large customers that can drive asset peaks ($/kVA) charged across an 'On' and 'Off' season.<br>• Energy charges to send a LRMC-based price signal to customers ($/kWh).<br>• Encourage usage at times that best suit the capacity of the network (both for peak demand and minimum demand) and manage the impact on customers' bills. |
| **Further segmentation of tariffs** | For small to medium business customers, we want to bring in further segmentation of Tariff 3 with new tariffs.<br>The Draft Plan proposed a 100 MW threshold, but subsequent feedback received from retailers suggested a 160 MW threshold, and also further segmentation into residential and non-residential. | To provide a more targeted price signal based on the characteristics of the customers and support optionality to any future review of the Pricing Order. |

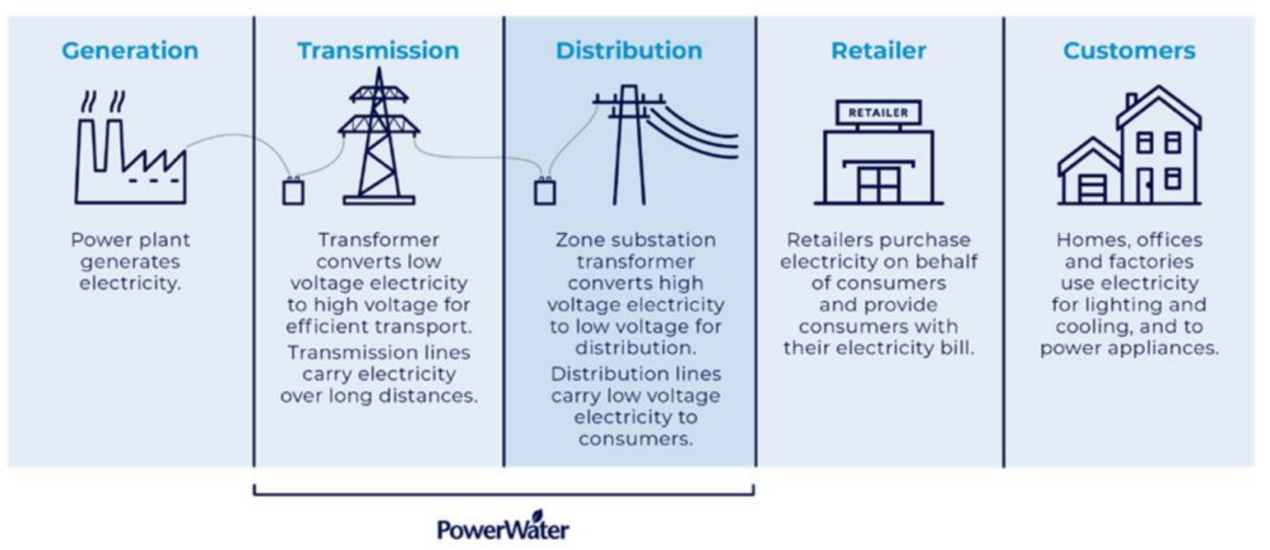
# 1. Background

## 1.1 Our network and customers

### We build, operate and maintain three stand-alone regulated electricity networks in Darwin-Katherine, Alice Springs and Tennant Creek which are regulated by the Australian Energy Regulator. These networks transport about 1,700 GWh of energy to over 84,000 customers across the regions.

We are the essential service provider in the Northern Territory (**NT**) providing electricity, gas, water and sewerage services. We are responsible for the transmission and distribution networks in the Northern Territory as seen in Figure 1.1. We facilitate the physical connection to energy and have obligations to provide safe and secure electricity services.

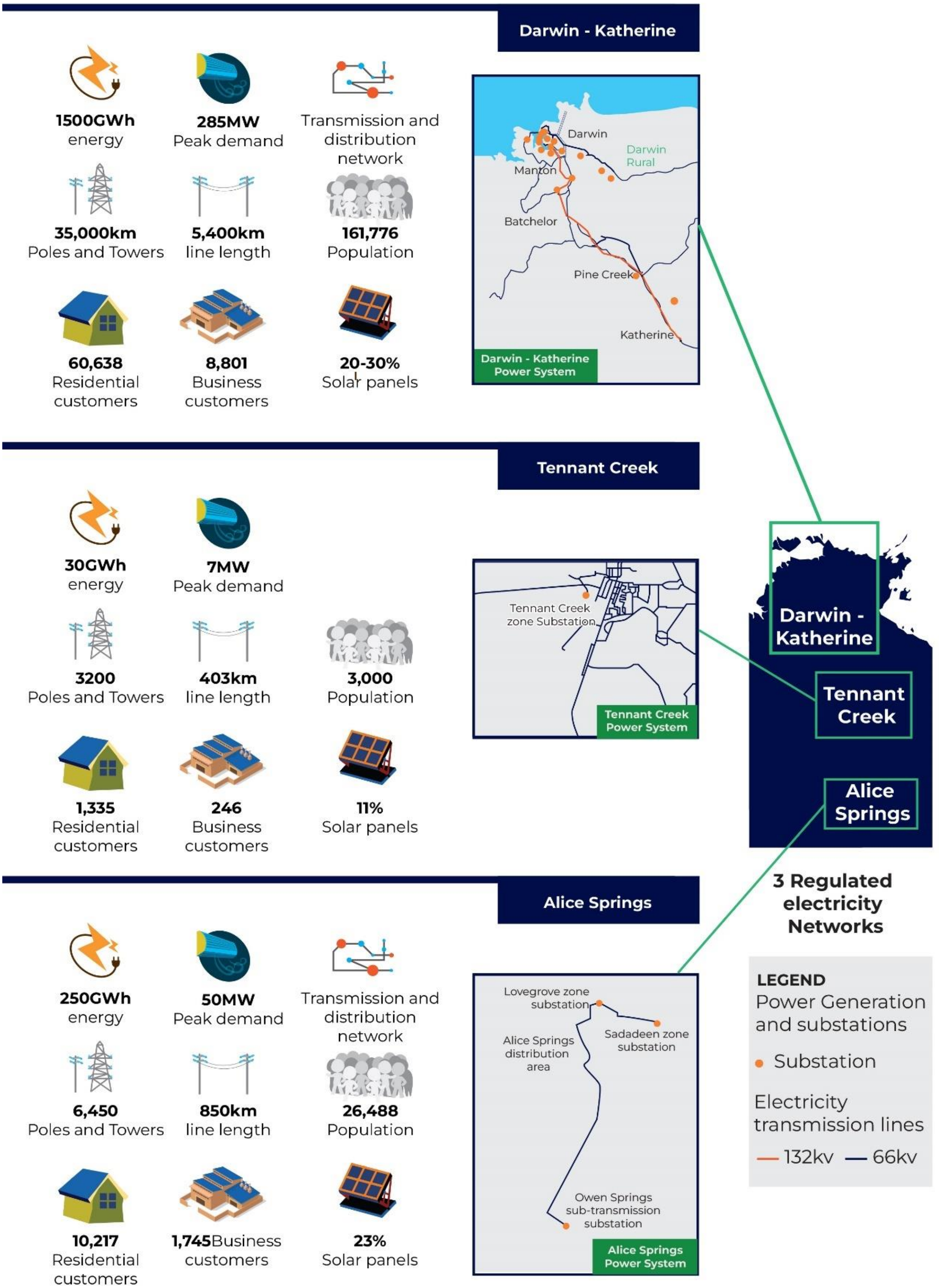
*Figure 1.1: Our role in the electricity system*




We provide electricity services to more than 90 communities in the Northern Territory over a landmass of 1.3 million square kilometres. The three regulated networks in Darwin-Katherine, Alice Springs, and Tennant Creek transport electricity to around 74,500 residential customers and 11,500 businesses. Each of our networks are unique, operating under different designs and environment as highlighted by Figure 1.2.

Despite having the smallest population of any of the Australian states and territories, the Northern Territory is a large landmass with a widely dispersed population. This results in a diseconomy of scale and relative disadvantage compared to other networks in Australia, exacerbated by resourcing constraints.

*Figure 1.2: Comparison of our regulated networks*



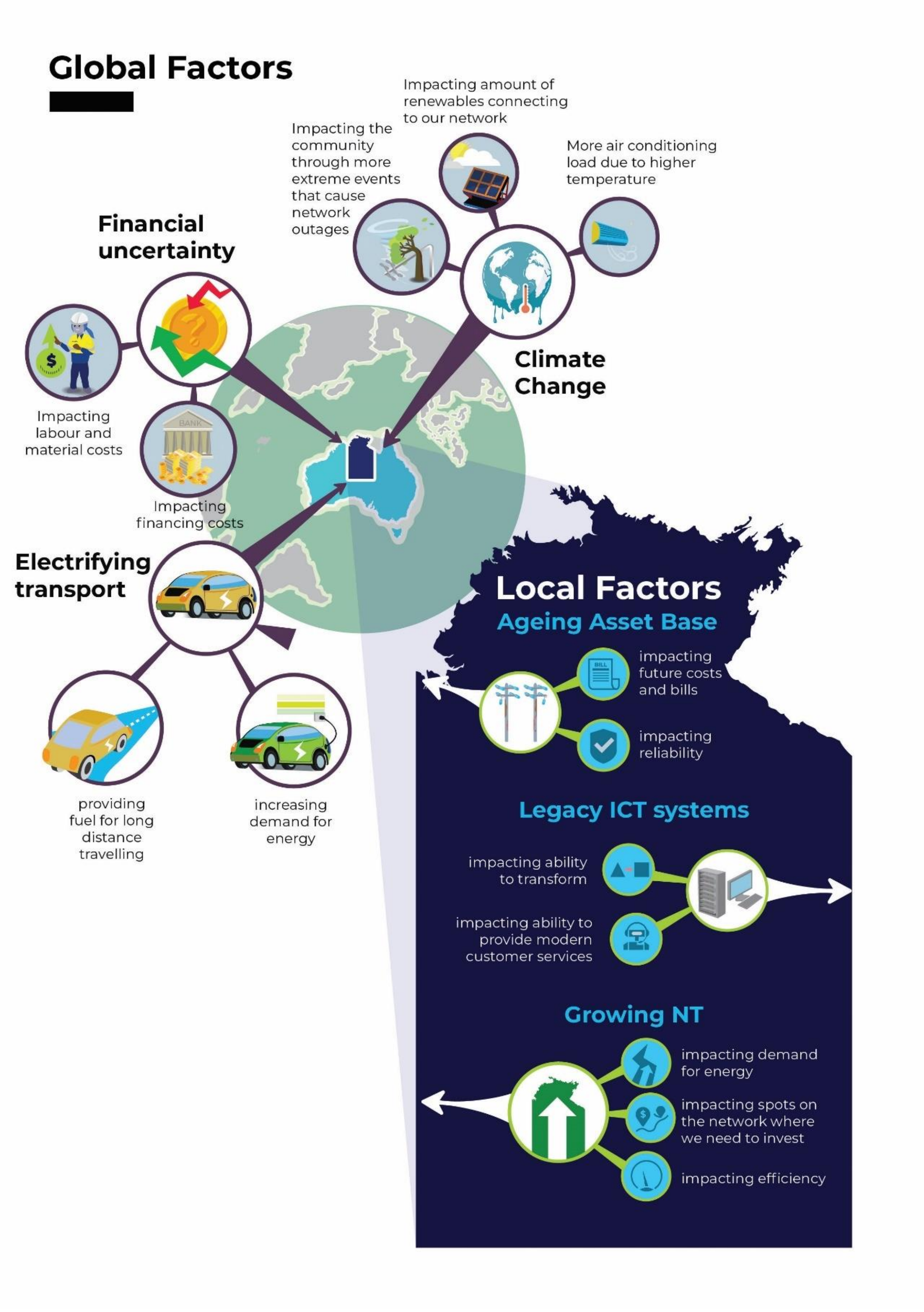

As at January 2023

In addition, we operate in difficult environments subject to extreme heat and weather events that place further pressure on service delivery. We understand that our services are essential to everyday lives and our business community. The extreme heat in the Northern Territory means our customers and businesses are far more reliant on cooling than other places in Australia. A typical household consumes about 8,500 MWh of energy each year, almost double the consumption of a typical New South Wales household.

Our networks are facing disruptive and fast paced change driven by global and local factors including climate change, electrification of transport, ageing network assets and a growing economy. Our stakeholders want us to be an active leader in facilitating renewables in the energy system, and to make prudent investments where there are clear benefits. This follows extensive conversations with our residential customers in our People's Panels, business customers and stakeholders in our Future Network Forums on both our Initial Regulatory Proposal and Revised Regulatory Proposal.

While our discussions with stakeholders have been centred on our three regulated networks, they have also involved consideration of our unregulated networks across the NT. Our discussions have focused on key changes impacting our networks. Our small network is being disrupted by global and local change factors, as identified in Figure 1.3.

*Figure 1.3: Global and local change factors impacting our network*



## 1.2 What is the Tariff Structure Statement?

A tariff is how we charge retailers for the services we provide to our customers. The tariff can be made up of different components such as fixed charges, energy charges or demand charges. These tariff components (or 'charging parameters') and the applicable indicative prices are outlined in our TSS.

Each year, we publish an annual pricing proposal, which sets out our actual tariffs for the year. Before we set our annual prices, we must determine how to structure our tariffs, and our policies and procedures for assigning and reassigning customers to tariffs. To aid this, our TSS explains the charging parameters within each tariff and a description of the approach we will take in setting tariffs in the annual pricing proposals. The accompanying TSS, once approved by the AER, will apply from 1 July 2024 to 30 June 2029.

The TSS must ensure the proposed tariffs conform with the pricing principles specified in the NT National Electricity Rules (**NER**). Under the NT NER, our tariffs must be set to recover the efficient costs of building and maintaining our networks, and for the support staff needed to keep the energy network operating.

Our proposed TSS has been informed by key NT NER changes that have occurred since our last TSS. The Australian Energy Market Commission's (**AEMC**) Final Rule Change *Access, pricing and incentive arrangements for Distributed Energy Resources*[1] removed the prohibition on networks from developing pricing options for energy exported to the grid. Export pricing is optional for each network, but it is a requirement to develop and include an export tariff transition strategy as part of the TSS.

The AEMC's final rule for the *Integrating Storage in the NEM* rule change also provides useful clarification that batteries will continue to be charged distribution use of system fees.[2] Participants with battery storage who choose to connect to our distribution network will receive a default Direct Control Service tariff or a storage tariff trial option, where offered.

## 1.3 Purpose and scope of the Explanatory Statement

This Explanatory Statement outlines the context for how we propose to set network prices for customers in the 2024-29 regulatory period and provides the reasons behind why we have proposed the tariff structures and assignment policy in our TSS. This Explanatory Statement includes:

- A description of our residential and business customers, and the changing way our customers use our networks.
- An explanation of how we engaged with customers and stakeholders and details how their feedback has informed our proposed TSS.
- A description of our pricing objectives and explains how these have changed to reflect customer feedback.
- Reasons for the tariff classes, tariff structures and assignment policies we are proposing, including an assessment against the pricing principles in the NT NER.

1 AEMC, *Access, pricing and incentive arrangements for distributed energy resources*, Rule determination, 12 August 2021.

2 AEMC, *Integrating energy storage systems into the NEM*, Rule determination, 2 December 2021.

This Explanatory Statement also includes:

- A description of our export tariff transition strategy including our proposed approach to determining the basic export level for the future export tariffs after having considered the AER's guideline requirements.
- An overview of our plans to develop opt-in trials for two-way pricing, battery and EV tariffs, which will inform our future approaches to export tariff transition, distributed energy resource (**DER**) integration and demand management.

## 1.4 Pricing principles and compliance requirements

Our TSS must comply with the pricing principles for direct control services in a manner that will contribute to the achievement of the network pricing objective:

> *The network pricing objective is that the tariffs that a distributor charges in respect of its provision of direct control services should reflect the distributor's efficient costs of providing those services to the retail customer.* [3]

This objective is designed to support our customers' long-term interests and also support our customers to make informed choices about how they source and use electricity as the energy sector transforms, through new technologies and decarbonisation policies.

Under the NT NER, we must set tariffs to recover the expected future costs of building new network infrastructure. This involves setting network tariffs that reflect the Long Run Marginal Cost (**LRMC**) of our network services. Any residual costs (which are measured as the difference between our total allowed revenues and revenues from LRMC-based charges) should be recovered by tariffs that collect revenue from customers in the least distortionary way.

Table 1.1 outlines how we have developed our network tariffs to meet our compliance obligations.

*Table 1.1: How we have addressed the NT NER pricing objective and principles*

| Requirement | How we have addressed the requirement |
|---|---|
| **The network charge for direct control services for each of our customers should reflect the efficient costs of providing those services to customers.** | The variable component of our network tariffs is at or above LRMC. Residual costs are being allocated in a way that minimises impact on customer usage decisions and supports smooth bill impacts as customers transition from anytime tariffs to smart meter time of use tariffs. |
| **Revenue to be recovered must lie between the stand-alone costs of serving customers and the avoidable costs of not serving those customers.** | This has been demonstrated in our Average Incremental Cost (**AIC**) LRMC model. In addition, each year our annual pricing proposal will demonstrate that the revenue we expect to recover from customers for each network tariff class lies between the stand-alone costs of serving customers who belong to that class and the avoidable costs of not serving those customers. |
| **Each tariff must be based on the LRMC of providing the service to which it relates** | The variable component for each network charge is at or above LRMC. The approach that best suits our available |

[3] NT NER, cl. 6.18.5(d)

| Requirement | How we have addressed the requirement |
|---|---|
| **to the retail customers assigned to the tariff.** | inputs and network characteristics, and the circumstances for cost reflective tariff benefit realisation (given the pricing order) is the average incremental cost approach. |
| **The revenue to be recovered from each network charge must reflect the total efficient costs of providing services to the customers assigned to that charge, in a manner that minimises distortions to use of the network.** | Our proposed 2024-29 charges align more closely to our estimates of the LRMC, taking into account customer bill impacts.<br>Residual costs are being allocated in a way that minimises customer impact and improves revenue stability. |
| **Consideration is to be given to the impact on customers of changes in network charges and the changes should be designed so they are reasonably capable of being understood by customers or reflected in their energy provider's tariffs** | We have implemented tariff designs having regard to the effects of the Electricity Pricing Order on how our customers experience our tariffs, and have sought to create optionality for potential future reforms of that pricing order. This Explanatory Statement provides bill impact analysis covering all individual customers that are not covered by the Electricity Pricing Order.<br>New connection and meter upgrade customers will be assigned to an appropriate cost reflective tariff based on their forecasted consumption and connection attributes. |
| **The structure of each tariff must be reasonably capable of being understood by customers that are or may be assigned to that tariff or being directly or indirectly incorporated by retailers or Market Small Generation Aggregators in contract terms offered to those customers.**<br>**We must have regard to the type and nature of those customers, and feedback resulting from the engagement with our customers, retailers and market small generation aggregators.** | We have retained charging structures that are simple to understand and which account for the Electricity Pricing Order (where possible).<br>We have consulted with our stakeholders and customers to ensure our approach to measuring and charging for the various components contained within our tariffs are easily understood and have removed demand charges for our smart meter customers who consume less than 750 MWh pa. |
| **A tariff must comply with the NT NER and all applicable regulatory instruments** | Our tariff class thresholds align with the Electricity Pricing Order. |

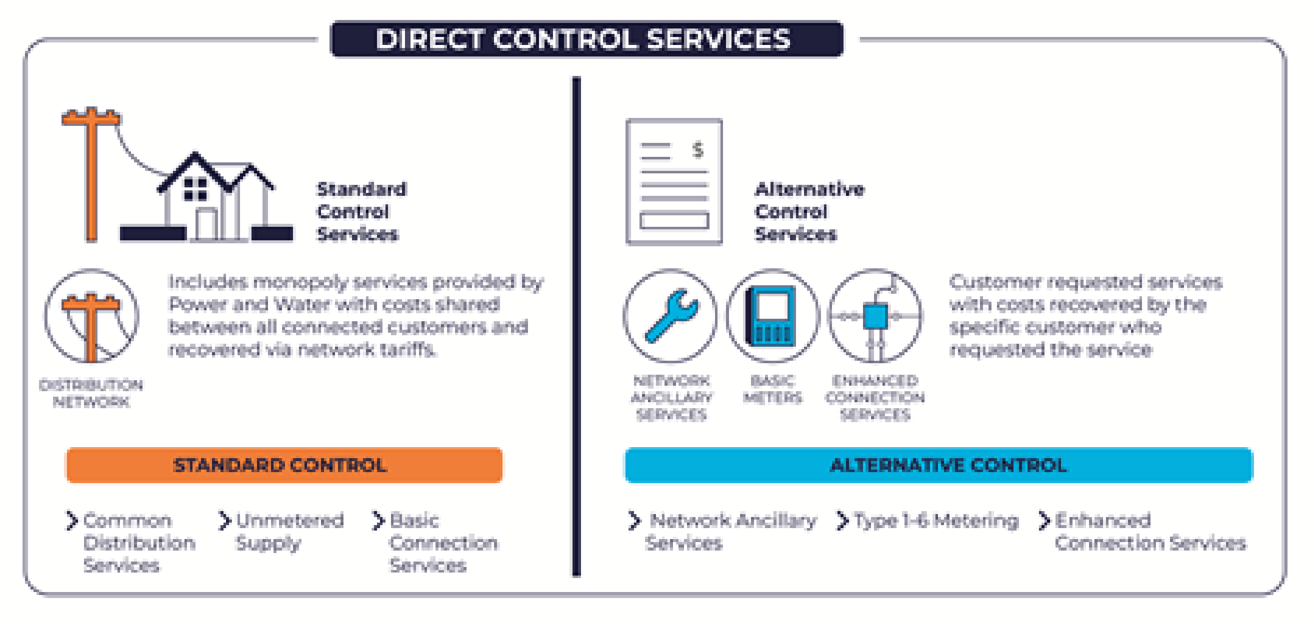
## 1.5 Classification of distribution services

The standard control services and alternative control services covered in the TSS have been classified by the AER in its Final F&A Decision for Power and Water (published on 29 July 2022).[4] Service classifications

4 https://www.aer.gov.au/system/files/AER%20-%20Final%20framework%20and%20approach%20for%20Power%20and%20Water%20Corporation%20%20for%20the%202024-29%20regulatory%20control%20period%20-%20July%202022.pdf

determine which of our services will be regulated by the AER, and where and how they will be regulated. The following figure summarises the AER's decision on the classification of direct control services.

*Figure 1.4: AER service classification*




## 1.6 Network tariff regulation

We have designed our TSS and tariffs with customer pricing impacts in mind, as required under the NT NER and Pricing Principles. While the TSS covers our network tariffs, which applies to all of our customers, not all of our customers will be directly affected and see the full impacts of cost-reflective tariffs.

Full retail contestability (**FRC**) was introduced across the Northern Territory on 1 April 2010. This means that all residential and business customers in the Northern Territory now have the option of either staying with the Northern Territory Government's locally owned retailer (Jacana Energy) or seeking a retail agreement with any retailer licensed to operate in our jurisdiction.

For most of our customers, changes in our prices currently have no impact on their retail bills. This is because electricity retail prices charged to residential and commercial customers that consume less than 750 megawatt hours of electricity per year, are regulated by the NT Government through an Electricity Pricing Order made by the Treasurer under the *Electricity Reform Act 2000*. The Electricity Pricing Order prescribes particular tariff structures for certain customer types. It also caps the prices retailers can charge for each tariff component.

The Electricity Pricing Order gives rise to two distinct types of customers for the purposes of tariff design, customer engagement and customer impact assessment:

**1. Customers who use less than 750 MWh per year** – These comprise approximately 85,200 of our customers who are residential and small to medium businesses. These customer groups are currently subject to retail pricing protection through the Pricing Order. Our tariffs will not directly affect these customer's retail electricity bills.

**2. Customers who use more than 750 MWh per year** – These are our around 220 largest energy users. They also see our network tariffs as a separate charge on their retail bill and the impact of our pricing strategies set out in our TSS will directly affect this customer group.

This means that our proposed network tariff reform will only directly impact the electricity retail tariffs of around 220 large customers using 750 MWh pa and above.

## 1.7 Tariff reform journey

In the 2019-24 regulatory control period, we started a journey to improve the fairness of our tariffs to better reflect each customer's share of network costs. While the AER accepted our 2019-24 TSS, it requested improvements in our approach in future regulatory control provides. Table 1.2 provides an overview of our response to the AER feedback and how it has been addressed in the 2024-29 TSS.

*Table 1.2: AER feedback to 2019-24 TSS*

| AER feedback | Our response |
|---|---|
| Establish a more robust approach to energy forecasting, consistent with system demand forecasting approach and consider a number of variables that may impact prices in a 12-month period | Forecast maximum demand is a key input to the development of LRMC estimates using the AIC methodology.<br>Our system wide demand forecasts, as well as our energy and billable demand forecasts have been prepared by independent experts, Energeia. We have included Energeia's System Minimum and Maximum Demand Forecast Report as Attachment 8.48, and Energeia's Energy forecasting report as Attachment 11.06 to our Initial Regulatory Proposal to the AER. |
| Investigate and refine our methods for estimating LRMC that also includes replacement expenditure | We have taken on board the AER's feedback and have refined our approach and methodology to calculating LRMC.<br>Energeia has developed our LRMC estimates, including specific consideration of AER's feedback in their report.<br>We have included Energeia's LRMC report as Attachment 11.05 to our Initial Regulatory Proposal to the AER. |
| Further investigate the timing of periods of our peak period window | Analysis performed by Energeia, demonstrated that our peak demand period occurs predominantly during the October to March period. This period is also known as Summer in our two Southern grids, and the Wet season for our Darwin-Katherine Interconnected System. All our regulated grids are affected by extreme weather events, including high temperatures and humidity, monsoons and |

| AER feedback | Our response |
|---|---|
| | cyclonic conditions which lead to increased demand across the various networks.<br>Analysis of system peaks using additional data from an increased level of smart metering, as well as peak period data from the 2019-24 regulatory period supports the AER's request for a shortening of the peak window. While still managing the slight variations across the three regulated electricity grids.<br>For our Tariff 3 customers protected by the Electricity Pricing Order we will be reducing the peak period by 15 hours per week to be 3pm to 9pm Monday to Friday, between 1 October and 31 March each year. This ensures a targeted signal to retailers for retail tariff design. For our major customers whose usage impacts our networks maximum demand across the entire year, we will apply the same peak period (3pm to 9pm Monday to Friday) but on an annual basis to ensure system security throughout the year.<br>We have included Energeia's report on periods of greatest utilisation as Attachment 11.04 to our Initial Regulatory Proposal to the AER. |
| Provide further information on individually calculated tariffs such as criteria for assigning customers to such tariffs and the method for determining the structures and levels of prices | We will no longer provide individually calculated tariffs to any customers in the 2024-29 regulatory period. |
| Describe in greater detail the proposed approach to allocating residual costs between customers and within the different charging parameters of each tariff. | We have taken on board the AER's feedback and has included more detail on the approach to allocating residual costs between customers within this Explanatory Statement document. |

A focus for us moving forward is to improve the utilisation of our networks by delivering more energy and solar export capacity, while minimising new network investment. Our tariffs seek to collect revenue from customers in an equitable way, where customers are allocated their fair share for the costs of network services. The objective of our tariffs is to encourage customers to best utilise the capacity of the networks for example by shifting demand to off-peak periods and when there is abundant solar energy in our network. This improves affordability for all customers by improving utilisation by lowering system peak demand and increasing system minimum demand.

Our pricing strategy has focused on the tariff reforms that would help manage rising peak demand in the evening and solar photovoltaic (**PV**) exports in the middle of the day. Our strategy is to place greater emphasis on time of use charges for customers consuming less than 750 MWh pa.

We recognise that the transition to cost reflective pricing must:

- Be supported by the roll-out of smart metering and updated back-end billing system.

- Acknowledge that the Electricity Pricing Order means most of our customers (all those consuming <750 MWh pa) will face no bill impact from change in our prices.
- Include education to bring our key stakeholders and customer along the journey, including through developing innovative tariff trails during the 2024-29 period.

### 1.7.1 Principles informing tariff design

It is relevant to note that the appropriateness of the proposed pace of network tariff reform must be assessed in the context of the customer impact principle under the pricing principles outlined in the NT NER.

Our pricing strategy has focused on setting tariffs that respond to the network impact of rising peak demand in the afternoon/evening periods in summer and growing solar exports in the middle of the day as well as the impact of minimum demand during the middle of the day during the NT dry / winter months.

Our tariff design and engagement process with stakeholders has been influenced by our key principles for tariff design as outlined in Table 1.3.

*Table 1.3: Our pricing objectives*

| Pricing Objective | Description | Alignment with NT NER |
|---|---|---|
| Keep our structures simple | Our pricing signals need to be clear and understandable. Customers, retailers and stakeholders should readily understand our network prices in order to make decisions about usage.<br><br>The structures must be capable of being incorporated by retailers or market small generator aggregators into contract terms. | Clause 6.18.5(i) – customers, retailers and stakeholders must be reasonably capable of understanding the tariff structures and tariffs must be capable of being incorporated into retail offers. |
| Reduce unmanageable bill impacts and maintain affordability | Access to network services should be affordable, including for vulnerable customers, having regard to the retail pricing protections afforded to Territorians under the Pricing Order | Clause 6.18.5(h) requires us to consider the impact on customers of changes in tariffs. |
| Equity | Each customer should pay their fair share of network costs, noting that there should not be a wide gap between customers with similar usage patterns. | Clause 6.18.5(h) and(i) require us to consider customer impact.<br><br>Clause 6.18.3 requires us to set tariff classes together on an efficient basis, but also with regard to avoiding unnecessary transaction costs. |
| Economic Efficiency | Where possible, ensure customers face the cost reflective price signals so that their decisions reduce network costs | Clause 6.18.5(a) - The network pricing objective.<br><br>Clause 6.18.5(e)-(g) – compliance with these pricing principles is consistent with providing efficient price signals. |
| Deliverability and Implementation | We should consider practical constraints such as billing systems, time to communicate new tariffs to customers and retailers and how the Pricing Order affects retailers' ability to reflect our network tariff structures in retail tariff offerings | Clause 6.18.5(i)(2) |

### 1.7.2 Drivers for tariff reform

Technological changes and the increasing shift to renewable energy is changing the way our customers use our network. We recognise that the new energy world requires us to develop network tariffs to ensure we can minimise our future costs and allow for economic development in the Northern Territory. Figure 1.5 provides an overview of the different drivers and trends influencing our tariff reform journey.

*Figure 1.5: Drivers for tariff reform*

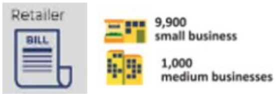
**1 Demand from electric vehicles**

Electric vehicles will significantly increase network investment by 2040 unless vehicles are charged outside the evening peak.

**2 Household solar exports**

Increasing household solar exports may require significant network investment by 2040 unless we can increase demand in the day.

**3 Retail competition**




We envisage that more customers will have choice on their retailer as we move forward over the next 20 years, so our tariff classes will need to be segmented to allow that opportunity to arise.

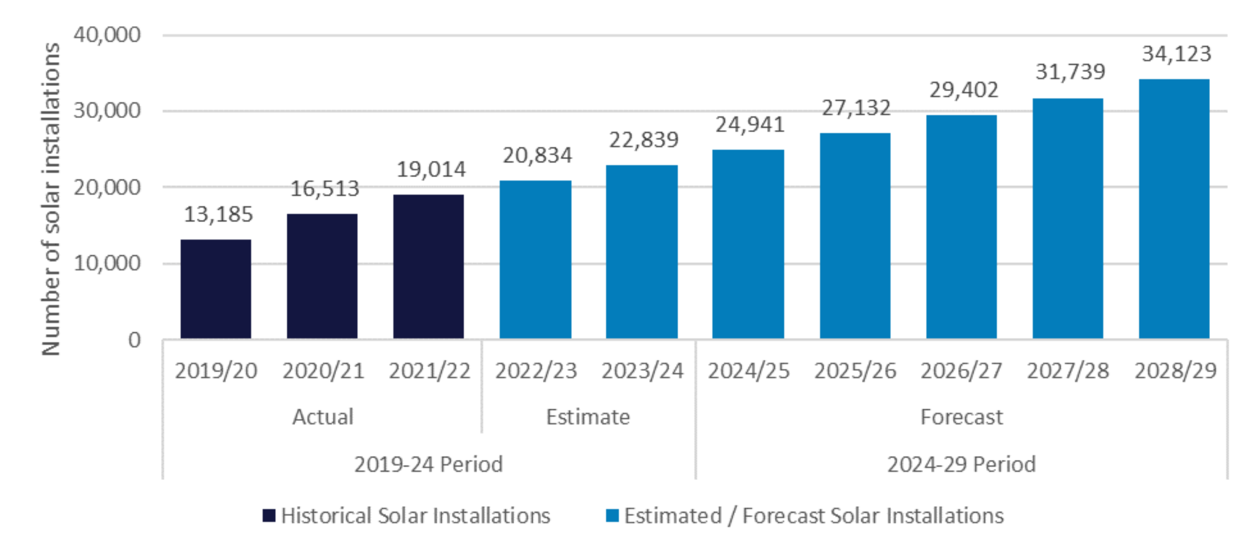
**4 Big industry**

The Northern Territory Government is looking for large industry to locate to the NT, and we need tariffs that are simple to understand and encourage location.

Attracting large users should help reduce the average cost of electricity by increasing the economies of scale of the energy system.

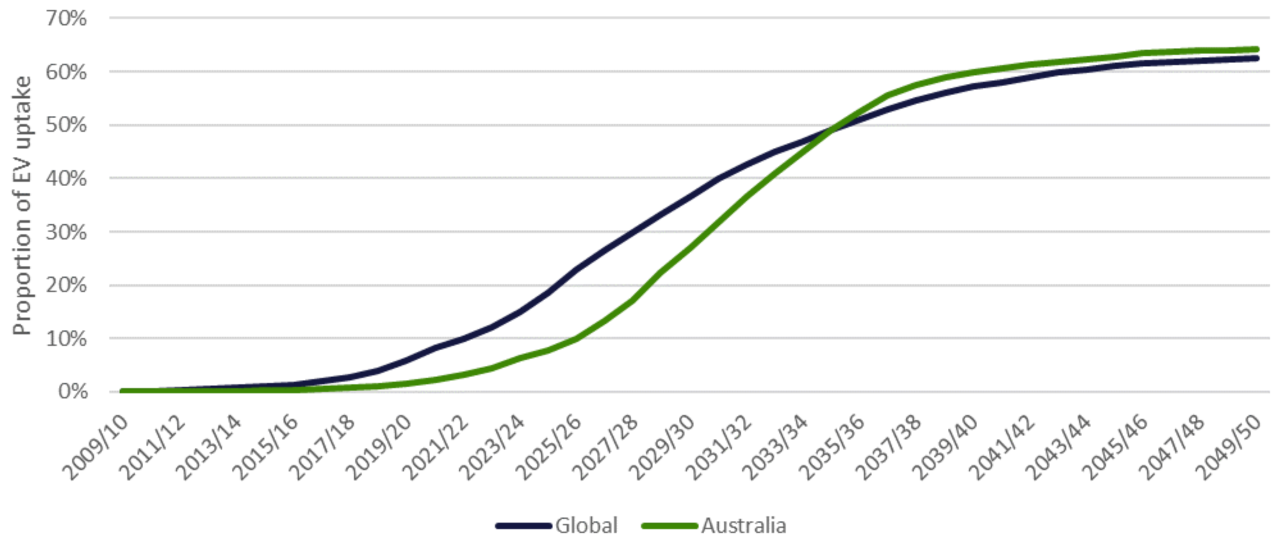
Our proposed tariffs for the 2024-29 TSS seek to reduce future network costs through tariff structures that encourage customers to shift consumption and solar exports to periods when our networks have spare capacity. We have seen unprecedented growth in rooftop and distributed solar PV adoption over the past five years, and we are forecasting an increasing rate of solar PV adoption under a business-as-usual scenario, which will lead to significantly higher capital and operational costs.

*Figure 1.6: Forecast growth in solar*



Residential batteries and electric vehicles (**EVs**) are not yet widespread in NT but are expected to fall in price over the next five years, leading to increased adoption. Changes to tariffs are also expected to drive more adoption, potentially leading to changes in our peak periods if they are all turned on at the same time to recharge during an off-peak period. Figure 1.7 provides an indication of the forecast uptake of EVs.

*Figure 1.7: Forecast EV uptake*




Source: Bureau of Infrastructure, Transport and Regional Economics, 2019, Electric Vehicle Update: Modelling a Global Phenomenon, Research Report 151, BITRE, Canberra ACT.

Rising solar PV generation and EV charging in particular are driving a change in our peak demand period, which is moving to later in the day when the sun sets. The rise in grid exports from distributed solar PV and batteries is creating a generation peak that does not align with our customers' consumption peak. This is increasingly driving capital and operational expense. Our current tariffs do not include a peak generation period or incentives for additional consumption to correspond with this generation peak. Our time of use structure for Tariff 3 seeks to address this.

The expected increase in the level of solar PV, batteries and EVs in our networks over the 2024-29 regulatory period means it is essential that:

- Tariffs signal the cost of generation during the generation peak or when it is most likely to drive additional costs.
- Peak periods consider the operation of batteries and EVs charging and discharging.
- Off-peak periods consider the potential for batteries and EVs charging to create new peaks by including a larger buffer than might otherwise be needed.
- Tariff structures avoid cross-subsidies and uneconomic bypass by using appropriate pricing mechanisms.

The NT NER and pricing principles require our network tariffs reflect our marginal costs during the periods of maximum congestion.[5] As such, it is important our proposed tariff structures reflect these emerging drivers of network congestion, the associated periods of maximum network congestion and the associated

[5] NT NER 6.18.5(f)

levels of investment and operational costs. Our approach to basing our tariffs on LRMC seeks to achieve this.

### 1.7.3 Enablers of tariff reform

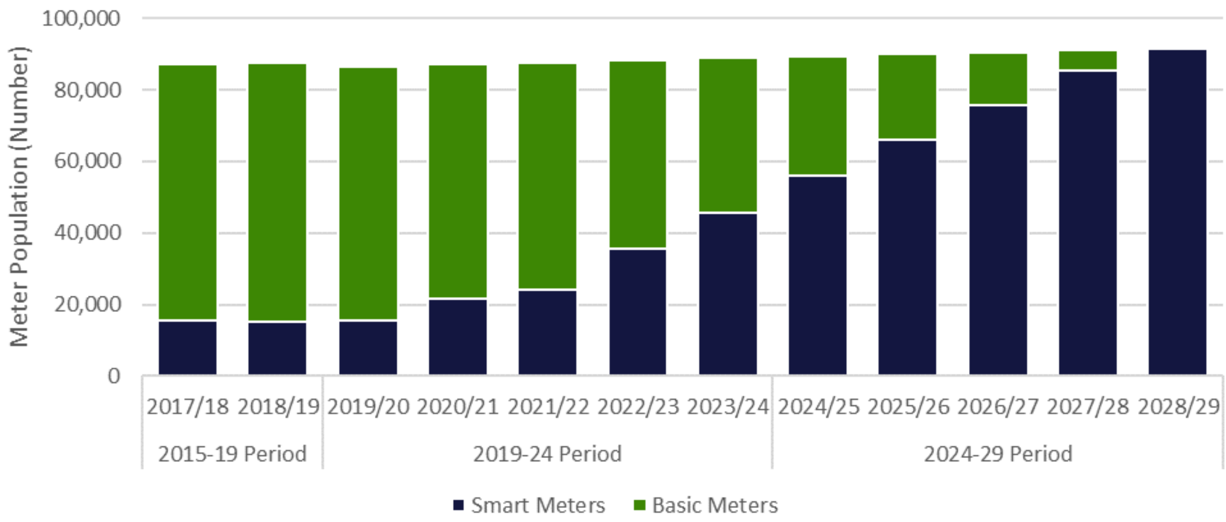
Our starting point in the tariff reform journey has been to consider changes to our existing network tariffs and tariff structures where there is a clear need to change. This recognises that wholesale change is difficult without the support of our customers and stakeholders and tariff reform needs to be compatible with retail billing systems as well as being enabled by smart meters.

We have been able to use smart metering data to improve our understanding of our customers' usage patterns to improve business operations, including tariff design, system planning and demand management initiatives. The additional information smart meters will generate will also enable us to further improve our tariffs and assignment policies for future TSSs.

Different meters support different tariffs, with the older accumulation meters only able to support anytime energy volume-based tariffs. The majority of our customers currently still have accumulation metering (type 6 meters), which only measure total consumption volumes and are not able to charge customers cost reflective prices for their usage during times of maximum grid congestion. Therefore, until all our customers have smart meters installed, we need to maintain existing tariff structures (for Tariff 1 and Tariff 2) for those customers with accumulation meters.

Figure 1.8 shows our forecast for the number of customers with smart meters installed compared to those customers that remain on accumulation / basic meters. Smart meters can support all types of tariffs structures and we anticipate, by June 2024, we will have approximately 50 per cent of the regulated customer base on smart metering. This includes most non-residential customers and the entire Tennant Creek electricity grid. We have forecasted that by 30 June 2029 the number of customers with a smart meter will increase to approximately 71,600 or 80 per cent of our regulated customer base.

*Figure 1.8: Changes in meter volumes*



# 2. Our approach to setting tariffs

The NT NER requires that we provide a description of the approach that we will take in setting each tariff in each annual pricing proposal during the regulatory control period. Compliance with the pricing principles in the NT NER requires that we continue towards LRMC-based pricing and the efficient recovery of residual costs. In developing our pricing strategy, we have focused on setting tariffs that respond to the impacts on our networks from rising peak demand in the afternoon/evening periods in summer and growing solar exports in the middle of the day.

The AER provided feedback on our 2019-24 TSS that we should provide greater certainty and clarity on our approach to setting prices through our annual pricing proposals. While we will maintain the same general approach to setting network tariffs each year, the overall average network tariff may differ (either increase or decrease) as a result of the following:

- The AER's final distribution determination for Power and Water for the 2024-29 regulatory period.
- Changes arising from pass-through events approved by the AER.
- Sales volumes varying from forecast levels, leading to an under-recovery or over-recovery of revenue that impacts the following year's prices.
- Differences between forecast customer numbers, energy and demand included in our TSS and any updated forecasts made at the time of each annual pricing proposal.
- Annual updates to the cost of debt that take place at the time of the annual pricing proposal, in line with the AER's Rate of Return Instrument.
- Changes in the Consumer Price Index (**CPI**) rate as forecasts become actuals.
- Application of incentive schemes as approved by the AER.

## 2.1 LRMC methodology and approach

### 2.1.1 Overview

The NT NER and pricing principles require that our network tariffs should reflect the LRMC of providing network services to customers on each tariff at the time of greatest utilisation. The long run is defined to be the period over which all costs are variable.

This means that each of our network tariffs for each of our services must be based on the cost to us of servicing one more unit of demand or adding one more connection, including all investment and associated ongoing maintenance costs for that investment. They signal to customers the future network cost of consuming the next unit of electricity during the period of greatest demand (i.e. the peak demand period).

LRMC is an important signal to the users of our networks to assist them in making efficient choices about electricity usage and when investing in energy related appliances and systems. Where there are no network constraints, such as in off-peak times, the cost of providing network services will be very low. However, if the network is reaching capacity at peak times, the cost to us of consumers using more energy/demand at that time will grow until we need to augment the networks to continue meeting demand. These additional costs should, under the NT NER, be reflected in the network tariffs.

### 2.1.2 Methodology

Our technical subject matter expert consultant, Energeia, has developed our LRMC estimates having regard to the AER's feedback. We have included Energeia's LRMC report as Attachment 11.05 to our Initial Regulatory Proposal provided to the AER in January 2023. For the 2024-29 TSS Period, we have retained the AIC approach for estimating the LRMC of our network services. This was decided following review of the costs and benefits of moving to more sophisticated, but higher cost, marginal investment cost or Turvey / Perturbation or long run incremental cost approaches.

Our AIC approach calculates LRMC by taking the ratio of the present value of growth related capital expenditure (**capex**) and operating expenditure (**opex**) to the present value of the forecast change in demand over the time horizon.

$$LRMC(AIC) = \frac{PV(growth\ related\ capex) + PV(growth\ related\ opex)}{PV(incremental\ demand)}$$

Where:

- Growth related capex is the total system capex to meet the additional demand and new customer connections forecast over the forecast period.
- Growth related opex is the incremental annual cost of operating and maintaining the newly constructed network and connection assets over the forecast period.
- Incremental demand is the forecast change in kVA demand compared with the base year.

In these calculations, we:

- Assume opex is equal to a proportion of capex based on typical planning estimates.
- Assume 35 per cent of forecast replacement capex is 'growth related' in that it would be lower if growth was negative (i.e. PWC would not replace assets on a like-for-like basis in this situation).
- Use a time horizon of 20 years.

We have retained the AIC method for several reasons:

- It relies on information that is currently available within our business and our longer-term asset planning processes.
- It is less data intensive than the alternative perturbation method or marginal investment cost method, making it easier to apply and to explain during stakeholder engagement.
- It has been adopted by other networks and is accepted industry practice.
- It has a relatively low cost of implementation and uses inputs that are readily available as part of preparing the regulatory proposal.
- We considered if the benefits of alternative more sophisticated and onerous to apply methods would warrant the effort of adopting one of those methods. Given the Pricing Order prevents most of our customers from seeing our tariffs and the low availability of smart meters, we considered that the

benefits were not likely to be realisable in our circumstances. We will continue to review this for future TSSs.

The AER's final decision on our 2019-24 TSS provided feedback for our future LRMC estimation approach. The AER suggested we extend the time horizon for projected costs and demand and include replacement expenditure. In response, we have extended the time horizon for our LRMC calculation method to 20 years and included relevant elements of our replacement expenditure forecasts.

We have included the following types of costs in the LRMC model:

- All system capex.
- We have assumed 35 per cent of all replacement expenditure is growth-related.

Costs include all avoidable costs, i.e. all assets required to meet a given level of peak demand, whether for augmentation, incremental capacity related replacement or operational expenditure.

We have explicitly excluded the following costs from the LRMC model:

- Non-system capex (e.g. ICT systems).
- Connection capex.
- Overheads not already allocated in the capex estimate.
- Export services.

## 2.2 Stand-alone and avoidable costs

The NT NER pricing principle in clause 6.18.5(e) requires that:

> *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.*

Pricing within the stand-alone and avoidable cost ensures that there are no inefficient economic cross-subsidies contained within the tariff classes for the following reasons:

- **Stand-alone cost**: The stand-alone cost of serving a given group of customers in a tariff class is the total cost of servicing those customers if we rebuilt the networks to meet their specific requirements or met their equivalent energy needs through a stand-alone energy solution. This upper bound ensures customers in any given tariff class do not pay more because we are servicing other customers than if they sourced electricity directly.
- **Avoidable cost:** If customers were to be charged below the avoidable cost, it would be economically beneficial for the network business to stop supplying the customers as the associated costs would exceed the revenue obtained from the customer.

The NT NER does not prescribe the methodology that should be used to calculate the stand-alone and avoidable costs of tariff classes of the network. The method we have used to evaluate stand-alone and avoidable costs requires a process of reviewing the cost of providing our network services to determine whether they are incurred directly by certain tariff classes or shared across the network. We have calculated the stand-alone costs based on the cost of a median customer in a tariff class going 'off-grid' with solar, battery and a diesel generator. In calculating avoidable costs, we have based it on the contribution to the system peak by each class, multiplied by the LRMC.

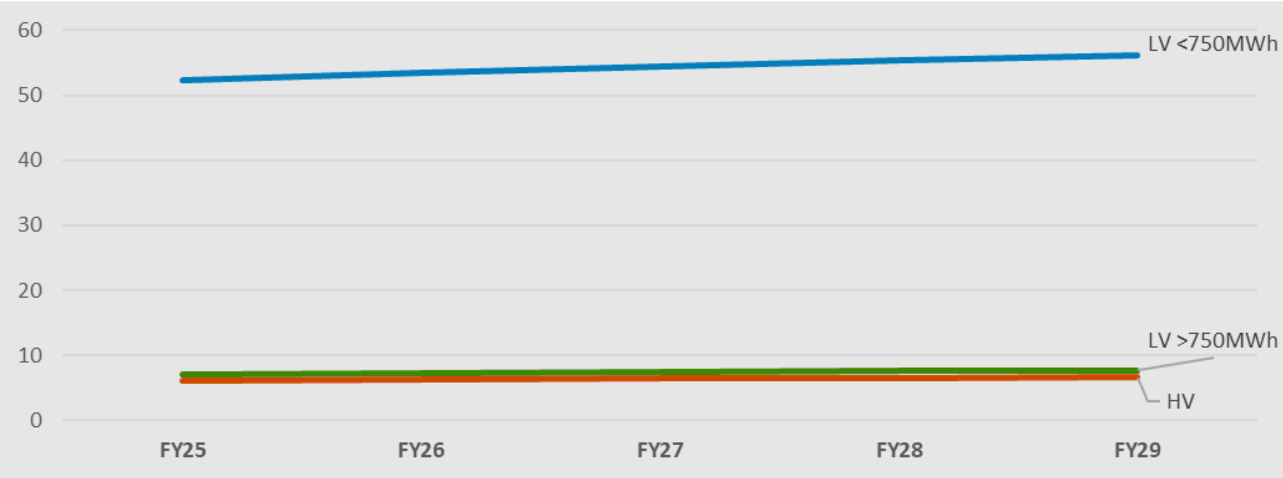
Our estimates of the stand-alone and avoidable cost for each customer class are included in our economic costs model. Our calculations show that, for each tariff class, the proposed revenue lies between the lower bound (avoidable cost) and upper bound (stand-alone cost). Table 2.1 provides an overview of the capex and opex inputs and the total LRMC at each voltage level.

*Table 2.1: LRMC calculations and inputs ($/kVA real 2023-24)*

| Voltage level | LRMC at voltage level | Growth capex | Replacement capex | Growth opex | Total LRMC at voltage level |
|---|---|---|---|---|---|
| **Low Voltage** | $/kVA | 26.86 | 85.11 | 59.60 | 171.56 |
| **High Voltage** | $/kVA | 34.04 | 31.48 | 34.87 | 100.39 |

The figure below reports on the results of our analysis of the avoidable LRMC by tariff class. This represents the forecast LRMC revenue, in $million, allocated across tariff classes based on estimated contribution to the coincident system peak load.

*Figure 2.1: Forward looking avoidable power system costs by tariff, $ million*




## 2.3 Setting price levels

We propose to signal to customers the LRMC of providing network services at times of greatest utilisation using the demand charging parameter in demand tariffs and the peak energy charge in time of use (**TOU**) tariffs, or anytime energy rate for the unmetered and accumulation meter tariffs (Tariffs 1, 2 and 4).

The demand charge and high period TOU charge were selected because these provide a signal to customers that more closely reflects the period of greatest utilisation and are therefore the key driver of network costs (i.e. peak demand). We then allocate residual costs across our various charging parameters to recover total allowed revenues.

Table 2.2 shows the revenue being recovered from the relevant charging parameter for each tariff is at least as high as the LRMC attributable to customers on that tariff.

*Table 2.2 Tariffs reflect LRMC compliance check ($ million real 2023/24)*

| Tariff | LRMC target | Peak kWh | Wet MD | Dry MD | Anytime kWh | Daily charge | Compliant |
|---|---|---|---|---|---|---|---|
| 1 | 19.1 | | | | 22.6 | | YES |
| 2 | 2.2 | | | | 2.1 | 0.1 | YES |
| 3a | 15.3 | 5.4 | | | | 9.9 | YES |
| 3b | 10.8 | 7.8 | | | | 3.0 | YES |
| 3c | 8.0 | 7.6 | | | | 0.4 | YES |
| 4 | 0.0 | | | | 0.0 | | YES |
| 5 | 8.6 | | 5.4 | 0.7 | | 2.5 | YES |
| 6 | 3.3 | | 2.4 | 0.6 | | 0.3 | YES |

## 2.4 Efficient recovery of residual costs

While LRMC is an indicator of forward-looking costs, the investment we have made in the past to build and maintain our networks is known as residual cost. These residual costs are the difference between the revenue we are allowed to earn each year to recover our efficient costs and our LRMC estimate. As most of our costs are fixed, we generally allocate the majority of residual costs to the fixed daily charge component of our network tariffs.

The efficient recovery of residual costs requires that these costs are recovered from network customers in a manner that minimises the distortion to efficient network usage. The fixed system availability charge (**SAC**) has the potential to be an economically efficient way to recover these costs because changes in the level of the fixed SAC do not typically influence the investment, network connection and consumption decisions of our customers. Nevertheless, it is important from a compliance perspective that the rate of SAC increases does not contravene the customer impact principle in the NT NER, which we have tested in our bill impact assessment, including looking at the customer impact of receiving a smart meter and being reassigned to the relevant tariff - Tariff 3.[6]

Figure 2.2 shows the proportion of residual costs that are recovered via the fixed SAC in 2024-25. Figure 2.3 shows how this changes by 2028-29 with migration of our small customers to smart meter tariffs over the regulatory period.

6 NER, cl 6.18.5(h)

*Figure 2.2 Residual cost recovery by tariff in 2024-25*

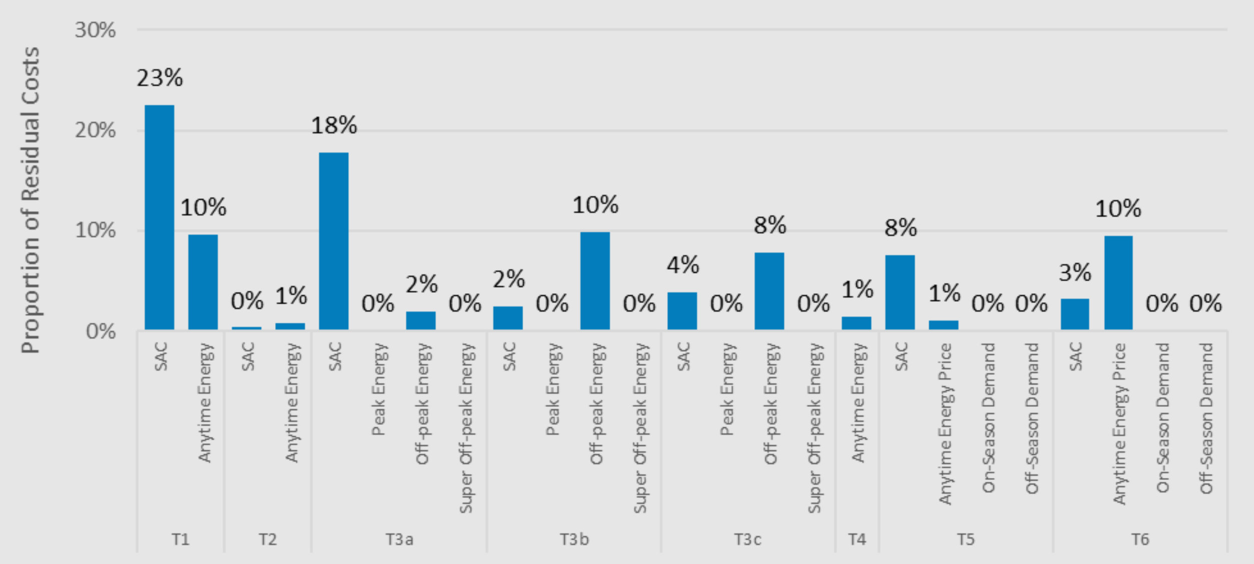
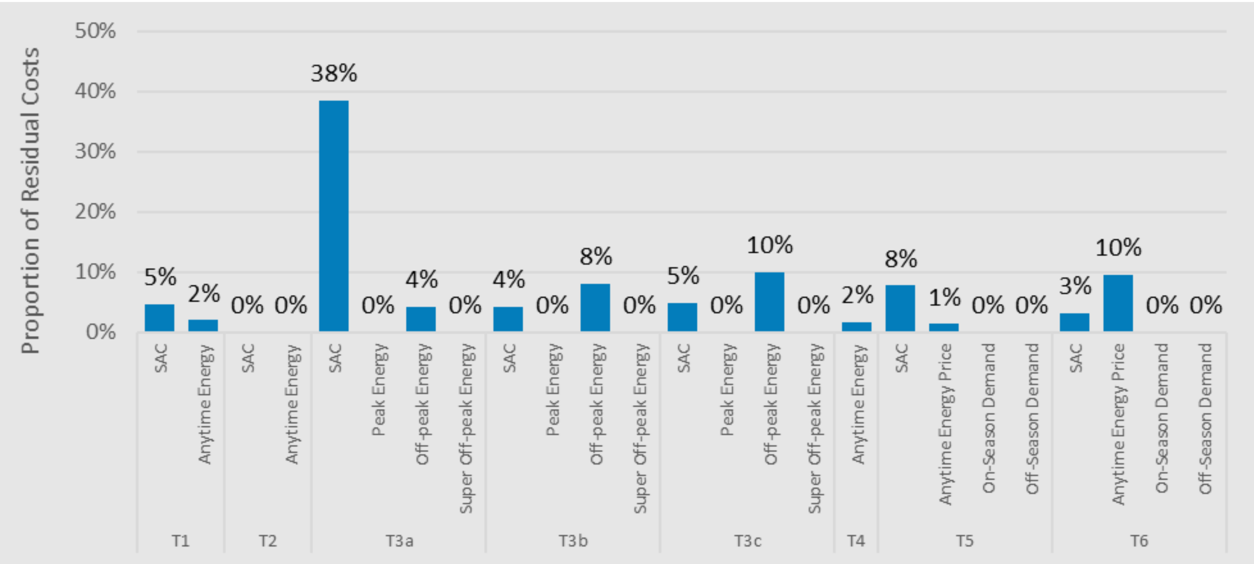



*Figure 2.3 Residual cost recovery by tariff in 2028-29*




## 2.5 Recovery of annual revenue requirement across tariffs

Clause 6.18.5(g) of the NT NER requires that the revenue we are expected to recover from each tariff must:

- Reflect the total efficient costs of serving the retail customers that are assigned to that tariff.
- Permit us to recover the expected revenue for the relevant services in accordance with the applicable distribution determination.
- Minimise distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principles.

We are regulated under a revenue cap and therefore must not recover more (or less) revenue when summed across all tariffs than the total revenue allowed by the AER. To meet the requirement under clause 6.18.5(g)(2) of the NT NER, we are required to demonstrate we have recovered only the expected revenue summed from all network tariffs in accordance with the distribution determination via the Annual Pricing Proposal.

Under a revenue cap, we have a three-step process to calculate tariffs and recover its approved revenue. The first step is to calculate the total allowed revenue as per the AER approved formula including any annual adjustments to account for ‘unders and overs’ balances. The second step is to forecast customer numbers (NMIs), energy consumption (kWh), and demand (kVA) in the relevant billing periods. And finally, the third step is to develop tariff rates that allow us to earn the total allowed revenue using an approach that aligns with our TSS.

When applying this approach, we seek to retain of relevant LRMC-reflective charging parameters at the LRMC-reflective price and adjust the residual cost recovery from other charging parameters in a manner that accounts for any year-on-year customer bill impacts.

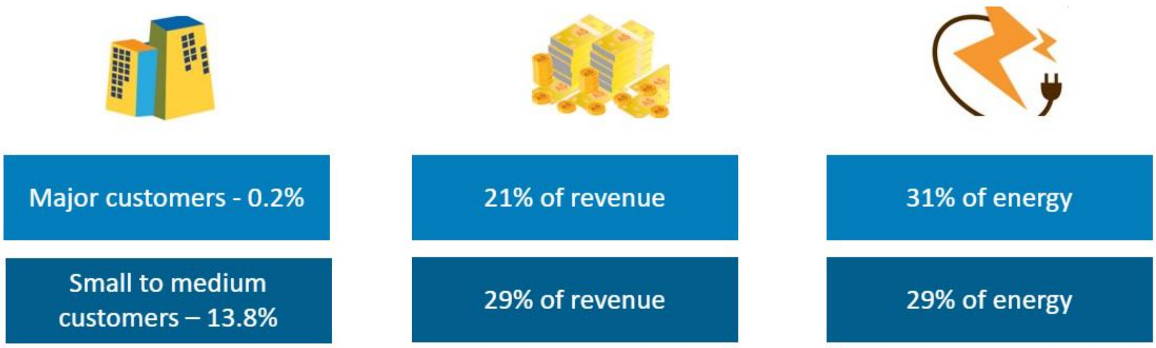
# 3. Stakeholder engagement

Power and Water has undertaken an extensive consultation process, with retailers, generators and, business customers who had an interest in, or might be impacted by, network pricing reform in the Northern Territory. We have sought to incorporate the key elements of feedback from our customers when developing and then refining our TSS. This engagement spanned our Draft Plan, initial TSS proposal and our revised TSS proposal.

## 3.1 Overview to our initial TSS proposal

Business customers were a focus of our engagement as we have approximately 200 major customers (those consuming greater than 750 MWh pa), and approximately 10,000 small and 1,000 medium business customers (those consuming less than 750 MWh pa). Figure 3.1 below provides an overview of customer segments and their impact on revenue.

*Figure 3.1: Customer segments and revenue impact*

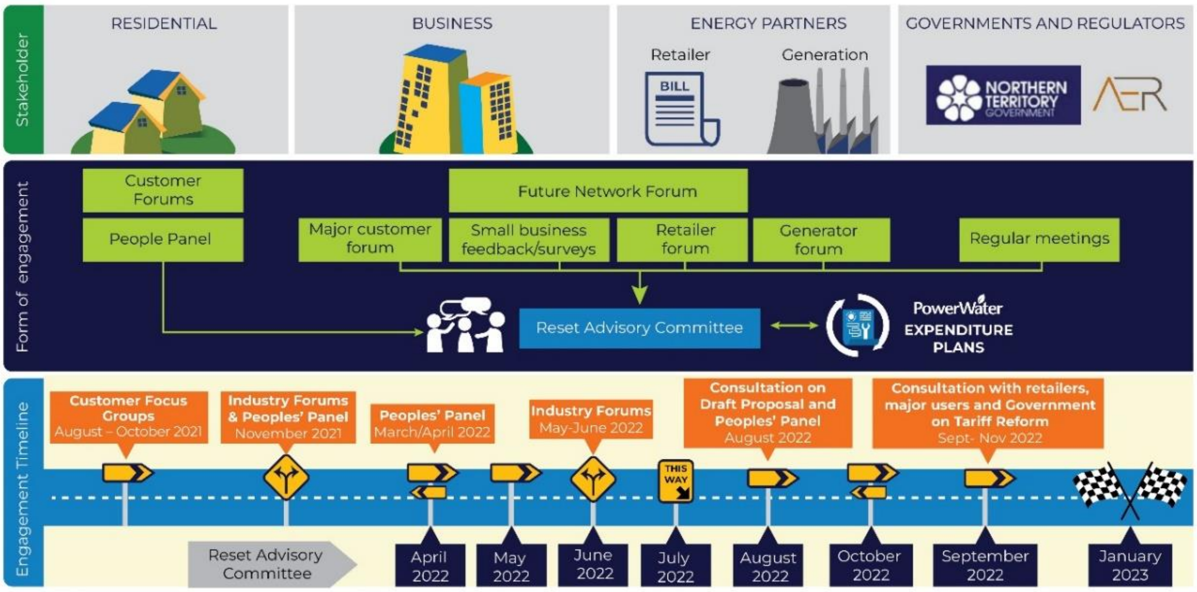



In our discussions with customers, retailers and stakeholders, we have noted that our network tariffs are not passed through to the customer by the retailer, and this limits our network tariffs providing a direct price signal to certain customers. For small customers (those consuming less than 750 MWh pa), retailers must use the tariffs provided in the Electricity Pricing Order, unless the customer chooses to enter into a negotiated sales agreement. These tariffs do not have a specific requirement to disclose the network component, nor are the charging parameters aligned with network tariffs. For larger customers (those consuming above 750 MWh pa), the retailer usually treats the network component as a direct pass through cost, showing our network tariff on the customer invoice.

We recognise that successful reform depends on effective engagement with our customers and stakeholders and as such, our engagement approach ensured that we involved all our customer segments, customer advocates, retailers, generators, the NT Government and the AER in our pricing forums and discussions. In this way, we were focused on bringing people together that would lead to tariff outcomes that provided a balanced view and a doable tariff reform pathway. Our consultation on tariff reform has been heavily focused with retailers who operate in the Northern Territory. It is these retailers who see our network charges and bundle these charges with other costs to bill customers. We have also engaged broadly with both residential and non-residential customers on pricing arrangements in the Territory.

Figure 3.2 below provides an overview of our engagement journey to the January 2023 Initial Regulatory Proposal.

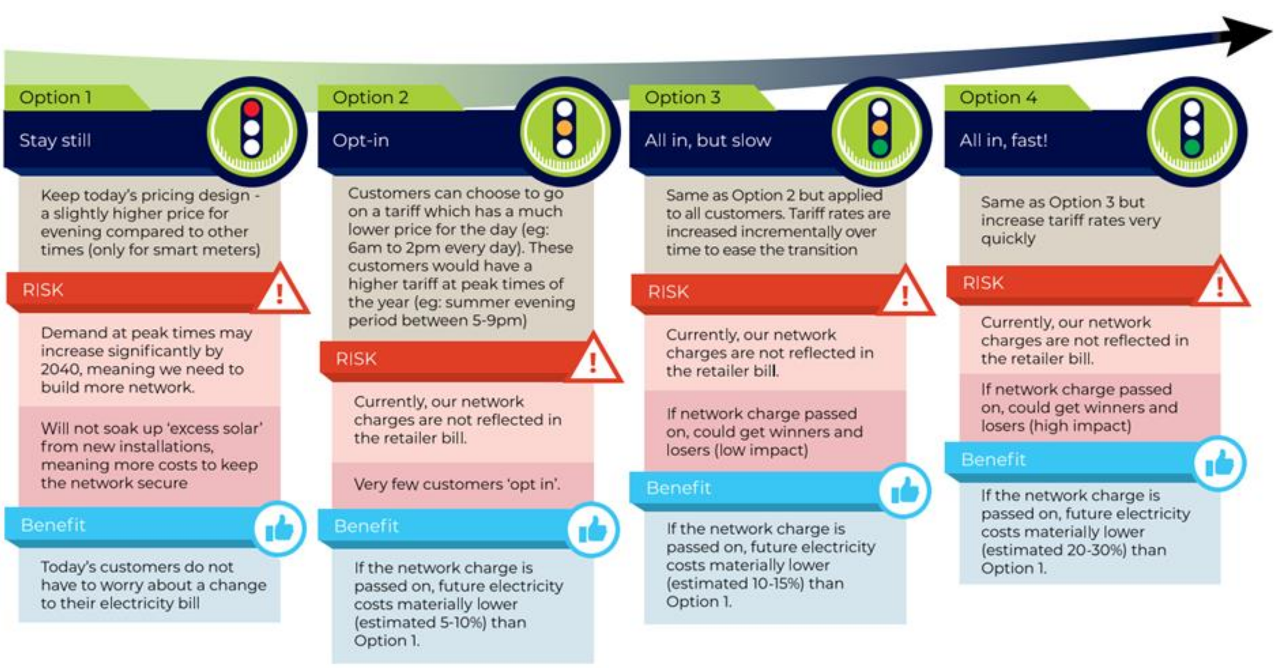
*Figure 3.2: Stakeholder engagement journey*




A centrepiece of our engagement was establishing a representative panel of residential customers in both Darwin and Alice Springs – termed our 'People's Panel'. The Darwin panel discussed the use of tariffs to support behaviours that would flatten demand and soak up excess solar from the grid. It was noted that the delivery of price signals through network tariffs is complicated by the fact that residential customers' electricity bills only reflect the Electricity Pricing Order structures, rather than the full itemised invoice. The constraints of a lack of smart meters which can record how much a customer uses and when was also discussed.

Following this discussion, our panels were provided with options on the speed and intensity of tariff reform for the 2024- 29 regulatory period (refer to Figure 3.3. The panels noted that tariff reform may disadvantage low-income households who cannot change their energy consumption patterns. For this reason, they opted for more incremental reform.

*Figure 3.3: Tariff reform options discussed at People's Panels*




Following the People's Panels, we published our Draft Plan in August 2022, which outlined our draft Pricing Strategy. The Draft Plan was open for consultation and submissions from all consumers across the NT and closed 13 September 2022.

However, we recognised that more targeted engagement was necessary on tariff reform and as such, after publishing the Draft Plan, we held further meetings with the following stakeholders to discuss the proposed tariffs, including potential tariff structures, export pricing and the future of the Pricing Order. These included:

- All-in meeting with retailers and stakeholders (9 November 2021)
- Major users (21 September 2022)
- Department of Infrastructure, Tourism and Trade (6 October 2022, 28 November 2022)
- Department of Treasury and Finance (24 October 2022, 4 and 28 November 2022)
- One-on-one meetings with retailers (20 and 21 October 2022)
- Territory Generation (3 and 15 November 2022)

## 3.2 What we proposed in our Draft Plan

Our starting point for tariff reform was to consider changes to our existing network tariffs where there was a clear need to change. This recognises that wholesale change is difficult to communicate to our stakeholders and may not be compatible with existing billing systems.

In the Draft Plan, we proposed the following changes:

- To separate the existing Tariff 3 for small customers with smart meters into more segments. This proposed change followed retailer feedback on how to encourage and expand retail competition in the future.
- A possible additional tariff segment for our largest customers.

- For the segment of smart meter customers consuming less than 100 MWh, we proposed not applying a demand charge and only applying energy consumption charges.
- To introduce new export tariffs from 2025/26 onwards.
- For customers consuming more than 750 MWh, we proposed the introduction of a charge reflecting the average of kVA demand in the peak period applied as a daily rate.
- For smaller customers with smart meters consuming less than 750 MWh, we proposed to narrow the hours of the peak period.
- To move away from a using a single period maximum (kVA) window to apply LRMC charges. Instead, customers using less than 750 MWh would be charged kWh rates in the peak period. For customers consuming less than 100 MWh, residual costs would be recovered via the system availability (daily fixed) charge and kWh rates in the off-peak period.

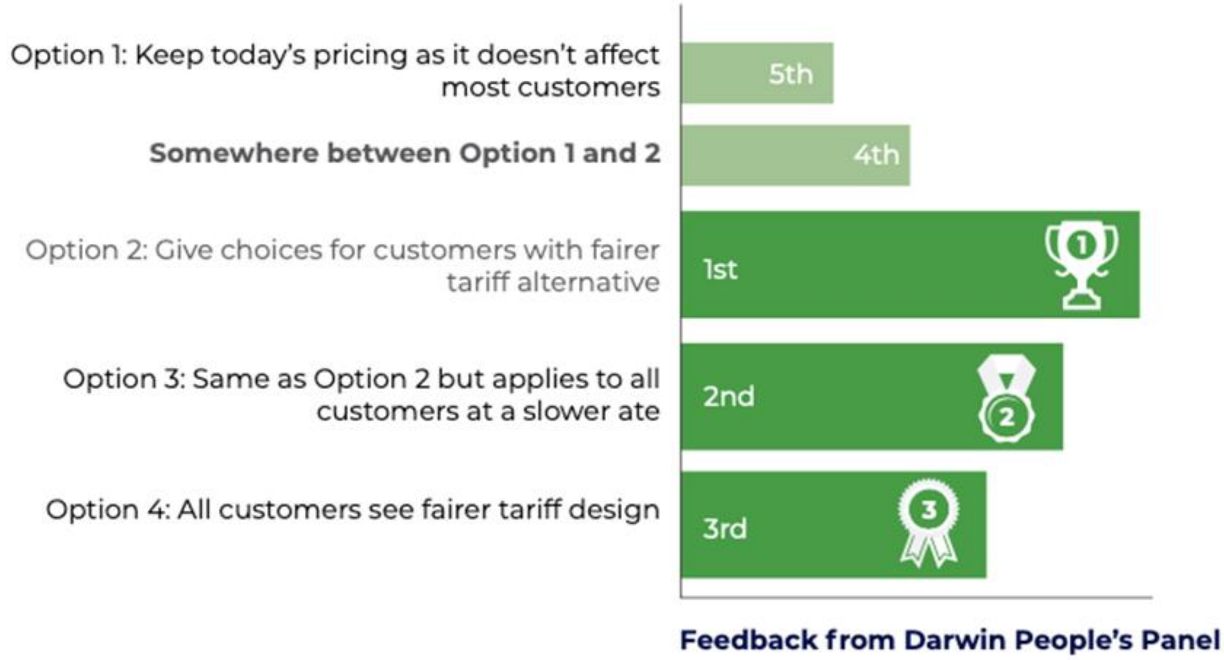
## 3.3 What we heard on our Draft Plan

There was a difference in perspectives in Darwin and Alice Springs People's Panels on the proposed concept of charging higher rates during the evening peak period to disincentivise network use when demand is higher and lower rates during the day to incentivise network use when there is greater supply. Panellists suggested we needed to:

- Provide sufficient information and education for consumers to change their behaviours and be able to make informed decisions.
- Consider safety nets for those who are disadvantaged or who cannot fully utilise the lower prices during the day.
- Undertake a gradual transition to implement the pricing changes, as well as only apply a marginal difference in price.
- Assume a role beyond applying the time-of-use pricing to assist a change in behaviour e.g., providing fridge magnets to encourage network use during specific periods of the day.
- Plan for the future without disadvantaging those using the network today.

Feedback from our People's Panel in Darwin (March / April 2022) noted the limitations of reform given that the tariffs of small customers are set in the Electricity Pricing Order and do not align with network tariff structures. Most panel members preferred retail options for customers to be able to choose from, but also recognised that there was a need for efficient price signals to impact all customers.

*Figure 3.4: Results of People's Panel tariff reform discussions*




Our engagement with retailers provided feedback that demand charges are already a complex concept and adding further complexity with rolling peak demand would only add further complexity. Retailers were generally supportive of the direction of our new tariff structures and highlighted that continued network tariff reforms needs to be supported by reform of the Electricity Pricing Order thresholds. Indeed, our largest NT retailer desired we adopt more simplistic network tariff structures that more closely mirror the Retail Electricity Pricing Order for the next TSS period.

We have received interest from a retailer to collaborate on tariff trials as an important way forward for Northern Territory tariff evolution and to support the renewable energy transition. Our retailer engagement told us that they didn't want seasonal charges. However, this was in contrast to feedback received from our major customers who advised us that they just want certainty in the tariff structures and were happy to have seasonal charges if this meant that they could have price certainty.

During our engagement with major customers, we heard that they:

- Are seeking certainty and predictability in their billing structures.
- Want tariffs that acknowledge that customers:
  - Have often paid large connection charges for the capacity we've built for them.
  - Often have stable and predictable loads.
  - Are able to work with us on potential curtailment during maximum demand periods.
  - Support network stability during minimum demand periods.

Engagement with the Northern Territory's newest retailer, Territory Generation, was also held to better understand the unique customers that they will be retailing to in the future regulatory periods. These customers will be some of the largest energy users to connect to our electricity networks. Several issues discussed included:

- **How we are charging retailers** - An overview of the evolution of our network tariffs from before structural separation compared to proposed network tariffs in the 2024-29 TSS.
- **How we are charging generators** - Covering the proposal to charge all generators an SCS tariff for consumption imported from the grid and given the connection point, scale of consumption and metering it is anticipated generators will likely be charged at Tariff 6 (HV greater than 10,000 MWhs).
- **Generation and network pricing alignment** - Discussed the potential to align generation pricing structures to our proposed network structures.

Territory Generation was supportive of the proposed network tariff structures, especially Tariff 7 super users as its customers are likely to fall into this category. Territory Generation also told us:

- It understood our proposal to charge generators for consumption imported from the grid, however suggested a threshold be introduced before charges apply.
- Ongoing metering and system stability issues would require further engagement.
- While it agrees generation tariff reform is needed, further discussion and analysis would be required, which Territory Generation is looking into.

## 3.4 How our initial TSS responded

Based on feedback received, we modified some of the positions we proposed in our Draft Plan. We then retested these changes with retailers (Jacana and Rimfire), Territory Generation, AER staff and NT Government.

We made the following changes to the positions outlined in the Draft Plan:

- The tariff structure by introducing an 'on' and 'off' season to the demand charges for our major customers. The 'on' season will be aiming to recover more of the demand revenue between 1 October and 31 March, whilst the 'off' season will aim to recover the remaining demand revenue and help to reduce the cost ($/kVA) during peak period. Both periods will be 3pm to 9pm Monday to Friday.
- Increased the thresholds for Tariff 3 from 100 MW to 160 MW, and also further segmenting into residential and non-residential.
- Retailers felt that demand charges are already a hard concept to explain without the added complexity of the rolling peak average so we moved away from the rolling average demand that was proposed and returned to peak maximum demand.
- Proposed a simplified two-part anytime tariff structure for Tariff 7 super user major customers consuming above 10,000 MWh pa.

In relation to feedback received on our proposed export tariffs and trials, we reassessed our unique regulatory environment under the Pricing Order. This means that we cannot assume any behavioural response from tariff designs for most customers. We proposed to collaborate with NT retailers and NT Government to design targeted trials that can:

- Inform our future network tariff design.
- Provide evidence to support the NT Government considering reform to the Pricing Order for either customer thresholds or tariff structures.
- Test specific pricing innovations.

## 3.5 What we heard on our initial TSS proposal and how we have responded

Following submission of our Initial Regulatory Proposal and initial TSS in January 2023 which the AER published, the AER then:

- On 28 March 2023, released an Issues Paper highlighting some of the key elements of our proposal.
- Held a public forum on our proposal on 5 April 2023.
- Invited submissions from stakeholders by 12 May 2023.

The AER received submissions from: Consumer Challenge Panel 27, Jacana Energy and Territory Generation. Of these submissions, only Jacana Energy and Territory Generation provided feedback on our TSS proposals.

Territory Generation submitted that it supported our introduction of time of use tariffs and our proposal to trial tariffs for dynamic operating envelopes, optimisation of EVs and distributed battery storage.[7] We have retained these features in our revised TSS proposal.

Jacana Energy submitted on several aspects of our initial TSS proposal.[8]This feedback and our responses are shown in Table 3.1.

*Table 3.1 Jacana Energy feedback and our responses*

| Feedback | Our response |
|---|---|
| It did not support our proposal to introduce a HV super users Tariff 7. | We have now removed this tariff as discussed in section 4.5.5. |
| It supported our proposed approach to trialling new tariff structures, including export and EV tariffs, and looks forward to collaborating with us on these trials. | We have retained our trial tariff proposals, see section 6.4. |
| It questioned the benefits of introducing seasonal TOU network tariffs to Tariff 3 customers who are protected by the Electricity Pricing Order. | We still consider that the change to TOU pricing is required to signal to customers when the network is experiencing peak demand in the evening, and when there is ample capacity to meet demand in the middle of the day.<br>Our engagement with NT Government indicates that having greater segmentation of our Tariff 3 smart meter customers and application of TOU pricing, will provide more optionality for future reforms to the Electricity Pricing Order. Such reforms can allow our customers to benefit from shifting consumption out of peak times and can better support NT retail competition. |

7 Territory Generation, Regulatory Proposal for the 2024-29 regulatory period, 23 May 2023, pp.2-3.

8 Jacana, Review of AER Issues Paper: PWC Electricity Distribution Determination 1 July 2024 – 30 June 2029 Jacana Energy Responses

| Feedback | Our response |
| --- | --- |
| | The AER's draft decision approved this proposal and we have retained it. |
| It questioned how our seasonal TOU network tariffs would work where accumulation meters are in use. | Our Tariff 3 seasonal TOU network tariffs only apply to customers who have smart meters.<br>Residential and non-residential customers who remain on accumulation meters will remain on our existing Tariff 1 and Tariff 2 respectively.<br>The AER's draft decision approved this proposal and we have retained it. |
| It requested further analysis on the impact to 'non-average' customers, particularly those who will be more adversely impacted. | Our bill impact analysis only uses customer averages for those customers who will not see our network bill impacts under the Electricity Pricing Order.<br>We have presented de-identified bill impact analysis for every customer who will be affected by our price impacts. This is shown in sections 5.4 and 5.5 below for our affected LV and HV customers.<br>If the Electricity Pricing Order is reformed in future, we will perform more detailed bill impact analysis for other customers at that time and will work to manage any bill impacts in accordance with the NT NER requirements. |

# 4. Overview of proposed tariff classes, tariffs and structures

We have a simple approach to classifying customers with relatively few tariff classes and we propose to retain this approach and the same tariff classes for the 2024-29 TSS to avoid unnecessary transaction costs.

Taking customer and retailer feedback into consideration, we propose a suite of incremental changes to our suite of network tariffs. In summary, we propose to increase customer segmentation in our below 750 MWh smart metered customers (Tariff 3) to distinguish between residential and business customers, and better align with retail competition thresholds. We will also introduce new energy (KWh) time of use charges and revise our peak periods for smart meter customers.

We propose to remove peak demand charging (kVA charge) for small customers (<750 MWh pa) and narrow the peak demand charging window for those customers with a demand charge.

To further understand customer preferences and the impact to our network, we propose to trial two new export tariffs and rebates to help manage solar PV export levels.

## 4.1 Progress towards LRMC based pricing

We propose to continue to assign customers to cost reflective tariffs for new connections and existing customers that have their basic accumulation meter upgraded or replaced. As a result of this policy, the number of residential customers on a cost reflective tariff will continue to increase over the next five years.

If passed on by their retailer, our TOU and demand tariffs provide cost reflective signals to customers about how the timing of their energy use influences our network costs. This will allow customers to lower their bills by shifting some of their consumption to when network demand is low or solar energy is abundant. If our customers respond to these price signals, our network tariffs can also help us control the growth in our network costs.

The NT NER's pricing principles include a principle that distributors must base tariffs on LRMC, including consideration of times of greatest utilisation of the relevant part of the network and the extent to which costs vary between different locations. We have attempted to address the pricing principles through more cost reflective tariffs with targeted peak periods including tailoring the peak period in summer and winter. This will send stronger and more efficient conservation signals to customers, which should lead to efficient reductions in capital expenditure over the long term.

Our approach to designing tariffs and tariff structures involved analysing:

- The efficient, forward-looking costs of serving each tariff class on a stand-alone and avoidable basis.
- The additional costs likely to be associated with meeting demand at times of greatest utilisation of the relevant part of the distribution network.
- The total efficient costs of serving all customers.
- The bill impact, understandability and the manageability through usage changes of various tariff components and structures.

- The potential for different customer classes to have different sensitivity to price increases, including through the effects of the pricing order.

*Figure 4.1: Overview of proposed tariffs and structures for 2024-29*

| Tariff class | Tariff | Description | System Availability Charge (SAC) ($/NMI/Day) | Energy (KWH's) Anytime (24/7) | Energy (KWH's) Low Period | Energy (KWH's) Mid Period | Energy (KWH's) High Period | Peak Demand (KVA) On Season | Peak Demand (KVA) Off Season |
|---|---|---|---|---|---|---|---|---|---|
| LV<750MWh | 1 | Residential customers with accumulation meter | O | O | | | | | |
| | 2 | Non-residential customers with accumulation meter | O | O | | | | | |
| | 3a (new) | Residential with smart meter consuming 0-160 MWh pa | O | | O | O | O | | |
| | 3b (new) | Non-Residential with smart meter consuming 0-160 MWh pa | O | | O | O | O | | |
| | 3c (new) | All customers with smart meter consuming 160-750 MWh pa | O | | O | O | O | | |
| | 4 | All Unmetered | | O | | | | | |
| LV>750MWh | 5 | All LV customers consuming above 750MWh pa | O | O | | | | O | O |
| HV | 6 (revised) | All HV customers | O | O | | | | O | O |

Better segmentation of the contestable PO market

No segmentation of our HV

Time of day signals to support load shifting if PO is modified

Removed demand based on stakeholder feedback for some tariffs and modified the periods for others

## 4.2 Proposed network tariff classes

We are required under Clause 6.18.3(b) of the NT NER to group customers into tariff classes for the purpose of setting the prices of standard control services (and for the purpose of supply alternative control services). A tariff class must be constituted with regard to the:

- Need to group retail customers together on an economically efficient basis.
- Need to avoid unnecessary transaction costs.

Tariff classes are important because the efficient pricing bounds test and the side constraint are both applied at the tariff class level.

We have a simple approach to classifying customers, with relatively few tariff classes. We propose to retain this approach and same tariff classes for the 2024-29 TSS to avoid unnecessary transaction costs. In addition, customers have been grouped together, recognising the material differences between customers arising from:

- The pattern and level of network usage between smaller customers and larger customers, which have different usage patterns and average consumption.
- The pattern and level of network usage between residential customers and business customers, which have different usage patterns and average consumption.
- Whether or not they will be impacted by changes to network prices due to the Electricity Pricing Order (i.e. whether they use above or below 750 MWh pa).
- The nature of the plant or equipment required to provide the network access service, in the case of the high voltage (**HV**) tariff class, as these customers do not make use of the low voltage (**LV**) network or distribution substations.

Table 4.1 sets out our proposed tariff classes for standard control services, and the proposed tariffs that would apply to customers in each tariff class. In assessing the appropriateness of our tariff classes, we assessed our approach against our pricing objectives and the pricing principles. In particular:

- **Equity** – we have grouped our customers together based on shared characteristics. This ensures that similar customers pay similar prices.
- **Efficiency** – our tariff classes enable us to design tariffs that encourage efficient usage decisions by ensuring that our charges reflect the extent to which customers use the network. For example, large business customers who connect at high voltage levels do not use the low voltage network. Also, limiting the number of tariff classes reduces complexity.

We propose to retain our legacy flat tariffs (Tariff 1 and 2) for small customers with an accumulation meter connected to the LV network. Flat tariffs spread the recovery of residual costs equally across users in proportion to their consumption. These are required because not all NT customers will receive a smart meter replacement by 2029.[9]

*Table 4.1: Proposed network tariff classes*

| Tariff class | Tariff/s | Eligible customers |
|---|---|---|
| **LV less than 750 MWh pa** | 1: Residential Accumulation Meter | Residential customers consuming less than 750 MWh pa per NMI with standard accumulation meters |
| | 2: Non-Residential Accumulation Meter | Non-residential customers connected to the low voltage network consuming less than 750 MWh pa per NMI with standard accumulation meters |
| | 3a: LV Smart Meter Residential | Residential customers connected to the low voltage network with a smart meter consuming less than 160 MWh pa per NMI |
| | 3b: LV Smart Meter Non-Residential | Non-residential customers connected to the low voltage network with a smart meter consuming less than 160 MWh pa per NMI |
| | 3c. LV Smart Meter | Residential and non-residential customers connected to the low voltage network with a smart meter consuming above 160 MWh and less than 750 MWh pa per NMI |
| | 4: Unmetered | Unmetered supply (for street lighting, traffic lights and other unmetered devices) consuming less than 750 MWh pa<br>This tariff applies to streetlights, traffic lights, NBN nodes and security cameras which are connected directly to our network and do not have meters attached to record their usage. |
| **LV above 750MWh** | 5: LV Majors | Customers connected to the low voltage network consuming above 750 MWh pa per NMI |
| **HV** | 6: HV Smart Meters | Customers connected to the high voltage network |

9 Note that outcomes of the AEMC's 2022 metering review will not apply in the NT.

| Tariff class | Tariff/s | Eligible customers |
|---|---|---|
| | | |

## 4.3 Proposed network tariffs and charging parameters

Our customers in each tariff are subject to a range of different components to which a charge is applied. This includes a daily SAC, an energy charge (kWh), and a demand charge (kVA) for customers with smart meters. All our tariffs include an anytime energy charge and charged on a $/kWh basis, as measured by the customer's meter, with the exception of customers on the Unmetered Tariff. Customers on the Unmetered Tariff are charged an anytime energy charge on a $/kWh basis, using the device's assumed consumption.

Table 4.2 outlines the proposed charging parameters for each of our tariffs for the 2024-29 TSS. The main changes from the 2019-24 TSS include:

- Reducing the peak window by 15 hours per week and introducing a low and medium energy period for energy consumption.
- Introducing an 'on' and 'off' maximum demand seasons, in conjunction with a reduction in the peak charging window by five hours per week.
- Removing the seasonal demand (kVA) charge for smart metered customers consuming less than 750 MWh pa.
- Introducing three TOU energy periods and maintaining an anytime energy charge for the accumulation, major customers (greater than 750 MWh pa) and unmetered
- Simplifying our HV pricing to a single HV tariff.

*Table 4.2: Proposed network tariffs by charging parameter from 1 July 2024*

| Tariff | Tariff class description | Eligibility | Connection voltage (HV/LV) | System availability charge (SAC) ($/NMI/day) | Energy (kWh)* | | | | Peak demand (kVA)* | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Anytime (24/7) | Low period | Mid period | High period | On season | Off season |
| **1** | Residential Accumulation | All residential customers with accumulation metering | LV | ✓ | ✓ | | | | | |
| **2** | Non-Residential Accumulation | All non-residential customers with accumulation metering | LV | ✓ | ✓ | | | | | |
| **3a** | LV Smart Meter | Residential with smart metering consuming 0-160 MWh pa | LV | ✓ | | ✓ | ✓ | ✓ | | |
| **3b** | LV Smart Meter | Non-Residential with smart metering consuming 0-160 MWh pa | LV | ✓ | | ✓ | ✓ | ✓ | | |
| **3c** | LV Smart Meter | All customers with smart metering consuming 160-750 MWh pa | LV | ✓ | | ✓ | ✓ | ✓ | | |
| **4** | Unmetered | All Unmetered | LV | | ✓ | | | | | |
| **5** | LV Majors | All customers connected to the LV network consuming above 750MWh pa | LV | ✓ | ✓ | | | | ✓ | ✓ |
| **6** | HV Smart Meters | All customers connected to HV network | HV | ✓ | ✓ | | | | ✓ | ✓ |

## 4.4 Proposed changes to tariffs from 1 July 2024

Our starting point for tariff reform was to consider changes to our existing network tariffs where there was a clear need or feedback from our stakeholders for change. Where change is required to meet the challenges of the future, we have thought about the optimal pace of tariff reform based on the proportionality and immediacy of the issue.

One important change we are proposing for small to medium business customers, is a segmentation of the existing Tariff 3 to include new tariffs. In our Draft Plan we proposed a 100 MW threshold for the segmentation, but in response to feedback from retailers we are proposing a 160 MW threshold, and also further segmentation into residential and non-residential. We believe that these changes will help to support retail competition and future Electricity Pricing Order change.

*Table 4.3: Proposed changes to Tariff 3*

| Tariff | Tariff description | Consumption (MWhs pa) eligibility | Connection voltage (HV/LV) |
|---|---|---|---|
| **2** | Non-residential accumulation | All non-residential customers with accumulation metering | LV |
| **3a** | Residential LV smart meter | 0 – 160 MWhs | LV |
| **3b** | Non-Residential LV Smart Meter | 0- 160 MWh pa | LV |
| **3c** | LV Smart Meter | 160-750 MWh pa | LV |

For our major users connected to the high voltage network, we are proposing to combine our HV Minors (0-750 MWh) and HV Majors (750-10,000 MWhs) tariffs into one all-encompassing HV tariff regardless of consumption volumes. This is due to the small amount of customers in the HV category (67 in total), combining both tariffs places downward pressure on pricing for this customer class, by spreading cost across more NMI's.

*Table 4.4: Proposed changes to HV tariffs*

| Tariff | Tariff description | Consumption (MWhs pa) eligibility | Connection voltage (HV/LV) |
|---|---|---|---|
| **6** | H V Smart Meters | All HV customers | HV |

## 4.5 Tariff structures and parameters

The pricing principles require that our tariff structures be reasonably capable of being understood by retail customers assigned to that tariff. Our tariffs are simple and easy to understand (particularly when compared to other utilities). We have simple tariff structures with a flat rate anytime energy and single peak demand charge for each tariff (with no off-peak demand charging). Most other networks have significantly more tariff-types. We have also retained simplicity in our tariffs by not having a menu of opt-in tariffs, which helps reduce transaction costs and is unnecessary amid the Electricity Pricing Order retail pricing protections.

Cost reflective tariff structures can efficiently reduce the need for future network investment by encouraging customers to invest in energy solutions, and behave in ways that minimise network demand peaks or solar PV export peaks. Our network tariffs can be made up of at least two or more types of charging parameters. Customers on each tariff are subject to a range of different components to which a charge is applied. Not all tariffs have a peak or off-peak demand charge, but all tariffs do have an access charge (other than unmetered supplied in Tariff 4) and a volumetric (energy) charge.

- **System accessibility charge (SAC) (fixed)** - A daily supply charge that applies to all customers in dollars per day and is not impacted by how much electricity a customer uses. It is applied as a $/day/NMI.
- **Energy charge (variable)** - A charge for each unit of electricity consumed in cents per kilowatt hour (kWh). Depending on the tariff, it may be a one rate 'anytime' charge or it may vary with the time of day or year.
- **Peak demand charge (variable)** - This charge relates to a customer's maximum demand for electricity or their maximum electricity capacity requirement in dollars per kilovolt-ampere (kVA) electricity.

*Figure 4.2: Tariff charging parameters*

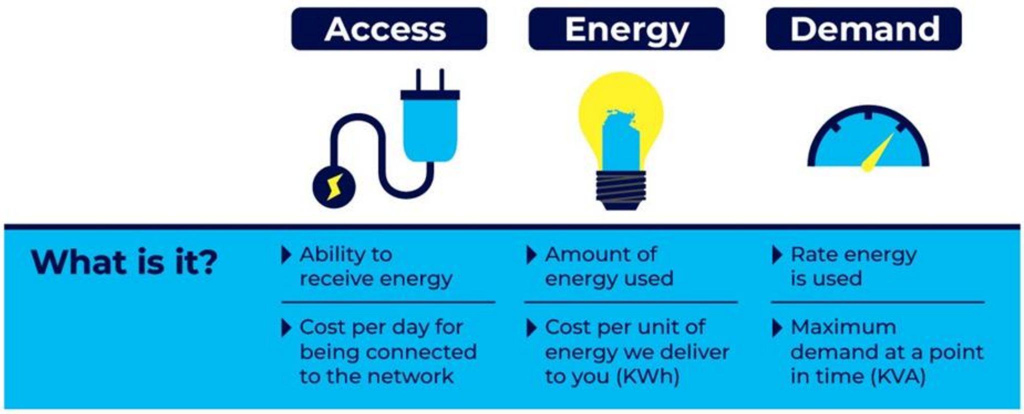



Figure 4.5 outlines the proposed charging parameters and the reasons supporting the proposed changes. The main changes from the 2019-24 TSS include:

- Reducing the peak charging window by 15 hours per week and introducing a low and medium energy period for energy consumption.
- Introducing an 'on' and 'off' maximum demand seasons, in conjunction with a reduction in the peak charging window by 15 hours per week.
- Removing the seasonal demand (kVA) charge for smart metered customers consuming less than 750 MWh pa.
- Introducing three TOU energy periods and maintaining an anytime energy charge for the accumulation, major customers (greater than 750 MWh pa) and unmetered.

*Table 4.5: Overview of tariff parameters and reason for change*

| Tariff structure | Parameter details 2019-24 | Parameter details 2024-29 | Reason for change |
|---|---|---|---|
| **Demand On Season**<br>**Peak period (kVA)** | **LV less than 750 MWh pa** – Measured as maximum demand (kVA per month) in the peak window (12:00-21:00) Monday to Friday (including public holidays). Charged Seasonally between 1 October and 31 March)<br>**LV greater than 750 MWh pa and HV**<br>Measured as maximum demand (kVA per month) in the peak window (12:00-21:00) Monday to Friday (including public holidays). Charged Seasonally annually | **LV less than 750 MWh pa** –<br>All Demand (kVA) charging removed for customers consuming below 750 MWh pa, replaced with TOU energy charges<br>**LV greater than 750 MWh pa and HV**<br>3pm to 9pm Monday to Friday (including public Holidays) from 01 October to 31 March | Feedback received through stakeholder and market participant engagement showed a strong preference to move away from demand charging for customers currently under the Electricity Pricing Order protection, with a preference to adopt TOU energy charges instead.<br>Our refined charging windows and seasonality reflect analysis from our expert advisors Energeia provided at Energeia's Analysis of the Period of Greatest Network Utilisation by Loads and Exports–Final Report, provided as Attachment 11.04 to our Initial Regulatory Proposal |
| **Demand Off Season**<br>**Peak period (kVA)** | **LV less than 750 MWh pa** – Measured as maximum demand (kVA per month) in the peak window (12:00-21:00) Monday to Friday (including public holidays). Charged Seasonally between 1 October and 31 March)<br>**LV greater than 750 MWh pa and HV**<br>Measured as maximum demand (kVA per month) in the peak window (12:00-21:00) Monday to Friday (including public holidays). Charged Seasonally annually | **LV less than 750 MWh pa** –<br>All Demand (kVA) charging removed for customers consuming below 750MWh pa, replaced with TOU energy charges<br>**LV greater than 750 MWh pa and HV**<br>3pm to 9pm Monday to Friday (including public holidays) from 01 April to 30 September | Feedback received through major customer engagement showed a preference to retain annual demand charges over seasonal demand charge. This would help to reduce potential price shock of a seasonal only charge and continue to send the correct pricing signal to major users. |

| Tariff structure | Parameter details 2019-24 | Parameter details 2024-29 | Reason for change |
|---|---|---|---|
| **Energy / Consumption**<br>**Low period (kWh)** | Not applicable | 9am to 3pm Monday to Sunday, all year | Feedback received through all levels of customer and stakeholder engagement supported the move to TOU energy over seasonal demand.<br>Analysis of the expected future cost implications of system minimum demand performed for our future networks business case. |
| **Energy / Consumption**<br>**Mid period (kWh)** | Not applicable | 3pm to 9am Monday to Sunday from 01 April to 30 September, and<br>9pm to 9am Monday top Sunday from 01 October to 31 March | Customers stated that TOU energy signals would be easier to respond to if the NTG was to amend the Electricity Pricing Order to allow these signals top flow through. |
| **Energy / Consumption**<br>**High period (kWh)** | Not applicable | 3pm to 9pm Monday to Friday (including public holidays) from 01 October to 31 March | A targeted window for recovering our LRMC from Tariff 3 smart meter customers. |
| **Anytime Energy (kWh)** | 24 hour a day, 7 days a week, is a flat rate (cents/kWh) that applies all day every day | **Unmetered, LV greater than 750MWh pa and HV only**<br>24 hour a day, 7 days a week, is a flat rate (cents/kWh) that applies all day every day | Anytime is the only option available for Tariffs 1, 2 and 4 due to the metering associated with these tariffs.<br>For Tariffs 5 and 6, the anytime charge is an important means of recovering our residual costs in a manner that is predictable and stable for these large customers, consistent with their stated preferences in our engagement with them. |

### 4.5.1 Time of use energy tariffs

TOU energy tariffs apply different charges to electricity consumption, in kWh, at different times of the day, week, and year and are generally considered easy to understand. The different parameters of the time of use tariffs may include:

- **Peak** – timed to correspond with the parts of the day most likely to see demand approach system or zonal capacity constraints.
- **Off-peak** – timed to correspond with the parts of the day least likely to see demand approach system or zonal capacity constraints, and in some cases.

For customers with smart meters, we are looking to move away from a demand tariff to TOU network tariffs. This would only apply to customers with smart meters consuming below 750 MWh pa, as accumulation meters do not provide this level of data. Customers are generally familiar with distributors charging them based on how much electricity they consume. We consider our customers will be able to understand TOU energy tariffs. Our customer panel sessions confirmed this, whilst noting the ongoing importance of customer education. We also note that TOU energy tariffs can be relatively efficient, in that peak consumption is correlated with user demand during coincidental peaks.

Our proposed changes include tightening the peak period to align with the time and seasons when our network experiences the highest demand. We also see the need to provide the right incentives for customers to use more energy in the middle of the day to manage when there is a significant decline in demand.

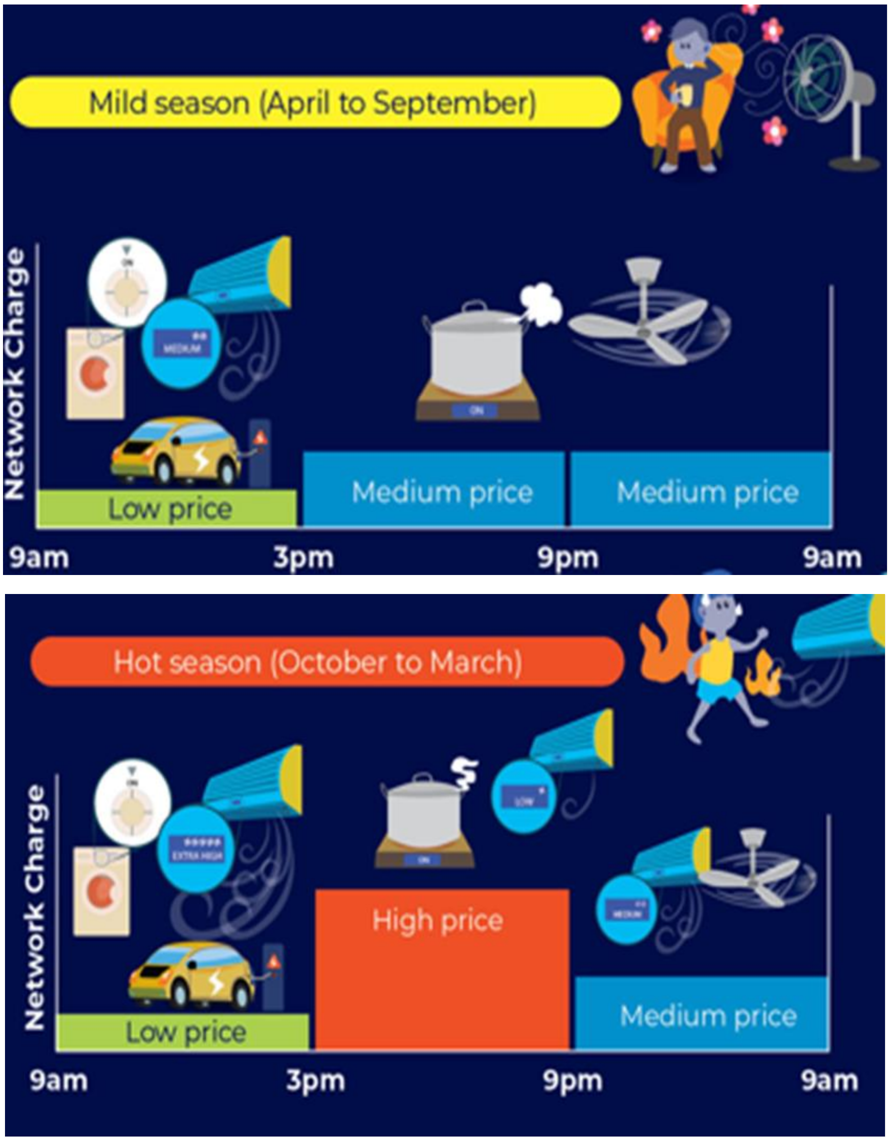
The right signals from network tariffs could incentivise customers to use more of their own solar, rather than exporting into the grid during those periods of high export demand. Additional demand in the middle of the day would also help increase load on minimum demand days. Both measures would help us lift constraints on solar exports.

We plan to include a greater distinction between peak and off-peak periods through the energy charge that will replace the 'anytime' charge for customers consuming less than 750 MWh pa. The anytime energy period remains for our largest customers consuming above 750 MWh pa or connected to our HV network. This change is intended to reflect when the network is experiencing peak demand in the evening, and when there is ample capacity to meet demand in the middle of the day.

Figure 4.3 below shows the proposed time of use charging parameters. The different periods for charging energy are proposed to be:

- High period (Peak) period: From 1 October to 31 March weekdays, between 3pm and 9pm.
- Medium (Off-peak) period: From 1 April to 30 September Monday to Sunday between 3pm to 9am and from 1 October to 31 March Monday to Sunday between 9pm to 9am.
- Low (Super off-peak) period: Every day of the year between 9am and 3pm.
- Anytime Energy period: 24 hour a day, 7 days a week all year round.

*Figure 4.3: Seasonal time of use pricing parameters*




### 4.5.2 Demand charge parameters

We currently apply a demand charge to all customers with a smart meter. For the new segment of customers with a smart meter consuming less than 750 MWh pa, we are proposing not applying a demand charge and only applying energy consumption charges.

During our engagement with retailers, the feedback received was that they didn't want seasonal charges. However, this view was contradicted by our major customers who said they just wanted certainty in the structure and were happy to have seasonal charges if it helped to reduce costs overall.

For our major customers, those consuming above 750 MWh pa or connected to the HV network, we will continue to apply an annual peak demand charge. However, this charge will be applied as an 'on' season, from 1 October to 31 March, and an 'off' season from 1 April to 30 September each year. For both seasonal periods, the demand charge will apply from 3pm to 9pm Monday to Friday.

The introduction of the two seasons allows us to better manage customer impacts, smoothing the 'on' season rate, by recovering during the 'off' season. This is important for customers who are not covered by the Electricity Pricing Order.

In addition to the feedback on seasonality, we are proposing to move away from the rolling average demand and will return to peak maximum demand. Retailers felt that demand charges are already a hard concept to explain without the added complexity of a rolling peak average. This position was also confirmed as our billing system vendor informed us that to introduce the rolling average demand concept would be extremely expensive and difficult to build into our billing systems.

### 4.5.3 Charging periods and rates

In the 2019-24 period, we applied a peak demand window of 12pm to 9pm on weekdays. For our larger customers (consuming above 750 MWh pa) this window applied all year round, while for our smaller customers it only applied seasonally, between 1 October and 31 March each year.

For the 2024-29 period, we are narrowing the peak period to send clearer signals to customers on when to conserve electricity and send a sharper signal on the drivers of future costs of our network. This reflects our analysis that shows our peak demand is continuing to shift further into the evening, when the network cannot rely on solar to help meet underlying demand and also reflects our desire to have the super off-peak period cover the window of system minimum demand. In assessing the peak period window, we also decided not to overly narrow the period due to the variability of when the peak demand occurs across the different locations of our regulated networks.

As part of this change, we also plan to apply these revised peak windows to the energy (kWh) component of our tariffs. This applies to those customers protected by the Electricity Pricing Order, as well as demand (kVA) component for the major customers.

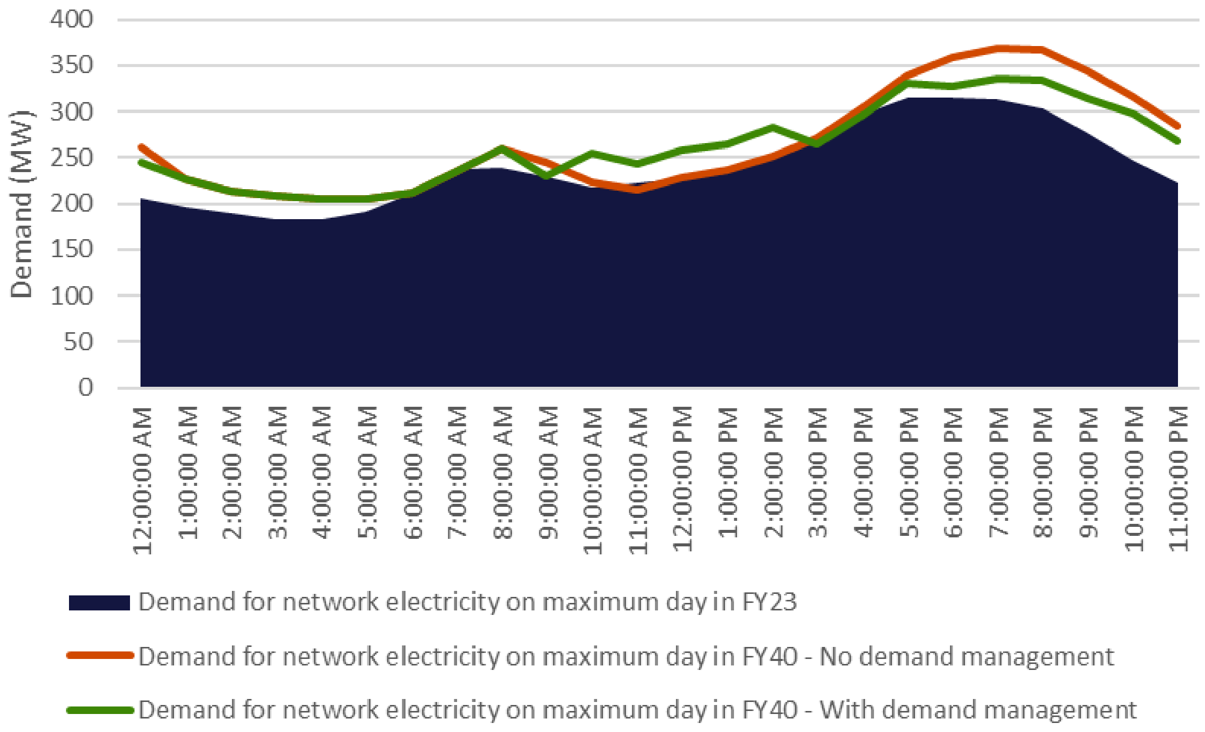
### 4.5.4 Why we chose 3-9pm peak period charging window

In the 2019-24 period, we applied a peak demand window of 12pm to 9pm on weekdays. For our larger customers (consuming above 750 MWh pa) this window applied all year round, while for our smaller customers it only applied seasonally, between 1 October and 31 March each year.

For the 2024-29 period, we are narrowing the peak period window. This window reflects our analysis (refer to Figure 4.4) that shows that our peak demand is shifting to the evening when the network cannot rely on solar to help meet underlying demand.

We have decided not to overly narrow the time period due to the variability of when the peak demand occurs at different locations of our network. As part of this change, we also plan to include a greater distinction between off-peak periods.

*Figure 4.4: Peak demand window*




The 3-9pm peak window will provide solar PV and battery customers improved incentives to:

- Install west facing solar panels.
- Charge batteries before 3pm and discharge after 3pm.

### 4.5.5 Why we have removed the initially proposed anytime super users tariff

Our initial TSS proposed to separate our HV tariff class customers into two tariffs:

- Tariff 6 for HV customers consuming 0-10,000 MWh pa, which the draft decision accepted, and
- Tariff 7 for HV customers consuming above 10,000 MWh pa, which the draft decision did not accept.

We proposed introducing a super users tariff (Tariff 7) with a flat anytime energy tariff for our 13 largest users. This proposal sought to recognise that the marginal cost of capacity provision to our HV-connected super users are accounted for in their individual network connection charges and corresponding connection agreements.

Consequently, these customers effectively have a booked capacity right via their connection terms. If they exceed this level of capacity, their ongoing Network Connection and Supply Arrangements includes provision for payment for the consequent network costs, and in extreme circumstances we may choose to isolate the customer from the network.

We considered that these arrangements mean that we do not need to further levy a peak demand or time of use energy charge on these customers, because the efficient network capacity utilisation is achieved via their connection terms.

The AER's draft decision considered the proposed anytime tariff is not compliant with the pricing principles because it is not based on LRMC. The AER considered that we had not sufficiently established there are no shared network assets upstream impacted by these customers, or that the customers have already fully paid for their capacity through connection charges.

Our revised TSS proposal does not propose a Tariff 7. We propose to instead adopt the approved Tariff 6 as a single tariff applicable to all customers in our HV tariff class. Our reasoning for this is that:

- Adding an LRMC charging parameter to Tariff 7 would involve adding demand charges that replicate the Tariff 6 structure anyway.
- Having two HV tariffs with identical structures:
  - would not achieve our original intent of Tariff 7; and
  - would not support the NT NER rule 6.18.3(d)(2) requirement that our HV tariff class be constituted with regard to the need to avoid unnecessary transaction costs, because there would be no gain from the transaction costs of establishing a second identically structured tariff within that HV tariff class.
- Our largest retail customer, Jacana, submitted to the AER on our initial TSS proposal stating that '*As there are only a handful of customers that would fall into the super user tariff category, Jacana Energy is of the view that creating new tariff structures and potentially new contracts only for these customers will be inefficient*.'[10]
- no other stakeholders submitted in support of introducing Tariff 7.

We tested the customer bill impacts of this change as shown in section 5.5.

## 4.6 Recovery of residual costs

Our LRMC driven costs and associated charging parameters are not sufficient to recover our total efficient costs. This is because our allowed total efficient costs include the recovery of both variable or growth costs (called marginal costs) *and* our fixed costs, which, together, allow us to recover our average costs.

We have a lot of fixed costs in providing network services. This means we have to recover residual costs (the difference between marginal costs and our allowed revenues determined by the AER). We seek to set our tariffs to recover residual costs in a way that:

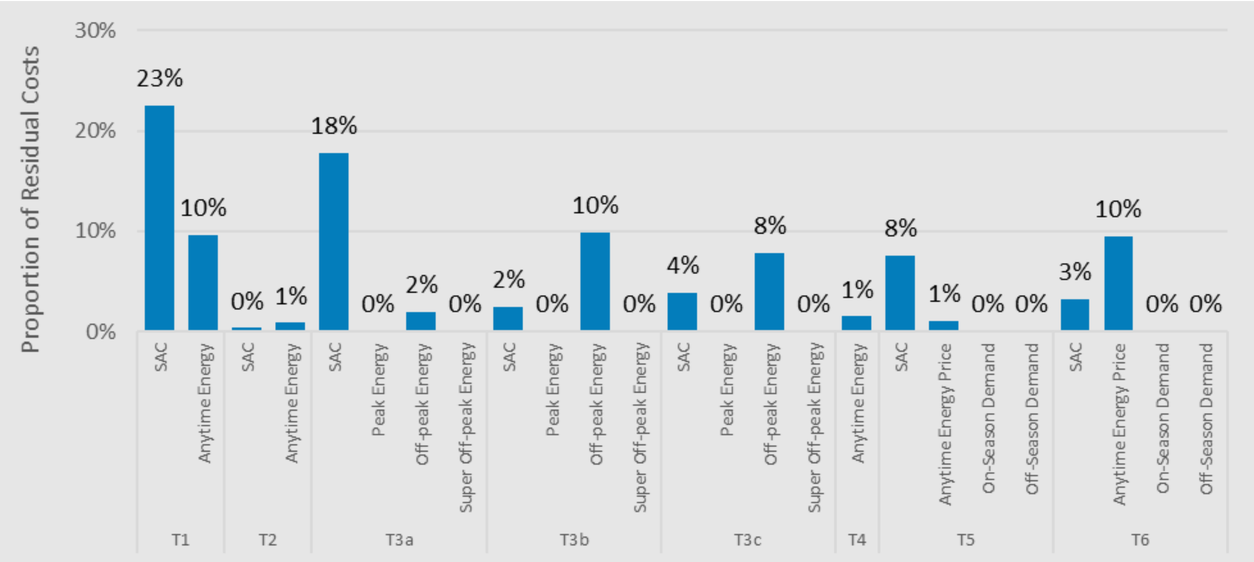
- Minimises distortions to efficient price signals, by aiming to keep demand tariffs in line with our LRMC estimates.
- Preferences residual cost recovery through the fixed daily system access charge where this can be done while managing bill impacts and seeks to reduce reliance on energy consumption charges.
- Considers the impact of residual costs on customer bills, and whether these bill impacts will distort usage decisions (including whether the Electricity Pricing Order will prevent bill impacts).
- Seeks to minimise bill impacts associated with tariff reassignments following installation of a smart meter to replace an accumulation meter.

10 Jacana, Review of AER Issues Paper: PWC Electricity Distribution Determination 1 July 2024 – 30 June 2029 Jacana Energy Responses, p.10.

We have given effect to this tariff setting approach in our proposed indicative tariffs for 2024-25 (the first year of the next period). This means further rebalancing within the regulatory period will be minimal and arise mainly through managing the adjustments for under and over recoveries under the revenue cap in a manner that manages customer bill impacts.

Recovery of our residual costs across our tariffs and tariff charging parameters in 2024-25 is shown in Figure 4.5. The relative shares of our residual costs from different tariffs are in line with the relative shares of our customer base on each tariff.

*Figure 4.5: Residual cost recovery shares by tariff and tariff charging parameters in 2024-25*



# 5. Customer and bill impacts

We must consider the impact of proposed tariffs on customers, and to vary tariffs when reasonably necessary. The NT NER also requires that tariffs be reasonably capable of being understood by customers.

We are mindful that we are presenting our expenditure forecasts and proposed revenue requirements at a time when the cost of living is rising due to a range of factors and as such, managing the network bill impacts for customers across the NT is extremely important, even if the majority of our customers are protected by the Electricity Pricing Order.

## 5.1 Overview

For most of our customers, changes in our tariffs currently have no impact on their retail bills. This is because electricity retail prices charged to residential and commercial customers (those consuming less than 750 MWh pa) are regulated by the NT Government through the Electricity Pricing Order made by the Treasurer under the *Electricity Reform Act 2000.*

Table 5.1 demonstrates the impact to average customers across each tariff, noting that the average price changes may vary for each customer, depending on their consumption level.

The following sections of the Explanatory Statement outline our assessment of the impacts of our proposed tariffs on customers, their ability to choose and/or mitigate these impacts, and the results of our investigation into whether they are reasonably able to be understood. It is important to note that our distribution costs are only one component of customers' electricity bills. Customers' bills also recover the costs of electricity generation and transmission, as well as retail and environmental scheme costs.

*Table 5.1: Movement in customers' network bills 2023-24 to 2024-25 (excluding GST, nominal)*

| Tariff | Description | 2024/25 (Year 1) NMIs | 2028/29 (Year 5) NMIs | Consumption | Demand | Network bill ($) 2023/24 | Network bill ($) 2024/25 | Network bill impact $ | Network bill impact % | Network component of residential bill[1] | Increase in total retail invoice[2] |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **1** | Residential accumulation | 41,039 | 35,461 | 8,500 | 0 | 1,053 | 1,232 | 179 | 17% | 52% | EPO[3] |
| **2** | Non-residential accumulation | 1,883 | 0 | 30,000 | 0 | 2,967 | 2,850 | -118 | -4% | 31% | EPO[3] |
| **3a** | Residential 0-160MWh | 32,776 | 39,357 | 8,500 | 20 | 1,254 | 1,231 | -23 | -2% | 52% | EPO[3] |
| **3b** | Non-residential 0-160MWh | 9,315 | 11,185 | 30,000 | 150 | 4,242 | 2,849 | -1,393 | -33% | 31% | EPO[3] |
| **3c** | Smart meter 160-750MWh | 846 | 1,015 | 250,000 | 500 | 14,232 | 24,401 | 10,169 | 71% | 33% | EPO[3] |
| **5** | LV >750MWh | 158 | 160 | 3,200,000 | 6,675 | 159,396 | 174,043 | 14,647 | 9% | 19% | 2% |
| **6** | HV smart meters | 67 | 68 | 5,400,000 | 6,850 | 182,150 | 231,317 | 49,167 | 27% | 16% | 4% |

Notes:

(1) Based on the network component of retail invoices issued in September 2023.

(2) Electricity Pricing Order (EPO) increase in the total retail bill will be determined by adjustments made to the EPO by the NT Government. Previously the NT Government have capped prices at no more than CPI. Last year the increase was set at 2.7 per cent despite CPI being 6 per cent.

(3) Major customer impact has been assessed by using retail invoices issued in September 2023.

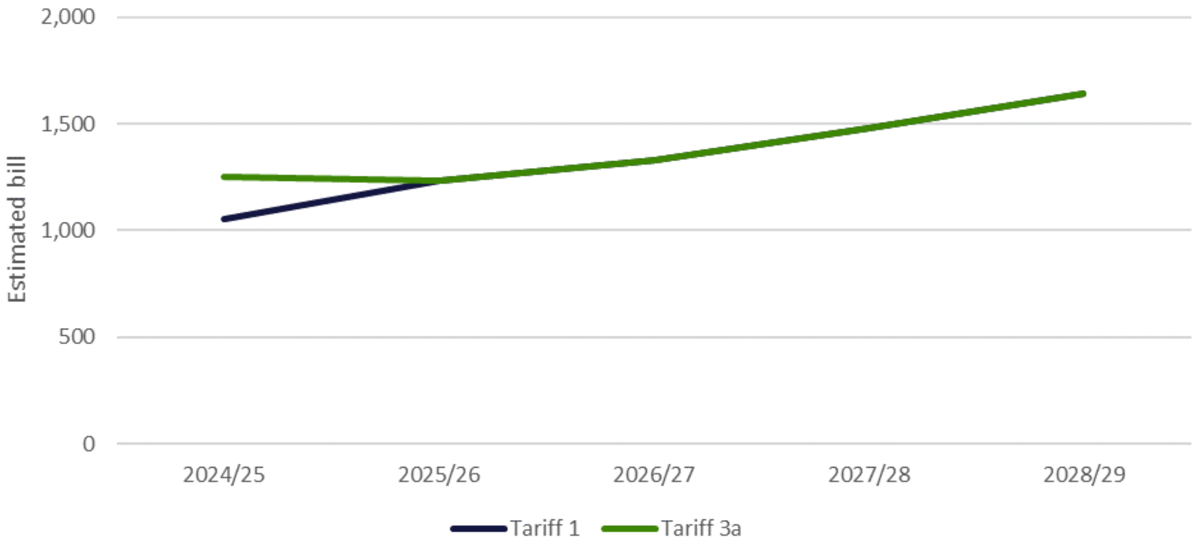
(4) Tariff 4 impacts are not able to be provided due to the large variation in unmetered loads connected to the electricity grid, as well as the pricing segmentation of unmetered loads in the Northern Territory's Electricity Pricing Order

## 5.2 Residential customers

In 2023, we had approximately 47,000 residential customers on Tariff 1, compared to approximately 27,000 residential customers with a smart meter assigned to Tariff 3. However, it is anticipated that by the end of the next regulatory period (2029) no customers will be on Tariff 1 or Tariff 2.

Figure 5.1 shows that if we were to assign customers currently on Tariff 1 to a more cost reflective Tariff 3a, the bill impact would be minimal. We have deliberately attempted to minimise bill change and impact to residential customers as they transition to cost reflective tariffs upon receipt of a smart meter.

*Figure 5.1: Residential customer bill impact analysis of Tariff 1 vs 3a ($ per year, nominal)*

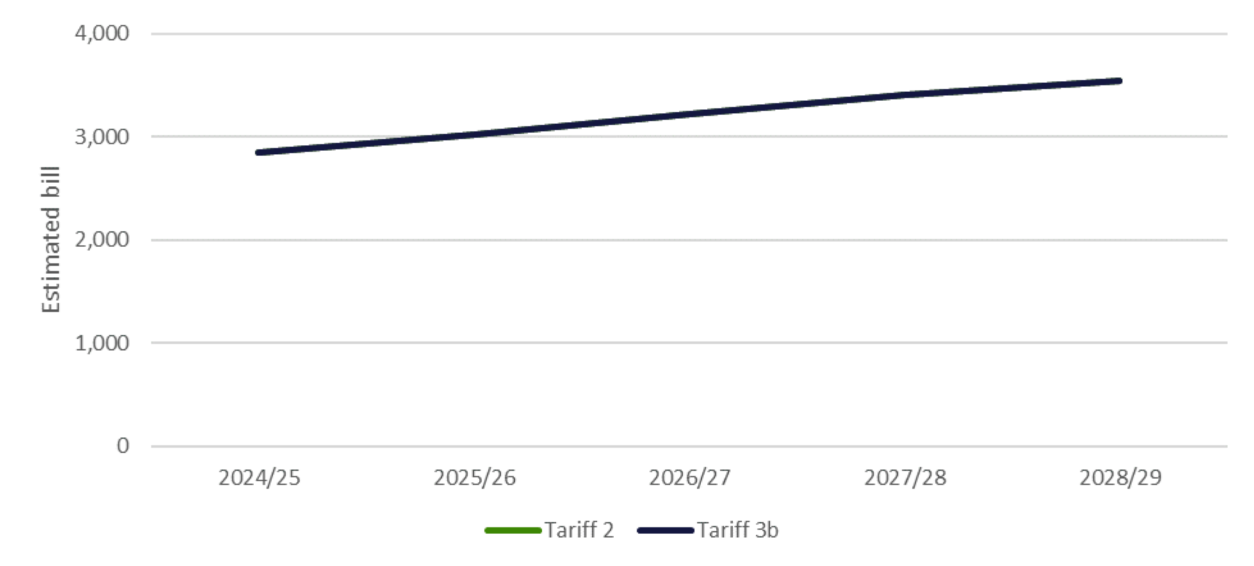



## 5.3 Small business customers

In 2023, we had approximately 7,350 non-residential customers on Tariff 2, compared to approximately 3,300 non-residential customers with a smart meter assigned to Tariff 3. However, it is anticipated that by the end of the next regulatory period (2029) there will no longer be any non-residential customers on Tariff 2 compared to 11,100 on Tariff 3b.

Figure 5.2 shows the bill impact to small non-residential customers on Tariff 2 compared to a cost reflective Tariff 3b. The two lines in this figure overlap because we have worked to align the customer bills under an accumulation meter tariff and smart meter TOU tariff to avoid bill shock when customers receive a smart meter.

*Figure 5.2: Business customer bill impact analysis of Tariff 2 vs 3b ($ per year, nominal)*

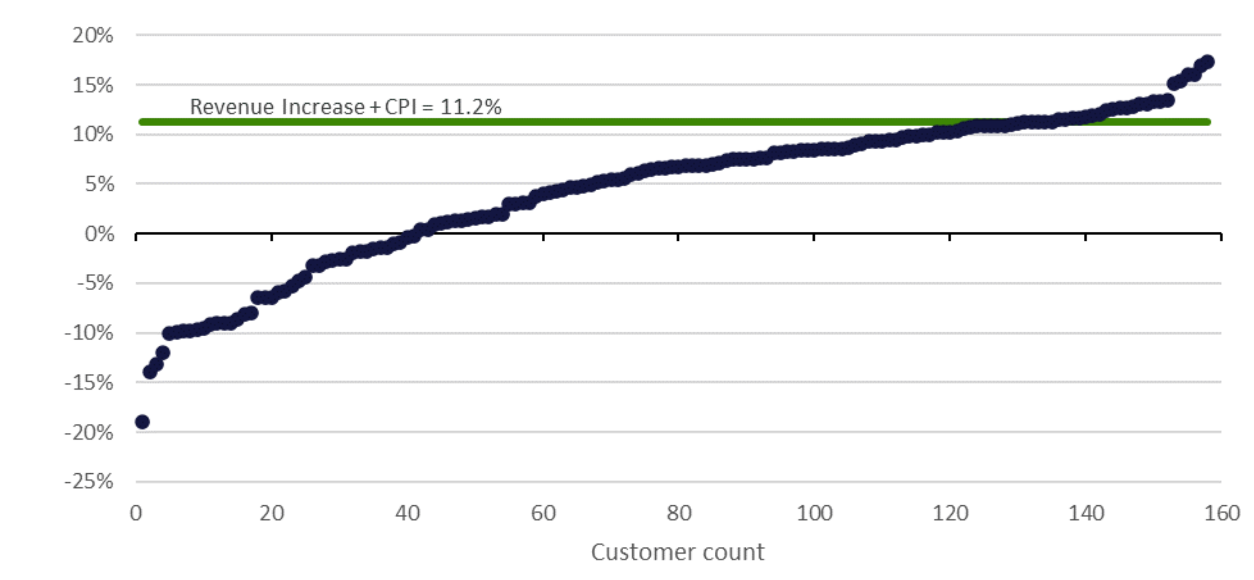



Note: Tariff 2 will cease to be needed when all business customers have a smart meter.

## 5.4 LV major connected customers

In 2023, there are currently approximately 160 customers assigned to Tariff 5. Figure 5.3 shows the anticipated bill impact to these customers

*Figure 5.3: Tariff 5 LV >750 MWh pa - Bill impact analysis (nominal)*




## 5.5 HV connected customers

In 2023, there are approximately 32 customers assigned to Tariff 6 and 35 to Tariff 7. By the end of the next regulatory period, this is anticipated be approximately 70 customers in total. Figure 5.4 shows the impact of all HV customers as they will now all be on the newly structured Tariff 6, while Figure 5.5 shows the bill impacts for those few customers that were part of Tariff 7 Super User group in our initial TSS proposal.

*Figure 5.4: Tariff 6 All HV Smart meters – Bill impact analysis (nominal)*

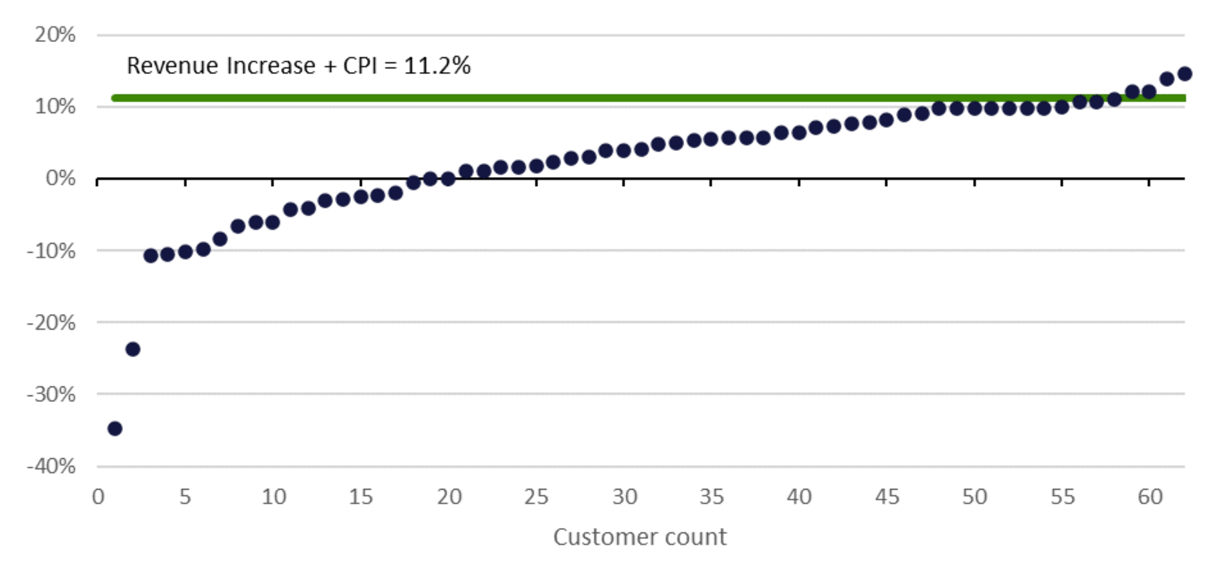
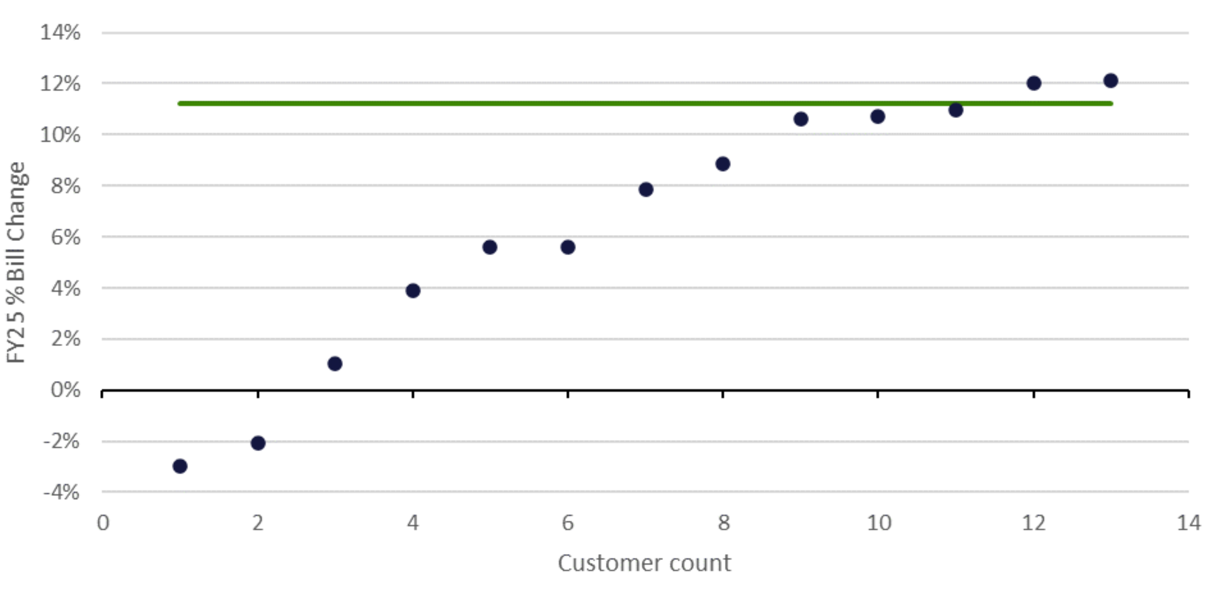



*Figure 5.5: Initially proposed Tariff 7 Super Users - Bill impact analysis on revised Tariff 6 assignment proposal (nominal)*



# 6. Export tariff transition strategy

Our unique circumstances in the NT with the Electricity Pricing Order currently shielding the majority of customers from the network component of their invoice, means that we cannot assume any behavioural response from tariff designs for most customers. Indeed, our largest NT retailer recommended we adopt more simplistic network tariff structures that mirror the Electricity Pricing Order. We therefore propose to collaborate with NT retailers and NT Government to design targeted trials.

## 6.1 Overview

We propose to trial two-way export tariffs during the 2024-29 regulatory period. Distributors not proposing to introduce two-way pricing for an upcoming regulatory control period are still required by the NT NER to provide an export tariff transition strategy to signal their future intentions. The purpose of this chapter is to describe:

- Our medium to longer-term strategy for introducing two-way pricing, including our planned export tariff trials.
- The forecast network demand, constraints, relationship and role that network tariffs have in addressing such constraints and improving utilisation.
- Our proposed methodology for calculating basic export limits and hosting capacity.

## 6.2 Future network strategy

Our customers have been at the forefront of the shift to renewables. In 2021, about 10 per cent of all energy consumption came from our customers' solar panels. More recently, we have seen large scale solar farms connect to our network. We expect rapid growth in the uptake of both small scale and large scale solar within the next ten years as the NT transitions its energy system.

We anticipate that in the near future, this transition will expand to include batteries, microgrids and EV charging. Customer reliance on electricity is likely to rise and rapidly accelerate over the next decade – driven by decarbonisation policies set by Government – resulting in a combination of increased rooftop solar, the uptake of household batteries, network digitalisation, and vehicle electrification.

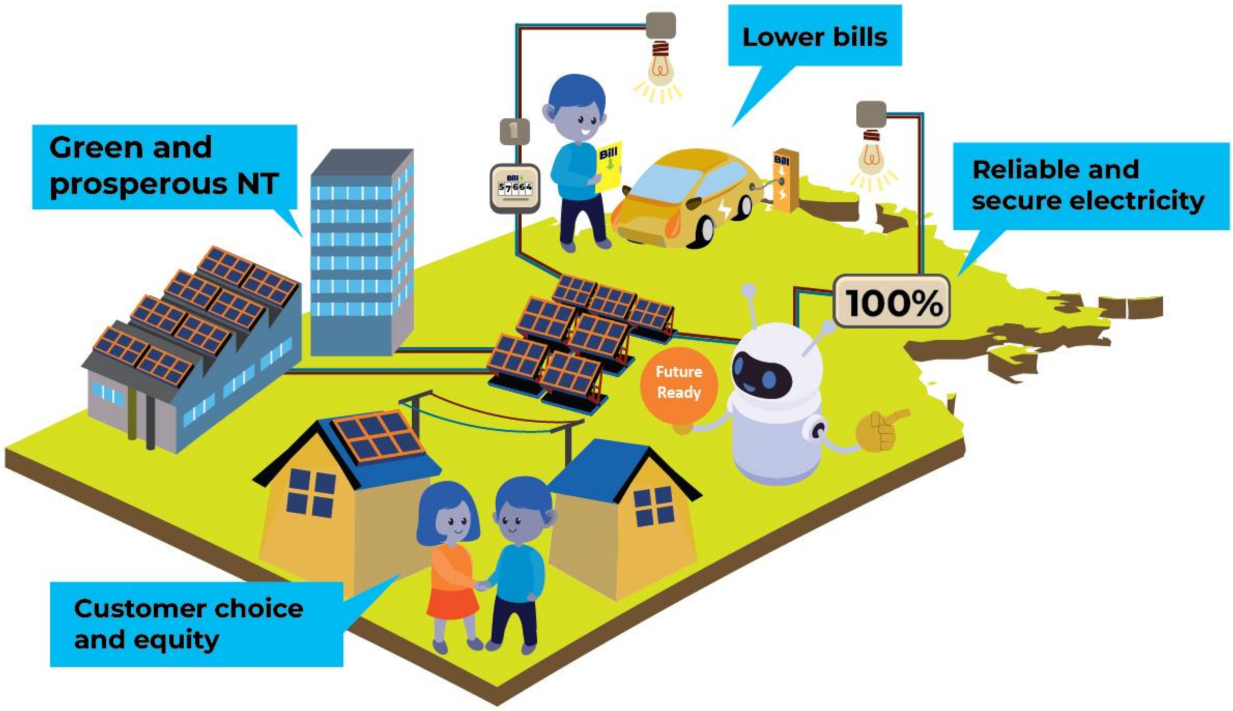
Our future network strategy identifies the potential benefits from unlocking renewables in the NT. Our future network strategy is directed at unlocking the following benefits:

- **Lower bills** – Analysis in the Darwin-Katherine Electricity System Plan[11] demonstrated renewable generation is significantly cheaper than emissions generation, providing opportunities to reduce wholesale costs.
- **A greener and more productive NT** – Clean energy not only helps the environment but also has the potential to unlock economic benefits in the NT, particularly our export markets that will increasingly need to demonstrate that products have minimised emissions.

[11] https://territoryrenewableenergy.nt.gov.au/strategies-and-plans/electricity-system-plans

- **Reliable and secure electricity** – Enabling rooftop solar PV to continue to connect, without compromising system security and power quality.
- **Customer choice and equity** – Facilitating renewables opens up the possibility of our customers earning a return on renewable investments. Further we see that there may be opportunities for lower income households to improve their situation through improved access to solar and energy efficiency.

*Figure 6.1: Objectives of the future network strategy*




There are significant engineering challenges for our network and power system to enable these benefits. The emerging challenge for our network is how to ensure the system remains secure on minimum demand days. Our analysis shows that rooftop solar will grow significantly by 2030 and will present a minimum demand challenge in the 2024-29 regulatory period. In the absence of investment, we would need to constrain new customers from exporting onto the network. There is benefit in investing in a solution (dynamic operating envelope) that can communicate to rooftop solar systems when the system is reaching a security threshold. This would enable us to allow customers to export solar at all other times, except for the limited periods when the system is facing a constraint.

The core of our future network strategy has been finding solutions that unlock small scale renewables at low cost, where we can demonstrate a net economic benefit to customers. Key strategies that draw on our customer preferences include increasing solar exports by getting a better understanding of the voltage and thermal limits on the distribution network and storing solar energy in home and community batteries for discharge in the peak evening periods.

Tariffs will play an integral role in both improving utilisation of the network and energy system, but also in providing additional incentives for customers to export when there is sufficient capacity on the network.

Setting tariff structures, levels and assignment policies that are compliant to the NT NER requires an understanding of our forecast network usage and congestion patterns, which in turn requires an understanding of growth in peak and minimum demand.

We expect demand to significantly increase over the next 20 years. The NT Government predicts our population will increase by more than 30 per cent by 2040. In addition, we will need to provide electricity to major industrial customers locating to the Territory.

EVs will also heavily impact demand for energy with each electric car adding approximately 30 per cent more consumption for a typical household. This provides our network with an opportunity to increase our scale and pass on lower costs to our customers through better utilisation of the network.

Our strategic priority is to provide customers with the right information and incentives to shift energy consumption to off-peak periods. Our five-year plan includes initiatives to improve our network tariff structures so they provide customers with price signals that reflect our future costs. This includes lower prices in off-peak periods during the day when low cost solar is available and when there is significant load capacity on our network.

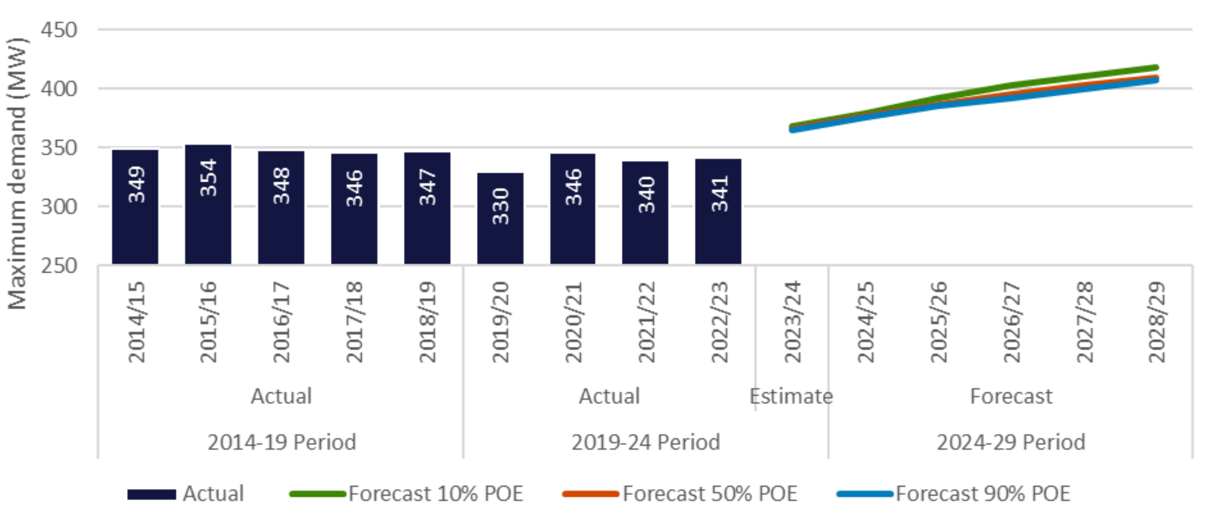
## 6.3 Impact of demand

### 6.3.1 Peak demand

Peak demand growth across our network has been relatively flat over the last decade. We forecast that peak demand could increase significantly after 2030 due to increasing growth in the NT and higher penetration of EVs. Our longer-term strategy is to encourage customers to use energy when there is spare capacity on our network in the daytime through more efficient tariff structures.

Due to the extreme heat, demand for electricity is highest in the middle of the day in the October to April period. Over the next decade, we are forecasting a significant increase in peak demand. We are seeing a significant increase in spot loads from residential and commercial developments, particularly in Darwin as seen in Figure 6.1. Our 2024-29 forecasts have assessed the impact of rising peak demand at a local level. In some cases, we are seeing high rates of growth in pockets of our networks that exceed the capacity of the network.

*Figure 6.1: Maximum demand forecasts across our three networks*




Note: the maximum demand sums the maximum demand on each of the Darwin-Katherine, Alice Springs and Tennant Creek networks. This may differ from the system wide maximum demand.

Figure 6.2 shows the underlying energy demand compared to demand delivered by the network on the maximum day in the Darwin-Katherine electricity system in 2020-21. Increasing solar will not help curb peak demand over the next 20 years now that peak demand has shifted to the evening.

*Figure 6.2: Maximum demand day profile Darwin-Katherine Network (MW)*

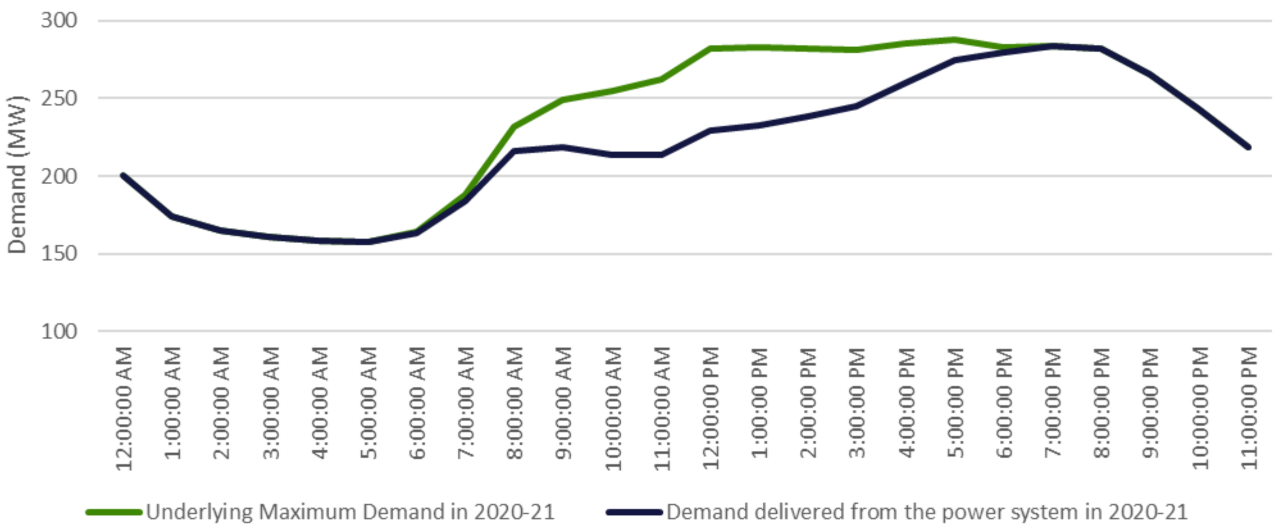
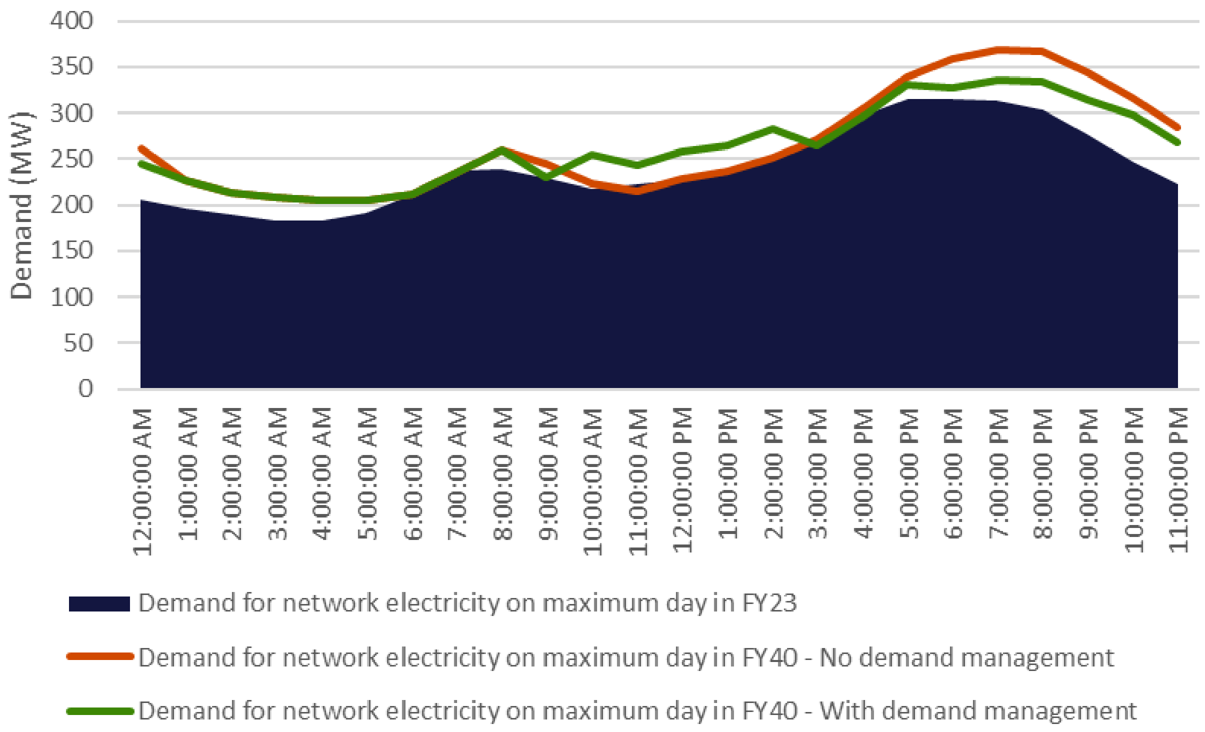



Figure 6.3 shows there was a sharp peak in the evening period on the day of highest demand in the Darwin-Katherine network in 2020-21. In contrast, demand for our network service is minimal in the day when many of our customers are using their solar panels to provide their electricity.

We undertook analysis on how peak demand would change by 2040 under a scenario where there was a 30 per cent increase in underlying demand, a doubling of solar capacity and no change in underlying daily demand patterns. The orange line shows that peak demand would significantly increase to 370 MW by 2040. This would require significant new investment to meet the demand. At the same time, demand in the middle of the day would not have significantly increased due to customers using their own solar to power homes.

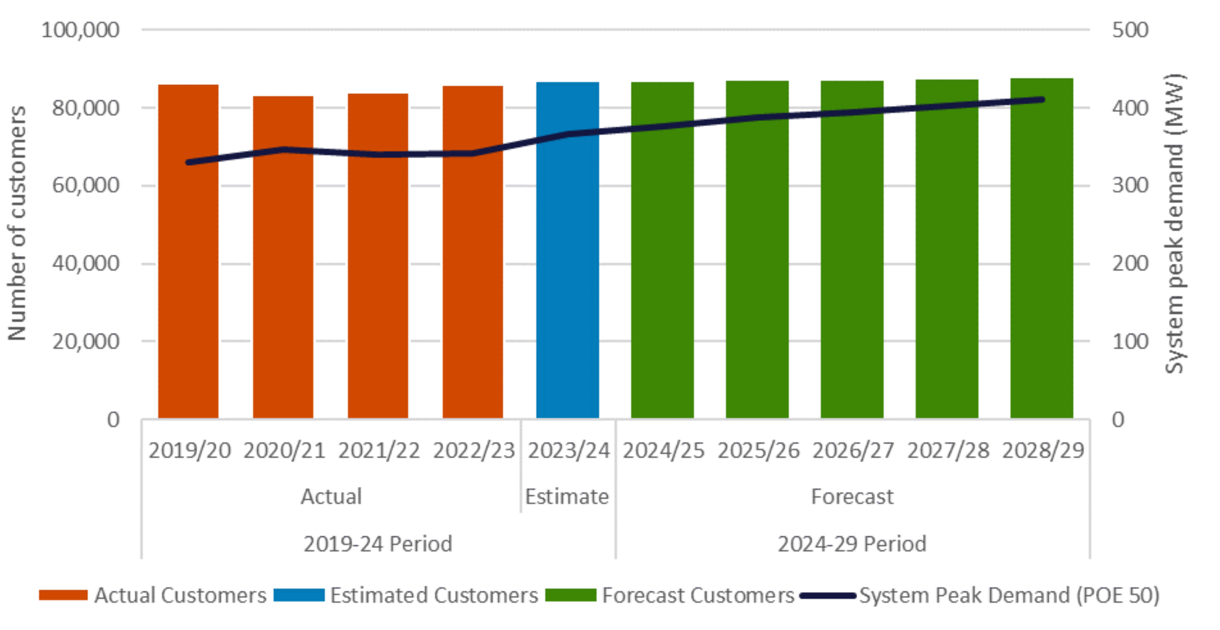
Alternatively, if about 10 per cent of energy at peak times is shifted to the middle of the day, we see that peak demand will rise closer to 330 MW. This will lead to significant reductions in our new growth capital expenditure in the future.

*Figure 6.3: Improving utilisation of our network*




We also expect an increase in customer numbers as well as an increase in coincident peak demand in the 2024-29 period as shown in Figure 6.4.

*Figure 6.4: Forecast growth in total connections and system peak demand*




Post 2030, we expect an acceleration in EV uptake in the Northern Territory. EVs will lead to significant increases in energy required from our network in all areas and will drive an increase in peak demand if customers charge in the evening peak period. While the network has some capacity to meet growth in peak demand, we anticipate that significant and systematic growth will necessitate a major need for new infrastructure at high cost. In this context, tariffs play a key role in providing signals for customers to use energy outside of peak times. While our current tariffs include a peak charge, there is an opportunity to provide more targeted signals on the cost of network electricity in peak periods relative to times of spare capacity.

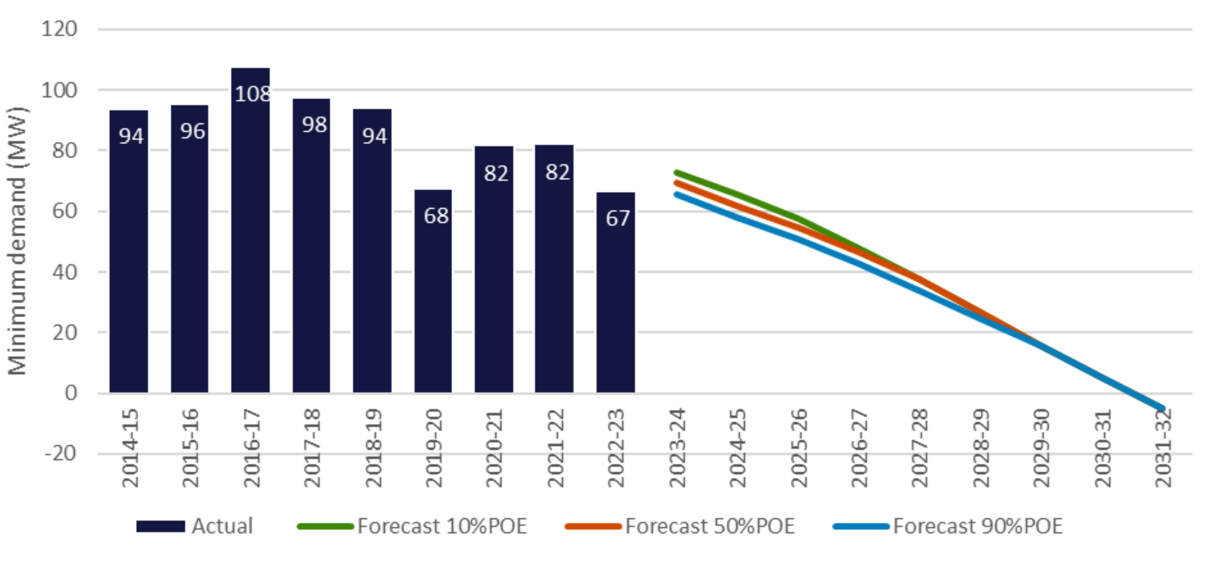
In the 2019-24 period, our demand charge in summer was set from midday onwards, which did not always provide the right signal to use more power between midday and 2pm, when solar production is highest. We also do not have any signal for customers to export more in the afternoon when the demand on the network is higher. Network tariffs could incentivise customers to use more of their own solar, rather than exporting into the grid during those periods of high export demand. Additional demand in the middle of the day would also help increase load on minimum demand days. Both measures would help us lift constraints on solar exports.

### 6.3.2 Minimum demand

Minimum demand has only become a significant cost driver in the last few years due to increased rooftop solar PV adoption. Falling minimum demand on the network is leading to rising levels of voltage excursions, which we are increasingly having to plan for. However, EV charging has the potential to alleviate minimum demand issues by utilising the excess solar generation.

Our forecast of weather adjusted minimum demand periods for the Darwin-Katherine network is outlined in the Figure 6.5. Annual minimum demand is expected to occur during the springtime when loads are relatively low and solar PV output is relatively high. It is worth noting that the timing of minimum demand is expected to be relatively consistent across our three interconnected networks.

*Figure 6.5: Darwin-Katherine network minimum periods (P10)*




The projected increase in the penetration of rooftop solar across our three regulated networks is increasing. The key driver of investment is managing minimum demand events that place the security of the network at risk.

A 'minimum demand event' describes an occasion when minimum demand falls below the threshold necessary to maintain system strength. On these occasions, there is of risk of insufficient inertia to manage a major system disturbance. According to Northern Territory Electricity System and Market Operator (**NTESMO**), a gas generator trips roughly once every six days. If tripping occurred during a period in which operational demand was below this 'minimum demand threshold', a system black event would likely occur.

To prevent system blacks from occurring during minimum demand events, NTESMO instructs Power Services to shed net generating parts of the network to lift minimum demand above the threshold. Power Services has little visibility of the LV network, making it difficult to identify these regions. Its approach to shedding is crude, effected by disconnecting parts of the LV network at the feeder level, and causing involuntary outages for all customers within the feeder area, regardless of whether they are net generators.

In response, we will apply dynamic operating envelopes (**DOEs**) to curtail solar exports at times of minimum demand but allow customers to export at all other times in the year. The prevailing advantage of DOEs is that they allow for maximum use of low cost renewable energy. They also provide the capability for our network to better manage electric vehicle charging in the future, which is consistent with our strategic priority to better utilise the network and electricity system.

As part of an integrated solution, we will adopt technology trials and trials of new export tariffs to incentivise change in consumption behaviour to assist with the issues. Incentives that impact user demand habits, such as time of use tariffs to incentivise use of electricity in off peak periods or peak renewable energy generation periods can also be used to minimise the network cost impacts of electric vehicles charging simultaneously.

In addition, we will use demand side management tools and technologies, such as network managed public charging infrastructure, that alters the flow of electricity based on network demand and supply. For example, EVs may be utilised to soak up the excess solar generation and minimise the impacts on peak demand.

## 6.4 Network tariff trials

In our Draft Plan, we proposed introducing export tariffs in the next regulatory control period. However, NT electricity pricing is governed under the Electricity Pricing Order, meaning we cannot assume any behavioural response from tariff designs for most of our customers.

Our existing tariffs only signal the costs of additional load during peak demand through peak charges. Offering cost-reflective tariffs and rewards for two-way energy flows is an important step to transform our approach to network tariffs, by offering our customers tariffs that empower both choice and control over their energy use and technology choices.

However, we appreciate the need to carefully manage our tariff reform process so changes in how we design network charges are fair and can be understood by customers and stakeholders. We therefore propose to not introduce two-way pricing just yet, but rather collaborate further with NT retailers and NT Government to design targeted trials that can:

- Inform our future network tariff design.
- Provide evidence to support any proposed reforms to the Electricity Pricing Order for either customer thresholds or tariff structures.
- Test specific pricing innovations.

The network problems that tariff trials could aim to solve include understanding:

- Whether customers will adapt their export scale, pace and timing due to export pricing or rebate signals.
- Whether differing prices for static versus dynamic customer connection or device controls are warranted, and the scope for these to encourage controlled load solutions that benefit both network costs and customer bill outcomes.
- How pricing for the behaviours of grid-scale batteries that can either drive up or help avoid our costs and help encourage efficient deployment of these batteries across our networks.

Trials are an important part of innovating how we design our network charges. However, trials alone will not be enough to deliver pricing innovation that is in the interests of our customers and our network. We will also consider other tools available, such as behavioural economics, to understand how customers may respond to price signals and will draw on lessons from other networks and jurisdictions about what works and what does not. Ongoing education and customer engagement are also important for pricing innovation, and we can test ways of providing this through our trial collaborations with retailers.

The timing of these trials would be after our investment in DOE capabilities are operational and following further engagement with retailers on trial tariff co-design.

## 6.5 Basic export limits and hosting capacity

In applying the pricing principles, we must also address transitional arrangements in clause 11.141.13 of the NT NER, which require that we propose a basic export level[12] (if applicable). For the next two regulatory periods, the transitional rule requires that we include, for each proposed export tariff, the basic export

[12] Basic export level means a threshold (calculated by reference to capacity, energy or other measure permitted in a distribution determination) specified for the purposes of clause 11.141.12(a) in the applicable TSS.

level threshold up to which a customer may export without charge or the manner in which the basic export level will be determined.

Whilst we are not proposing to introduce an export tariff for the next regulatory control period, in the interests of transparency we have outlined below our proposed approach and methodology for setting the basic export level. We will apply and test this methodology as part of the proposed export tariff trial.

The basic export limit is the amount of exports that we will provide a customer for free prior to imposing an export price during the next two regulatory periods. We propose to determine the basic export levels for use in export tariff trials having regard to:

- The export capacity of the distribution network (or part thereof) to the extent it requires minimal or no further investment (i.e. the network's intrinsic hosting capacity).
- Expected demand for export services in the distribution network (or part thereof).

In developing the methodology for determining our basic export levels, we will balance efficiency, complexity, understandability, fairness and equity.

We note that it is premature to set a firm number for the basic export limit(s) at this point in time and the NT NER does not require or prescribe this level of information. The above approach preserves flexibility to consider the limit when hawse have better information on LV system visibility and hosting capacity, and a better view of whether it should have different basic export limits for each of its power systems.

# 7. Assignment and reassignment policy

Our approach to classifying and assigning customers is based on clause 6.1.18 of the NT NER, which governs how customers can be assigned to tariffs. Our prescriptive assignment and reassignment policy is mainly unchanged from the 2019-24 TSS, which was acceptable to the AER.

## 7.1 Overview

We will take into account the following connection characteristics:

- The nature and extent of the customer's usage.
- The nature of the customer's connection to the network (i.e. voltage at coupling point and/or capacity of connection assets).
- Whether metering is installed and, if so, whether smart meter technology has been installed at the customer's premises.

In addition to the above, the following will apply:

- Customers with similar connection and usage profiles are treated equally.
- New connections with no previous load history will be assigned to the appropriate default tariff based on their network agreement specifications, expected energy usage, supply voltage and meter type.
- Customers with smart meters will be reassigned to a cost reflective tariff including those customers who instal an EV fast charger.

In the NT, the Electricity Pricing Order supports the need for a more aggressive approach to tariff assignment to cost reflective tariffs as there is currently no customer impacts or change to those customers who consume less than 750 MWh pa. Therefore, we will:

- Assign new customers to cost reflective tariffs upon initial connection.
- Reassign established customers who upgrade their connections through either:
  - adding embedded generation; or
  - completing a connection upgrade (e.g. upgrading to three-phase power when installing an EV fast charger).
- Reassign established customers who receive a new smart meter.

Our assessment to assign or reassign customers to the appropriate tariff has two steps:

- *Step 1 Assigning the customer to a tariff class:* The customer is assigned to the appropriate tariff class based on the tariff class assignment criteria outlined above.
- *Step 2 Assigning the customer to the appropriate tariff:* Once the customer is assigned to the appropriate tariff class, the tariff is determined based on the customer's metering characteristics and end use, specified against the criteria applicable to each tariff in the tariff class. This is based on the tariff eligibility criteria outlined above.

We do not offer customers who are assigned to cost reflective tariff with a smart meter the ability to opt-out to anytime energy network tariffs.

It is also important to note that we do not propose to allow customers on a cost reflective demand tariff to opt-out to anytime energy network tariffs. As a consequence, the number of customers on the non-cost reflective tariffs (Tariff 1 and 2) is forecast to steadily decline over the next regulatory period, mainly in line with the end-of-life replacement of basic accumulation metering.

Due to the proposed segmentation of Tariff 3, from 1 July 2024, existing customers on Tariff 3 LV Smart Meter, will require reassignment to one of the new tariffs (3a, 3b or 3c) based on whether they are residential and non-residential, and based on consumption greater than 160 MWh pa. The Electricity Pricing Order means this will not affect their retail bill. We expect that there will be approximately 40,000 tariff 3 customers that will require reassignment.  This reassignment however, will not impact their retail bills due to the Pricing Order.

## 7.2 How assignment occurs

Our procedures for assignment of customers to tariff classes and tariffs are as follows.

When a new customer is assigned to a tariff, that tariff will continue to apply until such time as the reassignment is triggered as a result of a change in the customer's load profile, total annual consumption, connection or metering characteristics, and consequently either:

- We initiate the tariff reassignment:
  - here the reassignment is due to changes in annual consumption (after providing the customer or their retailer notice prior to the reassignment); or
  - where the reassignment is due to installation of a smart meter that replaces an accumulation meter, we will notify the retailer through the existing business to business (B2B) process for meter exchange; or
  - the customer or the customer's representative applies for a tariff reassignment. Where the customer or the customer's representative wants to make a request for a tariff reassignment, they must apply in writing by using the Tariff Reassignment Request Form. In such cases the customer or the customer's representative will be charged the Network tariff change request fee. Note that no fee will apply where the amendment was due to a tariff assignment error made by us.[13]

Whether the customer, the customer's representative or Power and Water initiates a tariff reassignment, we will use the procedure described below to reassign the customer to the appropriate tariff.

## 7.3 When reassignment occurs

A reassignment is triggered:

- Following a review conducted by us:
  - we will trigger a reassignment as a result of the change in the customer's eligibility; and

13 Whilst a customer or the customer's retailer may request a reassignment we may determine that a reassignment is not warranted.  We may also charge for the assessment and recover its costs as an Alternative Control Service.

  - we will apply the procedure as detailed below to assign the customer to the appropriate tariff for commencement on 1 July.
- Following installation of a smart meter that replaces an accumulation meter.
- When a customer or their retailer requests a reassignment:
  - where a change of circumstance occurs, the customer or the customer's representative or retailer notify us in writing advising the change in occupancy using the Tariff Reassignment Request form, to enable us to assess that the customer is on the appropriate tariff; and
  - where the completed request form is received prior to the 15th of the calendar month, and no additional information is required, the new tariff assignment (if approved) will take effect from the commencement of the next billing cycle. The new tariff assignment will not take effect until we advise the applicant in writing of the approval and effective date of the new tariff assignment.

During the regulatory period, we will review customers' consumption at least annually. This review will include assessing:

- The customer's consumption level at the NMI, where assessment will be for the prior 12-month period (where available), form 1 February through to 31 January.
- Whether the customer's tariff assignment is correct.
- Whether the customer's consumption level warrants priority installation of a smart meter.

Any tariff class and/or tariff reassignment resulting from our review, and the resulting new charges, will commence from 1 July.

Where we believe a customer should be reassigned we will notify the customer or retailer directly in writing. The customer or retailer will have an opportunity to comment on the outcomes of this assessment from 1 March through to 31 March.

For new customers, six months after connection we may review their actual consumption to ensure the customer is assigned to the appropriate tariff. In the event we believe a tariff reassignment is required we will notify the customer or retailer directly in writing and provide the customer or retailer with an opportunity to comment on the assessment.

# 8. Alternative Control Services

For the 2024-29 regulatory period, we propose to continue replacing end-of life mechanical meters with smart meters, as well as installing smart meters for all new connections.

Developing an expansive smart meter fleet will allow our customers to continue to install distributed energy resources such as rooftop solar and batteries, while enabling innovative tariff setting and better asset management. It will also address the condition, accuracy and reliability issues with our current metering fleet.

We will continue to provide cost reflective fee-based and quoted services.

## 8.1 Overview

We provide some services to individual customers on an as-needs basis and charges the user a fee – these are referred to as Alternative Control Services (**ACS**). These fall into three categories, which aligns with the AER's Framework and Approach (**F&A**) Decision and the AER's Service Classification Guideline:

- Network ancillary services - customer and third party initiated services related to the common distribution service.
- Metering services - activities relating to the measurement of electricity supplied to and from customers through the distribution system (excluding network meters).
- Connections services - services relating to the electrical or physical connection of a customer to the network (other than basic connection services).

For ACS, we charge either an approved fee, which is based on an approved unit rate, or a quoted fee. Our proposed service classes (refer to the table below) for ACS have been determined according to the classification of services set out in the AER's F&A and Service Groupings provided for in the AER's Service Classification Guideline.

*Table 8.1: Overview of ACS*

| Service grouping | Service characteristics | Charging parameter |
|---|---|---|
| **Ancillary network services** | Includes services such as: provision of design information, access permits or clearances to work, network related property works, network safety services, network tariff change request, Retailer of Last Resort or customer requested network outage. | **Fee-based** – Represented as a fixed rate ($) per service. Reflects the estimated cost of providing each service and varies depending on the type of service requested.<br>**Quoted fee** – Represented as a quoted rate ($) per service. The quoted price varies based on actual resources required to deliver the type of service requested. |

| Service grouping | Service characteristics | Charging parameter |
|---|---|---|
| **Metering services – types 1-6 meters** | Provide type 1 to 6 metering services as set out in chapter 7A of the NER (NT), including but not limited to:<br>• Metering coordinator.<br>• Metering provider, including: providing, installing, maintaining, inspecting, replacing, recovery and disposal, and testing meters.<br>• Meter reading including scheduled and special meter reads (e.g. move in and move out meter reading, final read on removed meter).<br>• Meter data services including collection, processing, management, delivery and storage of metering data. | We propose a simple schedule of three metering service provision charges. Assignment to a meter service provision charge is based on the type of metering installed at the property, either:<br>• Single phase meter.<br>• Three phase meter.<br>• Low Voltage current transformer.<br>• High Voltage transformer. |
| **Connection services** | Includes services such as:<br>• Basic, standard and negotiated connection services.<br>• Enhanced connection services.<br>• Connection management services. | **Fee-based** - Represented as a fixed rate ($) per service. Reflects the estimated cost of providing each service and varies depending on the type of service requested.<br>**Quoted fee** - Represented as a quoted rate ($) per service. The quoted price varies based on actual resources required to deliver the type of service requested. |

## 8.2 Fee-based and quoted services

ACS prices are generally provided to customers as either one of the following:

- **Fee-based**: the work involved in some ancillary service activities are relatively fixed and are charged on a per activity basis. Fees are derived from the relevant labour rates and average time required to perform the task and are charged irrespective of the actual time taken to complete the activity.
- **Quoted services**: costs for some ancillary network services may vary considerably between jobs. This is often the case for one-off activities that are specific to a particular customer's request. For quoted services, charges are levied on a time and materials basis. Prior to commencing work, we must provide itemised quotes to the customer. At a minimum, the quotes must contain information on each of the cost components to demonstrate compliance with the control mechanism formula for quoted services.

Fee based and quoted services fees (other than for metering services) are designed to achieve cost recovery for each one-off instance of the requested service (i.e. rather than require ongoing payment). We have undertaken a study to estimate the cost of providing each service, which includes, direct labour, materials, vehicles, corporate overhead, network overheads, and tax.

The prices for fee based (price cap) services are set in accordance with specified service assumptions due to the standardised nature of the services. We have applied the AER's Ancillary Network Service and Metering ACS Models to develop the prices.

Prices for quoted services are determined at the time the customer makes an enquiry and therefore reflect the individual nature and scope of the requested service which cannot be known in advance.

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