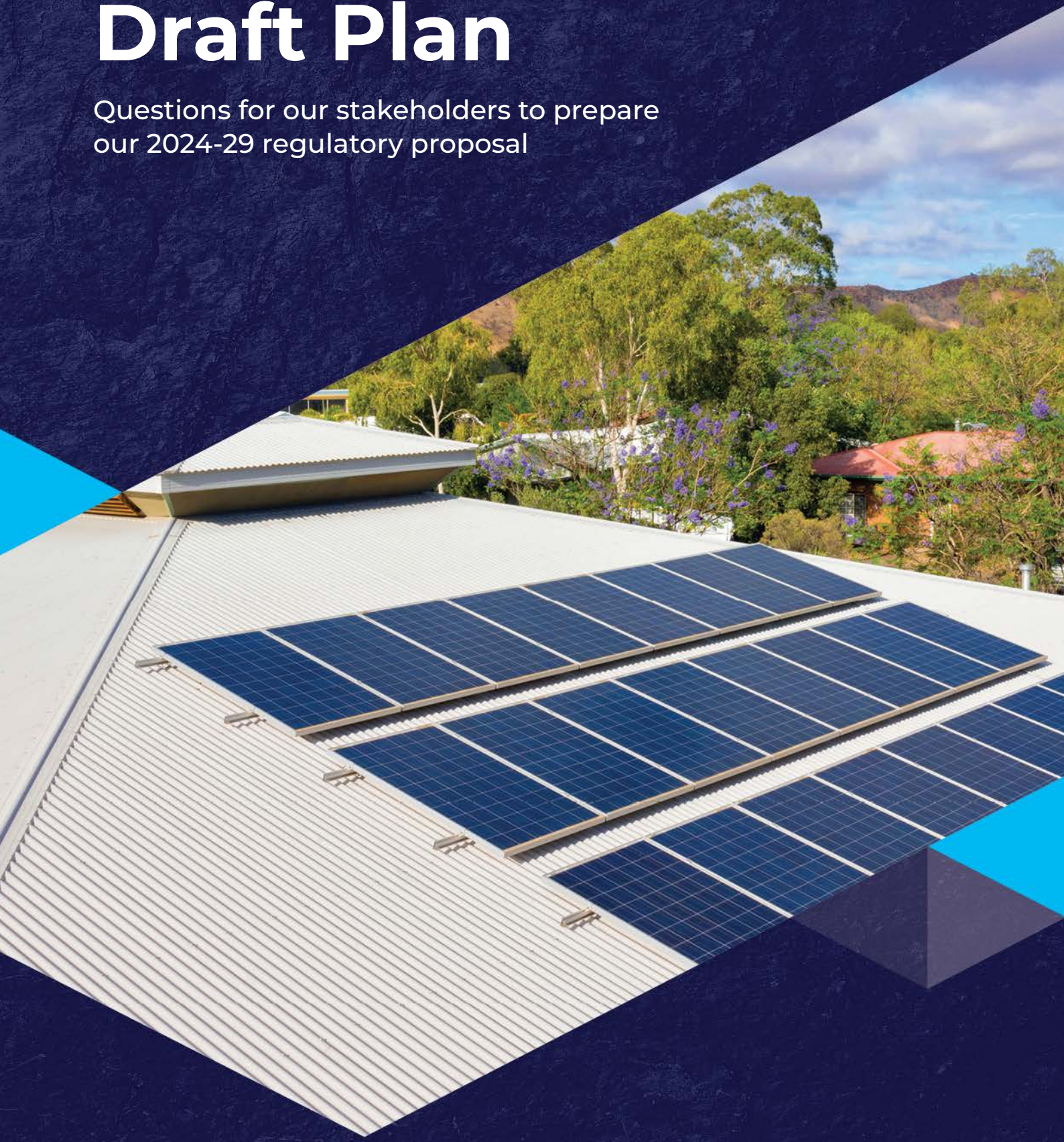
PowerWater

Draft Plan

Questions for our stakeholders to prepare our 2024-29 regulatory proposal



@PowerWaterCorp

About this report

Who is Power and Water?

We are the essential service provider in the Northern Territory (NT) providing electricity, gas, water and sewerage services as seen in **Figure 1**. Our purpose is to make a difference to the lives of Territorians. Our business connects our communities to reliable and affordable essential services and provides a foundation for economic growth.

What is this Draft Plan about?

Our electricity services provide power to 90 townships and communities across a vast landmass. Our three largest networks in Darwin-Katherine, Alice Springs and Tennant Creek are under price regulation. The networks provide electricity to 72,000 residential customers and 11,000 businesses.

Every five years, the Australian Energy Regulator (AER) undertakes a review of our proposed expenditure, revenue and tariff structures for our regulated networks. Our next regulatory period is from 1 July 2024 to 30 June 2029 (the 2024-29 regulatory period). The AER review process takes about 18 months with our initial regulatory proposal due on 31 January 2023.

This Draft Plan sets out our proposed plans for our upcoming 2024-29 regulatory period. Its purpose is to capture feedback from our customers and broader stakeholders on our plans before submitting our initial regulatory proposal to the AER.

As an essential service provider our role is to serve the community. It is vital that we listen to what our customers expect from our network both now and into the future. The five year regulatory proposal provides an important opportunity for customers to provide input into our strategic direction, and ensure their values, vision and priorities are reflected in our five-year expenditure plans.

Over the last year, we have met with our customers, energy partners and government representatives to hear what is important to them. This included an innovative new way to engage with everyday residential customers in Darwin-Katherine and Alice Springs – our People's Panels. Our Draft Plan seeks to show a 'line of sight' between the priorities of our People's Panels and our five-year plans.

This is only the start of our engagement journey. There are areas of our plans where we have not engaged with stakeholders. The Draft Plan sets out questions for customer feedback. We will be engaging further with our customers before finalising our proposal on 31 January 2023.

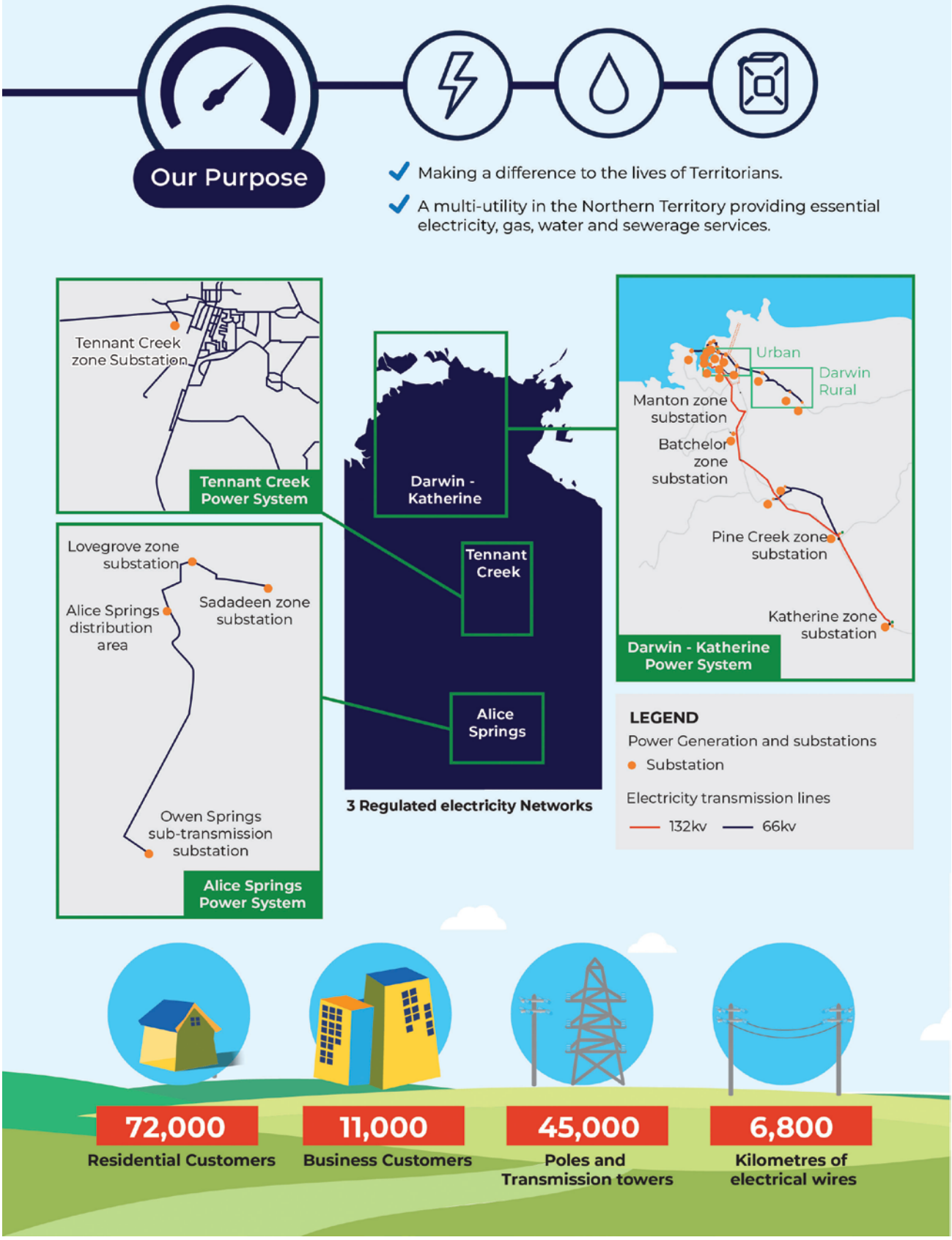
The AER will undertake an exhaustive review of our proposal and provide a final determination by April 2024. During this time, we will continue to engage with our customers and stakeholders on key issues.

How can you provide feedback?

We have developed a new web page called 'Your Say' that is focused on the upcoming 2024-29 regulatory proposal. This means you can directly provide your input to the questions we have posed in this Draft Plan, and provide any other comments. The web page can be accessed directly through this link (**https://www.powerwater.com.au/your-say/draft-plan**).

Consultations on the Draft Plan will close on 13 September 2022.

Figure 1 – Snapshot of our network



PowerWater

Residential customer at
People s Panel

Contents

Power and Water Staff with our People s Panel

A message from our Chief Executive Officer

Customers are at the centre of everything we do. It is therefore vital they are involved in developing our upcoming 2024-29 regulatory proposal for our regulated electricity networks in Darwin-Katherine, Alice Springs and Tennant Creek.

Our purpose as a business is to make **a difference to the lives of Territorians** and we have been consulting with our customers over the last year on their expectations of our business. We understand that our services are essential to everyday lives and our business community. It is important that we listen to our customers and embed their values, preferences and vision into our future strategies and plans.

These are exciting times to be in the energy industry. The shift to renewable energy started a decade ago with many customers installing solar on their roofs. Renewables are expected to supply 50 per cent of electricity consumed in Darwin-Katherine and Alice Springs by 2030.

The transition to renewables will be an **engineering challenge but there are clear benefits** to the NT from cleaner and more affordable energy.

The shift to renewables has been front of mind for our customers in our engagement sessions. We have laid out our vision of a being a **key enabler in the NT's transition** to a 50 per cent renewable energy future by 2030. As the operator of the transportation network of electricity, we lie at the centre of the shift to renewables. We agree with our customers that now is the time to redesign and re-engineer our network.

In this Draft Plan, we have identified new initiatives to increase the network's capacity to deliver two-way flows of energy using our customers' household solar. We are also exploring our **customers' preference** for an initiative to install community batteries that capture excess solar and would feed our energy system when the sun is not shining.

Our customers have also been telling us that we need to think **long term** to ensure the network remains reliable and secure. We have discussed challenges that lie ahead with replacing a significant proportion of assets installed after Cyclone Tracy. Our customers also want us to facilitate and fuel new technologies, including electric vehicles.

Our Draft Plan is being prepared at a time when **financial markets are volatile.** Financing costs are rapidly accelerating due to higher interest rates and global events in Ukraine. This has resulted in a forecast of revenue that is significantly above what we anticipated at the time of consulting with our customers in March and April.

The Draft Plan provides a good framework for **further conversation** on our plans going forward, particularly considering changing market conditions. We welcome your feedback.

Djuna Pollard

A message from our Reset Advisory Council

Electricity is complicated. Transport is a useful analogy for Territorians to help break down some of this complexity.

Power and Water does not make electricity, rather they deliver it. They are in the electricity transport business.

They are responsible for the electrical 'roads' that transport electricity from generators to customers. This includes the electrical 'highways' from the large generators to the substations where the transport routes divide into the electrical 'streets' that connect directly to customers. Since not that many of us store electricity at home we tend to rely on a continuous delivery service. Power and Water respond as fast as they can when there is an interruption to electricity delivery.

How do we want our electricity delivered to us for the rest of this decade? That is what is up for grabs as Power and Water develop their revenue proposal for the 2024-29 regulatory period. This represents a five year window where Territorians will rely on electricity as much, or more, than they do now.

To put a sense of scale to what is up for grabs, in the current five-year window, Power and Water has been approved to collect over $800 million dollars from customers via their electricity retailers. This was considered enough to pay for the operation, maintenance, refurbishment and expansion of the shared network.

But is this the right amount for 2024-29? Are there opportunities to be more efficient? Is there a case for spending more on certain things? By consulting with its customers, Power and Water will refine its proposal for 2024-29.

The role of the RAC is to keep a voice of the customer at the table as Power and Water consider the feedback from you – their customers.

The People's Panels and other sources of feedback have emphasised the following:

- Customer Service is really important – customers want to be able to talk to the business about important issues (new connections, move-ins, move-outs, metering and more) and clearly want to know more information when electricity deliveries are interrupted.
- The three regulated networks have some really unique attributes that mean that customers have quite different electricity delivery experiences and therefore have different priorities for the future.
- Customers have embraced the idea of 'home brew' electricity and want to share it more. They want Power and Water to ensure the electricity 'streets' are wide enough and in good enough condition for them to share with their neighbours. They are interested in sharing some local electricity storage as well.
- Customers also expect Power and Water to think about the long-term and invest in maintaining the electricity roads, streets, substations and so on to keep electricity deliveries as reliable as they are now – or even better for some customers – until 2030 and beyond. Customers understand that most of the infrastructure was built over a short period of time and it won't last forever – but they don't want to have to pay to replace it all over a similarly short time frame.

Customers have been consistent and clear that affordability for households and businesses are a top priority. So, it is important to also consider that investments in the future capability and capacity of the electricity delivery network will mean borrowing more money.

The existing 'regulatory asset base' (the amount still 'under finance') is over a billion dollars. It is becoming clear that the current period of low interest rates is over. This means it will cost more to finance the electricity network in the next five years compared to the previous five years. However, it is not yet clear just how much interest rates will go up. In an era of higher interest rates, some important trade-offs will be needed to keep revenues at the same levels as now.

Feedback on this document is a very important way of finding the right balance between the risk of underinvesting in the electricity delivery network and the risk of 'gold plating' and spending more than we really need. We look forward to hearing your feedback and we will do our best to represent that to Power and Water as we work towards a Draft proposal to the Australian Energy Regulator in January 2023.

Andrew Nance

The 2429 Reset Advisory Committee is made up of our broader customer base, with representation from everyday residential customers, advocacy bodies for socially and economically disadvantaged customers, youth and young people and small, medium and large-scale business. The committee has been working hard over the last few months, providing input to our regulatory proposals, assessing and reviewing customer engagement activities and ensuring our materials reflect what matters to them and the broader customer base.

Dr Andrew Nance is an independent consultant appointed by us to support the RAC. His role is to work with our Chair, Gavin Dufty and Committee members to gather input and feedback on our regulatory proposal from a customer perspective.

Residential customer examining options at People s Panel

Summary

The expenditure plans presented in the Draft Plan would lead to a revenue increase of 10 per cent (excluding inflation) compared to the 2019-24 current period. This is higher than anticipated at the time of our customer consultations in April 2022 due to a rapid increase in financing costs. In light of rising cost of living pressures, we consider this is an opportune time to re-visit our customers' preferences. The key issue is what expenditure can be deferred to improve short term affordability and what are the short and long-term risks.

This Draft Plan provides our initial view on the expenditure, revenue and tariffs for the 2024-29 regulatory period for our regulated electricity networks in Darwin-Katherine, Alice Springs and Tennant Creek. Chapter One of our proposal provides relevant background on our customers and our role in providing network services.

The purpose of the Draft Plan is to open a conversation with our customers on our strategic direction and the details of our plans. Our customers have been central to the development of our initial plans. Our engagement activities commenced in September 2021 and have focused on speaking directly to our customers.

A key innovative approach was to convene People's Panels in Darwin and Alice Springs – a group of representative customers that devote weekends to help shape our plans for the future. The vision, values and priorities have deeply influenced the plans set out in this document. Chapter 2 provides further information on our customer engagement activities and outcomes.

Adapting to unprecedented change

Our three separate regulated networks supply the smallest number of customers of any network in Australia. This places us under an immense scale disadvantage relative to other networks in Australia. We operate in difficult environments subject to extreme heat and weather events that place further pressure on delivering our services. Our small scale is further exacerbated by resourcing constraints in the NT.

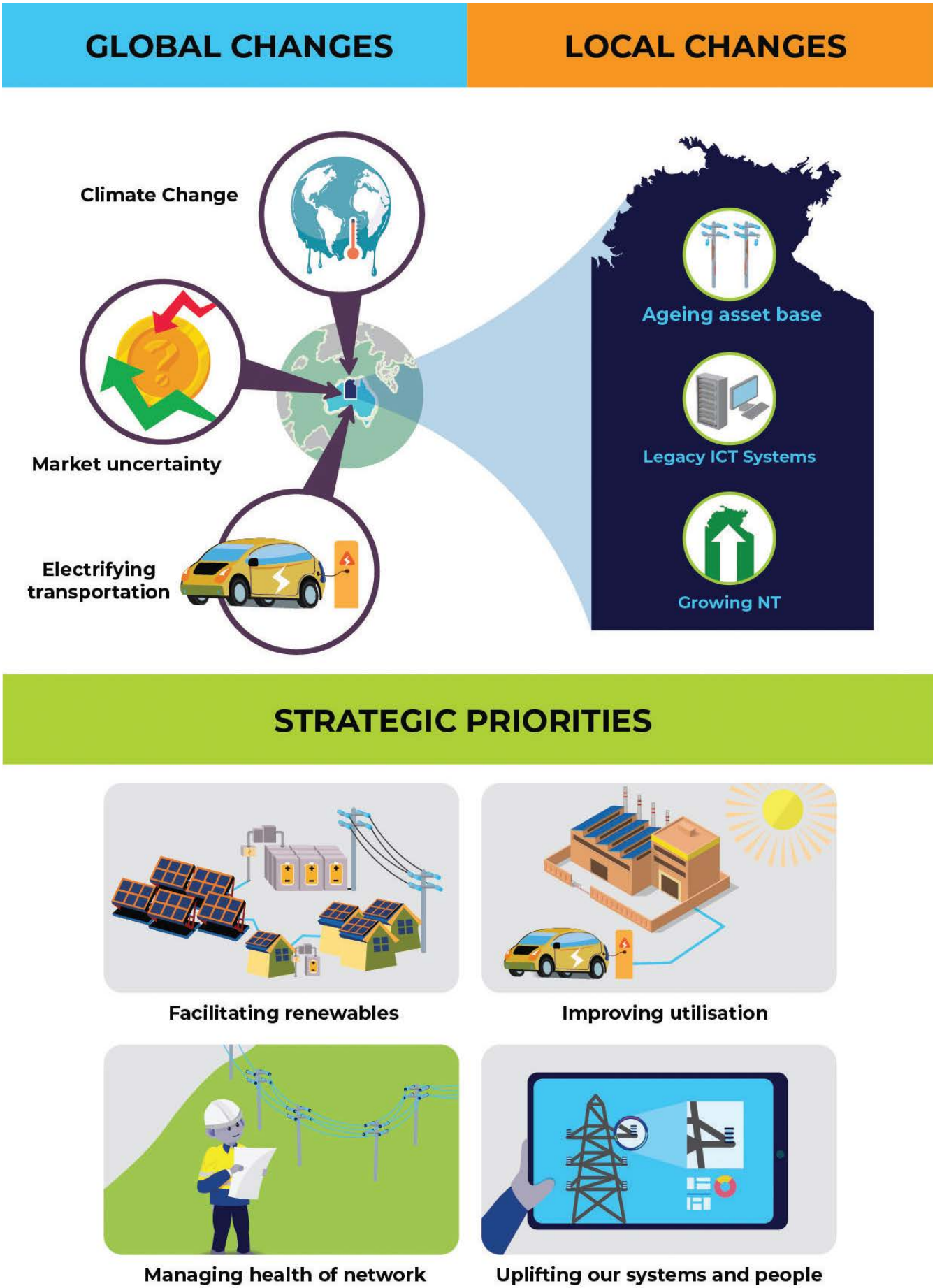
Our small network is facing disruptive and fast paced change driven by global and local factors including climate change, electrification of transport, ageing network assets and a growing economy. Our functions and cost structures will change dramatically over the next 20 years. The strategic priorities we discuss in Chapter Three of this Plan are about adapting to change in a way that can maintain affordability and quality of services. This is discussed below, and is depicted in **Figure 2**. Our regulatory proposal has sought to embed our strategic priorities in our five-year expenditure, revenue and tariff plans.

Transition to low-cost renewable energy

Our most pressing challenge is facilitating the NT's transition to renewable energy. Renewable energy offers the Territory the benefits of clean and low-cost power that can unlock capacity to grow our economy.

Our network lies at the centre of fulfilling the Northern Territory Government's (NTG) goal of 50 per cent renewable energy by 2030. Our transmission network will need to relocate and expand to meet a rapid increase in large solar farms including connecting new 'renewable hubs' announced by the NTG. We will also need to adapt our network to provide increasing exports at the street level.

Figure 2 – Drivers of change impacting our business



Our strategic planning is looking beyond 2030 as we plan for a NT electricity system that is more reliant on renewables. This will be a significant engineering challenge for our network which was built for one way traffic from large fossil fuel generators. We will need to draw on modern technology to re-shape our network to deliver exported energy at the street level.

Our five-year plans for 2024-29 include a new export hosting system to cost-effectively unlock higher levels of household solar. We will also be investing in community batteries to store excess solar in the day and discharge in the evening when the sun is not shining.

Meet the growing demand of Territorians

We expect demand to significantly increase over the next 20 years. The NTG 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.

Electric vehicles will also heavily impact demand for energy with each 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.

Managing the health of our network

We have emerging challenges ahead with managing our network assets. A large proportion of our assets were constructed shortly after Cyclone Tracy in 1974. By the end of 2030, these assets will be approaching 55 years of age. This may trigger a significant uplift in replacement capital expenditure in the following decade. We need to plan for these changes to preserve the reliability and security of the network into the future.

Our strategy will be to employ best practice asset management practices and risk tools to extend the life of these assets. At the same time, we will look to new technology to retire rather than replace ageing assets. Even with these measures in place, we still expect our replacement expenditure will need to increase significantly beyond 2030. We are looking at measures to smooth the expected price increase in the 2030 to 2040 period including through a novel approach suggested by our People's Panel – a 'saving for a rainy day' fund. Under this approach, a small amount of revenue would be put aside in the 2024-29 period to use when replacement capital expenditure increases in future periods.

Uplifting our people and systems

To deliver our increased functions, we will need to uplift our capability through smart systems and getting the best out of our staff. At present we use ageing Information Communication and Technology (ICT) systems that are losing functionality. We have made some investments in the 2019-24 period and will progressively implement new systems over the next 10 to 15 years. We already have in place a new operating model which will help capture synergies in the way our staff deliver services as our workload continues to rise.

Chapter Three of this Draft Plan seeks to capture feedback from our customers on our 20 year strategic outlook, including the four key priority areas that have influenced the development of our 2024-29 expenditure, revenue and tariff plans.

The right balance – affordability and investing for the future

A consistent theme in our engagement with customers has been the right balance between maintaining affordability of our network service and long term sustainability.

The change in network revenue between regulatory periods is a good metric for assessing impacts on affordability. **Figure 3** shows that our revenue is forecast to increase by 10 per cent in 2024-29 compared to 2019-24, excluding the impacts of inflation. Despite this, our forecast revenue is below the allowance set by the Utilities Commission in 2014-19 and the subsequent Ministerial direction that had been put in place to reduce revenue over that period.

The revenue forecast is higher than our expectations at the time of our People's Panels sessions in April 2022, largely due to a significant change in financial markets. **Figure 4** shows the change in our forecast revenue as a result of the People's Panels sessions and subsequent changes in financial markets.

Commitment to target reductions in forecast revenue

In our April People's Panels sessions we noted that our initial estimates of expenditure plans indicated a revenue forecast of $892 million, about 7 per cent higher than the 2019-24 period. We discussed levers that could reduce revenue to 2019-24 levels. This included prioritising capital expenditure, changing our accounting treatment of overhead allocation to capitalise more overheads (which defers cost recovery), and implementing efficiency stretch targets for operating expenditure. This reduced revenue to $835 million, close to actual revenue in the 2019-24 period.

Testing customer preferences for additional programs

Our customers wanted us to invest for the long-term including facilitating renewables, proactively managing the ageing of our network and improving customer service. We provided customers with options for additional programs not included in our initial expenditure estimates at the time. Customers were comfortable with the inclusion of these future looking programs even if they resulted in a small increase in revenues for the 2024-29 period compared to 2019-24. The implementation of customer preferences added $29 million to the forecast resulting in revenue forecast for 2024-29 of $864 million.

Global headwinds – financing costs impacting our forecast revenue

Since our customer consultations, our expected financing costs for the 2024-29 period has increased markedly due to higher interest rates, and global events. These uncontrollable factors have caused a further uplift in our forecasted revenues to $921 million, 10 per cent higher than the last regulatory period (excluding inflation). At the same time, inflation has risen significantly since April 2022, and this will add further cost of living pressures to our customers.

The key question posed in the Draft Plan is whether priorities for customers have shifted in light of higher than expected revenue. Improving affordability in the short-term will mean projects are deferred, and that reliability and safety risks will rise. Deferring expenditure also places price pressures for future generations, compounding the expected increase in replacement capital expenditure to manage the ageing assets built after Cyclone Tracy.

Figure 3 – Forecast revenue for 2024-29 compared to current and previous periods ($, 2024 real)

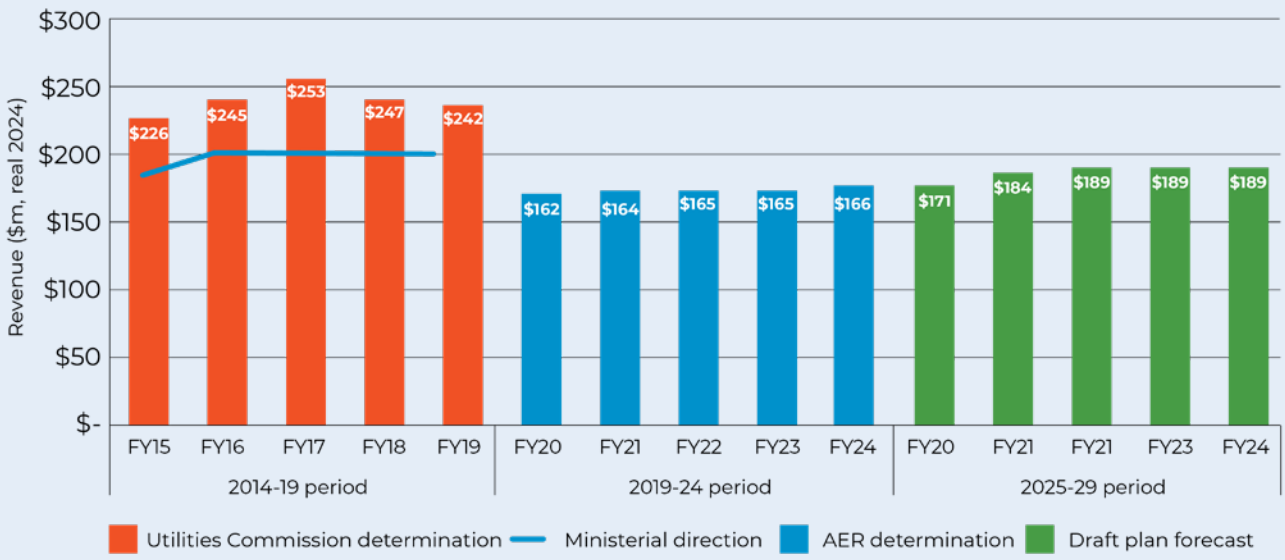
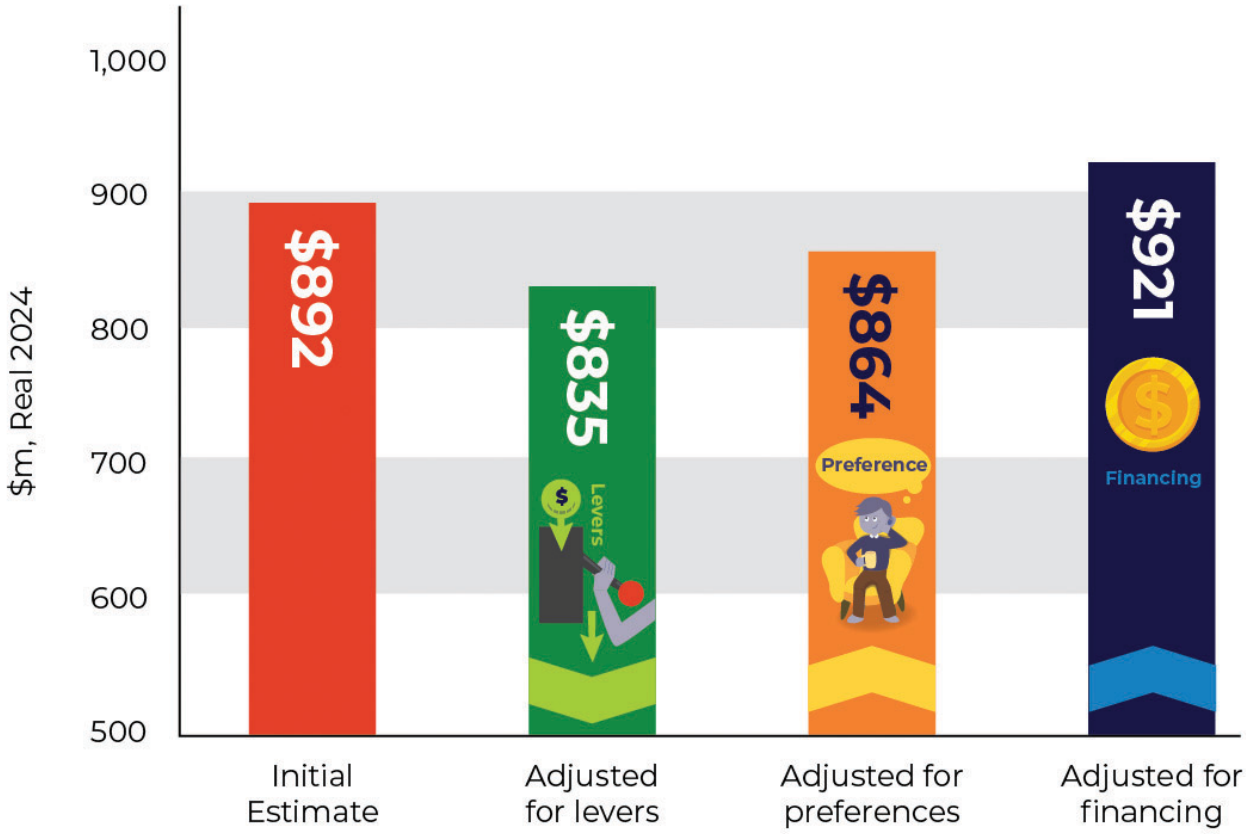


Figure 4 – Changes to our revenue forecasts since our People's Panel sessions in April 2022 ($, 2024 real)



Numbers at a glance

Figure 5 identifies the key expenditure and revenue inputs in our Draft Plan. Our investment costs have risen significantly due to an increase in our forecast capital expenditure combined with an increase in the rate of return. However, the reduction in operating expenditure in the 2024-29 period is placing downward pressure on revenue. Below we provide a summary of our expenditure plans, revenue plans and tariff structure changes. All numbers are expressed in real $2024 except for bill impacts which are in nominal dollars.

Capital expenditure

We forecast a significant increase in capital expenditure in the 2024-29 period. Higher capital expenditure is driven by an expected increase in replacement and growth capital expenditure.

Replacement of network assets accounts for 40 per cent of forecast capital expenditure. The key driver of higher expenditure is an expected decline in the condition of our assets due to age and environment. The higher expenditure also reflects a replacement fund that seeks to bring forward future replacement based on customer preferences. Growth capital expenditure accounts for about 28 per cent of forecast capex in the 2024-29 period. We expect significant growth in some parts of our network to meet new residential and commercial connections. We are also investing in hosting capacity and community batteries as part of our future network strategy consistent with customer priorities.

Non-network capital expenditure accounts for about 13 per cent of forecast capex in 2024-29. We are planning to make scale-efficient and prioritised investments in the 2024-29 period to gradually refresh our ageing ICT systems. We will continue with our current lease arrangements for fleet and property, while remediating properties in poor condition. Capitalised overheads are forecast to account for 20 per cent of forecast capex in the 2024-29 period. More overhead expenditure has been allocated to capital expenditure after recent changes to align our methods with peer networks. Chapter Four provides more detail on our forecast capital expenditure.

Operating expenditure

We are forecasting a thirteen per cent decrease in operating expenditure resulting in forecasts of a similar level to what was approved by the AER in the 2019-24 determination. This is driven by improvements in how we measure underlying labour costs and efficiency targets we have embedded into our forecast.

The change in overhead allocations results in a realistic comparison of our operating expenditure performance compared to peers and is more consistent with the efficient level of expenditure substituted by the AER in the last regulatory determination. We propose to include a staggered 10 per cent efficiency stretch target reflecting our ongoing commitment to delivering real and sustained reductions in our costs over time. Chapter Five of this Draft Plan provides more detail.

Revenue and bill impacts

The 10 per cent increase in revenue is largely a result of changing finance conditions. Current market conditions are leading to an eight per cent increase in our rate of return compared to the AER's 2019-24 determination. A further driver of higher revenue is the increase in our regulatory asset base (RAB) as our forecast capital expenditure increases in the 2024-29 period.

We have used revenue as a proxy for the expected bill increase of our customers. **Figure 6** sets out the bill impacts for small customers on an accumulation meter based on forecast inflation. Chapter Six provides more detail on revenue and customer impacts.

Figure 5 – 2024-29 forecasts compared to the 2019-24 period ($2024, real)

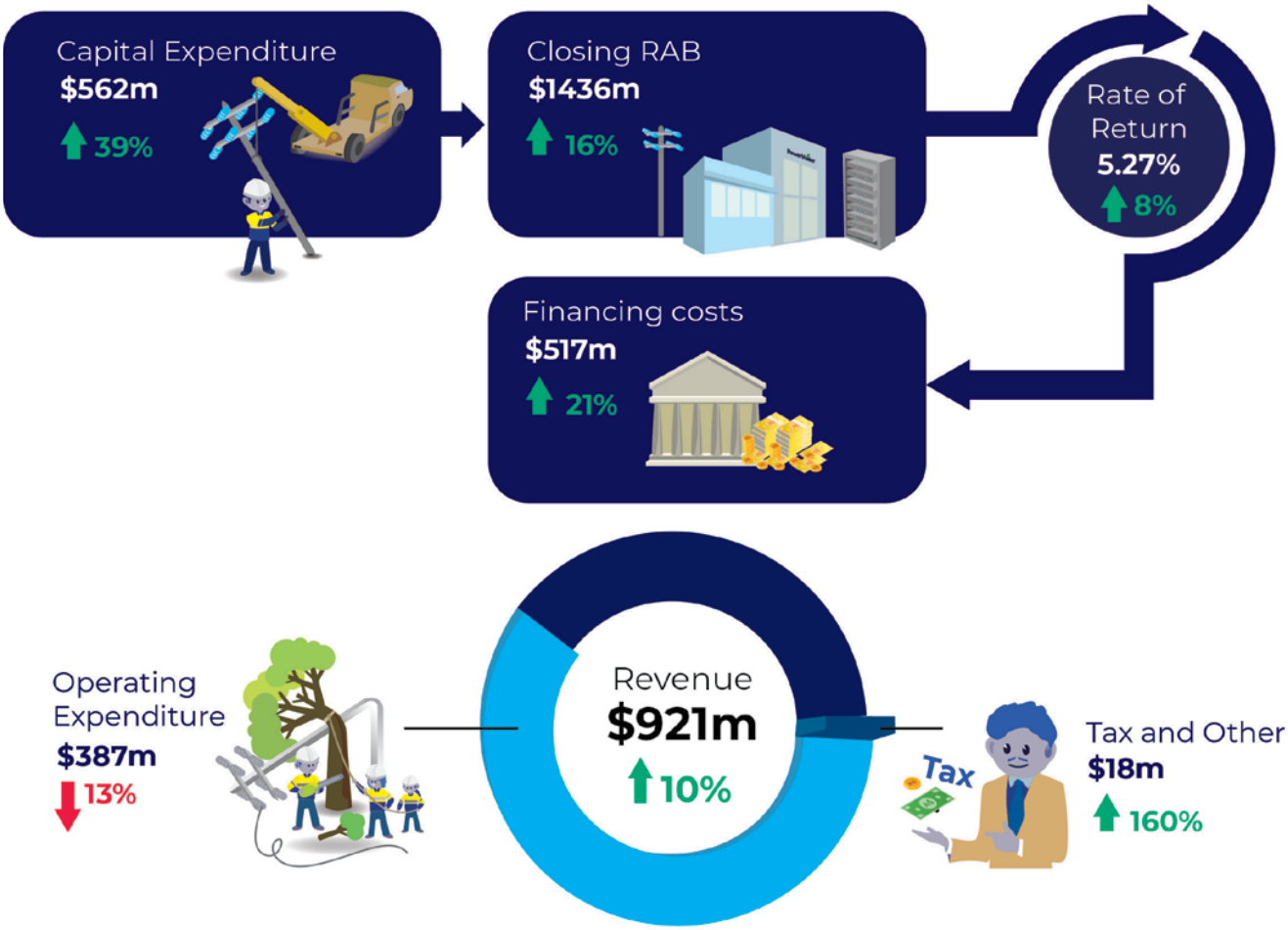


Figure 6 – Bill impacts for a typical small customer with an accumulation meter (nominal $)

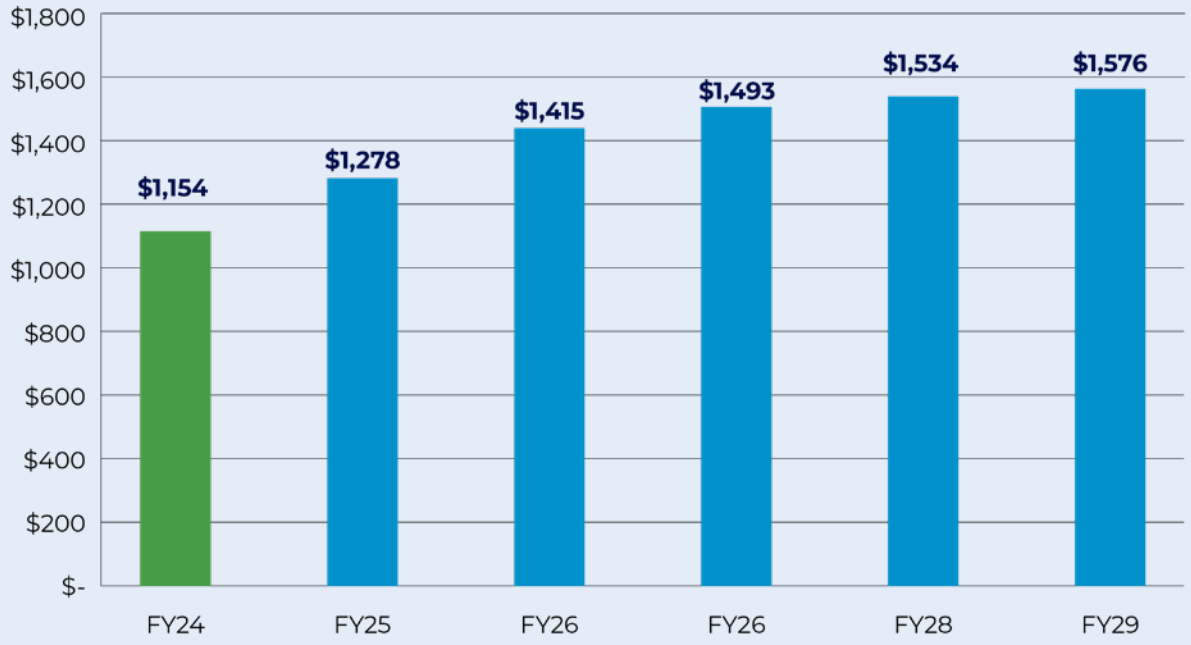
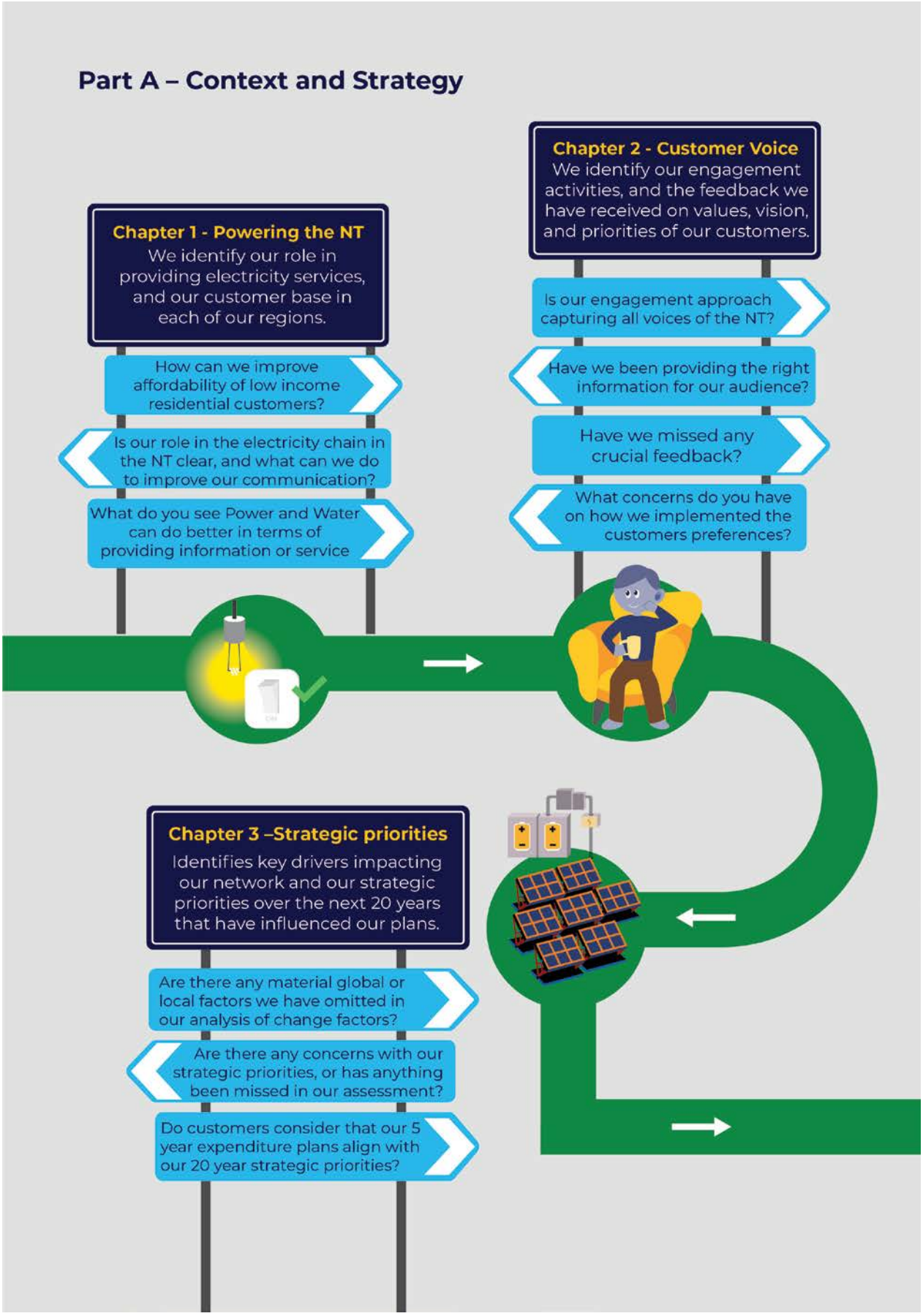
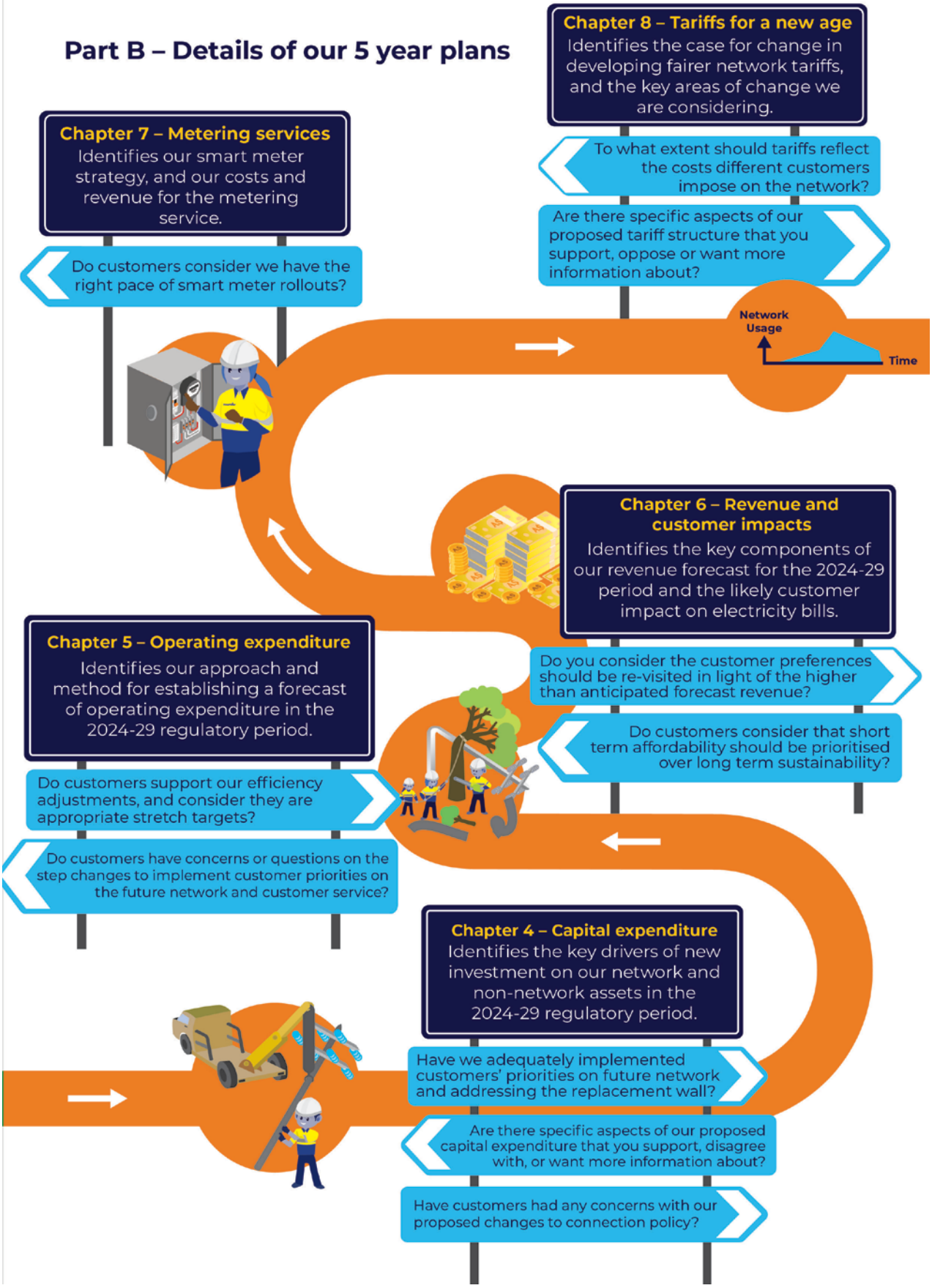


Figure 7 provides a structure map for the Draft Plan including the key questions we are seeking feedback on from customers and broader stakeholders.




Part B – Details of our 5 year plans
Chapter 8 – Tariffs for a new age
Identifies the case for change in developing fairer network tariffs, and the key areas of change we are considering.
To what extent should tariffs reflect the costs different customers impose on the network?
Are there specific aspects of our proposed tariff structure that you support, oppose or want more information about?
Chapter 7 – Metering services
Identifies our smart meter strategy, and our costs and revenue for the metering service.
Do customers consider we have the right pace of smart meter rollouts?
Network Usage
Time
Chapter 6 – Revenue and customer impacts
Identifies the key components of our revenue forecast for the 2024-29 period and the likely customer impact on electricity bills.
Do you consider the customer preferences should be re-visited in light of the higher than anticipated forecast revenue?
Do customers consider that short term affordability should be prioritised over long term sustainability?
Chapter 5 – Operating expenditure
Identifies our approach and method for establishing a forecast of operating expenditure in the 2024-29 regulatory period.
Do customers support our efficiency adjustments, and consider they are appropriate stretch targets?
Do customers have concerns or questions on the step changes to implement customer priorities on the future network and customer service?
Chapter 4 – Capital expenditure
Identifies the key drivers of new investment on our network and non-network assets in the 2024-29 regulatory period.
Have we adequately implemented customers' priorities on future network and addressing the replacement wall?
Are there specific aspects of our proposed capital expenditure that you support, disagree with, or want more information about?
Have customers had any concerns with our proposed changes to connection policy?

Power and Water staff with customers at our People s Panel

Part A

Context and Strategy

1. Powering the NT

We provide electricity services to more than 90 communities in the NT over a landmass of 1.3 million square kilometres. Our regulated networks in Darwin-Katherine, Alice Springs, and Tennant Creek transport electricity to 72,000 residential customers and 11,000 businesses. Each of our networks are unique, operating under different designs and environment.

The NT community is vibrant and diverse. Power and Water's purpose is to make a difference to the lives of Territorians. This involves providing reliable electricity that promotes economic growth and contributes to our community's aspirations.

We provide electricity, gas, water and sewerage services to townships and small communities across the NT. We have the smallest population among all Australian states and territories, but our population is dispersed over a large landmass. Our multi-utility structure is an advantage in addressing the diseconomies of scale in providing essential services to a relatively small population.

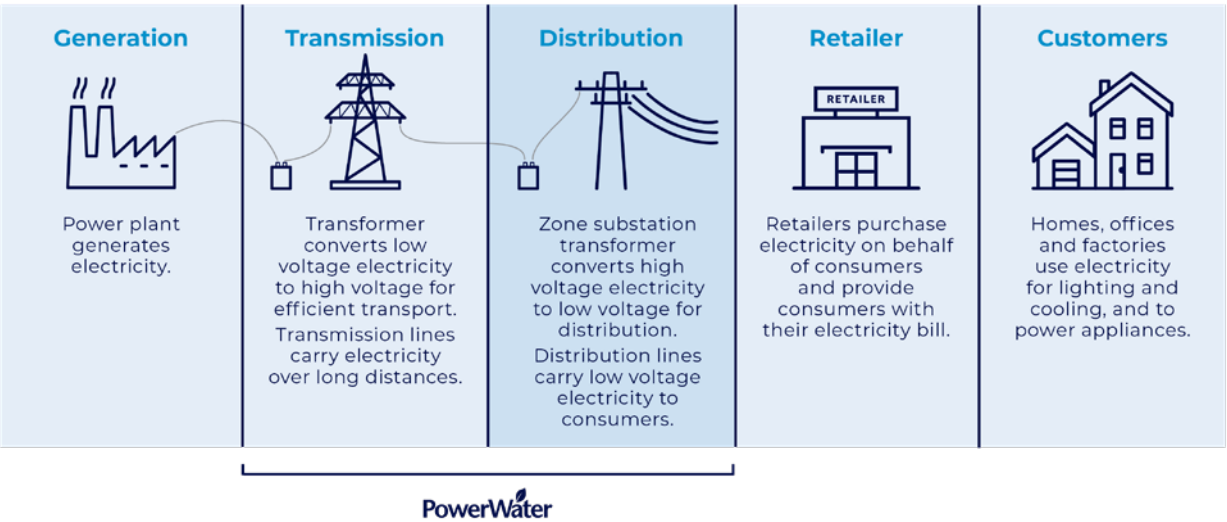
1.1 Our role in the NT regulated electricity systems

The scope of our electricity services varies across our townships and communities. In our regulated areas of Darwin-Katherine, Alice Springs and Tennant Creek, we are responsible for the transmission and distribution networks as seen in **Figure 8** below. Our role is to transport electricity from generators to our residential and business customers using our poles, cables, conductors, and transformer assets. We also undertake a metering service to identify how much energy our customers have used.

Until recently, all electricity was generated at large scale power plants. Over the last decade, we have seen more of our customers produce solar and use our network to export the power to other customers. We have also seen more large scale solar farms connect to our network, a trend that will further accelerate with the NTG's policy to have 50 per cent of electricity supplied by renewables by 2030.

The retailer has the primary relationship with customers, managing the electricity bill and organising connection. However, in many cases we also have a direct relationship with customers. For instance we provide information on network maintenance and outages, ensure energy use and billing data is correct and provide design advice on connecting to the network. We also facilitate the physical connection and have obligations to provide safe and secure electricity services. **Figure 8** provides a visual of our role in the electricity sector in the NT.

Figure 8 – Our role in the electricity system



1.2 Understanding what our customers want

About 72,000 households and 11,000 businesses receive power from our electricity network in the regulated regions. The power is crucial to cooling and heating homes, cooking, lighting, charging computers and mobiles, laundry and all the everyday ways we use electricity. Electricity is also a vital input for all NT businesses and a critical input for some of our larger industries.

A key feature of our engagement to date has been trying to understand how our business impacts the lives of customers. **Figure 9** is the 'Customer Lifecycle' – our attempt to understand what customers expect and want from us across their journey as a customer. This includes when they connect, when the power is on, when power is interrupted and when power is disconnected.

Our customers have been clear on what they want from our network at each point of the lifecycle:

- **Connecting** – When customers are connecting to our network, they want fast and easy connection. This is a period where customers actively interact with us and want us to ensure we partner with retailers on making the process seamless.
- **Connected** – When customers are connected they want reliable energy at fair pricing. Customers felt that the meter reading and the billing process was vital to ensuring that bills were fair. Many of our customers also want fair rewards for contributing their solar energy to the generation mix. More generally, our customers are impacted by our regular maintenance activities including tree trimming, and want to ensure that we are taking adequate action to ensure the greenness of the streetscape.
- **Outage** – Customers want good communication when they experience an outage. They want to be able to contact us in ways that are convenient for them – from telephone to social media to direct notifications. Most of all they want clear information on restoration times. Finally customers want us to take care when we need to enter their property to fix an outage.
- **Disconnected** – Customers who wanted to move out indicated that prompt timing and reconnection were vital to their experiences. There was also a want for accurate metering reads, and prompt billing at the end of disconnection.

In Chapter Two, we discuss the current pain points our customers experienced across the lifecycle, and how we engaged with customers on these issues. This included the impact of our tree trimming on the street landscape, the meter and billing process, and our role in providing objective information to customers about broader electricity issues such as connection of solar panels.

Figure 9 – The Customer Lifecycle

1.3 Energy affordability is an issue in the NT

The extreme heat in the NT means we are far more reliant on cooling than other places in Australia. A typical household consumes about 8500 MWh of energy each year, almost double the consumption of a typical NSW household as seen in **Figure 10.** This means that electricity bills comprise a larger portion of disposable income compared to the national average.

For customers on low incomes, the relatively high costs of cooling become even more pronounced. Turning off the power to reduce the bill has social and health implications in the extreme heat. We also have more customers on low incomes compared to the rest of Australia. ABS data shows that 6 per cent of Territorians were on income support compared to the national average of 3 per cent in 2019.

In our engagement sessions, customers told us we need to be more proactive in improving energy affordability of low income households. A key concern was energy efficiency, with low income households tending to live in old housing that requires significantly more cooling due to insulation issues. Low income households are also generally renters, with the NT having the highest number of renters per capita in Australia. This means that the existing cooling appliances tend to be inefficient, leading to higher costs of energy compared to the average household.

Key measures to improve energy efficiency include better insulation in the ceilings, windows and floors. Replacing older cooling appliances with newer models is also likely to lower the amount of energy consumed. We see a role for positive incentives to encourage these initiatives.

A key issue we seek to explore with our stakeholders is the role we should play in improving the energy efficiency of customers. Should we lead the conversation, provide more information on our website, or should we implement our own initiatives which are then funded by all customers?

Figure 10 – Annual energy consumption for typical residential customer

Residential customer at People's Panel

1.4 Our activities and services

In our engagement sessions, customers wanted to know how our activities fit into their experience with our network. We used a framework that mapped our activities to the customer lifecycle described in section 1.2.

Figure 11 shows our electricity network and support activities align to one or more of the phases of the customer's journey.

- In the **connecting** phase, we build new assets to meet demand from residential and commercial developments, and work with our retailers to connect new customers to the grid. This includes installing new meters when a new customer connects to the network
- We keep customers securely and reliably **connected** to our network by maintaining and replacing our network assets. We also undertake vegetation management to ensure our electrical assets do not contact trees and shrubbery. Finally, we read meters to ensure customers receive an accurate bill for the energy they have consumed.
- Our customers experience an **outage** when there is scheduled maintenance or due to unplanned events such as extreme weather or an asset failure. When there is an unplanned outage, we undertake emergency repairs such as during Cyclone Marcus in 2018. We also use our customer service team and rely on our ICT systems to notify customers of restoration times.
- We **disconnect** customers when requested. Our role is to work with the customer's retailer and to ensure a final and accurate meter read for the last bill.

There are also many core activities we perform across the customer's lifecycle. Our network planning team are monitoring the health of our assets and identifying emerging needs. This activity is important for maintaining the reliability, safety and security of the network. Our non-network activities are directed at ensuring we have the necessary ICT, property and fleet support to perform our network activities. Like any business, we also need to perform corporate activities such as finance, legal, procurement and human resources support.

The AER classifies our activities into services. This is to ensure that the regulatory processes focus on parts of our business where we are a monopoly or dominant provider, and does not unnecessarily regulate a market where there is sufficient competition. In the 2019-24 determination, the AER classified our services into three broad categories.

Services are classified as standard control if there is no prospect of competition. The AER set a revenue cap for these services based on financing and operating costs. The transportation of energy through our network to our customers is a standard service which is recovered through our network tariffs from a customer's retailer. We discuss our plans for standard control services in Chapters Four, Five and Six.

Alternative services relate to one-off services for an individual customer, or services where there is the prospect of competition. Alternative services are paid for directly by the person or entity receiving the service. This includes our metering services which is discussed in Chapter Seven.

Unclassified services relate to areas of the business where there is sufficient competition in the market.

The AER recently published a preliminary position paper on changes to the classification of services for Power and Water, following a submission we provided. In the paper, the AER noted the changing nature of the energy market and the possibility of new emerging services. The AER also recognised the importance of a customer's connection and ability to export their energy to the network.

Figure 11 – Power and Water activities

1.5 Our costs

Figure 12 shows the relative contribution of activities to total network costs over the last decade and the type of costs we incur.

Capital expenditure relates to building or replacing assets that provide services over a longer period. This includes replacing network assets, building new network assets and connecting customers to the network. Capital expenditure is recovered over the expected life of an asset.

Operating expenditure relates to regular annual expenses such as maintaining assets, vegetation management and emergency response to outages. These costs are recovered on a yearly basis.

Some activities have a mix of operating and capital expenditure. Like other businesses, we have Information, Communication and Technology (ICT), property and fleet assets to support our network activities. Some of these costs relate to assets such as hardware, while others relate to regular expenditure such as ICT support. We also invest in new meters and incur operating expenditure to manage our metering functions.

Network and corporate overheads support our network services. Network overheads include asset management activities we undertake to plan, control and manage the network. Corporate overheads including finance, legal, procurement and human resources to support activities across our electricity, water, sewerage and gas lines of business. We allocate overheads to each line of business in accordance with our Cost Allocation Methodology. We also allocate these costs to capital and operating expenditure depending on the nature of the activity.

Our network has many unique characteristics that impact on our relative costs compared to our peers.

Small scale

We have the smallest electricity network compared to other networks in the National Electricity Market on measures such as customers, energy volumes and peak demand. At the same time, our network is relatively spread out meaning we need to build more network to meet the demands of each customer. We also must meet the same regulatory obligations as larger networks but have to spread the costs over less customers.

Transmission network

Together with Tasmania, we are the only business in Australia that has complete carriage of transmission and distribution functions. Our transmission network in Darwin-Katherine and Alice Springs is extensive with about 400 kilometres of transmission line, 3000 towers and four sub-transmission substations. Being a transmission operator also means we need to ensure that large scale generators can connect safely to our network.

Extreme weather

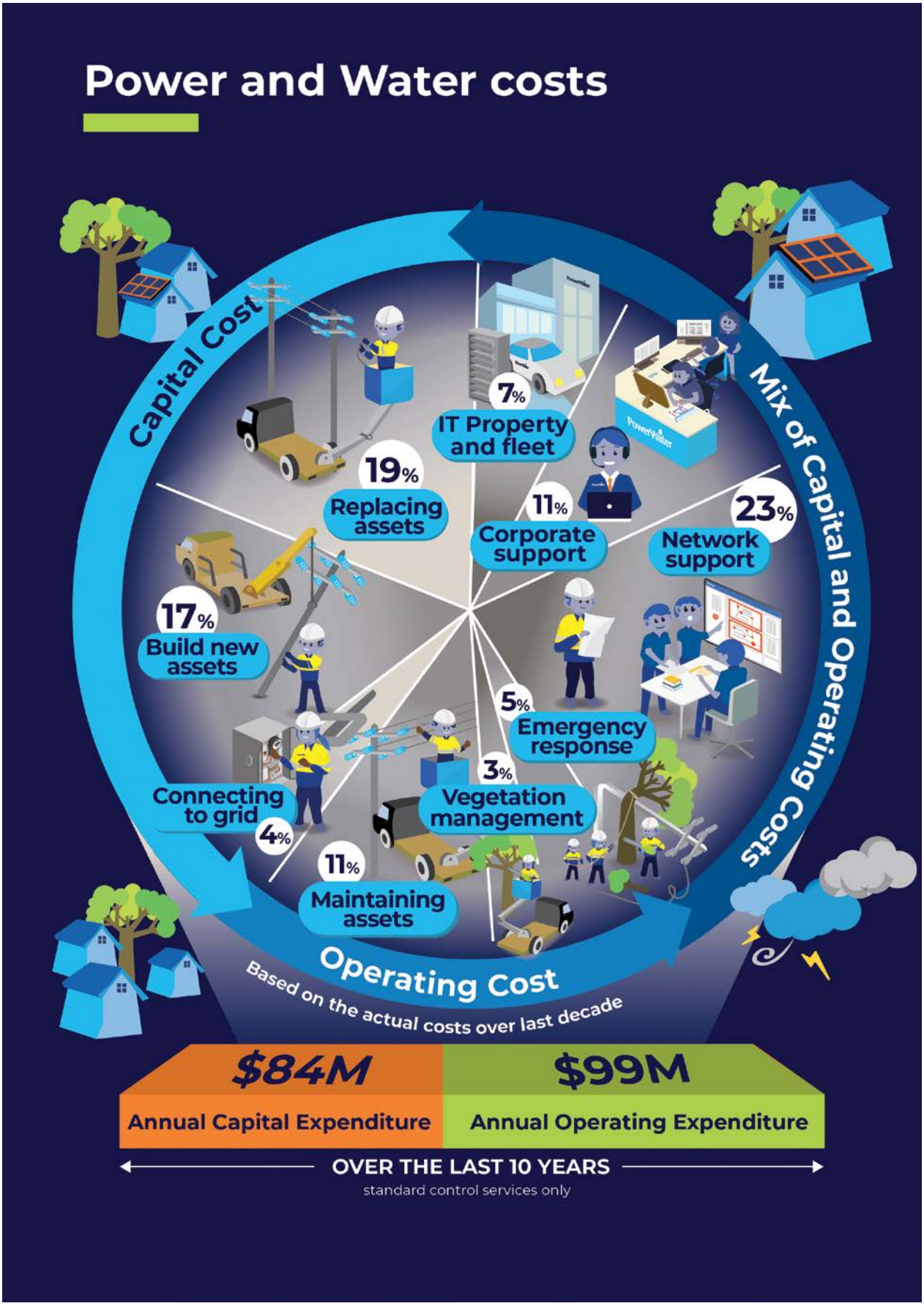
We operate in extreme environments particularly in Darwin which has high humidity in the wet season and is prone to destructive cyclones and tropical storms. We also have extreme heat compared to other places in Australia. These conditions tend to increase our emergency management costs compared to other networks and can lead to more wear and tear of our network assets.

Weather also impacts on labour productivity in humid weather, with our field crews productivity impacted by the extreme conditions.

Unique regulations

Like all other networks, we have licence and reporting obligations and must comply with environmental regulations. We also have unique obligations that impact our costs including traversing sensitive environmental areas. This requires mitigation practices which increases time and cost to undertake network activities. Further, the Northern Territory has many sites of cultural significance and all programs of work need to assess and mitigate against adverse cultural heritage impacts leading to additional costs.

Figure 12 – Types of costs over the last decade



Power lines in Katherine

1.6 Our networks and customers in the three regions

In our consultations with customers, a key message was that each region has its own circumstances and that our decisions should reflect and adapt to meeting the needs of different customers.

We also discussed how each of our regions have a unique network design and environment, and how that impacts our decisions. For example, the assets in Darwin are prone to cyclones and extreme events, while assets in Alice Springs face salinity issues due to the water table. Our customers wanted to understand these differences and how we make decisions in the interests of all customers.

Figure 13 shows the differences between each region in terms of the network and the socio-demographic characteristics. This is discussed further in the sections below.

Darwin-Katherine

The Darwin-Katherine electricity system is a stand-alone power system that provides power to 150,000 people and 8,200 businesses in Greater Darwin and outer suburbs. The system also provides power to 16,000 people and 800 businesses in Katherine. It is our largest electricity network in the NT, accounting for 83 per cent of energy consumption across the three regulated regions.

The Darwin-Katherine electricity system is predominantly powered by gas turbines south of Darwin. In recent times we have seen more large-scale solar enter the energy system and we expect this to accelerate significantly over the next decade in combination with storage to produce 35 per cent of all electricity in the region. In addition to large scale generation, about 10 per cent of electricity production comes from rooftop solar owned by our customers. This is expected to increase to 15 per cent by 2030.

Our transmission network transports electricity north to Darwin and surrounding regions. The Darwin-Katherine transmission line also brings power to customers all the way south to Katherine through Manton, Pine Creek and Batchelor. The transmission network includes 400 kilometres of line and 2,700 towers. Our distribution network is extensive with more than 5,000 kilometres of lines, 32,000 poles, 3,000 transmission towers and 3 zone substations.

Alice Springs

The Alice Springs electricity system is significantly smaller and less complex than the Darwin-Katherine network. It provides power to 26,500 people and 1,750 businesses. It accounts for about 15 per cent of energy consumption across the three regulated regions.

Electricity power is predominantly generated by a large-scale gas turbine south of the main population area. The NTG has a policy to increase renewables to 50 per cent of all energy consumed by 2030. About 20 per cent of our customers have solar panels accounting for about seven per cent of energy production. There is also some large-scale renewables connected to the grid accounting for about four per cent of energy produced.

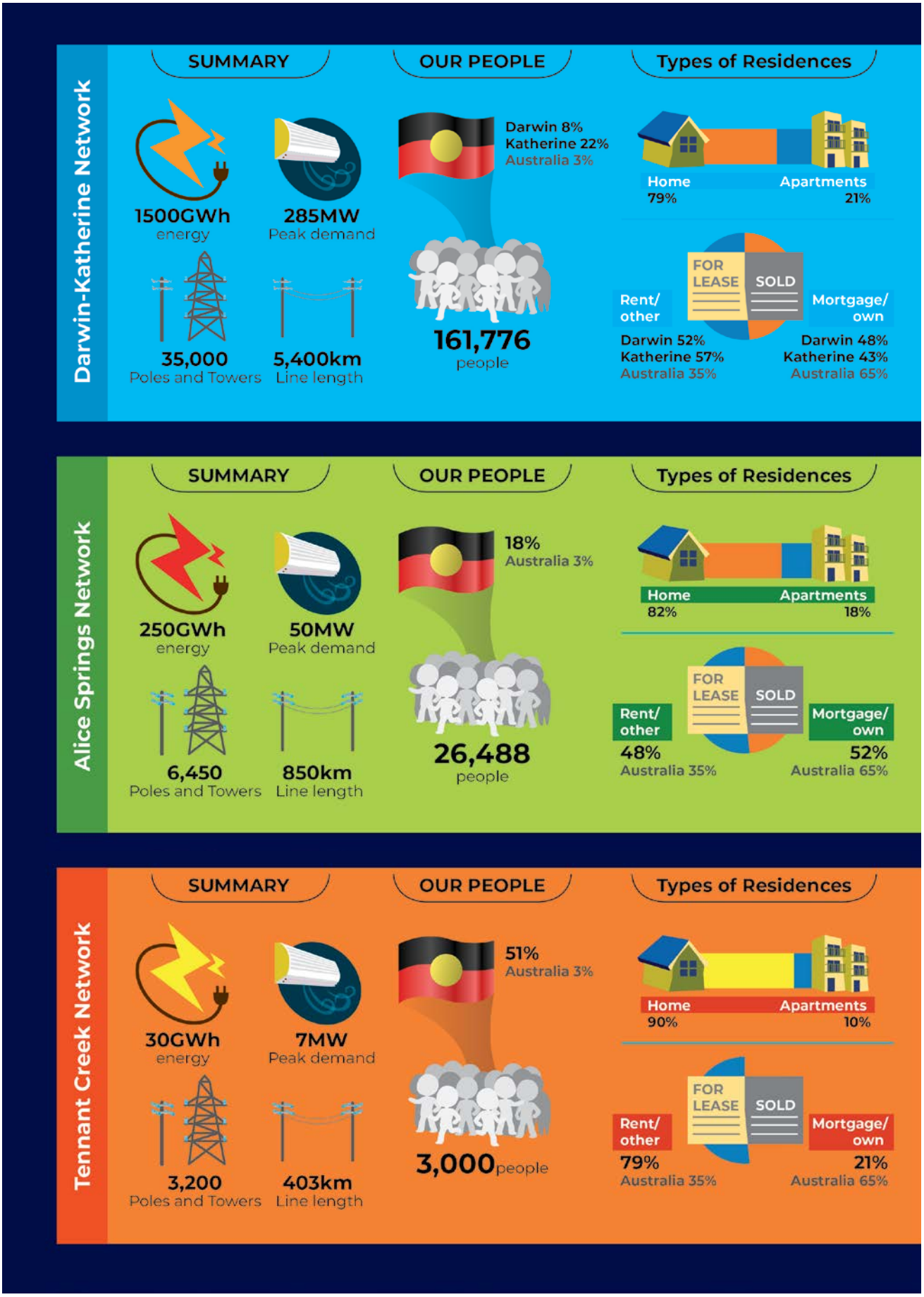
About 30 kilometres of transmission line transports the power to our zone substations. The distribution network comprises about 850 kilometres of electricity lines and 6,500 poles.

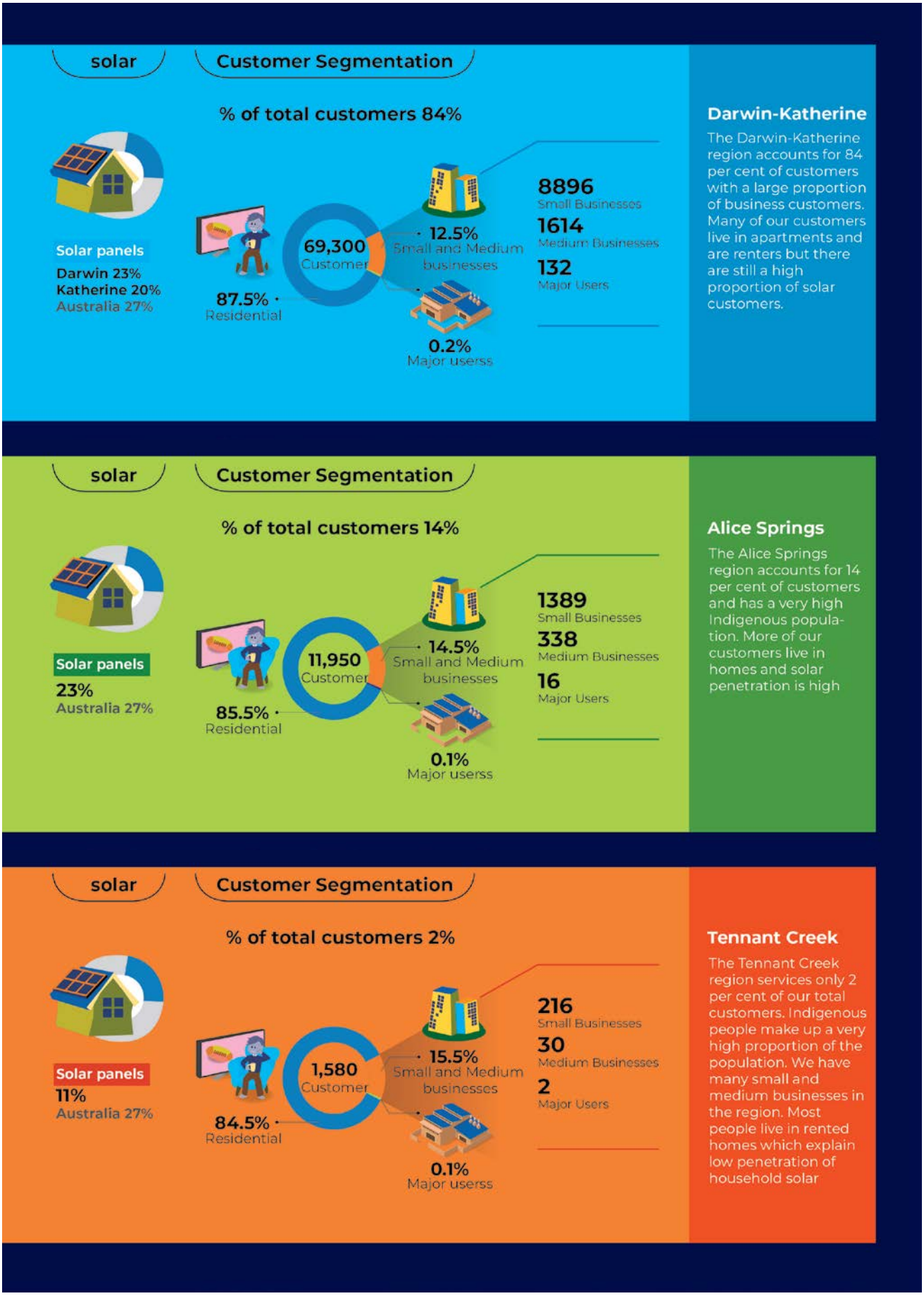
Tennant Creek

The Tennant Creek electricity system is the smallest of our regulated networks. It provides power to 3,000 people and 250 businesses. It accounts for only two per cent of total energy consumption across our three regulated regions.

Electricity is generated by the Tennant Creek Power station and transported to the zone substation. The distance of the network is relatively large for the customer base comprising 400 kilometres of lines and 3,200 poles, reflecting the rural location.

Figure 13 – Comparison of key networks




solar
Customer Segmentation
% of total customers 84%
Solar panels
Darwin 23%
Katherine 20%
Australia 27%
87.5%
Residential
69,300
Customer
12.5%
Small and Medium businesses
0.2%
Major userss
8896
Small Businesses
1614
Medium Businesses
132
Major Users
Darwin-Katherine
The Darwin-Katherine region accounts for 84 per cent of customers with a large proportion of business customers. Many of our customers live in apartments and are renters but there are still a high proportion of solar customers.
solar
Customer Segmentation
% of total customers 14%
Solar panels
23%
Australia 27%
85.5%
Residential
11,950
Customer
14.5%
Small and Medium businesses
0.1%
Major userss
1389
Small Businesses
338
Medium Businesses
16
Major Users
Alice Springs
The Alice Springs region accounts for 14 per cent of customers and has a very high Indigenous population. More of our customers live in homes and solar penetration is high
solar
Customer Segmentation
% of total customers 2%
Solar panels
11%
Australia 27%
84.5%
Residential
1,580
Customer
15.5%
Small and Medium businesses
0.1%
Major userss
216
Small Businesses
30
Medium Businesses
2
Major Users
Tennant Creek
The Tennant Creek region services only 2 per cent of our total customers. Indigenous people make up a very high proportion of the population. We have many small and medium businesses in the region. Most people live in rented homes which explain low penetration of household solar

Power and Water staff with customers at our People's Panel

Key Questions for stakeholders in Chapter One

How can we improve affordability for low income residential customers?

Is our role in the electricity chain in the NT clear and what can we do to improve our communication?

What can Power and Water do better in terms of providing information or service quality?

What role should we play in improving energy efficiency of households?

2. Customer Voice

Customers are at the centre of everything we do and we pride ourselves on delivering valued services. The regulatory proposal is the perfect time for us to engage with customers on what they value and prioritise, so this can feed into our five year plans for 2024-29. Our engagement program has focused on talking to customers about what is important to them and providing the tools to give informed feedback on our strategies and plans. We have specifically incorporated key customer priorities on the future network, addressing the replacement wall, customer service improvements and tariff reform into our plans.

Our engagement has been significantly more extensive and longer than what we undertook in the 2019-24 determination. This reflects an industry-wide recognition that customer involvement in the decision making process can help steer a business towards outcomes valued by our customers. We also see that our customers are more active and engaged in the energy market, particularly given the high levels of investment in rooftop solar panels. Energy is also a household topic as electricity systems transition from fossil fuels to cleaner sources of energy.

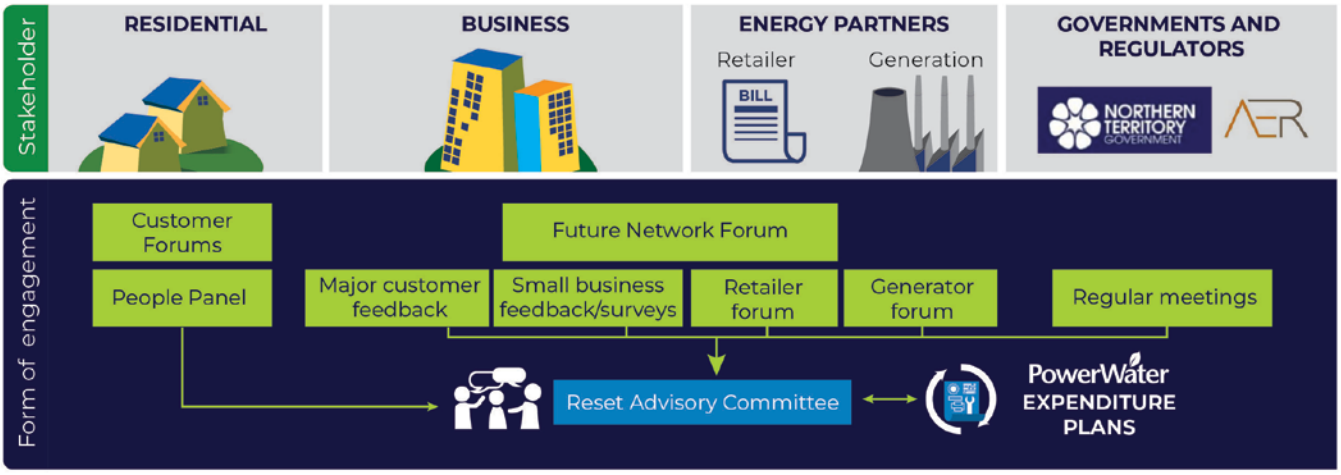
In this chapter, we identify our approach to engagement, the feedback we have received and how we have implemented customer preferences in our five-year plans.

2.1 Engagement to date

Our engagement program has been directed at understanding what our customers value, and what they expect us to prioritise. A key point of difference is that our engagement has moved from seeking the feedback of informed advocates to talking directly to customers about their experiences with our services.

Figure 14 shows that we have involved customers, energy partners, and governments and regulators in our engagement approach through a series of forums and panels. To provide an overarching frame to bring together feedback, we also established a Reset Advisory Committee (RAC) consisting of informed advocates, major users and residential customers.

Figure 14 – Stakeholder engagement segments and forums



Residential Customers

We have made a concerted effort to talk directly with the customers that use our electricity services. This includes establishing People's Panels in both Alice Springs and Darwin. The panels are a representative group of about 20 residential customers in each region. Over two weekends in November 2021 and April 2022, the People's Panels reflected on their experiences as a customer, and what we could do better. The Panels also provided a clear vision of Power and Water in the future and the priorities they thought we should pursue. We have also sought to talk to specific customer groups about their experience including Culturally and Linguistically Diverse (CALD) customers and a Youth Forum.

Business Customers

We have also sought to involve businesses in our engagement activities. Businesses are short on time, and so we sought their views through a survey that aimed to capture the key values and issues they feel are important.

The customer preferences we have identified in this Draft Plan largely reflect the findings of our residential customers through our People's Panels. We recognise that we need to engage more intensely with our business customers in the months ahead to understand if they share the same priorities.

Energy partners

While our customers have been the focus of our engagement, we have been mindful that we are only one element in the 'end to end' electricity system. Our customers expect us to work with generators and retailers to provide a seamless service that puts the customer experience at the forefront. We recognise that this means we need to ensure our plans are compatible with the systems and vision of generators and retailers, and that together we improve the overall customer experience. We have held retailer forums to discuss common issues including improving customer service.

Governments and regulators

Governments and regulators play an important policy and oversight role in our business. The NTG is both our shareholder and legislator. We must ensure our plans align to NTG strategic direction, and this has been a focus of our engagement. We have been also meeting regularly with the AER in pre-engagement on the regulatory proposal and our engagement approach to date. The AER has a dedicated Consumer Challenge Panel that observes our engagement activities and report back to the AER. Finally, we need to discuss our plans with our local technical regulator, the Northern Territory Utilities Commission, who is responsible for setting our local technical and performance standards.

Reset Advisory Committee

Our Reset Advisory Committee (RAC) provides us guidance on bringing together the preferences of different customer segments, ensuring there is a line of sight between our expenditure proposals and customer preferences, and advising on the questions we should be asking stakeholders.

The RAC is comprised of informed consumer advocates with previous experience in regulatory proposals in the National Electricity Market (NEM), local NT customer advocates and representatives from our customer forums. We have not sought to get approval from our RAC for our expenditure plans through a series of deep dives. Such an approach may have excluded the voice and lived experiences of our customers, due to the complexity of material that would need to have been presented. For this reason, we have not sought "fast tracking" of our regulatory proposal by the AER.

The RAC has met at regular intervals since April 2022, and has provided guidance on what questions we should ask in this Draft Plan.

2.2 Topics covered in engagement sessions

Our engagement approach has started from the lens of our stakeholders, focusing on topics and issues of interest to the group, and broadening the topics as information and knowledge expands. We considered alternative approaches such as deep dives into our building block plans but considered this would not provide the foundations for meaningful and informed feedback.

We have sequenced our discussions in four steps:

- **Baseline knowledge** – The first step has been to ensure our stakeholders have a baseline knowledge of Power and Water's business and our role in the regulated electricity network. We also wanted customers to have a baseline understanding of the services we provide and the activities we perform. We also developed materials and sessions that helped explain the AER regulatory process including how our regulatory proposal impacts on electricity costs, bills and services.
- **Exploring themes** – The second step in the process was to identify topics and themes that were important to the stakeholder. We found that all our stakeholders shared a passion and enthusiasm on how renewables will be integrated into the energy system, and our role in facilitating this transition. This led to us hosting two Future Network Sessions in November 2021 and June 2022. A further theme was the strategic challenges that lie ahead for Power and Water and how we can offer an affordable and reliable service in the long run. This theme also explored our journey to date and the role of benchmarking.
- **Identifying pain points with our current services** – Using the customer journey framework discussed in Chapter One, we explored areas of our business where customers felt we could improve. **Figure 15** on the next page shows the key issues and our discussions with customers on avenues for improvement
- **Identifying values, vision and priorities** – The fourth step was to understand our customers values, and the relativity of these values. The key to this conversation was the trade-off between affordability and service quality, particularly long-term outcomes. In this context, we were able to understand that customers were not willing to pay more for services except key priorities such as the future network. This conversation also led to a better understanding of our customers' vision for Power and Water in the NT.

The Draft Plan provides an opportunity to contextualise how customer feedback has influenced our strategic thinking and expenditure plans. For example, our initial plans presented to the People's Panels in March and April 2022 did not include automated solutions to unlock solar and did not seek to plan for an expected uplift in replacement beyond 2030. Based on the People's Panels recommendations, we have now included these specific expenditure items in our 2024-29 expenditure plans. A further example is the reductions in our bottom-up plans compared to our initial estimates to lower the revenue in the 2024-29 period.

The final steps in our engagement approach will be to delve deeper into our expenditure plans and revenue as part of our engagement sessions after this Draft Plan is released. By bringing our customer groups on the journey over the last nine months, we consider they are in a better place to provide informed feedback on our plans. In future engagement sessions, we will focus on topics that are both material and can be influenced by customer feedback.

Figure 15 – Pain points of our customers

Tree trimming

What we heard?

You would like us to take better care when trimming trees so they remain visually attractive and healthy.

How we are responding?

- We continue to employ qualified arborists and trimming crews to manage vegetation to a high standard.
- Started a tree replacement program trial in Alice Springs so that problematic trees are replaced with more appropriate species.
- We have implemented a new 'Hazard Tree' identification process to work with customers and councils to replace trees that pose a direct risk.

Meter reading

What we heard?

You would like to see more reliable meter reading with less reliance on estimates of electricity usage.

How we are responding?

- We engaged a new meter reading contractor in late 2021. Additional meter readers are being employed and we are working with the new contractor to improve performance.
- We are deploying new meters that can be remotely read without the need for a meter reader and the associated challenges.
- We are upgrading our IT systems which will improve our management of customer data.

Communicating with customers

What we heard?

You would like more face-to-face engagement, especially for those customers who are not online.

How we are responding?

- We will increase customer awareness of the option to request a face-to-face meeting if required via the call centre.
- Investigating options to have a 'pop-up' shopfront at major shopping centres once a month.

Information on solar

What we heard?

You would like more information on solar and the installation process, and impartial information on products and options.

How we are responding?

- Our website has updated information and links to assist customers in understanding solar. This includes what to consider when purchasing and connecting solar, and where to find further information.
- Our website also provides links to The Clean Energy Council which represents companies who work in and around renewables and has guides and advice on buying and installing solar.

Moving house

What we heard?

You would like us to consider improvements to our connection and disconnection processes when moving house.

How we are responding?

- We have improved the information published on our website to provide all the information customers need to know about connection and disconnection in an accessible format.
- We are investigating development of an online process for applying for connection to further simplify the process for customers.

Outages

What we heard?

You would like better communication from us during disruptions.

How we are responding?

We have implemented new processes and supporting technology to more rapidly assess damage after a cyclone. Similarly, these new processes and systems will also apply to managing the hazards associated with damage to the network such as fallen power lines.

2.3 Our customers' vision for Power and Water

In our stakeholder consultations, we focused on unpacking what our customers thought about the future and the role our network should play in it.

A key theme has been about embracing the renewables future. Our customers wanted us to facilitate and actively support the shift to renewables. Our Darwin People's Panel thought we should even go further by leading change on renewables. This was also central to the views of broader stakeholders in Future Network Forums. There was a view that Power and Water needed to have a Future Network Strategy that sets the network up to facilitate growing renewables well beyond 2030.

A further theme was about helping customers in broader decisions on energy – from how to use power efficiently, to decisions on solar, batteries and electric vehicles. In particular, our customers felt that our active involvement in the energy industry was vital in a changing market where customers had to make decisions without a trusted advisor.

Our Panels also talked about improving our communications, including platforms that are more active and responsive. There was a view that we had to improve the diversity of our communications so that we were accessible in all forms used by customers – from face to face, to telephone to social media. Inherent in these discussions was a view that Power and Water should keep pace with modern technology, but also accommodate traditional modes of communication.

In our discussions with stakeholders, there was much emphasis on not letting the network run down, with the memory of the Casuarina zone substation failure in 2008 front of mind. Our customers wanted us to think ahead on these issues.

Figure 16 provides the vision designed by each Panel in Darwin and Alice Springs. This has informed our strategic priorities for the next 20 years as discussed in Chapter Three .

Figure 16 – Vision of customers in our Alice Springs and Darwin People Panels

2.4 Values and trade-offs

A key focus of our engagement sessions has been trying to unpack the values and vision of our customers and how this has influenced the feedback provided. This has helped us make decisions on complex trade-offs when developing this Draft Plan.

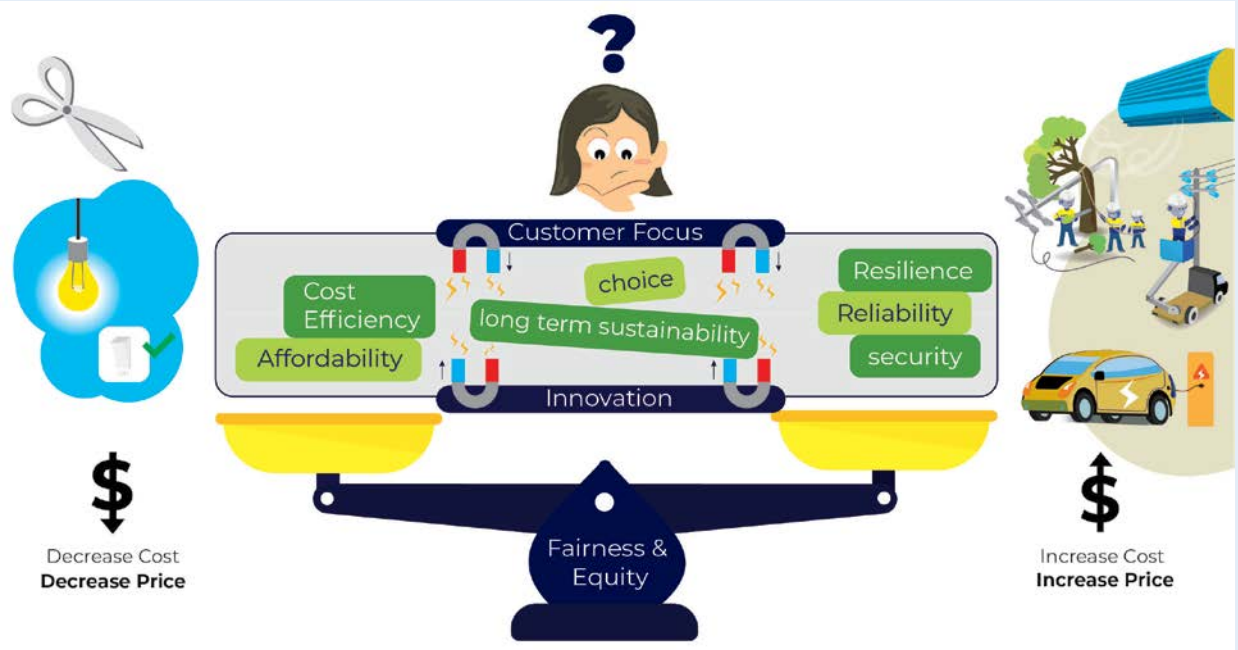
In our initial People's Panels, we explored the key values customers thought were essential for our business to consider. The conversation showed there were multiple values that were important to customers including affordability, sustainability, measures of network performance such as reliability and security, cost efficiency, equity and fairness and choice.

We also discussed the relative trade-off in values that may bear on decisions and feedback as depicted in **Figure 17**. For example, our customers recognised that improving affordability could come at the cost of reliability and long-term sustainability. There was also an understanding that the relative importance of values can change in different contexts – for example affordability is more important when there are other cost of living pressures.

Overall, our customers considered that all values were important. At the centre of decision making was the issue of affordability, particularly for customers with lower incomes. Customers did not want to see an increase in the electricity bill unless there was a clear need. Customers had a clear expectation that Power and Water will safely manage reliability, safety and security noting that they did not want the network to be 'run down'.

Customers recognised that Power and Water needs to look to the future when developing the five-year plans, and that this may entail some trade-offs with short term affordability.

Figure 17 – Customers values and trade offs



2.5 Customer preferences on key issues

In our People's Panels sessions in Darwin and Alice Springs, our customers provided feedback on the direction we should pursue on key strategic areas. **Figure 18** identifies each of the four priorities and how they have been embedded in our expenditure, revenue and tariff plans for the 2024-29 period.

In our discussions on preferences, we sought to understand how our customers were weighing up and trading off values. This was to ensure that customers understood the implications of preferences, but also to provide us with a deeper understanding of what is important to customers in making our business decisions.

Customer Preference One – Future Network

A consistent theme in our customer consultations was the need to facilitate increasing renewables on the energy system in the NT.

We explained to customers the difficulties in managing two-way flows on the network due to voltage issues and minimum demand and noted this would mean more of our new customers may face constraints in how much they can export. We also noted that constraining exports would mean a lost opportunity for all customers due to the relative low cost of solar compared to thermal generation.

We provided options to customers on solutions that could unlock and store more solar. The general view of our People's Panels was that we should invest more to facilitate and support solar where technologies are proven and that we should move forward by piloting new technologies. Community outcomes should be considered to ensure no one is left behind.

The Draft Plan includes additional expenditure to support our Panel's preferences including:

- Hosting capacity program (estimated $28 million capital expenditure) in our growth capital program. We are currently working through a business case where we are developing a scalable hosting solution that will increase the ability of the network to increase exports over the 2024-29 period.
- Community batteries (estimated $13 million capital expenditure) in our growth capital program. We are undertaking a business case assessment on community batteries in Darwin and Alice Springs.
- Step changes in our operating expenditure related to enabling future network initiatives ($4 million) and ICT opex ($3 million).

Customer Preference Two – Addressing replacement wall

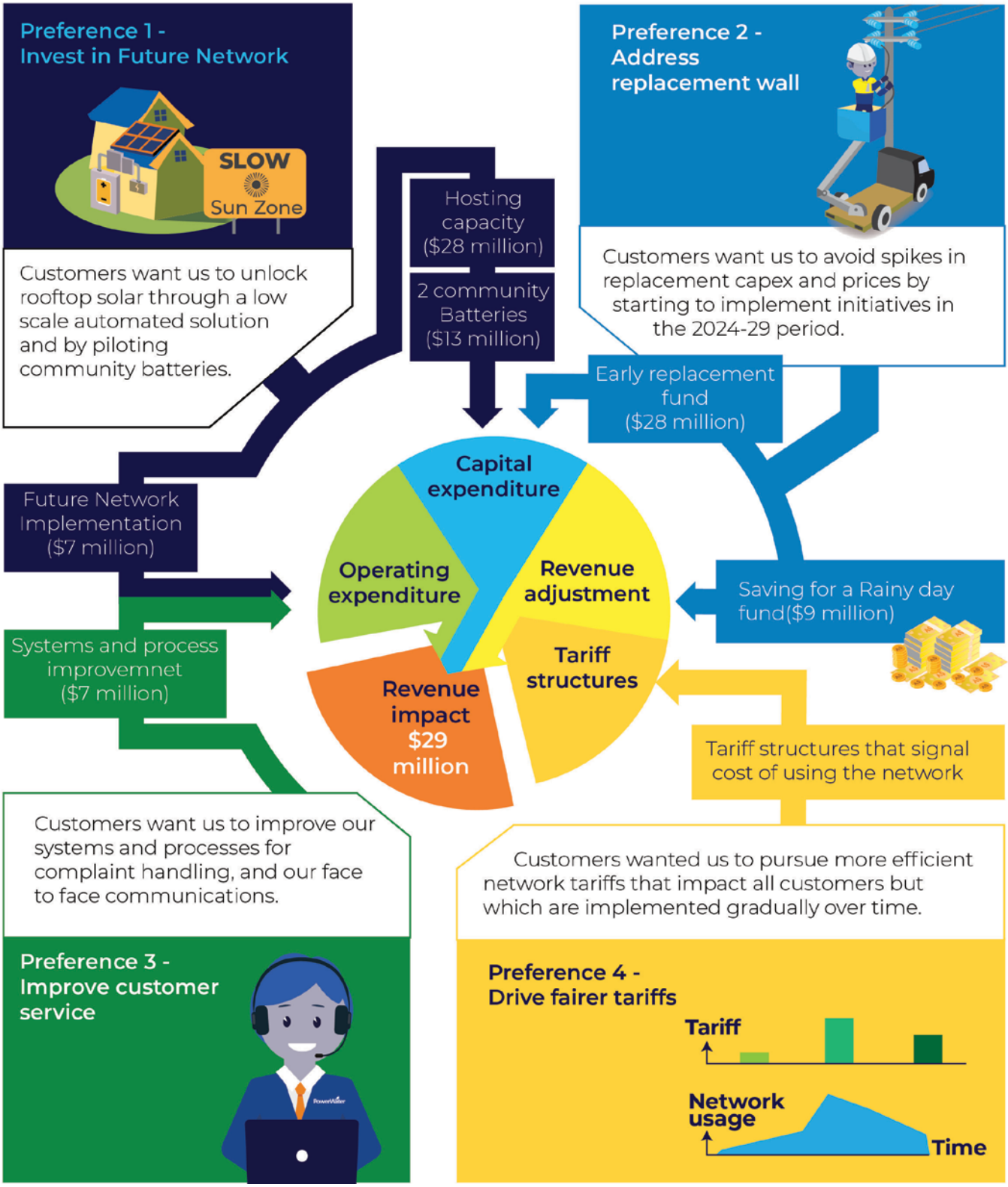
Our People's Panels wanted us to maintain the health of the network for the long term. In our discussions, we noted that significant renewal of the network will be required over the next 20 years to replace the high proportion of assets installed after Cyclone Tracy in 1974. These assets are likely to reach the end of their technical life between 2030 and 2040, with about a third of assets over 50 years of age by 2040. We noted that a sudden uplift in replacement capex would lead to a spike in our electricity revenue in that period and cause affordability issues if passed on to customers.

We noted that our replacement plans for the 2024-29 proposal were focused on replacing assets where the risks exceed the costs. We noted alternative options to address the potential spike in replacement needs and revenue beyond 2030 including bringing forward replacement and a saving fund for future replacement. Our customers considered that a combination of these alternative options should be pursued.

The Draft Plan includes two initiatives to implement the preferences of our People's Panels.

- In our capital plans, we have included a replacement fund of $28 million in the last three years of the 2024-29 period to replace assets that could technically be deferred to beyond 2030 with minimal risk. The replacement fund adds about 10 per cent more to our forecast replacement capex.
- In our revenue adjustments, we have included a "saving for a rainy day fund" equivalent to one per cent of annual revenue in each year of the 2024-29 regulatory period. This adds $9 million of revenue to the 2024-29 period.

Figure 18 – Customer preferences and impact on our five-year plans



Customer Preference Three – Improving customer service

Our People's Panels raised issues with our customer complaint process. Our Alice Springs Panel also considered that the closure of our shopfronts had restricted face to face communications with our staff.

In our discussions on the complaint process, we discussed potential options that may improve the process, including minor improvements to our process and systems, a dedicated officer within Power and Water or appointing an independent person to decide before the matters go to the Ombudsman. The Panels noted we need to do more than currently. They asked that we consider systems which provide more feedback on complaints, better communication on existing options to integrate with face-to-face engagement, and refinements to the existing telephone system to provide feedback on whether enquiries were addressed.

The Panels recognised that shopfronts were costly and noted that we currently provide all customers with an option to meet face-to-face with our staff. They also noted our current arrangements to visit the customer if requested. The Panels considered Power and Water should look at ways to increase face to face options for customers, including better communication, and consider joint initiatives with other energy partners such as Jacana.

The Draft Plan includes a step change in our operating expenditure program ($4 million) for new systems and processes to activate customer preferences on improving customer service.

Customer preference Four – Fairer tariffs for all customers

Our People's Panels recognised that all customers could benefit from price signals that indicate the cost of providing network services. While they understood that small customers do not see the network component of tariffs on their electricity bill, they still saw a need for driving more efficient tariffs.

Our Panels were provided with options on the speed and intensity of tariff reform for the 2024-29 regulatory period. 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. However, they were of the view that all customers should be impacted by changes in tariff structures.

In total, the customer preferences have added $29 million of revenue to our forecast for the 2024-29 period.

A question from a residential customer at our People's Panel

Key Questions for stakeholders in Chapter Two

Is our engagement approach capturing all voices of the NT?

Have we been providing the right information for our audience?

Have we missed any crucial feedback?

What concerns do you have on how we implemented customers' preferences?

3. Strategic priorities

Our small network will be subject to significant global and local changes that impact the way we deliver electricity to our customers over the next 20 years. We have identified key long-term strategic priorities that have influenced the development of our five-year expenditure, revenue and tariff plans. Our customers' vision and priorities have played a pivotal role in shaping these priorities.

We are living in a period of unprecedented and rapid change. Our small network is being disrupted by global trends from climate change to market uncertainty. At a local level in the NT we are also facing a myriad of change factors in the years ahead from the need for a significant uplift in replacement of network assets to meeting the demand needs of a growing NT. This is reflected in **Figure 19.**

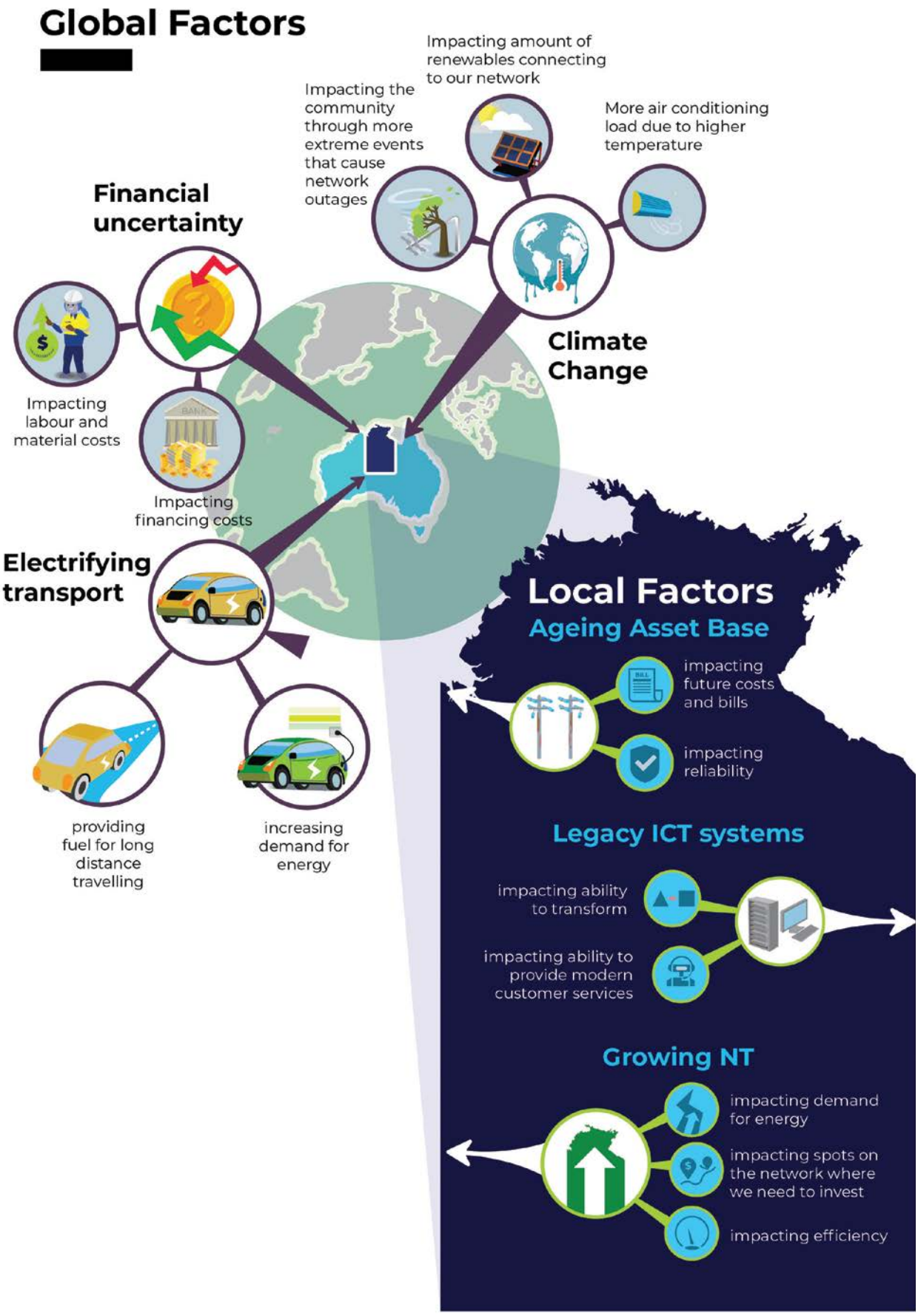
The global factors include:

- **Responding to climate change** – Climate change has accelerated the need to switch to renewable energy, impacting the way our network delivers energy to our customers. The impacts of climate change will also impact reliability of our services, with more extreme weather events such as cyclones requiring a greater need to make the network more resilient. We also see that increasing extreme heat days may lead to more extreme peak days as customers use more air conditioning.
- **Electrification of transport** – The shift to electric vehicles will significantly increase consumption and demand for electricity in the NT. This will also impact the time, seasons and locations where energy is required to be delivered from our network depending on when and where customers charge their vehicles.
- **Financial uncertainty** – During recent times of low interest rates, our customers have benefited from a reduction in our costs to finance our investments. However, financial conditions are currently volatile with high inflation likely to result in higher interest rates. Disruption to supply chains together with higher inflation are also likely to lead to higher input costs for delivering our services.

In respect of local factors we see three drivers of change:

- **Replacement wave** – Unlike other states and territories, a significant proportion of our asset base was built following the aftermath of Cyclone Tracy in 1974. This means that inherent reliability will likely decline as our assets age beyond their standard life. To maintain reliability, we will likely need to increase our replacement well above today's levels which will have a consequent uplift to our costs.
- **Refresh of ageing ICT system** – With the exception of our metering and billing systems, our existing fleet of ICT systems have not been refreshed for a generation. This impedes our ability to transform efficiently as a business and to deliver modern services required by our customers.
- **Growing NT** – The Northern Territory Government has set an ambitious goal of achieving a $40 billion economy by 2030. We note that many major infrastructure projects have already been announced. We also anticipate increasing connections from large users over the coming years will impact on network demand and may trigger the need for targeted investment in particular parts of Power and Water's network to accommodate increased demand for network capacity.

Figure 19 – Changes impacting our network



In response to global and local drivers, we have identified four key strategic priorities for the next 20 years. These strategies have influenced the development of our five-year expenditure plans.

3.1 Strategic Priority One – Facilitating renewables

Under NTG policy, we expect that 50 per cent of energy consumed will come from renewable generation by 2030. Approximately 30 per cent will come from large scale renewables that connect through our transmission network. About 20 per cent is expected to come from roof top solar connected to our smaller customers' houses and exported back into the grid.

This presents engineering challenges for the design of our network. For the transmission network, we will need to build lines to connect generation located in different areas to the current thermal generation stock, and ensure that the network can securely transport the renewables to the load centres. For our distribution network we will need to manage voltage and minimum demand challenges from two-way flow of exports.

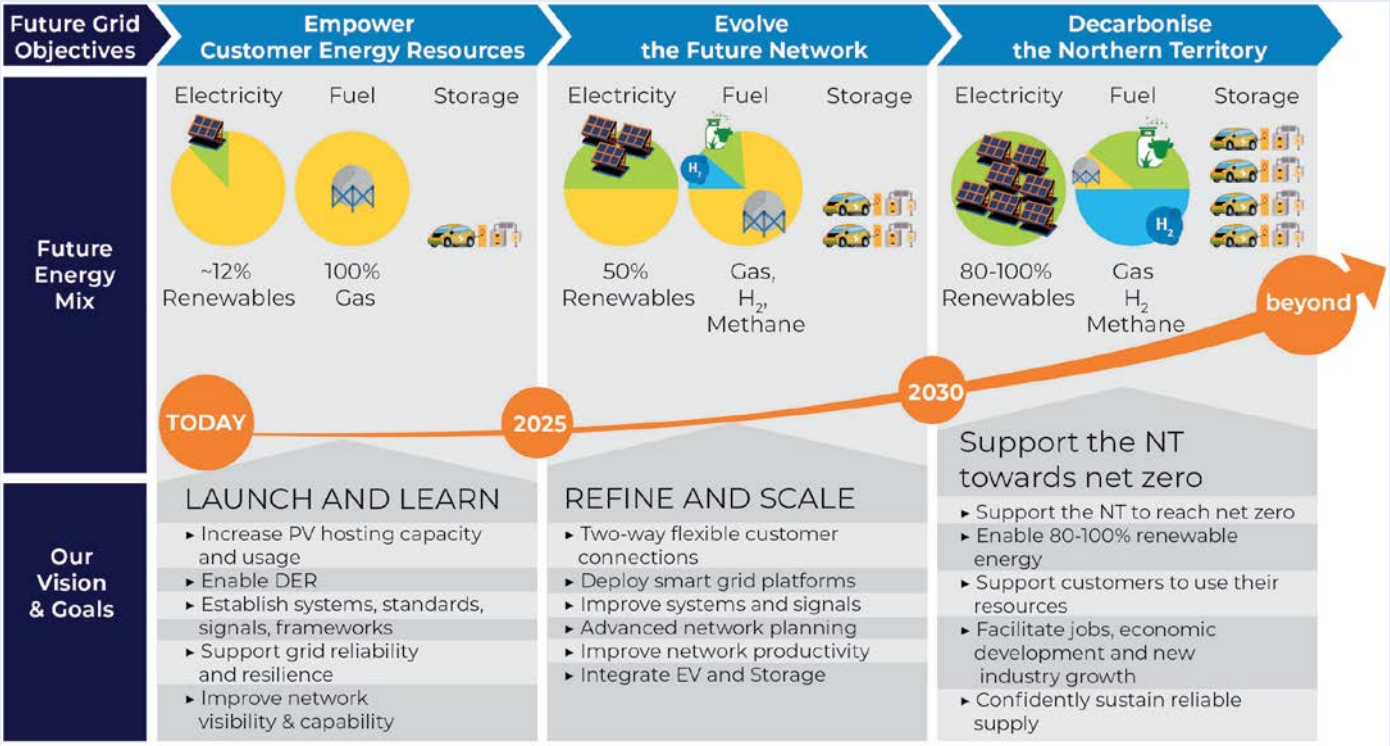
While there are challenges ahead, we also see great potential benefits from unlocking renewables in the NT. Our current electricity system is predominantly powered by gas, which is a relatively costly fuel source. In contrast, solar is abundant in the NT and the technology is significantly less costly than gas. Building a network that can facilitate large scale transmission and household exports can provide lower generation costs for all customers that outweighs new expenditure on the network.

We also see that playing our part in decarbonising the globe will help avoid catastrophic environmental changes that will impact us here in the NT. Abating the impacts of climate change will mean spending less on making our network resilient in the face of cyclones and extreme heat.

A key theme in our engagement with customers has been the need for Power and Water to facilitate a renewable energy system in the NT. We have responded by developing a Future Network Strategy with the purpose of ensuring our network can eventually facilitate net zero.

In June 2022, we held a second Future Network Forum which discussed the development of our strategy to 2040. **Figure 20** provides an overview of the timeline and plan. The plan discusses three key phases to facilitate higher levels of small scale renewables. The Empower stage is about increasing export capacity using existing tools while building the systems and visibility of the network. The Evolve stage is about activating exports through a smaller scale dynamic export solution, where the network can send out signals to ramp up and ramp down exports based on real time constraints. The Decarbonise stage is about scaling up our systems and solutions to unlock exports to meet a 100 per cent renewable target if required.

Figure 20 – Future Network Strategy



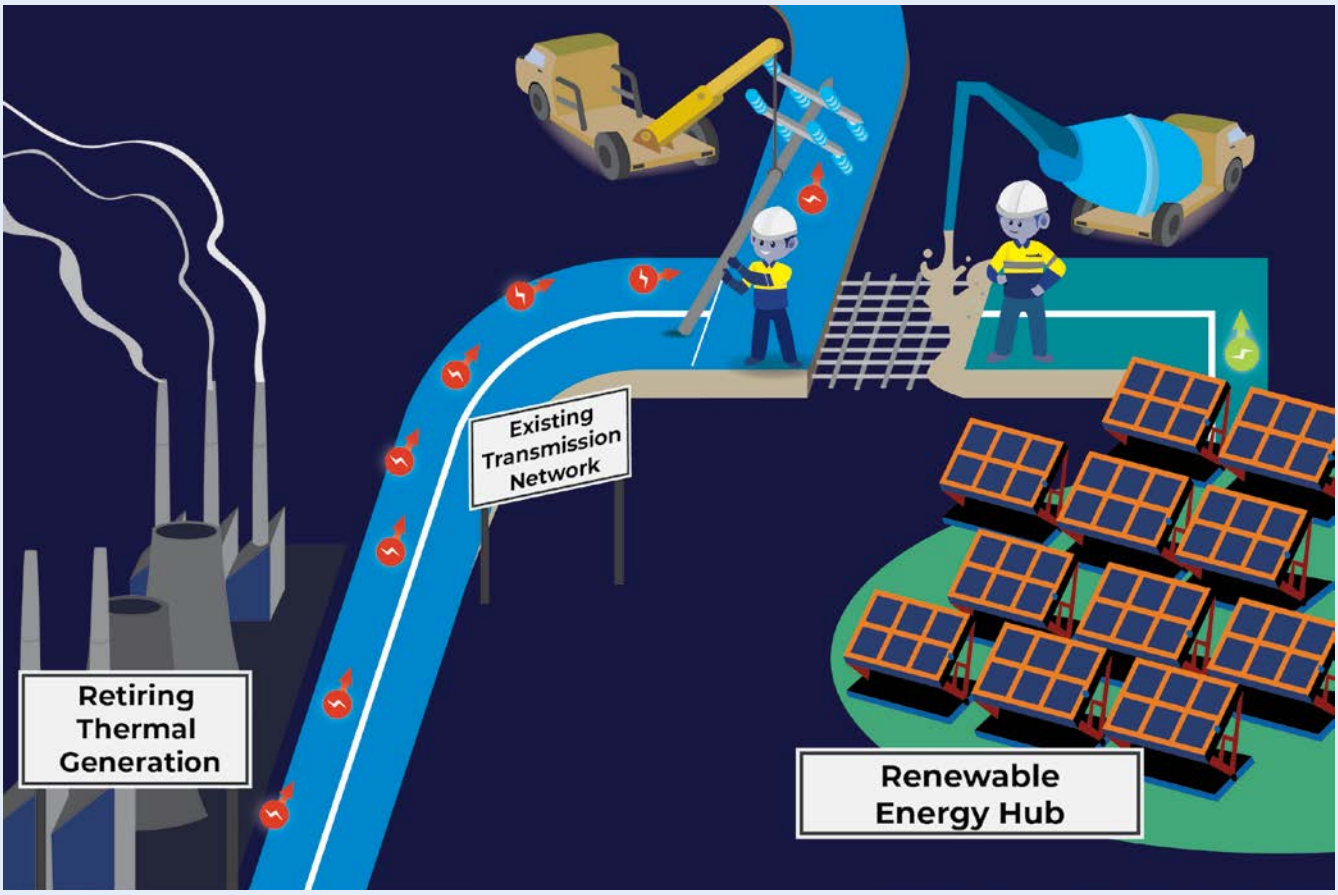
Connecting renewables to our transmission network at least cost

The first element of our strategy is to design the transmission network to connect new large-scale renewables at lowest cost. This has the benefit of reducing our long-term transmission costs and improving affordability for all customers. The key to lower costs is for generators to locate close to existing transmission infrastructure with spare capacity as seen in **Figure 21.** For this reason, we strongly support the concept of a Renewable Energy Hub identified in the Darwin-Katherine Electricity System Plan.

The renewable hub is still in an implementation phase so there is not sufficient clarity on costs, timing or scope to include in our capital expenditure allowance at this stage. Under the regulatory framework such projects are excluded from the allowance, and included as a contingent project. We discuss this further in section 5.6. While we see the Renewable Hub as increasing our network costs in the 2024-29 period, we note the NTG's analysis which shows it unlocks lower generation costs in the electricity system.

Beyond 2030 we expect even more large-scale renewables to connect and deliver higher levels of energy to support growing demand. This means the transmission landscape is likely to become complex in the future and may require expansion. We consider that transmission costs are likely to be minimised through more Renewable Energy Hubs that allow for centralised, rather than piecemeal expansion of the transmission network.

Figure 21 – Renewable hubs for large-scale generation



Cost effectively unlock small scale renewables

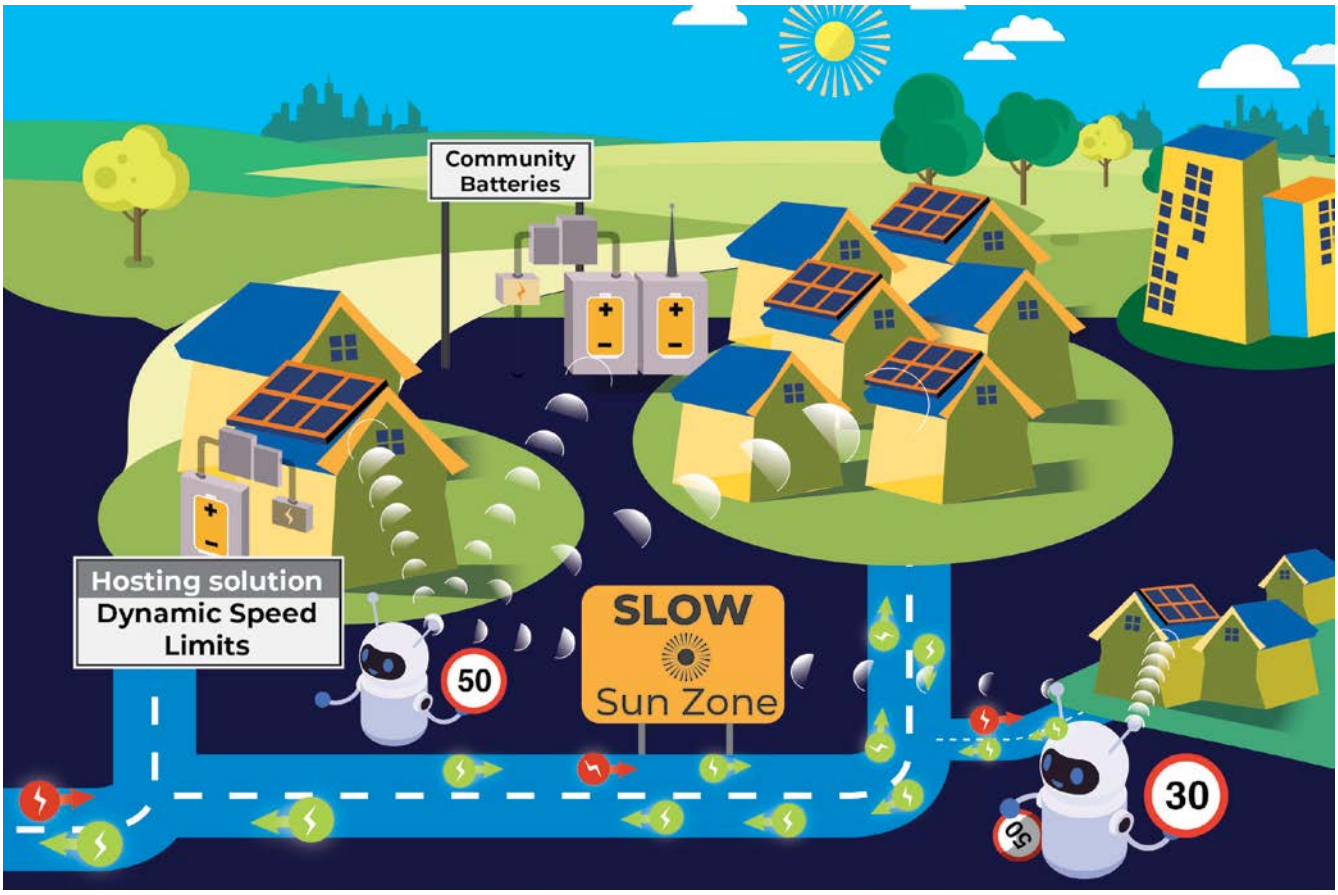
In its current design, the network will not be able to securely export all of the forecast generation from rooftop solar due to voltage and minimum demand challenges.

This adversely impacts on customers installing new solar who cannot maximise their investment. It is also a lost opportunity to reduce generation costs for all customers as solar has significantly lower cost than thermal generation.

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 in our Future Network Strategy 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.

Figure 22 provides a visual of dynamic operating envelopes working in a similar way to dynamic speed limits. In the figure, the hosting solution is depicted as robots that sense when the network is outside of safe voltage and thermal limits and seeks to reduce the speed of exports. At times of constraint, power can be stored in community batteries and discharged in the evening peak period.

Figure 22 – Unlocking household solar



3.2 Improving utilisation

One of the keys to unlocking affordability is providing more power to customers while minimising new expenditure.

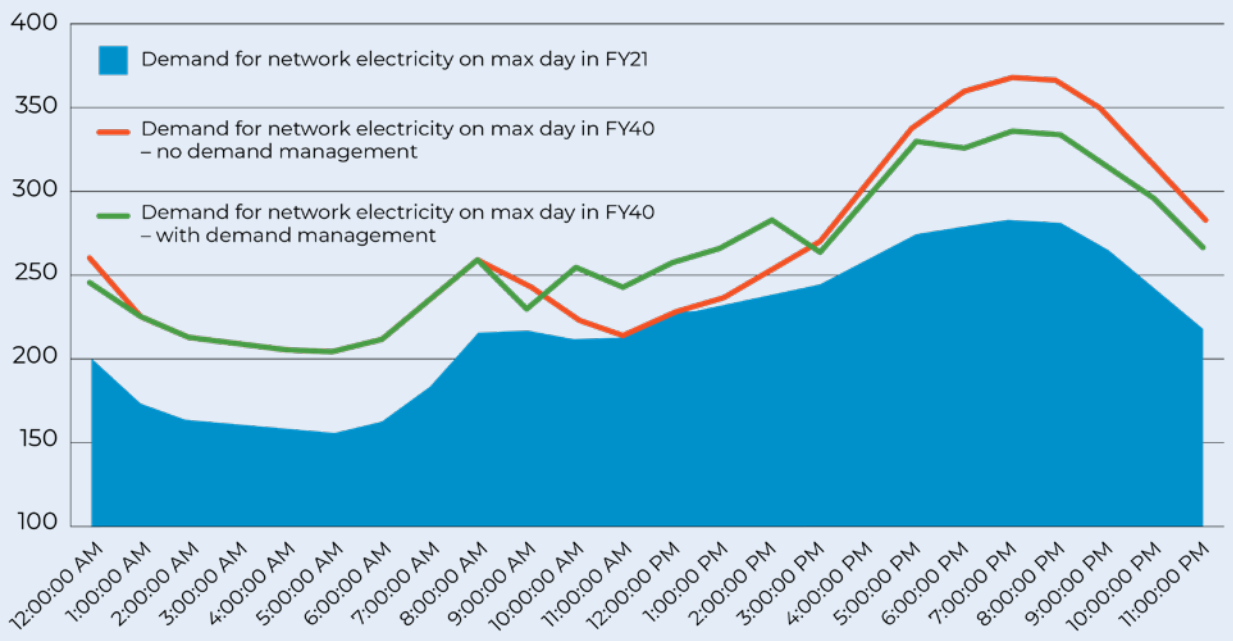
A key strategic priority is to encourage new and existing customers to use electricity in off peak periods that coincide with low cost solar. Early analysis shows that electric vehicle charging times are one of the key levers to improving utilisation beyond 2030. A further strategy is to see if storage batteries can also be used to store excess solar in the day and discharge in the evening peak.

In our discussions with customers, we have noted that tariff design is a key mechanism to encourage customers to use more energy in the day. This is a key element of our 2024-29 Draft Plan as discussed in Chapter Eight.

Figure 23 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 370MW 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 330MW. This will lead to significant reductions in our new growth capital expenditure in the future.

Figure 23 – Improving utilisation of our grid (MW)



3.3 Managing the health of our assets smoothly over time

A key strategic priority for Power and Water is safely maintaining the reliability of the network as assets age over the next 20 years while minimising cost and price spikes for customers. This has been a key theme in our engagement consultations with customers.

Our current replacement rate is well below a long-term sustainable rate due to most of our assets being younger than their expected manufacturing life. The dark blue line in **Figure 24** shows that nearly all our network assets are under 50 years today but that a significant cohort are close to this age. This is explained by the unique circumstance in the NT where our network was re-built in a short period of time following Cyclone Tracy in 1974. The orange line shows that by 2040 a large proportion of these assets will be over 50 years by 2040 even if replacement is uplifted to $50 million per annum.

At present our strategy to manage the health of our assets has been to only replace when the asset fails in service or if the risks to safety, reliability and environment outweigh the costs. This is a strategy to ensure we maximise the full life of the asset while keeping risks within a reasonable bound.

However the rapid ageing of our cohort of Cyclone Tracy assets will require a significant uplift in our capital expenditure when the assets start to deteriorate and risks emerge. The expected scale of replacement in a short period is unique to our network given a large portion of our assets were built at the same time. A sudden rise in capital expenditure has a consequential impact on the revenue we require to fund our investments.

In our discussions with stakeholders we considered how we should approach the issue to avoid potential price shocks in the 2030 to 2040 period. The key strategies we have developed include:

- **Asset management to extend asset life** – The key to addressing the replacement wall is to lengthen the lives of assets so investment can be spread out over a longer period. Over the last decade, we have vastly improved our monitoring and decision-making on maintaining and replacing assets. This has helped us keep some of our assets in service longer than their technical life despite the inclement conditions on our network. We recognise that continual improvement in our asset management process such as our new risk quantification will help us better prioritise works so that we are replacing assets in order of highest risk.
- **New technology and design to retire assets** – New technology may provide some of the tools to help us retire rather than replace assets, keeping a lid on the replacement wave ahead. For example, we are currently looking at microgrid solutions for some parts of our remote areas rather than re-building existing infrastructure.
- **Smoothing mechanisms to mitigate against price shocks** – A novel mechanism suggested by our People's Panels was a savings fund where some revenue is set aside today to pay for an expected increase in costs in the future. Our customers also considered that some replacement activity could be brought forward to minimise risks when the assets age at the same time and this would smooth out revenue over time. These programs have been included in our expenditure plans to forecast capital expenditure in Chapter Four, and revenue in Chapter Six.

Figure 25 provides some early analysis of why this strategy can help smooth capex over time without exposing our customers to high risks. We developed three scenarios that are based on ensuring network risk levels from older assets can be managed over the next 20 to 30 years.

Scenario One is a situation where we minimise replacement to 2030. Under this scenario, we would expect to increase replacement when systematic conditions emerge in 2030-35 and accelerate replacement significantly in the 2035-40 timeframe. Based on this replacement profile, we would safely manage the reliability of the network by ensuring only 20 per cent of the total population is over the age of 50 by 2040. Under this strategy, there is a spike in capital expenditure in the 2035-40 period of close to $500 million for replacement, which would flow onto a spike in our revenues.

Scenario Two seeks to smooth capex through spending more on replacement in the 2025 to 2035 period. While there is a significant uplift in the 2035 to 2040 period, it is less pronounced than Scenario 1. In this scenario, we would use mechanisms such as 'saving for a rainy day' fund to help keep the revenue impacts as low as possible in the period of uplift. We would also be focusing on improved asset management techniques to allow risks to be maintained at similar levels to Scenario 1 by keeping a greater proportion of older assets on the network.

Scenario Three seeks to further extend the life of assets together with a focus on retiring rather than replacing assets on the network. Under this preferred strategy, we would be able to minimise the extent of capital uplift over the next 20 to 30 years. While this is the optimal strategy it relies on technology solutions that we do not have today.

Figure 24 – Ageing of the asset population

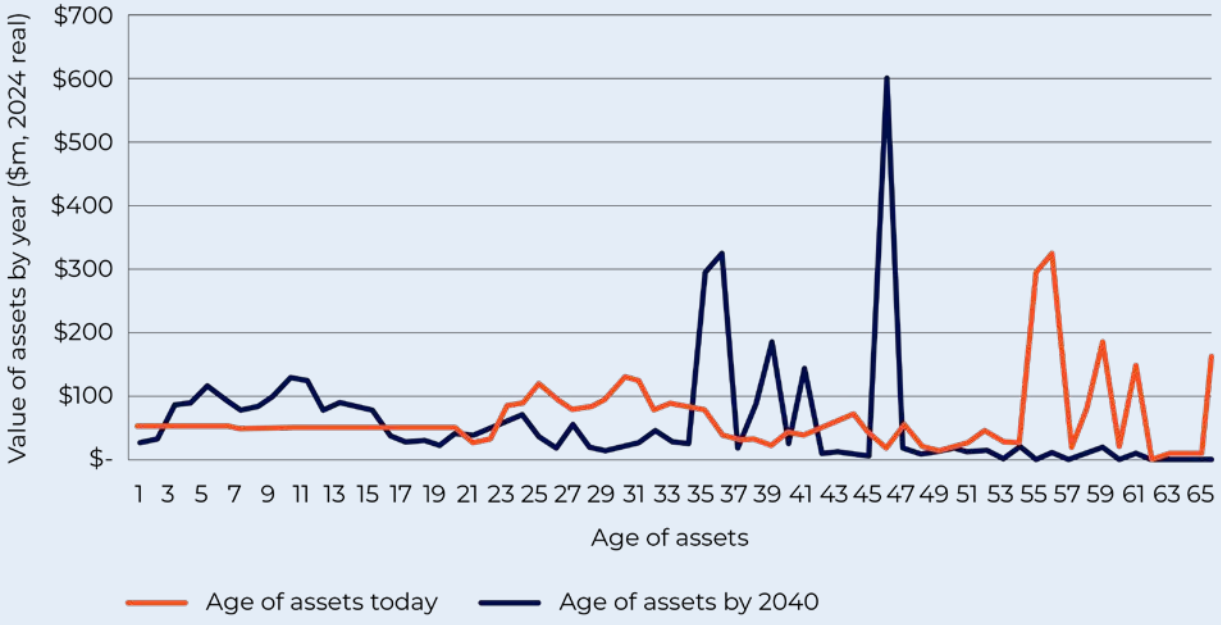
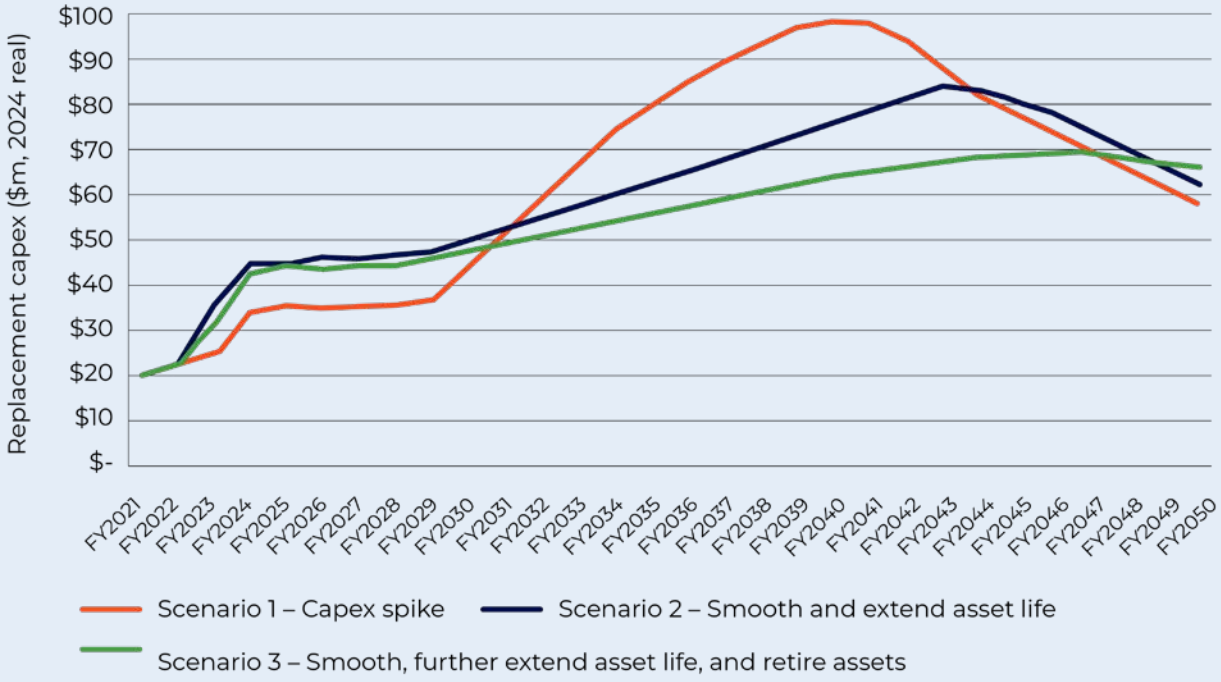


Figure 25 – Long term replacement capex scenarios



3.4 Uplifting our systems and people

Our business will need to deliver more as we transition to a network that delivers two-way renewable energy and which meets higher levels of demand for electricity in a more complex environment. At the same time, our customers are telling us that we need to maintain the affordability of our services. In this context it is vital that we invest in smarter systems and organisational change that allows us to meet new demands for our network services while keeping a lid on our costs.

In the 2019-24 period we embarked on a transformation journey that involved a new operating model and a refresh of our ageing ICT systems. It was an ambitious program and complex to implement at the speed we had intended. This was due to the difficulty of undertaking transformation when other change factors were impacting our business, including our transition to the national energy regulations and the increase in renewables on the network. The inter-related nature of the transformation program placed further challenges on developing the optimal sequence of change.

We have also prioritised our planned ICT system refresh on complying with new regulatory obligations. This includes a new meter and billing system that ensures we comply with the new NT NER rules relating to meter data, testing and validation.

Our transformation strategy going forward has been built on these learnings. The program is now planned to be completed over a longer period, consistent with the experiences of peer networks. The refresh of ICT systems will take place over a longer 10-year horizon to correspond with optimal sequencing and the key change areas of the business, including increasing renewables on the system. Chapter Four of this Draft Plan identifies the key ICT capital programs included in the 2024-29 proposal. Chapter Five of this Draft Plan provides more information on our transformation journey in the 2019-24 period and how this is impacting our operating expenditure costs moving forward.

Power and Water staff explaining a poster on our Future Vision at our People's Panel

Key Questions for stakeholders in Chapter Three

Are there any material global or local factors we have omitted in our analysis of change factors?

Are there any concerns with our strategic priorities, or has anything been missed in our assessment?

Do customers consider that our five-year expenditure plans align with our 20 year strategic priorities?

Transmission towers at Berrimah in Darwin

Part B

Our five year plans

4. Capital expenditure

We forecast a 39 per cent increase in capex in the 2024-29 regulatory period compared to the 2019-24 current period. The key drivers of forecast capital expenditure are higher replacement to address condition issues with an ageing network, increased growth capex to facilitate growing renewables and address rising local peak demand, and a continued refresh of our ageing ICT systems. A further driver of higher expenditure has been a change in our allocation of overheads which results in higher capitalisation of overheads.

This chapter sets out our initial capital expenditure (capex) plans for our standard electricity service. In section 1.4, we noted that capex relates to money we spend on assets. We recover our initial investment from customers over the expected life of the asset .

Figure 26 provides a profile of forecast capex compared to actuals and estimates in the 2019-24 period and compared to the AER's regulatory allowance. In total we forecast capex in the 2024-29 period will be $159 million higher than our estimated capex for the 2019-24 period, an increase of 39 per cent.

Figure 27 identifies our forecast of capital expenditure for the 2024-29 period by category, and the expected change from the current 2019-24 period.

- **Replacement capex** – We replace or remediate assets with condition issues, or which fail in service. In our initial plans, we expect that about 40 per cent of forecast capex will be on replacement in the 2024-29 period, an increase of $87 million compared to 2019-24 period. The key driver is a forecast decline in the condition of our assets due to age and environment, particularly given lower delivery in the current period than expected. The higher expenditure also reflects a replacement fund that seeks to bring forward future replacement consistent with our customers' preferences explained in Chapter Two.
- **Growth capex** – We build new network assets to meet additional demand for services (augmentation) and connect individual customers to the network (connections). This accounts for 28 per cent of forecast capex in 2024-29 period, an increase of $69 million compared to the 2019-24 period. We expect significant growth in some parts of our network to meet new residential and commercial connections. We are also investing in hosting capacity and community batteries as part of our future network strategy consistent with our customers' priorities.
- **Non-network capex** – We invest in support assets including Information, Communication and Technology (ICT), corporate property and fleet. This accounts for 13 per cent of forecast capex in 2024-29, a reduction of $15 million. In the 2019-24 period, we commenced a journey to refresh our ICT systems. We will continue to make scale-efficient and prioritised investments in the 2024-29 period while maintaining our existing systems. We will continue with our current lease arrangements for fleet and property while remediating the properties we own.
- **Capitalised overheads** – This relates to the share of network and corporate overheads that are allocated to capital assets in accordance with accounting standards. This accounts for 20 per cent of forecast capex in 2024-29, an increase of $16 million. This is due to a change in our allocation of overheads, which has resulted in a greater proportion of capitalisation.

We also are likely to include six contingent projects for uncertain but material projects including the construction of a Renewable Energy Hub to connect large scale renewable generation.

Figure 26 – Forecast capital expenditure in 2024-29 compared to actual/estimated in 2019-24 ($m, real 2024)

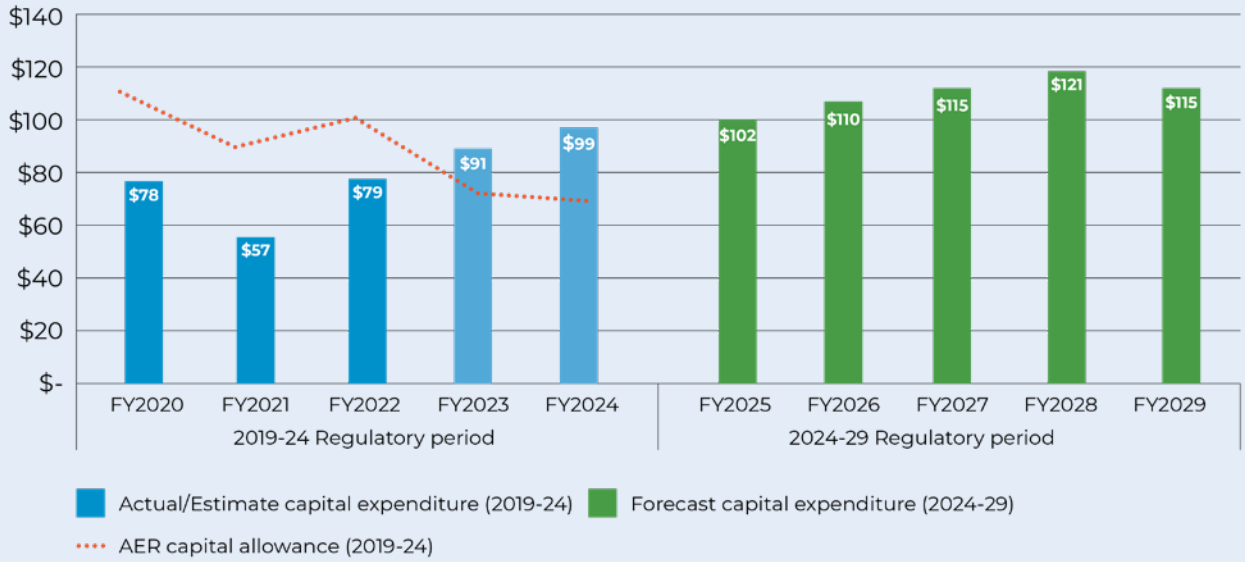
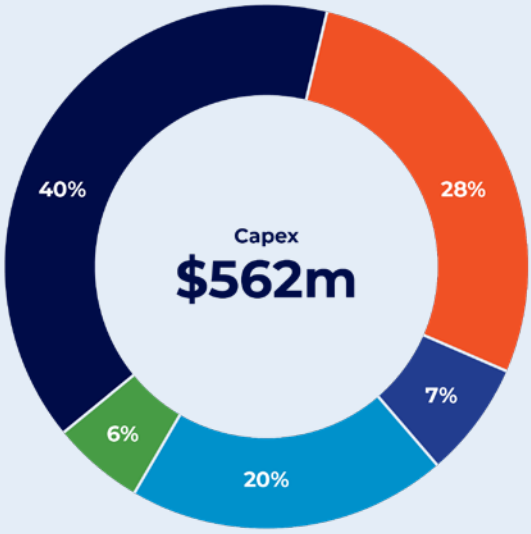


Figure 27 – Forecast capital expenditure in 2024-29 by AER category ($m, real 2024)



Network Asset Replacement
$224m Replacement of assets that pose safety and reliablilty risks

New network assets (growth)
$157m Augmenting and connecting the network to meet demand for network services

Non-Network ICT
$39m Capex on Information and Communication Technology

Capitalised overheads
$111m Support costs that have been allocated to capital expenditure

Non-network other
$32m Capex on support assets including property, fleet and facilities

4.1 Forecast Method

In June 2022, we submitted our Forecast Expenditure Methods document to the AER. The document identified the approach we were taking to developing our forecast methods for capital expenditure. The capital forecasts put forward in this Draft Plan reflect this process, but we have still not implemented or finalised all elements of the forecast approach.

Our forecast methods have evolved considerably since the 2019-24 regulatory determination process. We have implemented feedback provided by the AER and stakeholders on applying risk quantification, modernising our demand forecast models and integrating top-down prioritisation into the development of our capital expenditure forecasts. We have also sought to undertake more analysis of long term needs of the network in a rapidly changing energy landscape. The purpose was to develop a credible forecast for the 2024-29 period that aligned to the broader strategies identified in Chapter Three.

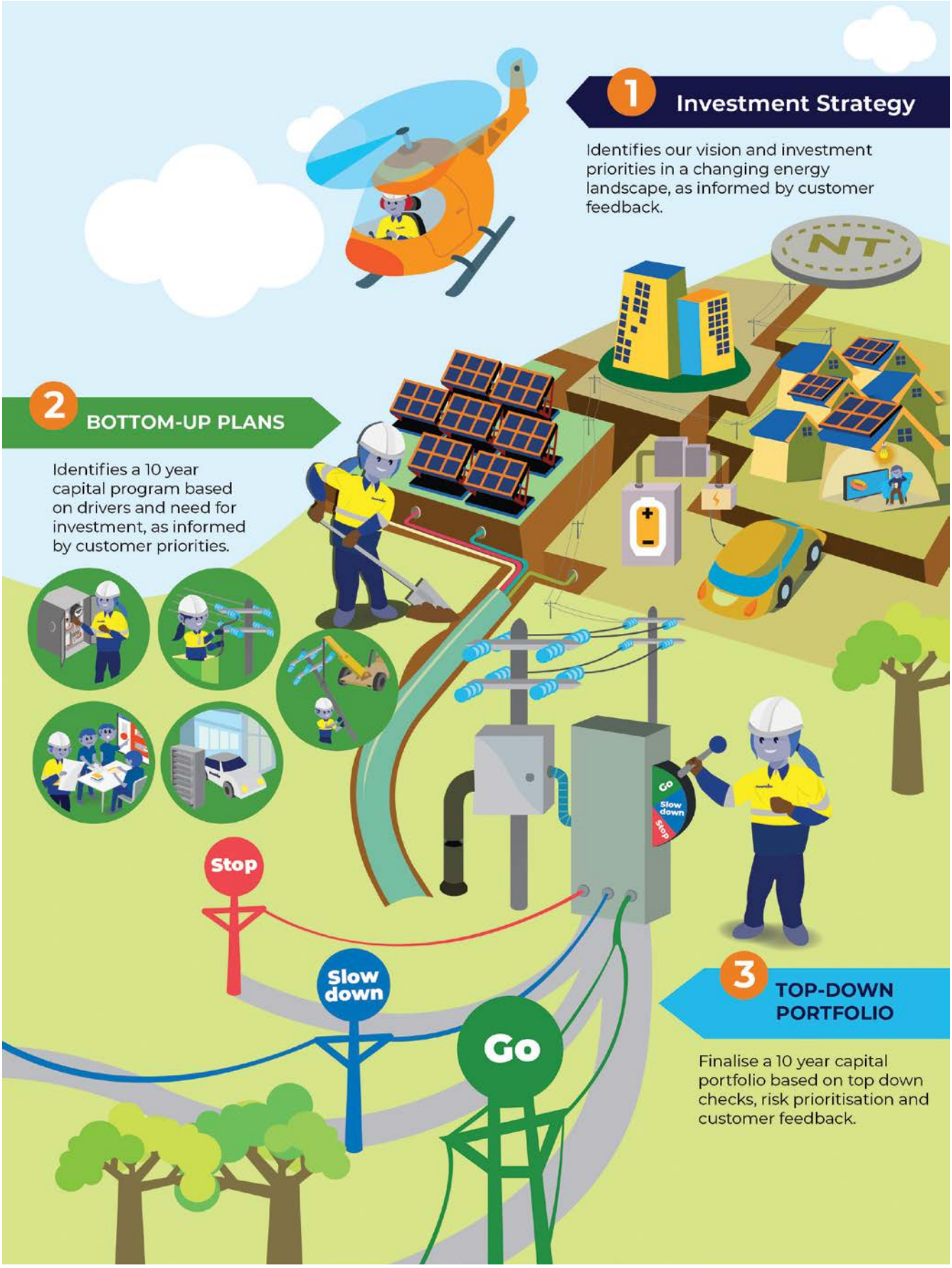
At a high level, there are three steps we will apply to developing the capital forecast expenditure for 2024-29, as seen in **Figure 28.**

1. **Identifying strategy** – The starting point for our expenditure forecasts is to understand our changing environment over a longer-term horizon. Our strategy is informed by the feedback provided by our customers on values, vision and priorities for investment.
2. **Bottom-up plans** – We identify key drivers of investment such as asset condition, growth in network usage, support from non-network assets, and overhead requirements. We then undertake needs and options assessment to develop a bottom-up list of projects and plans over a 10-year horizon.
3. **Top-down portfolio** – A portfolio view helps identify the optimal mix of projects and programs that provide optimal value, align with longer term investment priorities and deliver customer preferences.

In our forecast method document we noted that the business case is the primary evidence we use to assess the veracity of our capital expenditure forecasts. We are currently still developing the full suite of business cases and we expect that this process may lead to differences in the estimates presented in this Draft Plan. We are mindful that checks are useful to ensure the portfolio can be further verified in terms of delivery and as points of comparison with other high-level models. We also consider that a prioritisation process may provide insights into the overall change in total risks. We plan to undertake a series of checks over the next six months including our deliverability.

Our overall approach carefully considered guidelines published by the AER including the Expenditure Forecast Assessment Guidelines and the Capital Expenditure Assessment Outline for Electricity Distribution. Our forecast method seeks to align to the guidelines. We also considered the AER's Industry Practice Note on Asset Replacement Planning by applying its risk-cost assessment methods. We will also be presenting our ICT forecast to align with the approaches identified in the AER's guidelines including presenting our programs in recurrent and non-recurrent categories.

Figure 28 – Capital expenditure Forecast Method



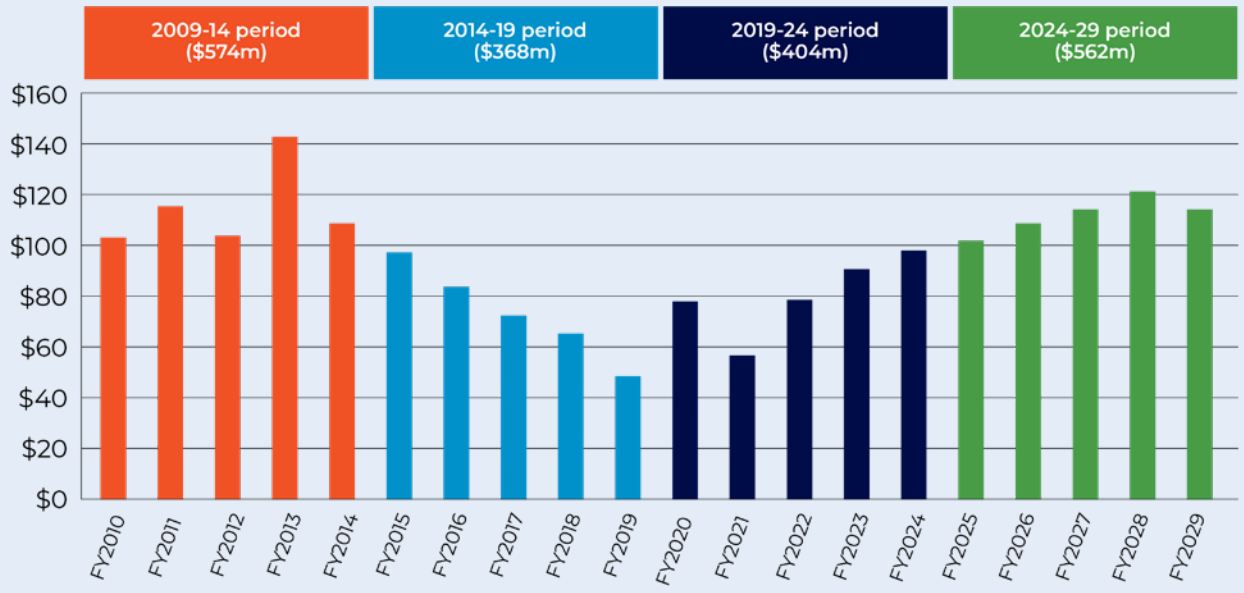
Nomad substation in Darwin

4.2 Drivers of capex

Capital expenditure is generally 'lumpy' responding to key drivers of investment at a point in time. Periods of high capital expenditure impact the affordability of electricity services due to an uplift in costs to finance more investments.

Figure 29 identifies capital expenditure in the 2024-29 period to actuals and estimates in the previous three regulatory periods. There has been significant volatility in capital expenditure over this period reflecting circumstances at the time.

Figure 29 – Capital expenditure between 2010 to 2029 ($m, real 2024)



In 2008, the network suffered a major outage in Casuarina, that led to an external review of our network activities. The review showed that the network was in poor condition after sustained under-investment and maintenance. Reliability deteriorated significantly for customers over this period and as a result, we invested significantly in the 2009-14 period focusing on zone substations. The high capital spend in the 2009-14 regulatory period reflected a 'catch up' for under-investment in the previous years.

Capital investment fell in the 2014-19 period as we sought to reduce our costs. The reduction in capex was possible due to the improvement in the network and the relatively low number of older assets. Further, we did not invest in any new ICT assets. At the same time, peak demand started to flatten relative to historical levels as customers used their solar panels to meet energy needs. The combination of these factors meant our capital expenditure fell significantly during this period.

In 2019-24 we sought a moderate increase in capital expenditure. The key driver of capital expenditure related to an increased need for major replacement projects and programs, where asset data showed significant condition issues and high risks from failure of the assets. We project to be under the AER's regulatory allowance by the end of the regulatory period. The key reasons for the underspend are:

- Deliverability issues in the first three years of our system capital program as we sought to uplift our capability and resources to deliver the capital program while encountering overlapping priorities.
- Re-prioritisation of our planned refresh of major ICT systems which led to the deferral of major projects. This was to ensure the program was targeted at highest priorities, and that the investment was efficient for a network of our small scale.

The implication of under-delivery is that the 2019-24 expenditure level is not a relevant 'baseline' to forecast a 'needs based' expenditure profile.

In the 2024-29 period, we are forecasting significantly higher capital expenditure compared to actuals in the 2019-24 period. This is driven by five key factors discussed in the following sections.

a. Managing renewables on the network

As discussed in Chapter Three, a key pillar of our long-term strategy is to ensure the network can efficiently facilitate the expected acceleration of renewables in the grid. By 2040, there is a likelihood that the network may be required to transport 100 per cent renewable energy to our customers, increasing from the current NTG policy of 50 per cent by 2030. Our transmission network will need to expand to reach new large-scale renewables, while ensuring our network can securely manage exports of small-scale renewables.

As discussed in Chapter Two, investing in the future network was a key priority of our customers. Our 2024-29 forecast includes three key projects that relate to efficiently facilitating renewables – a new hosting capacity solution that can unlock more solar, community batteries to store solar in the day and discharge at night, and an Advanced Distribution Management System (ADMS) that will provide a longer-term solution to facilitating growing renewables post 2030. We also have a contingent project relating to the NTG's plans for our transmission network to connect to a new large scale renewable hub south of Darwin.

b. Ageing assets

A key theme in our customer feedback was that we should maintain our network and minimise the risk of reliability incidents experienced in the 2009-14 period. In our engagement sessions, we noted that replacement levels have been well below long term sustainable levels due to the relative youth of our network assets.

Over the next 20 years, we see that many of our assets will require replacement as they reach the end of their technical life. Unlike other places in Australia, most of our network was rebuilt after Cyclone Tracy in the short period after 1974. By 2030, a high proportion of these assets will be over 50 years old. Our asset management team have identified emerging issues with the condition of assets on the network that is prompting higher levels of replacement in 2024-29. As noted in Chapter Two, we have also listened to our customers' preferences for smoother long term capital expenditure by forecasting a replacement fund to help the expected spike in replacement by 2040.

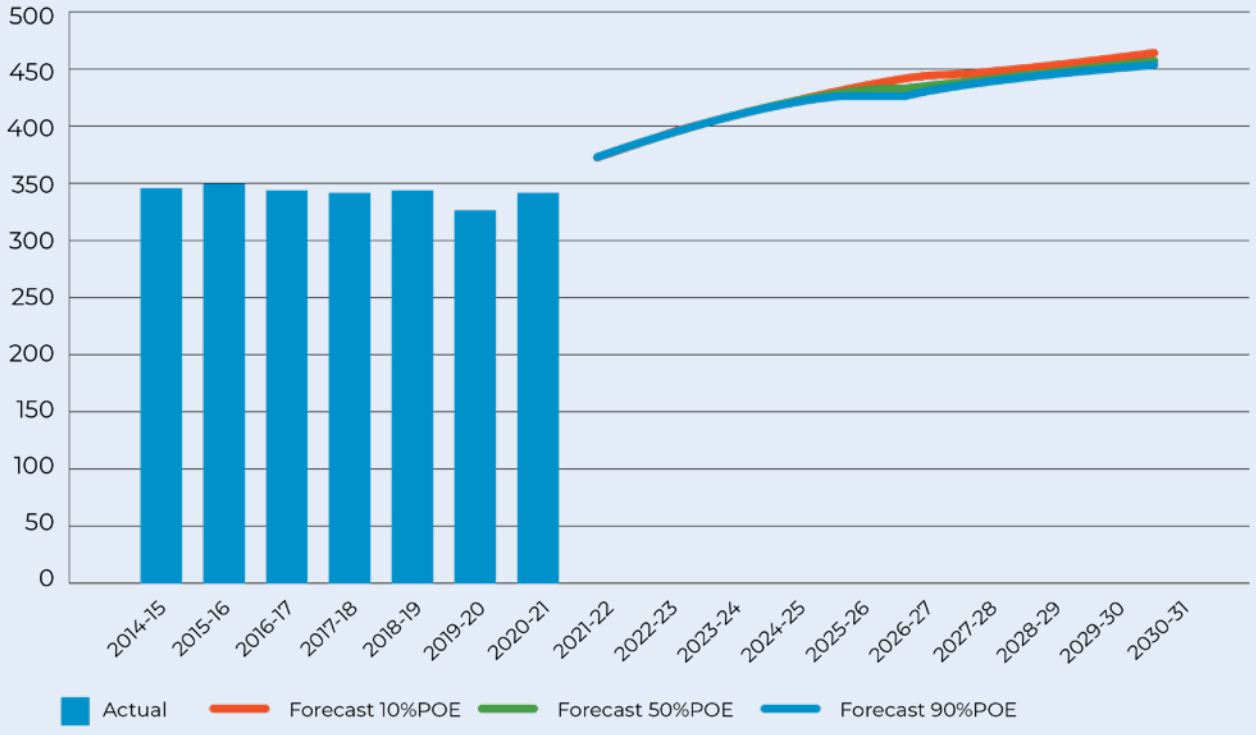
c. Rising peak demand

In recent years, we have seen moderate to falling peak demand growth at a system level, meaning that new network investment has fallen significantly. A key driver has been customers using their own solar to power their homes. A secondary driver has been relatively subdued economic activity which has led to slower growth in residential development and commercial connections.

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 30**. 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 network that exceed the capacity of the network.

As noted in Chapter Three, we see that peak demand could increase significantly after 2030 due to higher penetration of electric vehicles and increasing growth in the NT. 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.

Figure 30 – Maximum demand forecasts across our three regulated networks



Substation in Darwin

d. Continued refresh of our ageing ICT systems

Power and Water continues to operate ICT systems that were built a generation ago. In the 2019-24 period, we expect to make some progress in implementing refreshed ICT systems including a new metering and billing system, and upgrading our Energy Management System. For the 2024-29 period, we have undertaken further analysis of the pace and priorities of our ICT refresh. We have prioritised investments in an Advanced Distribution Management System (ADMS) which will assist us to meet the challenges of transitioning to a renewable energy system, while improving our outage management capabilities.

e. Uplift in delivery capability

In our engagement sessions with customers, we discussed the factors that have resulted in lower delivery of capex than allowed by the AER in the first three years of the current period. While many factors have contributed, a clear reason has been overlapping priorities as we engage with a changing energy landscape.

At present, we are implementing an action plan that methodically seeks to increase our delivery capability. We recognise that implementation will take time, and our forecasts have therefore sought to defer some of the works required over the next three years into the 2024-29 period. We have sought to mitigate the additional risks, by prioritising major projects and programs.

4.3 Replacement capex

We forecast replacement capex of $224 million in the 2024-29 period, an increase of $87 million compared to the 2019-24 period as seen in **Figure 31**. The key drivers of higher capex include:

- As noted in the previous section more assets are approaching end of life in the next regulatory period, which has led to more identified condition issues.
- Consistent with our customers' preferences, we have included a replacement fund of $28 million to assist us to smooth the expected steep incline in replacement between 2030 and 2040.

We categorise replacement activities into three types. Firstly, our planned replacement is for assets that we seek to replace or refurbish before they fail in service. These are assets that have a high consequence of failure in terms of safety, customer reliability, security, compliance or environmental impact. Secondly, we have assets which are scheduled for replacement based on a known defect. Scheduled replacements aim to replace or refurbish the asset before it fails due to moderate risk of consequence. Reactive replacements occur after an asset has failed in service. This would likely occur in cases where the risk is minimal or where the event was unlikely based on our regular maintenance data.

As noted in section 4.1, a key improvement to our forecast approach for replacement is a new risk quantification approach to consistently appraise the costs and benefits of investments. This is a relatively new approach for Power and Water and follows extensive feedback from the AER in our last proposal. By providing a quantitative basis for valuing risks, we can more consistently consider needs across the capital portfolio.

We identify the probability of a risk occurring, and the consequence such as safety, reliability, environment and other factors consistent with our Enterprise Risk Management Framework. Such an approach allows us to defer investment and improve affordability where the risks can be managed appropriately. The key values in our new approach include health and safety of workers and the public, compliance, direct financial costs, environmental, service delivery and customer experience. Each of these values have a dollar impact based on whether the consequence is insignificant, minor, moderate, major or severe. The risk is measured as the probability of the event occurring, multiplied by the likelihood of a consequence from the event multiplied by the value of that consequence.

Figure 31 – Forecast replacement capex in 2024-29 compared to actual/estimated in 2019-24 ($m, real 2024)

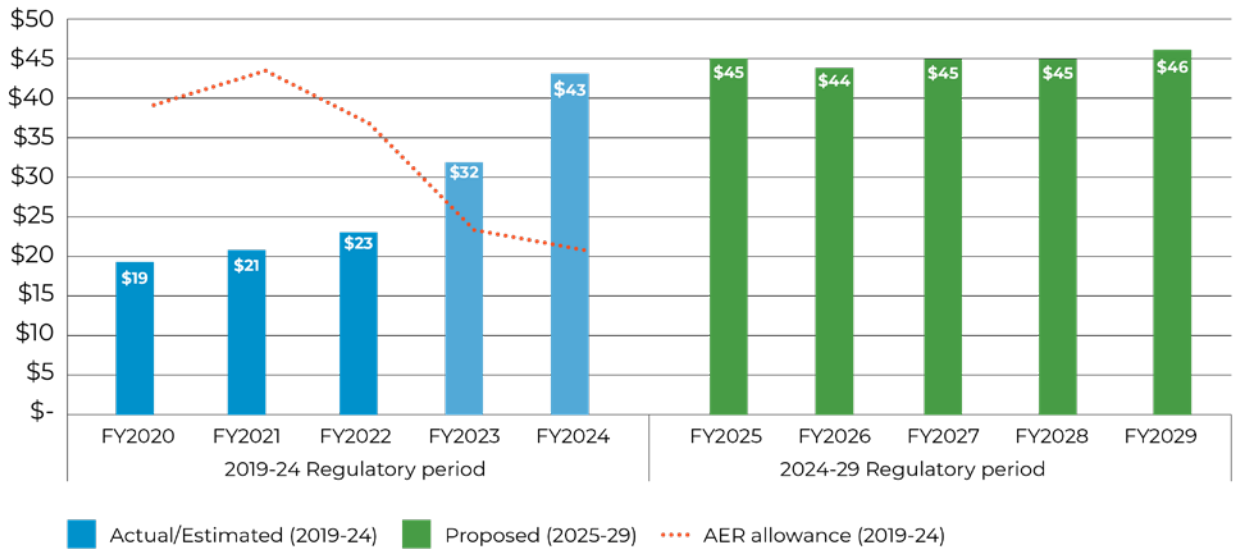
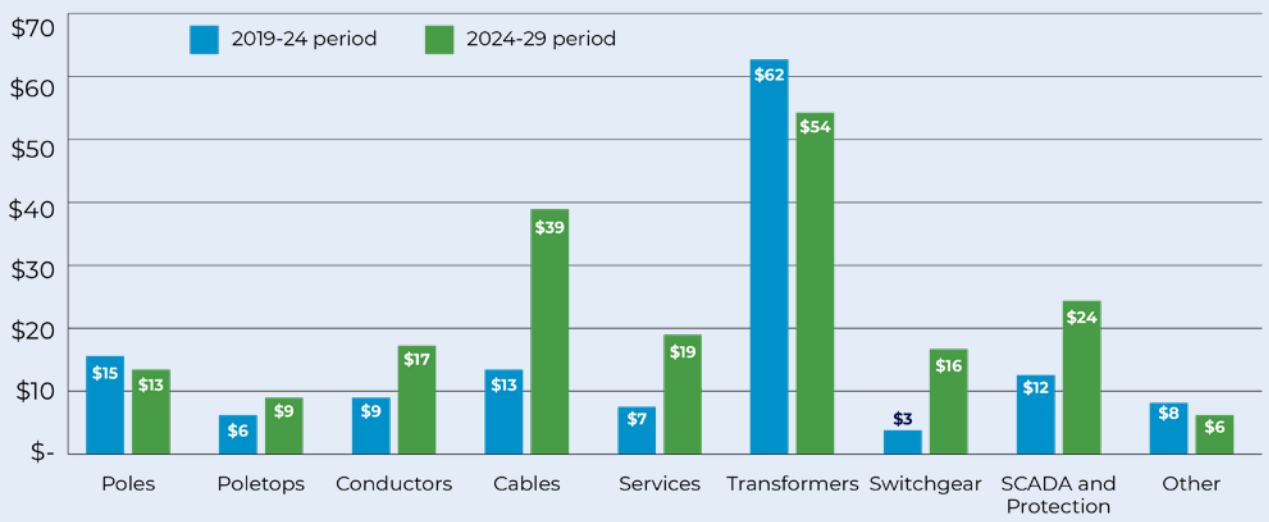


Figure 32 provides a breakdown of the forecast replacement program for 2024-29 compared to the 2019-24 period. The areas of significant increase are cables, services and SCADA and protection. The increase in cables reflects the lower delivery of the Northern Suburbs cable program than in the AER allowance in the 2019-24 period, and the deferral of the Port Feeder project to the 2024-29 period. The increase in services reflects a new planned program to replace assets in poor condition and which are expected to require replacement in the 2024-29 period. SCADA and protection replacement relates to obsolescence issues we are experiencing with these assets as they approach end of life.

The major replacement projects and programs included in the 2024-29 proposal include:

- **Darwin Northern Suburbs high voltage cable program ($27 million)** – The program has already commenced and will uplift from 2022 to 2024 where we will replace about 40 kilometres a year and replace about six kilometres each year from 2025 to 2030. Due to the location of the cable on the coast, the sheath of some segments is damaged, allowing water ingress which has caused deterioration of the cable's internal components. The corroded screens will increase the risk of electric shock and adversely affect our protection systems. This exposes our workers and the public to safety risks.
- **Alice Springs network optimisation ($17 million)** – Four of the transformers at two zone substations are approaching end of life based on testing of residual insulation strength. At this stage we are also assessing the 11 kV switchboard at Lovegrove and 22 kV switchboard at Sadadeen, both of which will be 42 to 44 years old in the planned year of replacement and have known defects. All associated protection and SCADA are also forecast to be replaced.
- **Humpty Doo transformer replacement ($10 million)** – There are condition issues with the assets within the zone substation including the 66kV circuit breaker which has a history of failures associated with the operating arm, and the power transformers which have an excessive level of moisture in the paper insulation largely due to significant continuous oil leaks. There are also condition issues with the 22kV switchgear including gas leaks, and the secondary systems are obsolete and spares are difficult to source.
- **Alice Springs corroded poles ($8 million)** – The major targeted program for pole replacement and refurbishment is in Alice Springs. The poles are corroded from high salinity and moisture levels in the soil. We plan to replace and refurbish about 200 poles each year for the next decade. This causes structural integrity issues leading to safety risks to the public and our field crews if the pole falls. We will be targeting replacement and refurbishment of the poles that are in the worst condition and pose highest risk to the community. The project will be ongoing for the next decade due to the high volume of degraded poles.

Figure 32 – Forecast replacement by AER asset class ($m, real 2024)



4.4 Growth capex

We forecast $115 million on augmenting the network and connecting customers to meet new demand for our network services ("growth capex") in the 2024-29 period, an increase of $69 million compared to the 2019-24 period as seen in **Figure 33.** The primary drivers of the increase in capital expenditure include:

- An increase in demand on local areas of our network from residential and commercial development that requires new network infrastructure.
- A forecast doubling of small-scale solar installation by 2030, which necessitates a hosting solution to safely export our customers solar without imposing strong export constraints.

We have made significant improvements to our methods to forecast demand for energy and solar exports over the last year to give us an improved understanding of when the network needs to be upgraded. Our new method involves a more granular analysis of historical trends and drivers of change. We have also improved our method for estimating the expected load and timing of new large connections.

Similar to our replacement program, we will be assessing investments against our risk quantification methodology. This includes identifying the value of customer reliability when considering upgrades to the capacity of the network.

Figure 33 – Forecast growth capex in 2024-29 compared to actual/estimated in 2019-24 ($m, real 2024)

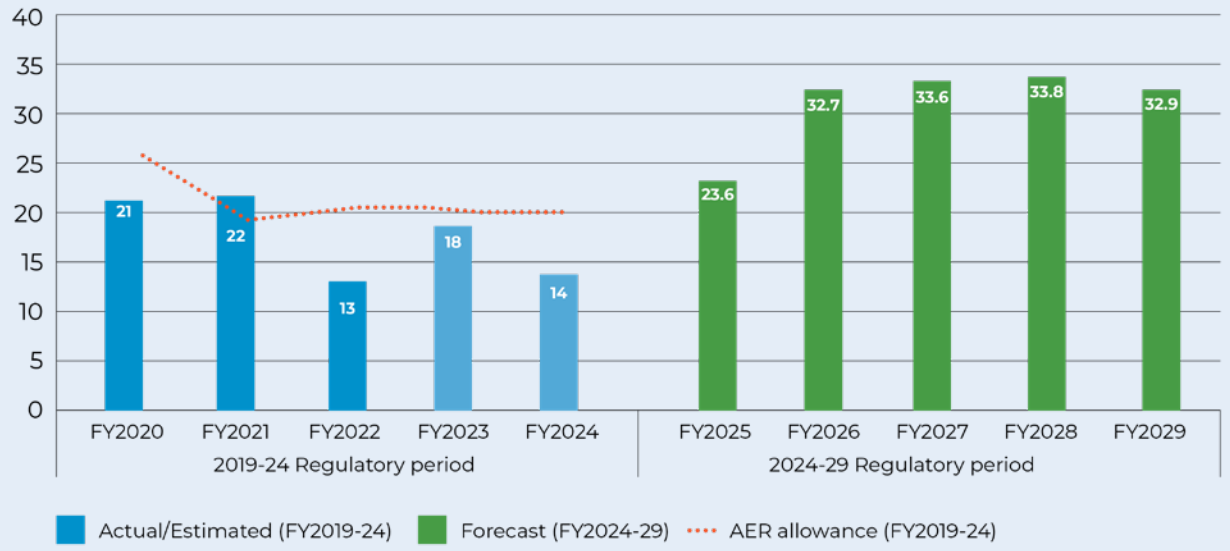


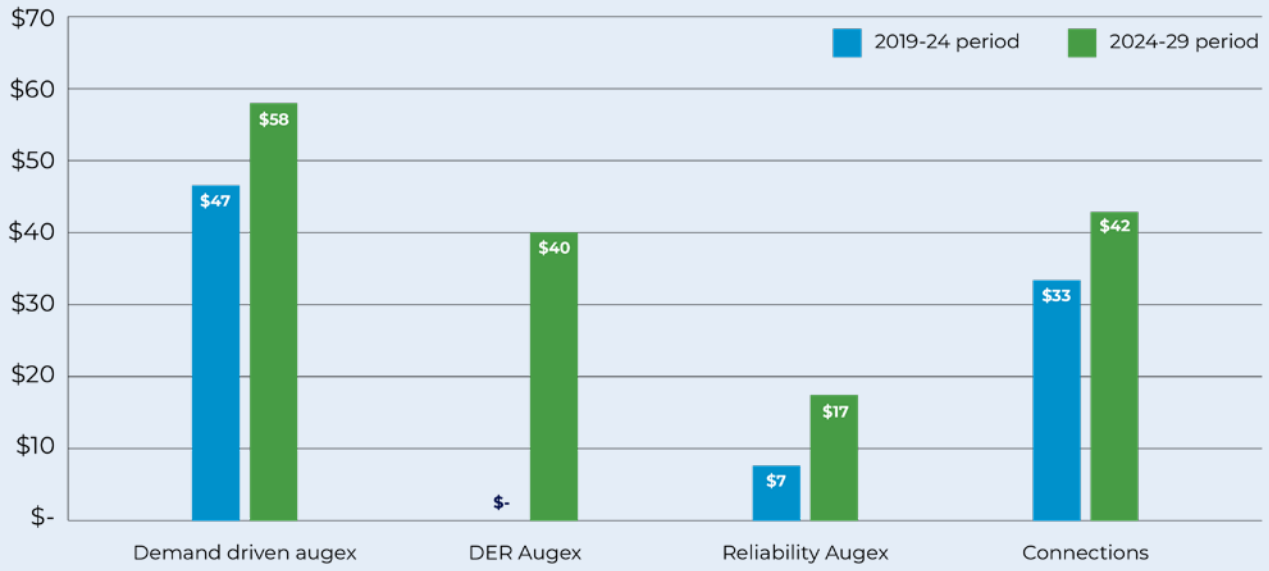
Figure 34 sets out forecast growth capex program by AER categories. Demand driven capex relates to investing in new infrastructure to meet higher peak demand for electricity in sections of the network and accounts for $58 million. This includes a major project to upgrade Katherine zone substation, and a series of minor programs and projects. Investment in our future networks program (termed DER augex) is a new type of investment and accounts for $40 million to address challenges we expect to face with exporting higher amounts of household solar. Reliability augex is increasing to $17 million as we seek to ensure we meet voltage performance targets, while continuing to meet our obligations to improve performance for customers who receive poor service.

Connections capex relates to new infrastructure for an individual customer. Connections capex is forecast to increase to $42 million in the 2024-29 period, largely due to an increase in large connections. We apply a connection policy to determine the capital contribution that a customer makes to the connection costs. We are proposing to make changes to our connection policy including expanding the connection policy to include export and simplifying the capital contributions process by linking it to the threshold for basic connection services.

This means customers seeking a basic connection (this will be set out in our connection policy, but covers most residential and small business connections) will not pay a contribution. Customers seeking a different or enhanced connection will contribute by meeting the full cost of their connection and their connection will be a negotiated connection service.

A key change for our customers in relation to connection services is how negotiated connection services will be classified in the 2024-29 period, which has flow on effects in terms of how these costs are charged and recovered. As part of its decision in its Framework and Approach, the AER classified negotiated connection services as an alternative control service. This means that customer connections that fall within the definition of a negotiated connection in our connection policy will now see a cost reflective price for their connection than under previous arrangements where they only paid a small portion of their true costs upfront.

Figure 34 – Forecast growth capital expenditure by AER category ($m, real 2024)



The major growth projects and programs in the 2024-29 forecast include:

- **Katherine zone substation upgrade ($22 million)** – The zone substation is already overloaded under a single critical contingency (N-1) of a transformer failure. In the short term, we are considering lower cost options to support load if one of the transformers fail, such as batteries or an agreement to supply additional load from a local generator. In the longer term, we see the need to upgrade the capacity of the zone substation as load continues to increase. Large housing developments and commercial loads are forecast to locate to the east of Katherine. This means that the load at risk will become significantly higher and a longer-term solution will be required. At this stage, we consider the least cost feasible option to address the long term need will be to upgrade the existing zone substation.
- **Future Network Hosting and Community Batteries ($40 million)** – As discussed in section 2.4, our People's Panels considered we should implement a technology solution to help the network export more household solar without building new infrastructure. The People's Panels also wanted us to pursue two community batteries that would store excess solar produced in the day and discharge the energy in the night during the peak evening period. We are currently in the process of analysing the need, options and benefits with consideration to recent AER guidelines on the cost of curtailed exports. At this stage, we have provided a rough estimate of $40 million to help inform our stakeholders on the materiality of the initiatives.
- **Install reactors at Katherine zone substation ($8 million)** – Quality of supply relates to voltage disturbances that can impact a customer's energy supply and appliances. Katherine is significantly above the limits for a significant proportion of the time. To address this issue, we will be installing switched inductive compensation to lower voltage at the bus in the zone substation, which will have the impact of absorbing reactive power.
- **Uprating transmission lines in Darwin ($5 million)** – We have undertaken contingency analysis of our transmission lines to identify if any lines would exceed capacity. Under a critical contingency (N-1) on the line from Hudson Creek to Palmerston zone substation, the 66kV line is expected to exceed capacity by the end of the decade. Similarly, under a critical contingency on the line from Hudson Creek to Archer zone substation, the 66kV overhead line from Hudson Creek to Palmerston line is expected to significantly exceed capacity by 2029-30. The two options to address the overloads under N-1 include procuring additional generation at Weddell power station and uplifting the line ratings from 64MVA to 90MVA for each of the lines.

4.5 Non-network and overhead capex

We forecast $182 million in total on non-network ICT, non-network other, and capitalised overheads in the 2024-29 period, an increase of only $1 million compared to the 2019-24 period as seen in **Figure 35.**

Figure 35 – Forecast non-network and overhead capex in 2024-29 compared to actual/estimated in 2019-24 ($m, real 2024)

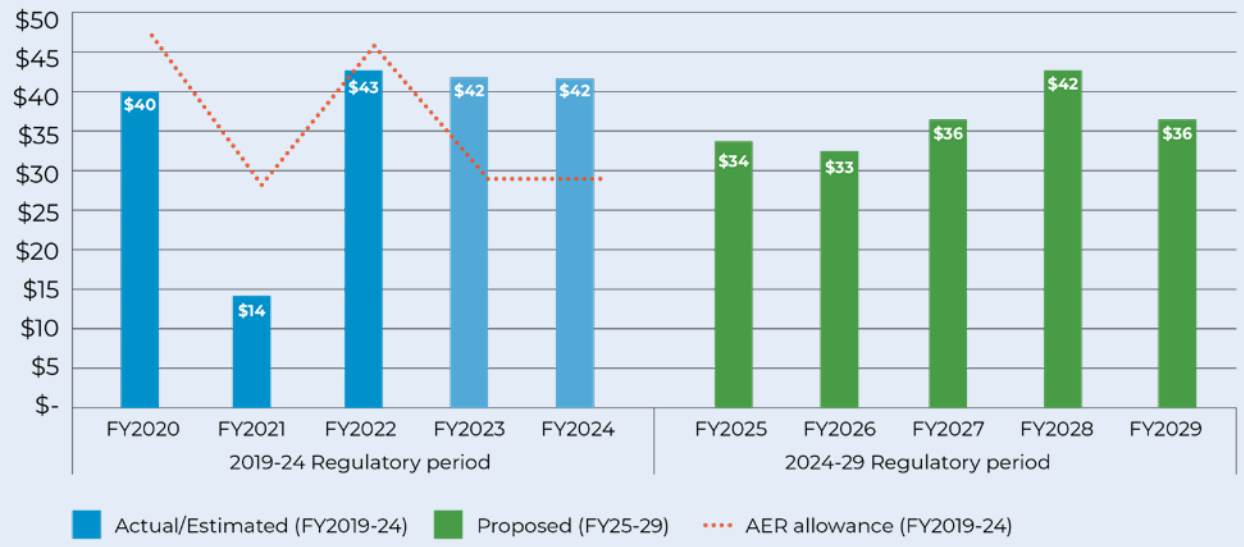
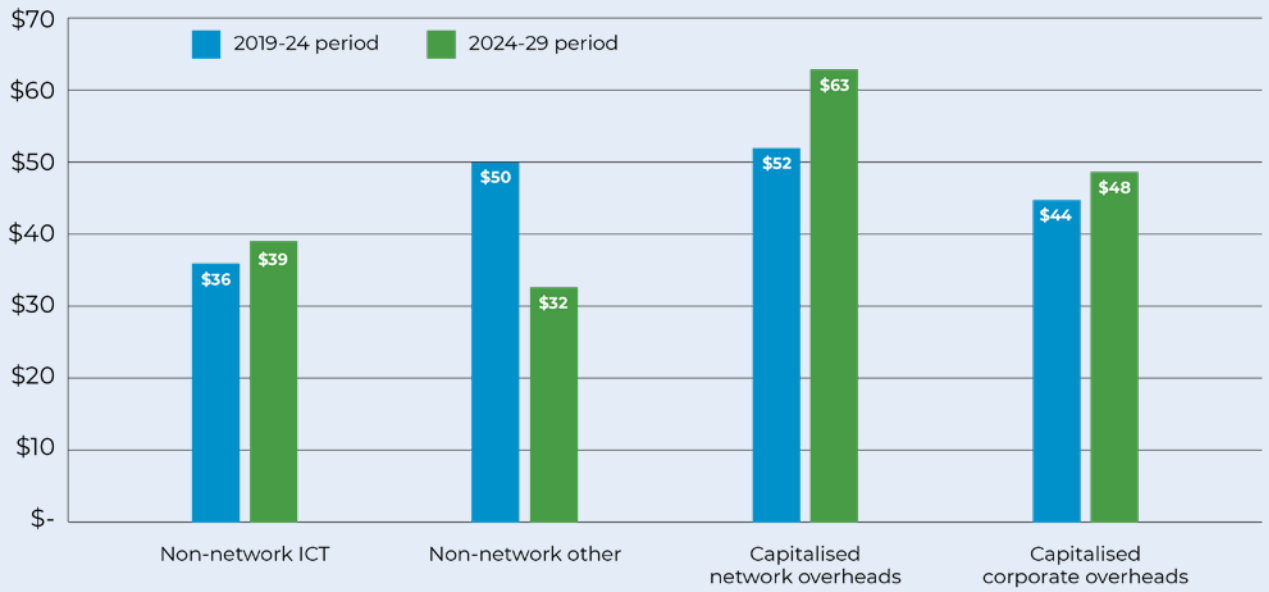


Figure 36 provides a breakdown of the forecast in the 2024-29 period by AER category compared to the 2019-24 period. Non-network ICT is at similar levels to the current period, and non-network other is forecast to be significantly lower. Overheads are increasing compared to the current period.

Figure 36 – Forecast non-network and overheads capex by AER category ($m, real 2024)



About 85 per cent of the forecast ICT capex relates to refreshing our major ICT systems, many of which are losing currency and functionality. About 15 per cent of ICT is for maintaining the currency and cyber security of our existing assets. As a multi-utility, we allocate a portion of the total capex of ICT systems to standard control services in accordance with our Cost Allocation Method.

We commenced our ICT refresh journey in the 2019-24 period, with the expected completion of our meter and billing system and upgrade to our Energy Management System by the end of the period. We have significantly re-prioritised our ICT refresh program compared to our regulatory proposal, taking a more cautious and prudent approach to investing in large ICT systems.

This has meant that some of the systems we had initially intended to commence in 2019-24 will now occur in the 2024-29 period including a new Asset Management , Mobility and Capital Delivery system and the Physicals to Financials ICT systems. These systems will be vital to implement given our expected ramp-up in capital expenditure over the next 20 years as we replace ageing Cyclone Tracy assets.

We are also forecasting capex on the initial stages of an Advanced Distribution Management System (ADMS), focusing expenditure on improving our visibility and control of the distribution network and customers' distributed energy resources. We see that this will be vital in the context of accelerating renewables after 2030, where we will need more data and controls to keep the network safe and secure.

Property leases account for about $9 million of non-network other capex, and largely relate to the expected costs of leasing our existing commercial properties including the Mitchell Centre. We also expect to incur about $7 million on refurbishing our depots to address non-compliance and remediate sites. Fleet leases account for $12 million of non-network capex.

Network overheads include asset management activities we undertake to plan, control and manage the network. Corporate overheads including finance, legal, procurement and human resources support activities across our electricity, water, sewerage and gas lines of business. We allocate overheads to each line of business in accordance with our Cost Allocation Methodology. We also allocate these costs to capital and operating expenditure depending on the nature of the activity. Our method to forecast capital overheads has considered the allocation methods of other networks, and the uplift in capital expenditure programs as we return to improved delivery.

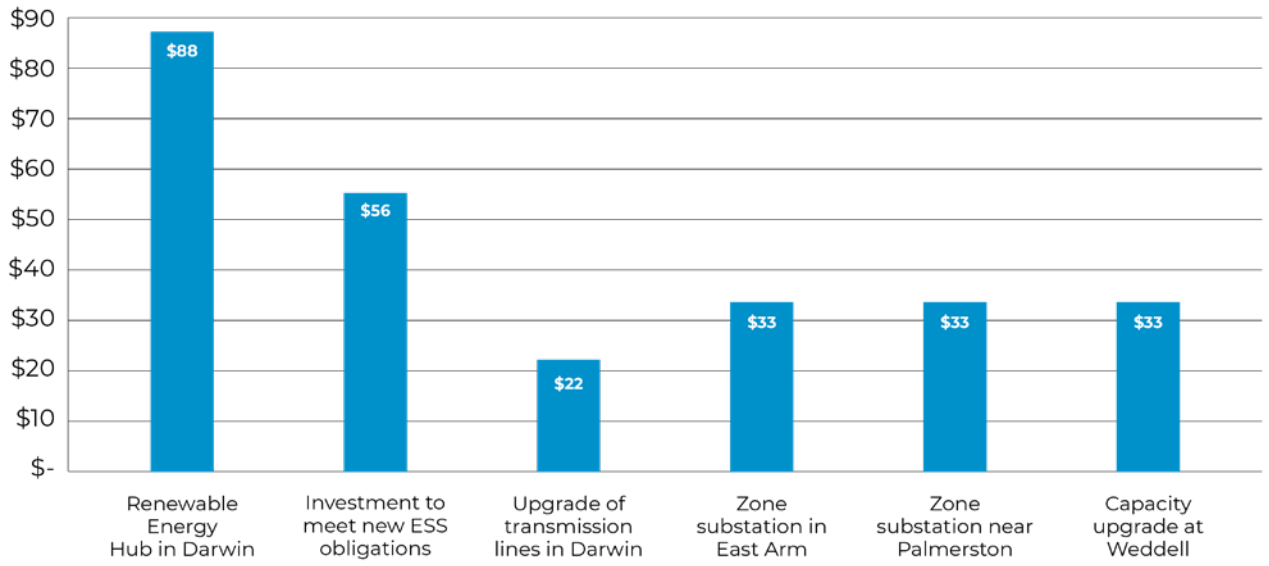
4.6 Contingent projects

In developing our capital expenditure forecasts, we have identified a number of large projects, projected to cost in excess of $15 million each, which may be required during the 2024-2029 period but which are highly uncertain in terms of timing, scope or funding arrangements. The regulatory framework requires that these projects be excluded from the forecast capital allowance, and separately identified as a contingent project. If a contingent project is allowed by the AER, we would need to demonstrate that a 'trigger' has occurred and that our capital expenditure is prudent and efficient.

The relatively high number of contingent projects reflects the uncertainty over the likelihood or timing of large projects in the NT including the development of renewable hubs, land releases and large industrial hubs. If these projects were to arise during the 2024-29 period, our revenue would increase from the estimate presented in the Draft Plan. It is therefore crucial that our stakeholders understand the nature of these projects. The estimated capital expenditure if these projects proceed are set out in **Figure 37** and include:

- **Renewable Energy Hub in Darwin** – The NTG's Darwin-Katherine Electricity System Plan includes a Renewable Energy Hub where large scale solar and battery will connect to available capacity on our transmission network. This will require the construction of new transmission infrastructure and a sub-transmission substation. We are working with the Northern Territory Government to understand our role in the implementation of the initiative.
- **Investment to meet new ESS obligations** – Under the proposed NTG Essential System Strength framework, we have obligations to maintain local system strength. Depending on the scope of the obligation, this may necessitate large investment such as a synchronous condenser.
- **Upgrade of transmission lines in Darwin** – While not committed, we expect a significant increase in demand in east rural and south Darwin. This may require a larger upgrade to the planned replacement of the zone substation and may require additional transmission infrastructure.
- **Zone substation in East Arm** – A new zone substation is likely to be required to meet industrial growth in East Arm. However, there is uncertainty on the timing of connections to the area.
- **Zone substation near Palmerston** – The Government's land plan contemplates a new urban district in Holtze, near Palmerston that would necessitate the construction of a new zone substation in the area. However, no firm commitments are in place at this stage.
- **Capacity upgrade at Weddell** – This would meet the expected demand from industrial developments at the Middle Arm Sustainable Development Precinct.

Figure 37 – Contingent projects – excluding capitalised overheads ($m, 2024 real)



Residential customers at People's Panel

Key Questions for stakeholders in Chapter Four

Have we adequately implemented customers' priorities on future network and addressing the replacement wall?

Are there specific aspects of our proposed capital expenditure that you support, disagree with, or want more information about?

Do customers have any concerns with proposed changes to our connection charges?

5. Operating expenditure

We forecast a 13 per cent decrease in operating expenditure in the 2024-29 regulatory period compared to the 2019-24 current period. The lower expenditure primarily relates to improvements in our measurement of underlying labour costs comprising our operating activities. This has resulted in more overhead costs being allocated to capital expenditure in accordance with our approved cost allocation method and in line with the practices of other networks. Our lower level of operating expenditure incorporates an efficiency stretch target and step changes relating to our customer preferences for future network programs and customer service improvements.

Operating expenditure (opex) relates to regular annual expenses. These costs are recovered from customers by Power and Water on a yearly basis.

As noted in section 1.4, there are three broad categories of opex:

- **Network opex** – includes maintenance of assets, emergency response costs, and vegetation management.
- **Non-network opex** – relates to expenditure on maintaining and operating ICT assets, corporate property assets and fleet assets.
- **Overhead opex** – relates to the share of network and corporate overheads that are allocated to operating expenditure in accordance with accounting standards and the AER approved cost allocation methodology.

Figure 38 compares our forecast operating expenditure for the 2024-29 regulatory period to actuals and estimates for the current 2019-24 period and the AER's allowance. The figure shows that while opex remained higher than the AER's allowance at the start of the 2019-24 regulatory period, actual opex has been declining over the last two years and is expected to further decline by the end of the period. Our forecast opex (including debt raising costs) of $387 million for the 2024-29 regulatory period is 13 per cent lower than the AER's allowance for the 2019-24 period.

This lower amount largely reflects changes in our accounting practices relating to the treatment of overheads to be more in line with standard industry practice. This allows for a more realistic comparison of our operating expenditure performance compared to peers and is more consistent with the efficient level of expenditure substituted by the AER in the last regulatory determination. We propose to include a staggered 10 per cent efficiency stretch target on our opex network and corporate overheads, reflecting our ongoing commitment to delivering real and sustained reductions in our opex over time, as our business continues to mature and develop its understanding and capabilities under the NT NER.

Figure 39 provides a breakdown of our operating expenditure for the 2024-29 regulatory period. It shows that our corporate and network overheads comprise a significant proportion of our forecast opex.

Figure 38 – Forecast opex in 2024-29 compared to actual/estimated in 2019-24 ($m, real 2024)

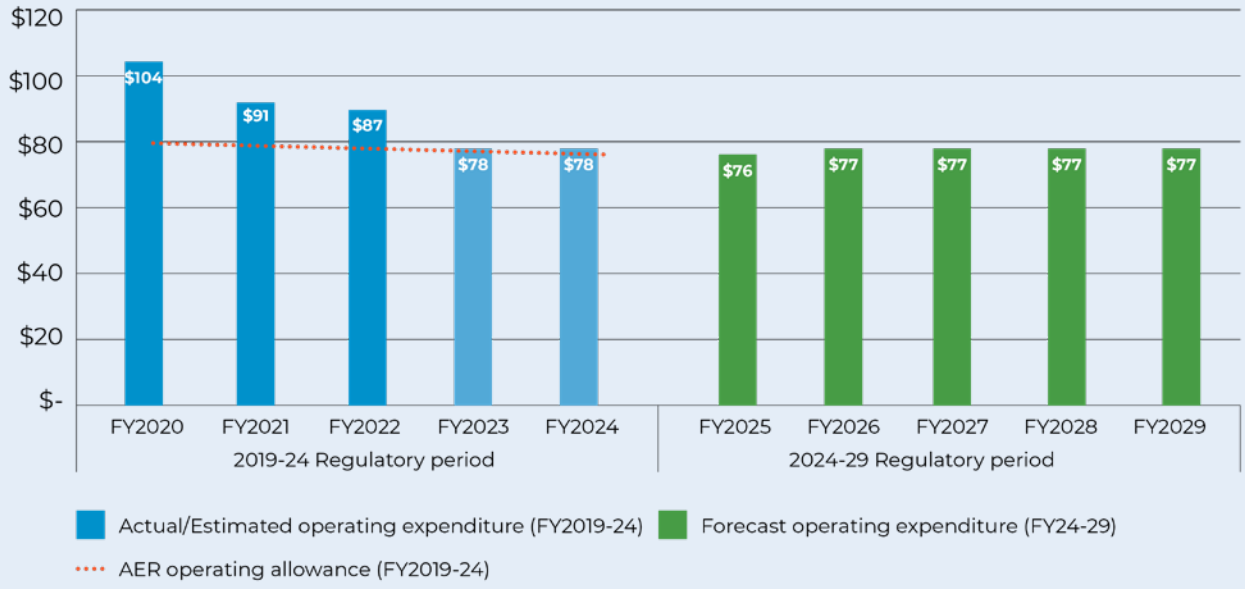
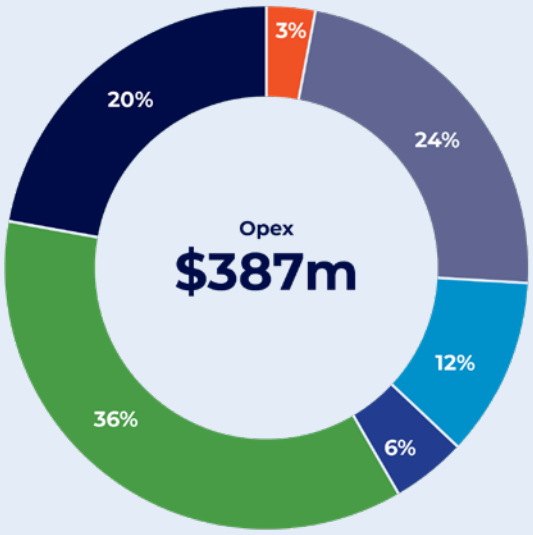


Figure 39 – Breakdown of operating expenditure in the FY24 to FY29 period ($m, real 2024)



Corporate overheads
$77m Corporate costs that have been allocated to operating expenditure

Vegetation Management
$10m Cutting back vegetation rom network infrastructure

Maintenance
$91m Inspection, testing, regular and corrective works on network assets

Emergency Response
$47m Inspection, testing, regular and corrective works on network assets

Non-network
$24m Maintaining our ICT assets and maintenance on property and fleet

Network overheads
$138m Network overheads that have been allocated to operating expenditure

5.1 Forecast method for operating expenditure

We have applied the AER's approach in its Expenditure Forecast Assessment Guidelines to calculate the operating expenditure for the 2024-29 period. This is based on the base- trend- step method depicted in **Figure 40** on the next page which consists of:

- **Base Year –** Operating expenditure tends to be recurrent from year to year. This means that most recent expenditure generally provides a good indication of future levels.
- **Trend –** Consistent with the AER's approach we will apply a rate of change to the base year to account for changes in input prices, work activity from increasing network size, and productivity.
- **Step changes –** We will identify changes impacting our business environment that will change our costs. Consistent with the current period we will also add step changes for annual efficiency adjustments if required.

While we are adopting the AER's preferred approach towards developing our operating expenditure forecasts, our application will differ slightly to other electricity networks. This is largely due to legacy issues associated with our existing systems ability to capture and report data and our unique operating circumstances. These factors make it difficult for Power and Water to be meaningfully compared to other peer networks. Other networks have significantly larger customer numbers to spread their costs across, operate interconnected networks over a much smaller geographical area than the Territory, and generally do not operate as the primary provider of both transmission and distribution services.

We have been working closely with the AER to explore options for how benchmarking could be applied in a meaningful way to Power and Water given the substantial differences that exist with our operating circumstances relative to our peers. Given the significant amount of work required to quantify appropriate operating environment factor adjustments, the AER has indicated that it will likely not apply econometric benchmarking for assessing our base year efficiency, and will instead rely on other top-down checks, such as category benchmarking and examining cost trends over time. This is consistent with the approach applied by the AER in our current regulatory determination.

In applying the AER's mechanistic approach towards developing our operating expenditure forecasts, we have also sought to consider the 'big picture' of how our network will need to adapt to major changes impacting the energy industry, and internal drivers.

The key strategic drivers outlined in Chapter Three, coupled with our discussions with customers and stakeholders has significantly shaped and informed how we have developed our forecast operating needs for the 2024-29 period. Importantly, in preparing our forecasts we have sought to ensure that we have sufficient resources to efficiently realise customers' vision for how our network should operate in the future.

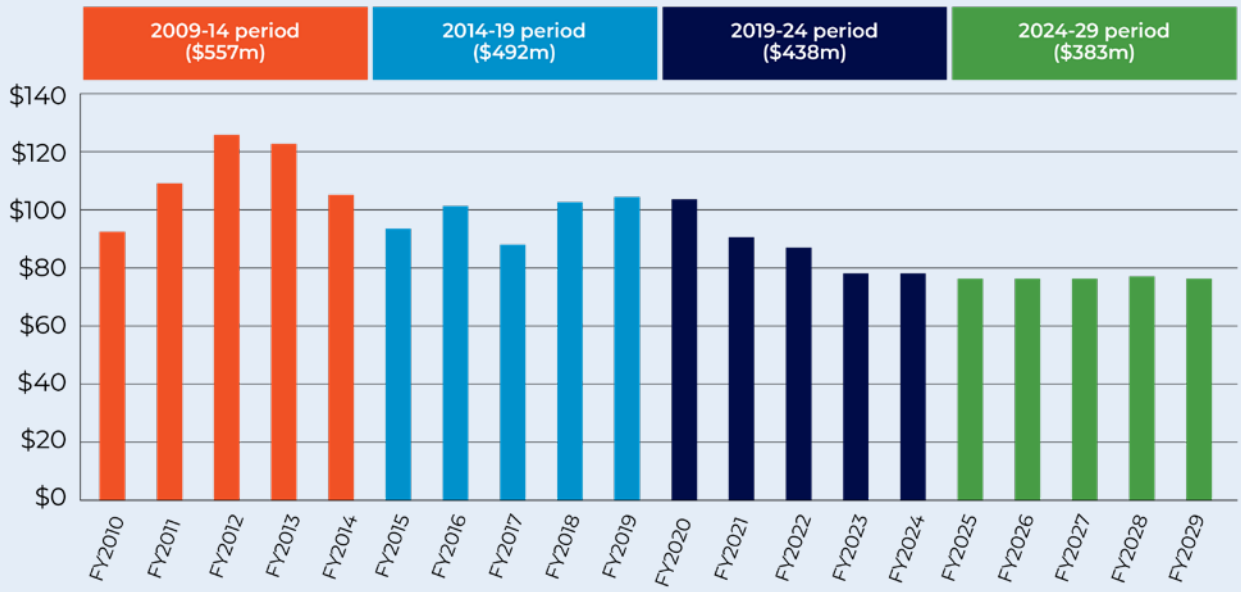
Figure 40 – Operating expenditure Forecast Approach

5.2 Drivers of change in operating expenditure – past to future

In seeking to understand the reasonableness and efficiency of our opex forecasts and our performance to date, it is necessary to take into account the circumstances in which Power and Water transitioned to the national electricity framework, and the significant change events which have since occurred.

Figure 41 provides a long-term view of our operating performance and shows how our operating expenditure has reduced significantly over time from historical levels in 2010-2014. The following sections are intended to provide further context on our performance to date and explain some of the key change events which have impacted our operations resulting in a much longer transition to more efficient and sustainable levels of opex.

Figure 41 - Operating actual and forecast expenditure from 2010 to 2029 ($m, 2024)



Understanding our operating expenditure target and performance to date

Power and Water joined the national electricity framework on 1 July 2015, with the staged adoption of obligations by 1 July 2019. This required a substantial work program to transition our obligations from jurisdictional instruments and codes to compliance under a national framework (the NT NER). This included work to prepare our first regulatory proposal, submitted to the AER on 31 January 2018.

At the time of submitting our regulatory proposal, analysis had not been undertaken to properly assess the differences between jurisdictional and national arrangements. Given our lack of experience with meeting our obligations under the national regime, a number of key assumptions were made in developing our opex forecast for the 2019-24 period, both in our initial and revised proposal. This included the extent to which we could absorb any additional obligations associated with transitioning to a national framework and the extent we could reduce our recurrent costs to be in line with industry peers.

It was assumed by Power and Water and the AER at the time that only minor differences between jurisdictional and national arrangements existed and that compliance with the regime would operate much the same as jurisdictional arrangements.

While accepting the limitations of traditional top-down analytical techniques, the AER concluded at its draft determination that operating expenditure targets should be set lower than our actual recurrent expenditure at that time. This conclusion was reached using category-based analysis and benchmarking and took into account other evidence and qualitative factors.

We largely accepted the AER's position that forecast operating expenditure should be based on more efficient maintenance practices and committed to refreshing existing ICT systems and transformation of our operating structure to reduce our costs over time. On that basis, we proposed, and the AER accepted, ambitious operating expenditure targets for the 2019-24 period amounting to more than 20 per cent reduction in recurrent costs in the first year of the period. In addition, the target included a step change reduction in overheads, staggered over the five-year period.

a. Transforming our operating model

Delivering an ambitious reduction in target operating expenditure involved a transformation process across the organisation. Given the limited availability to capture economies of scale, Power and Water sought to implement a new operating model aimed at capturing economies of scope by centralising and grouping 'like' functions rather than by line of business. While a "lift and shift" of functions has been performed to consolidate like functions the full benefits of transitioning to this new operating model have yet to be captured. This is mainly due to:

- Impact of COVID-19 in both business disruption and the ability to bring new capability into the organisation
- Executive turnover, industrial relations, and difficulty in attracting skilled resources to the Territory.
- Delays in enabling ICT infrastructure development and implementation.
- Impacts associated with transitioning to a more complex national framework, market reform, renewables uptake and other external influences.

Notwithstanding the changes made to the organisation structure, benefits in the form of cost savings have been offset by the need for additional resources to manage large solar connections and government policy changes to increase renewable energy penetration. This has not only changed our resourcing priorities but also our decision making regarding technology investment, which is explained further below.

b. Transitioning to the NT NER

Meeting our obligations under the NT NER has proven to be a more costly and challenging exercise than anticipated, for several reasons including:

- Requirements under the NT NER have proven to be more onerous than anticipated – requiring more detailed analysis, justification, and information than under jurisdictional arrangements. Meeting our reporting requirements has posed a significant challenge for Power and Water as our systems lack the capability to capture and report data at the granular level required by the AER. Given limitations associated with our existing ICT systems, meeting our reporting requirements often requires substantive manual effort to compile the information which diverts resources away from their normal business as usual activities and creates a backlog of tasks.
- Arrangements under the national regime are constantly evolving – unlike jurisdictional arrangements which were largely stable, the National Electricity Rules has evolved significantly since Power and Water has joined. The complexity in how National Electricity Rule changes flow through into the NT NER, and the pace and volume of change occurring at a national level, has proven difficult for Power and Water to keep up with. At the time of submitting our regulatory proposal the NT NER was at version 21. After four years, it is at version 88. This has meant that at the same time Power and Water was seeking to transition to compliance with the NT NER, the rules themselves have been changing. Power and Water is a small network, relative to other networks. We are unused to and ill-equipped (due to ageing ICT systems) to respond to the volume of change (particularly the transformational nature of change) that has been occurring at a national level.

These factors contributed to higher levels of opex during the 2014-19 regulatory period and at the start of the current regulatory period, as further work was required to address compliance gaps associated with meeting our connection framework obligations and our obligations under the AER's ring-fencing guideline.

c. Market reform and rapid uptake of renewables

Territorians have embraced solar and renewable energy at a rapid pace. Market frameworks and Power and Water's network have not been managed to keep pace with this rapid rate of change. This issue quickly came to the forefront of attention in the Territory with the Alice Spring's system 'black' event in October 2019.

The system black event was triggered by the power system not being in a secure operating state and having insufficient spinning reserve to cope with unexpected cloud cover that caused solar generation to drop suddenly. In response to this incident, a review of the state of system security and the adequacy of existing market arrangements to support the 50 per cent uptake of renewables and emerging technologies was undertaken.

This has resulted in a series of urgent priority reforms being progressed by the NTG in June 2020, as part of the Northern Territory Electricity Market (NTEM) priority reforms process. While that significant jurisdictional reform was occurring, reform at a national level aimed at addressing system security issues and integration of distributed energy resources was also occurring. Both of these developments and the sudden influx of solar farms seeking to connect to Power and Water's network triggered the need for Power and Water to reprioritise its focus to ensure that our network is more resilient to impacts from accelerating large scale and small scale solar. This resulted in the need for additional changes to our operating model and necessitated the resequencing of ICT system upgrades that were planned as part of Power and Water's transformation program.

d. Level of business maturity and system limitations

A contributing factor to our high level of operating costs in the past has been the fact that a number of Power and Water's core operating systems are approaching, or are already beyond, their useful life. Our existing systems do not have the capability of capturing or tracking data at a granular level, and are not configured to extract data in the format required by the AER. This creates a significant reliance on manual reporting and data manipulation, which in other networks would ordinarily be automated and centralised through ICT systems.

While Power and Water proposed a significant uplift of its ICT systems during the 2019-24 regulatory control period to address this issue and embed greater efficiencies in our operations this has not come to fruition for the following reasons:

- Projects relating to centralising and upgrading system control functions to provide additional functionality to SCADA, system management and fault response were put on hold early in the period pending greater certainty around market reforms.
- The costs associated with delivering our ICT program have proven significantly higher than anticipated at the time of preparing our forecasts. This is in part attributable to our lack of business maturity in this space and reliance on external consulting advice which underestimated the complexity and cost impact from operating a government owned multi-utility. Further market research and analysis has since revealed that our forecast overstated benefits and our delivery capability, and understated costs. This has triggered the need for reprioritisation and sequencing of ICT programs to determine what can be realistically delivered within the allowance and in light of changing business priorities.

Consequently, the full suite of planned system upgrades to deliver efficiencies and uplift business capability have not been delivered during the current regulatory period. Instead, this will be delivered in the forthcoming regulatory period based on a more accurate understanding of costs, delivery capability, and is reflected in the lower levels of opex projected for the 2024-29 period.

e. Changes in accounting treatment of shared costs

Decisions regarding Power and Water's target operating expenditure in 2019 were made on the observation that our recurrent operating costs were much higher than industry peers. The reasons for these higher costs could not be reconciled between different operating and environmental considerations, the effects of different reporting and accounting approaches, or some level of inherent inefficiency which customers should not pay for.

Inconsistencies in historic financial data and the ability to reliably compare Power and Water's own costs at an aggregate and category level with peer networks further contributed to uncertainty regarding the relative efficiency of Power and Water's operating expenditure.

We have been reviewing our regulatory accounting practices and sought advice as to whether improvements can be made to better compare our costs against industry peers. The advice recommended transitioning accounting treatments for labour cost and support costs so they were more consistent with industry peers and would assist with better comparison of Power and Water operating costs.

In response, we have made changes to how we capture internal labour rates and how we attribute labour related costs to operating activities. We have also tried to align our approach to attributing overhead costs to direct capital and operating activities so it is more consistent with industry peers. While both of these changes have not fully explained reasons why our costs are higher than industry peers, our analysis of backdated data demonstrates that some of the category analysis benchmarking would have presented differently if we had applied the same approach in our previous determination.

Key opex drivers

Moving forward, key drivers of our operating costs for the 2024-29 regulatory period are likely to be:

- **Ongoing market and regulatory reform** – changes in our obligations will impact upon compliance costs and can trigger the need for additional resourcing and system changes.
- **Technology enablement** – our ability to reach a more sustainable and efficient level of opex is dependent upon our ability to modernise our ageing ICT systems.
- **Customer preferences** – initiatives to reduce costs in customer service areas were challenged by customers in our People's Panels engagement. While most were reasonably satisfied that closure of shopfronts was the right decision, they provided reasons why Power and Water may need to do more than networks in other regions in respect of providing education, advice and support. Our proposal includes such preferences as step changes to our recurrent forecasts.

5.3 Adjusted base year

Our forecast method proposes the use of audited 2022 financial year actual operating expenditure as the base year. This will represent the most recent audited financial year at the time we submit our regulatory proposal. Adjustments for non-recurrent expenditure and top-down efficiency checks will be made to ensure it is useful for forecasting future costs.

For this Draft Plan, we have used a year-to-date projection of actual operating expenditure for the 2022 financial year (FY22). This is because our Draft Plan has been prepared ahead of finalising our statutory and regulatory accounts by October 2022. We may choose to adopt audited FY23 expenditure to support a revised forecast at the time of our revised proposal, depending on any material changes between years.

Based on our FY22 cost incurred to March 2022, we are projecting the following adjustments need to be made to the base year to normalise it for forecasting purposes:

- Adjustments to one-off project related costs that will not be incurred in the next period.
- Adjustments to reflect our expectations of labour costs that will be incurred and attributed to operating activities by the completion of the full financial year.
- A further one-off adjustment to reflect the fact that a greater proportion of overhead costs will move to capital expenditure in the next period.

a. Top-down efficiency check

We have noted above the challenges in explaining the variance between our recurrent costs and those of our peers. This has been improved through changes to how we account for costs to improve the metrics we are comparing. However, the reality is that there are a range factors which conceptually explain why the uniqueness of our business will result in higher costs and many of these factors are difficult to quantify.

The AER also acknowledges the challenges and indicated that work would continue during the period to investigate how some of these differences could be quantified. Our concerns relate to the implicit cost of attempting to properly quantify some of these unique differences which may still result in an unclear conclusion.

Some of the important differences of our business compared to others include:

- We are an end-to-end supplier of power across the Territory, with roles and responsibilities much broarder than single role DNSPs.
- We are the main essential services provider in the Territory operating a multi-utility with a back office sized to support all services.
- Power and Water is the only network operator regulated by the AER that has no interconnection with the National Electricity Market.
- While not regulated by the AER, significant costs are incurred by our networks division for remote and regional essential electricity network services. The application of our AER approved Cost Allocation Method drives a higher portion of all overhead costs to our activity on regulated networks. Our regulated network services include corporate overhead costs which would otherwise be attributed to remote and regional services if the allocation percentages were the same.
- We provide essential transmission related services in Darwin-Katherine and have a much closer operational relationship with system control and market operation activities compared to other distribution networks.
- Power and Water's network operation supports critical roles in system control and network operation in the Territory, and is responsible for developing various technical instruments that enable statutory objectives to be met, notably the Network Technical Code and System Control Technical Code. It performs a technical role equivalent to the Chapter 5 NER Schedules.
- As the only NSP regulated under the NT NER, it is relied on as the sole entity that can provide informed insights from the network perspective to policy debates and rule changes subjecting it to greater regulatory burden and associated costs under the NT regulatory arrangements.
- Other environmental factors already recognised by the AER continue to exist.

Power and Water engineers

b. Adjustment to base year for efficiency

The challenges around making the necessary adjustments for meaningful benchmark comparisons were well documented in the last distribution determination.

Despite the uncertainties around the gap, Power and Water still recognises there is a responsibility to set strong targets for improvement in the level of operating expenditure. Our internal examination of our base year to identify efficiencies has involved looking at our performance in the past and assessing if there were any opportunities for efficiencies to reduce the base year amount. Our approach to adjustments in the future period is as follows:

- For direct operating expenditure items, we will use the AER determined operating expenditure target identified in the last determination as a guide to establish our forecasts. We will use the lower of the out-turn actual expenditure in the base year and the AER's previous allowance.
- For overhead related items, we recognise cost reductions in the current period do not align with the AER's expectations implied in the allowance. This was due to necessary changes in our service model to establish the foundation for cost reductions to be delivered over time. We have consequently proposed that stretch targets from the AER's current allowance be extended into the next period so that overhead related costs are reduced by 10 per cent – staggered over the period.

5.4 Trends

We calculate the trend in forecast operating expenditure from the adjusted base year expenditure amount. This reflects changes in workload levels, prices of materials and labour, and productivity compared to our base year. We will calculate a trend adjustment for each year from FY23 to FY29 using the AER's rate of change formula. Three factors we look at include:

- **Input cost escalation** – We use materials, labour and contractors to undertake operating expenditure activities. While we automatically include inflation in our forecasts, the price of the inputs may be higher or lower depending on demand. We are working with network service providers in NSW, ACT and Tasmania to ensure a common methodology and independently verified outputs are used for escalation of labour, materials and land value.
- **Output growth** – As our network and customer base expands, we must perform more activities such as maintenance and customer service. This means that our costs will likely increase from the base year. We will apply the AER's calculation which includes change in customer numbers, energy demand at peak times, and circuit length.
- **Productivity growth** – Our customers would expect us to improve productivity over time through technology advances, and improved processes. We will likely use the AER's preferred approach to use industry estimates to establish the expected productivity growth and will also consider individual circumstances.

These factors are likely to change with market conditions and could change significantly between now and our regulatory proposal in January 2030. Our forecast rate of change is shown below in **Table 1.**

Table 1 – Rate of change forecast

Rate of change	Jun 2025	Jun 2026	Jun 2027	Jun 2028	Jun 2029
Forecast output change	1.68%	1.72%	1.71%	1.68%	1.65%
Forecast price change	0.48%	0.39%	0.36%	0.43%	0.56%
Forecast productivity change	0.50%	0.50%	0.50%	0.50%	0.50%
Forecast rate of change, year-on-year	**1.66%**	**1.61%**	**1.57%**	**1.62%**	**1.71%**
Forecast rate of change, cumulative	**1.66%**	**3.29%**	**4.91%**	**6.60%**	**8.43%**

5.5 Step changes

Step changes relate to increases or decreases in expenditure related to changes in our business environment, and which have not been reflected in the base year adjustments or trends adjustments. We will use the criteria in the AER's Expenditure Forecast Assessment Guidelines to identify potential step changes.

This includes identifying new obligations in NT and national regulations. Our organisation has been adapting to material changes in our regulatory obligations. Significantly, our ongoing transition to national electricity regulation requires an uplift in resources and systems to comply. We will seek to identify new obligations and provide detailed information on the efficient costs to comply. The obligations that we will need to manage in the transitioning Northern Territory Electricity Market are still to be resolved. Recent changes to National Electricity Rules in respect of export services will require a step change in costs, particularly when combined with the increasing need for our network to host greater capacity of solar while ensuring safe and reliable supply of energy. This will require increases in costs.

We discussed with customers the changing service delivery model to enable greater penetration of renewables in our system. Our customers generally believed that we should increase costs to facilitate and support the uptake of solar. They noted:

- Where technologies are proven, they should be adopted to help achieve renewable targets.
- We also need to move forward by piloting new technologies.

- Community outcomes should be considered to reduce or optimise outcomes and to minimise disadvantaged, so no one should be left behind.
- More needs to be done for remote and disadvantaged communities, which could be facilitated through government support.
- There needs to be overall benefits across the community through optimising investment and innovation.

Our forecasts therefore include costs to reflect greater obligations to enable more solar on the grid. This will be backed by our Distribution Energy Resource Integration Strategy and Future Networks Plan.

Other step changes relate to customer feedback in the area of customer service. Power and Water adopted a number of strategies which reduced operating costs. Customers at our People's Panel were concerned that some of these changes – particularly those relating to the closure of shop fronts – did not reflect community expectations around Power and Water's advisory and support role. We were able to explain to customers some of the changes that we have incorporated to still ensure support – including face to face discussion – is available and effective, but at much lower cost.

While our outlined response provided some comfort, customers still wanted more to be done regarding face to face communication and customer centric advocacy. Our step changes include additional expenditure consistent with these recommendations.

Our proposed step changes are outlined in **Table 2.**

Table 2 – Step changes

Step changes ($m, 2024)	Jun 2025	Jun 2026	Jun 2027	Jun 2028	Jun 2029
Customer Service – support/admin officer and customer advocate	0.43	0.43	0.43	0.43	0.43
Customer Service – travel and marketing	0.11	0.11	0.11	0.11	0.11
Customer Service – Enabling ICT	0.21	0.21	0.21	0.21	0.21
Future Networks – Hosting capacity and DER integration	0.8	0.8	0.8	0.8	0.8
Future Networks – ICT enablement	0.54	0.54	0.54	0.54	0.54

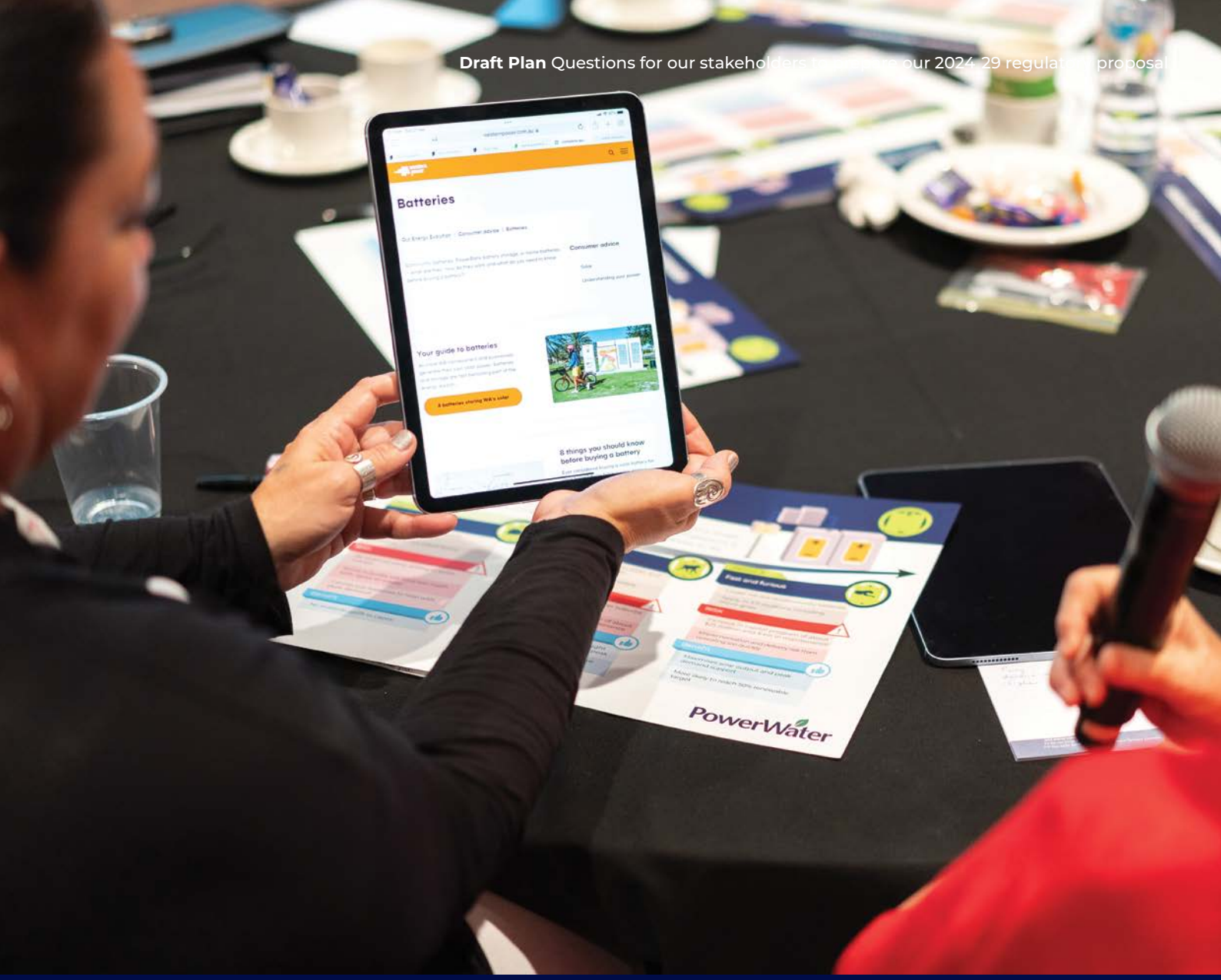
5.6 Category Specific Forecasts

A category specific forecast may be justified if, as a result of including a specific opex category in the base opex, total opex becomes so volatile that it undermines our assumption that total opex is relatively stable and follows a predictable path over time. Our proposal includes the category specific forecast for debt raising costs.

Debt raising costs are the benchmark costs of issuing debt, including the costs of maintaining an investment credit rating needed to issue this debt. **Table 3** presents the debt raising costs included in our proposal.

Table 3 – Debt raising costs

Step changes ($m, 2024)	Jun 2025	Jun 2026	Jun 2027	Jun 2028	Jun 2029
Debt raising costs ($m, 2024)	0.61	0.63	0.65	0.67	0.69



Customers discussing options at our People's Panel

Key Questions for stakeholders in Chapter Five

Do customers support our efficiency adjustments and consider they are appropriate stretch targets?

Do customers have concerns or questions on the step changes to implement customer priorities on the future network and customer service?

6. Revenue

There is considerable uncertainty in financial markets that have resulted in a marked increase in the rate of return since we met with our customers. This has resulted in our revenue forecast being 10 per cent above the 2019-24 period, higher than what we expected to present to customers. We note considerable uncertainty on the rate of return going forward, and this volatility will impact the revenue forecast we submit to the AER on 31 January 2023.

In its determination, the AER sets a cap on the annual revenue we can recover from customers through our network tariffs. The annual revenue is calculated based on the following elements:

- Investment costs associated with our regulatory asset base (RAB) which is the value of the stock of our assets at a point in time. The RAB comprises the depreciated value of our stock of assets, together with the forecast capital expenditure discussed in Chapter Five. The financing costs include a return on the RAB based on the current estimate of the rate of return, and depreciation of the RAB (often termed "return of" investment).
- Forecast operating expenditure for the upcoming regulatory period, as discussed in Chapter Six, together with an estimate of taxation costs.
- Adjustments to the revenue depending on our performance under the AER's incentive schemes and amounts to fund new innovation.

The calculation of forecast revenue relies on the AER's revenue model (Post tax revenue model) which includes the capital and expenditure forecasts discussed in the previous chapter together with inputs regarding the current value of our asset base and current market assumptions.

Revenue trends

Figure 42 identifies our forecast revenue for 2024-29 compared to the 2019-24 and 2014-19 regulatory periods. Our 2024-29 revenue is 10 per cent higher than the 2019-24 period, but still significantly below the allowance set by the jurisdictional regulator in 2014-19.

In the 2014-19 period, the jurisdictional regulator set a total revenue allowance of $1213 million due to high capital and operating expenditure together with high rates of return in the market conditions. A Ministerial Direction later required us to reduce our maximum revenue to closer to $1000 million.

Network revenue fell significantly in the first year of the 2019-24 period. The primary drivers were the AER's decision to reduce our operating expenditure, and a low rate of return due to prevailing market conditions. Further, the opening regulatory asset base was re-visited under the national economic framework, which led to a reduction in the return on assets (depreciation).

The higher revenue in the 2024-29 period is primarily explained by higher rates of return on investment due to a recent change in market conditions. Other drivers include increasing capital expenditure, which has led to higher financing costs including depreciation. However, the reduction in forecast operating expenditure has helped keep revenue from rising further.

Figure 43 identifies the components of our revenue forecast for 2024-29. The return on and return of the RAB comprise our investment costs, and together drive 56 per cent of revenue. Operating expenditure and tax comprise about 43 per cent of revenue. Revenue adjustments account for only 1 per cent of revenue.

Figure 42 – Revenue building blocks ($m, real 2024)

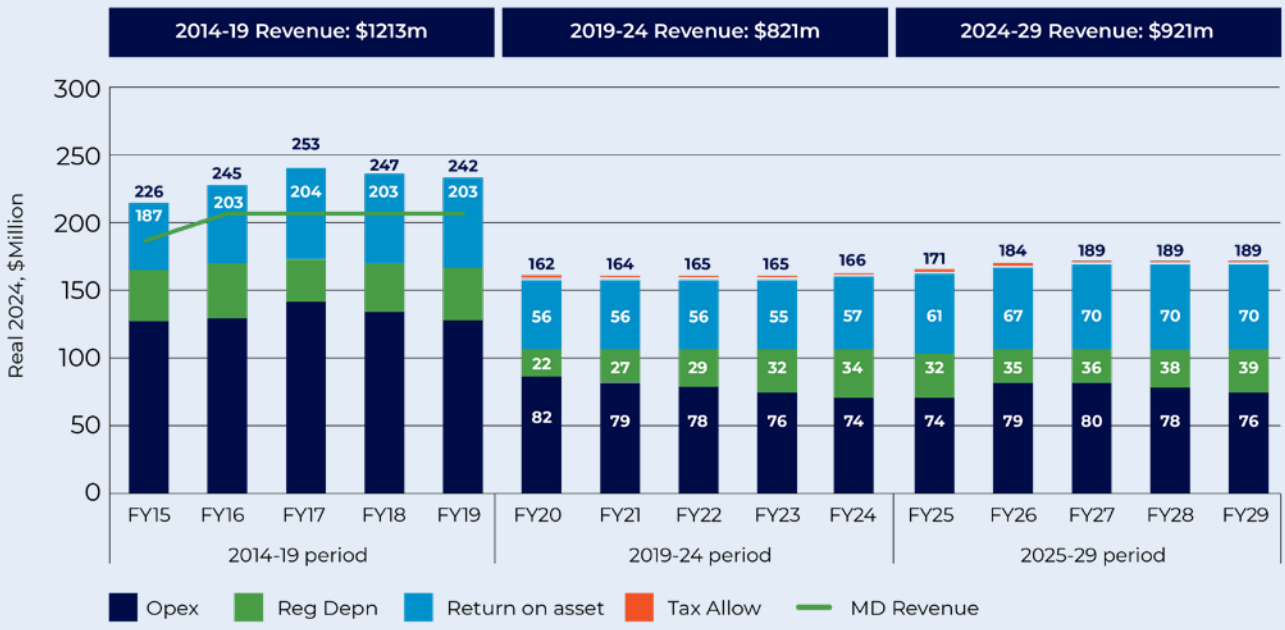
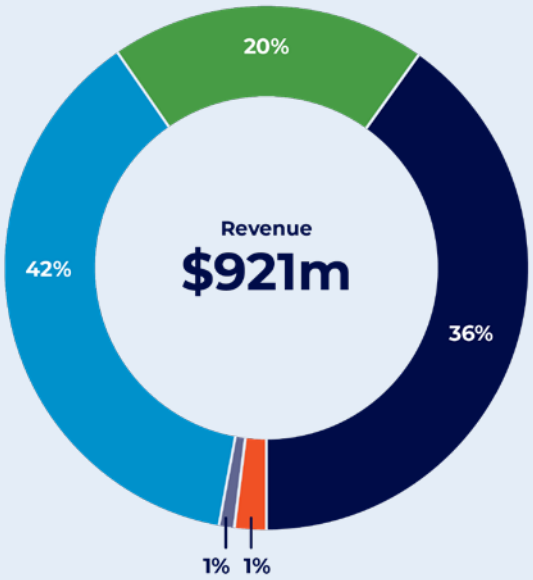


Figure 43 – Revenue breakdown



Return on Capital
$337m Returns on asset based on market conditions including rate of return

Return of capital (depreciation)
$180m Regulatory depreciation based on value of RAB and age profiles of asset classes

Operating expenditure
$387m Inspection, testing, regular and corrective works on network assets

Revenue adjustments
$9m Includes estimate of incentive paymentas and saving for a rainy day fund

Tax allowance
$9m Corporate income tax liabilities

6.1 Overall approach to develop revenue forecast

In our April 2022 People's Panels sessions, we noted our expenditure plans at the time were resulting in materially higher revenue forecasts for the 2024-29 period compared to the 2019-24 period. Our customers supported our objective of using available levers to reduce revenue to similar levels to the 2019-24 period. We proceeded to implement levers to keep our revenue forecast for 2024-29 at similar levels to 2019-24 in real terms (excluding the impact of inflation). This included reducing capital expenditure based on risk prioritisation and delivery capabilities, aligning our overhead allocation to other networks resulting in more capitalisation of overheads, and implementing efficiency stretch targets for operating expenditure.

With this target in mind, we consulted customers on their preferences for higher expenditure on future network, replacement and customer service. Our customers signalled that they were comfortable with a small increase in revenue above 2019-24 levels to implement their preferred options.

More recently however, our expected financing costs for the 2024-29 period increased markedly due to higher interest rates and global events. These uncontrollable factors have led to an unexpected 10 per cent increase in our revenue forecast for 2024-29 compared to the 2019-24 period. Inflation has also risen significantly since April 2022, and this will add further cost of living pressures to our customers.

What levers are available to reduce revenue, and what are the risks?

A key question in this Draft Plan is the extent and availability of levers to bring down revenue, and the trade-offs that may arise in respect of short term risks and longer term sustainability.

A key limitation is that a significant proportion of forecast revenue is fixed. For example, about 51 per cent of our forecast revenue for the 2024-29 period relates to the costs of financing previous investments in network and non-network assets, tax liabilities relating to past investment, and incentives for performance in this period. Only 49 per cent of forecast revenue is impacted by our forecast expenditure in the 2024-29 period. This can be seen in **Figure 44.**

Further, the current financial market is highly volatile and in this environment it is difficult to provide customers with certainty that we can achieve revenues at 2019-24 levels. Under the AER's calculations, the risk free rate is set in a period closer to the AER's determination based on market observations. Our financing costs are highly sensitive to this parameter, and it is beyond our control to influence the rate. **Figure 45** shows the recent volatility in the risk free rate with a significant increase since April 2022. This raises the issue of whether achieving a revenue neutral target is desirable or achievable.

Regardless, we understand that our customers require clear information on what elements of our future expenditure could be deferred or avoided, and the trade-offs that entails. We have identified five levers:

1. Re-consideration of customer preferences which have added $29 million to revenue.
2. Increasing our capitalisation of overheads beyond current levels. This would have the effect of reducing the pace of revenue recovery, but further consideration is required in relation to aligning with accounting standards.
3. Deferring regulatory depreciation to future periods, noting that this will accentuate the pressures on rising electricity prices in the future.
4. Further reductions in capital expenditure by taking on more short term risk and deferring ICT systems. This would have limited impact on reducing revenue. It would also mean that we take on more reliability, safety, and security risks in the 2024-29 period, together with building the conditions for a significant capital expenditure increase in future periods.
5. Further reductions in operating expenditure beyond the efficiency stretch targets in our forecasts. This would require a reduction in the level and cost of core services we undertake. Similar to capital expenditure, this would result in higher risks in the 2024-29 period, given we have already sought to apply stretch targets and most of this expenditure is recurrent and required.

Figure 44 – Revenue that is fixed based on past costs compared to future costs ($m, real 2024)

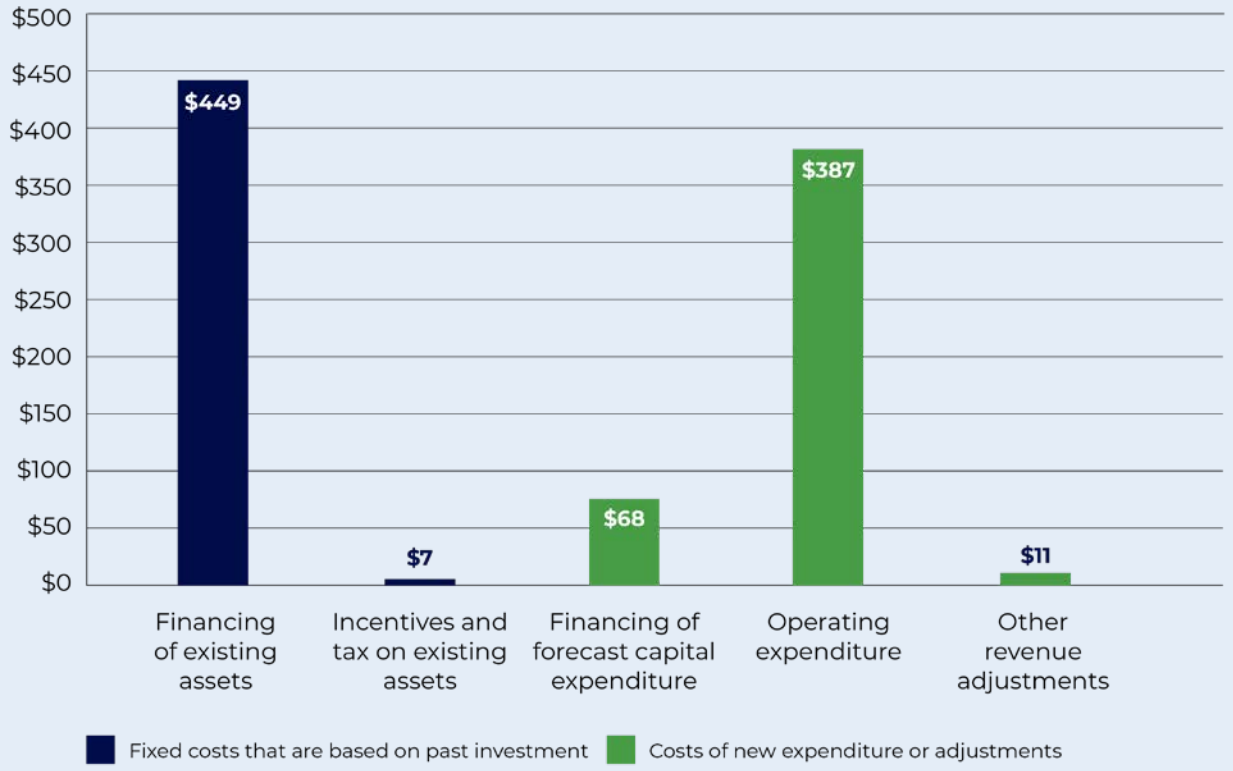


Figure 45 – Risk free rate

6.2 Returns on investment

About 56 per cent of our forecast revenue for the 2024-29 period relates to funding our past and future investments.

The calculation of financing costs is based on the value of the RAB and the remaining life of assets. The RAB is the sum of the depreciated value of past capital expenditure and forecast new capital expenditure. We make adjustments to the RAB to exclude capital contributions and asset disposals. The columns in **Figure 46** shows the movement in our RAB over the previous, current and forecast period for our network and non-network assets. The green line shows that the RAB per customer will stay relatively constant in the forecast period.

We note the RAB is significantly less than our estimate of the replacement cost of assets of about $3 to $4 billion, indicating that the current asset base is highly depreciated. The movement in our RAB per customer largely reflects the increase in capital expenditure over the period being higher than depreciation on past capital expenditure. We expect this trend to continue as we invest in new assets and replace assets that are highly depreciated in the RAB.

Return on assets

The AER determines a return on investment allowance for each year of the regulatory period. The allowance is calculated by multiplying the nominal rate of return by the nominal value of the RAB. The rate of return represents the expected rate of financing required to finance a benchmark efficient business facing similar risk. The nominal vanilla weighted average cost of capital is the proportion of the return on equity and return on debt based on a defined gearing ratio.

Rate of return parameters and values are largely pre-determined through the application of the AER's Rate of Return Instrument, but in some cases are based on market data either at the time of the determination or through updated data in the regulatory period.

A key change to the calculation of the rate of return has been the sudden increase in the risk free rate, which has a consequential impact on the return of equity. The risk free rate has increased significantly since our consultations with customers in April 2022 due to higher interest rates and other global factors. The risk free rate will be calculated closer to the time of our determination over an averaging period, and is then likely to be locked in for the duration of the 2024-29 period. We will continue to advise stakeholders on updates, but note that this is an uncontrollable factor influencing our overarching objective of maintaining revenues in the 2024-29 period at levels similar to 2019-24.

A further change that has impacted our calculation of the rate of return has been the AER's draft decision on the 2022 Rate of Return instrument. Once final, this will be a binding instrument that will be applied in our regulatory determination for the 2024-29 period. The AER's draft decision includes increasing the market risk premium which has the effect of increasing the return on equity. However, the AER will be using a five-year risk free rate period, which will likely lead to lower estimates of the return on equity.

Return of assets (depreciation)

We recover a revenue allowance equal to the depreciation returns calculated in the AER's revenue models. The depreciation included in the revenue allowance is net of assumed indexation. Straight line depreciation of existing assets as at 30 June 2024 is calculated using the AER's depreciation model, which applies the year-on-year tracking method. Straight line depreciation on new assets forecast for the 2024–29 period is calculated within the AER's Post Tax Revenue Model using the same method. In both cases, we have retained the asset classes and standard lives adopted by the AER for the 2019–24 period.

Figure 47 identifies the returns on and of assets.

Figure 46 – Movement in RAB over time ($m, real 2024)

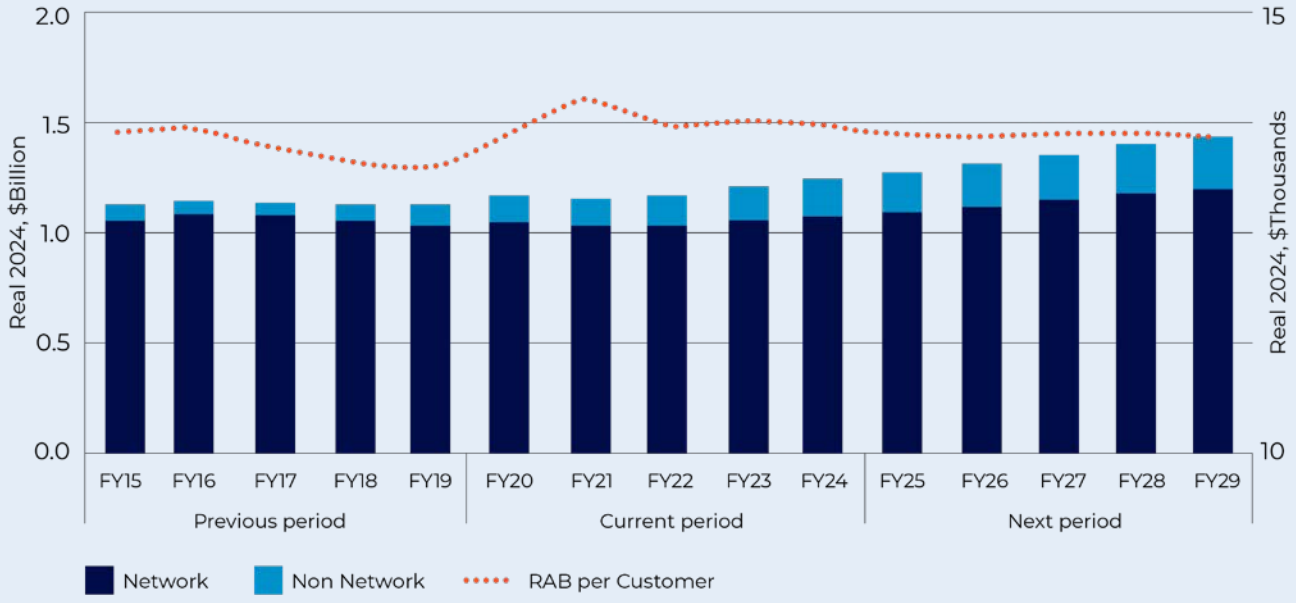
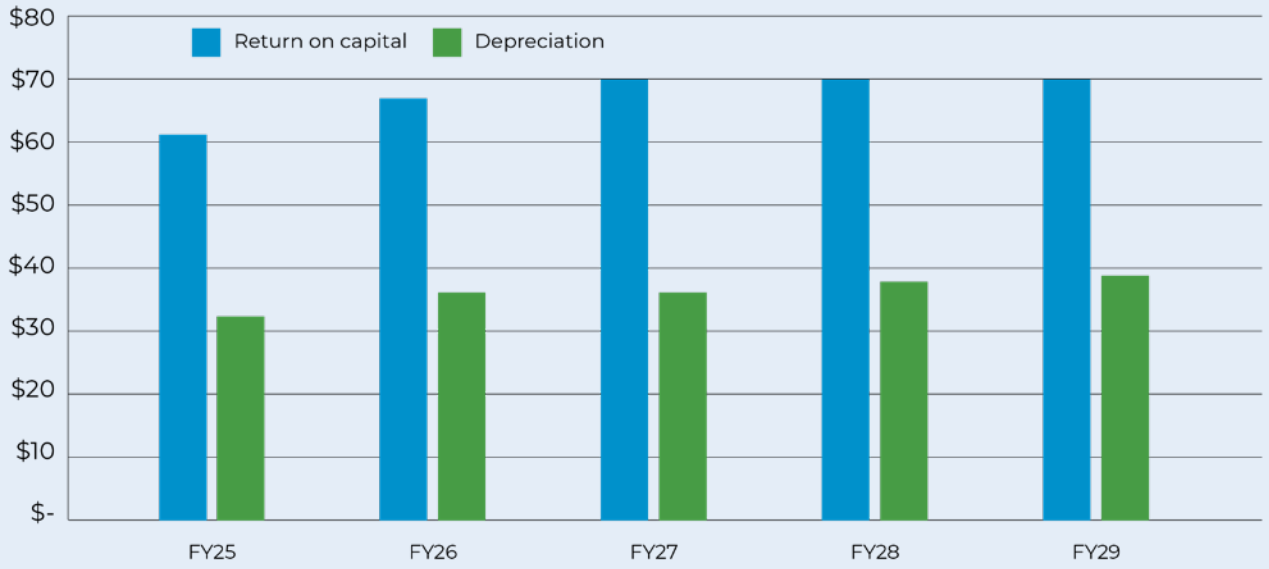


Figure 47 – Returns on investment in the 2024-29 period ($m, real 2024)



6.3 Other revenue items

About 37 per cent of the forecast revenue relates to operating expenditure forecasts. These forecasts were set out in Chapter Five of this Draft Plan and account for $387 million of forecast revenue in the 2024-29 period. As operating expenditure is an annual cost that is unrelated to an asset, the cost is passed through directly as a revenue item.

Like other businesses, we must pay income tax to the government. The allowance for tax costs in our building block proposal reflects our expected tax liabilities over the next regulatory period. We have forecast this allowance using the AER's revenue model as seen in **Table 4.**

Table 4 – Corporate income tax ($m, real 2024)

	FY25	FY26	FY27	FY28	FY28	Total
Estimated cost of corporate income tax	2.9	1.9	1.1	1.1	2.0	9.0

As well as shared asset revenue, our building blocks revenue is also adjusted for any incentive allowances. These can be positive or negative and are intended to give effect to schemes applied by the AER to ensure equal sharing of benefits from efficiency improvements over the period.

For the 2024–29 period, our proposed revenue includes two incentive allowances:

- CESS carryover amounts – these result from applying the AER's capital expenditure sharing scheme to our actual capex incurred over the 2019–24 period
- DMIA – this is an ex ante allowance for demand management innovation.

We have also included an adjustment to implement the customers' preferences for 'saving for a rainy day' fund of $9.1 million.

Adjustments to revenues for these additional allowances appear in **Table 5.**

Table 5 – Other revenue adjustments ($m, real 2024)

	FY25	FY26	FY27	FY28	FY28	Total
CESS carryover amounts	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(2.4)
DMIA	0.38	0.38	0.38	0.38	0.39	1.9
Saving for a Rainy Day Fund	1.76	1.77	1.80	1.85	1.91	9.1
Total adjustments	1.6	1.7	1.7	1.7	1.8	8.6

The AER may adjust revenues for benefits we and our customers receive from shared assets over the current regulatory period. The small number of assets we currently use to provide both regulated services and unregulated services do not generate sufficient revenue at this stage for the AER to make any adjustment. We will revisit this issue prior to submitting our regulatory proposal in January 2023.

6.4 Typical customer impacts

In our conversations with customers, we have been discussing the complexity of translating the impact of a change in network revenue in 2024-29 to a customer's electricity bill.

Similar to other states and territories in Australia, a customer's electricity bill is issued by their retailer. The bill reflects the customer's share of the total cost of supplying energy including generation of electricity, the use of our transmission and distribution network, the retailer margin, and the costs of managing the power system and market operating costs as seen in **Figure 48**.

In the NT, the NTG provides a subsidy for smaller customers through the Pricing Order that reduces their electricity bill. This means that the tariffs in a customer's bill do not relate to the relative costs of each sector, making it complex to specify the relative contribution of our costs. In our conversations with customers we have noted that in Australia, network costs account for 40 to 45 per cent of the electricity bill**.**

An increase in our network revenue in the 2024-29 period would increase the total cost of electricity in the NT. The extent to which this is passed on to customers depends on how the NTG Pricing Order will change in the 2024-29 period. However, for discussions on affordability with customers we have assumed that an increase in our network revenue would be fully reflected in a customer's bill.

For larger customers, it is more probable that an increase in our network revenue would be passed through by the retailer, although this will depend on the specific tariffs of the retailer.

For the purposes of this Draft Plan, we have assumed that the annual change in smoothed revenue will have a direct impact on each of our "*typical customers*" in each tariff class. As noted in Chapter Nine, we are also seeking feedback on making changes to our tariff structures. This may mean that there are likely to be differences between our customers on how the increase in network revenue is shared among customers. We have yet to fully undertake this analysis and will provide stakeholders with information in our engagement sessions and our regulatory proposal. The analysis also does not take into account the changes in customers, energy and demand that also have an impact on electricity bills.

Figure 49 identifies the indicative bill impact from the 5-year plans presented in this Draft Plan for our typical smaller and medium sized residential and non-residential customers. **Figure 50** identifies the indicative bill impact for our industrial and large industrial major customers.

Figure 48 – Typical electricity bill breakdown

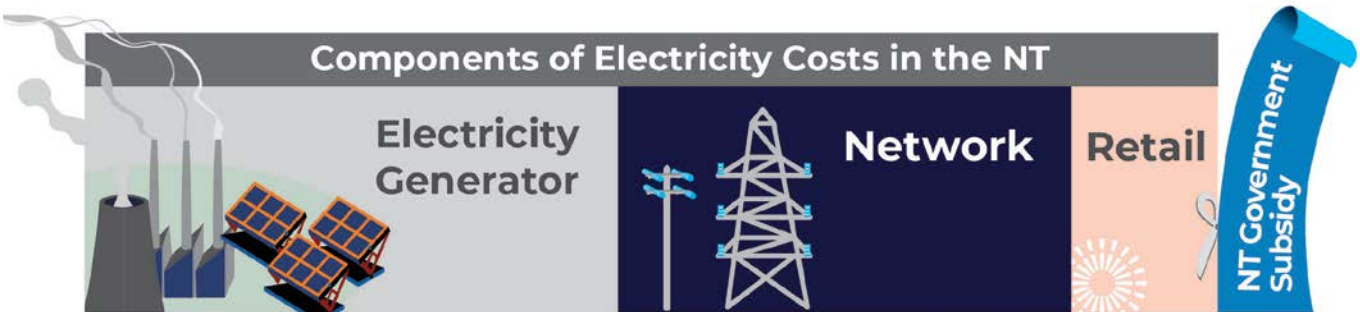


Figure 49 – Indicative impact of 2024-29 network revenue on smaller customer's annual electricity bill ($, nominal)

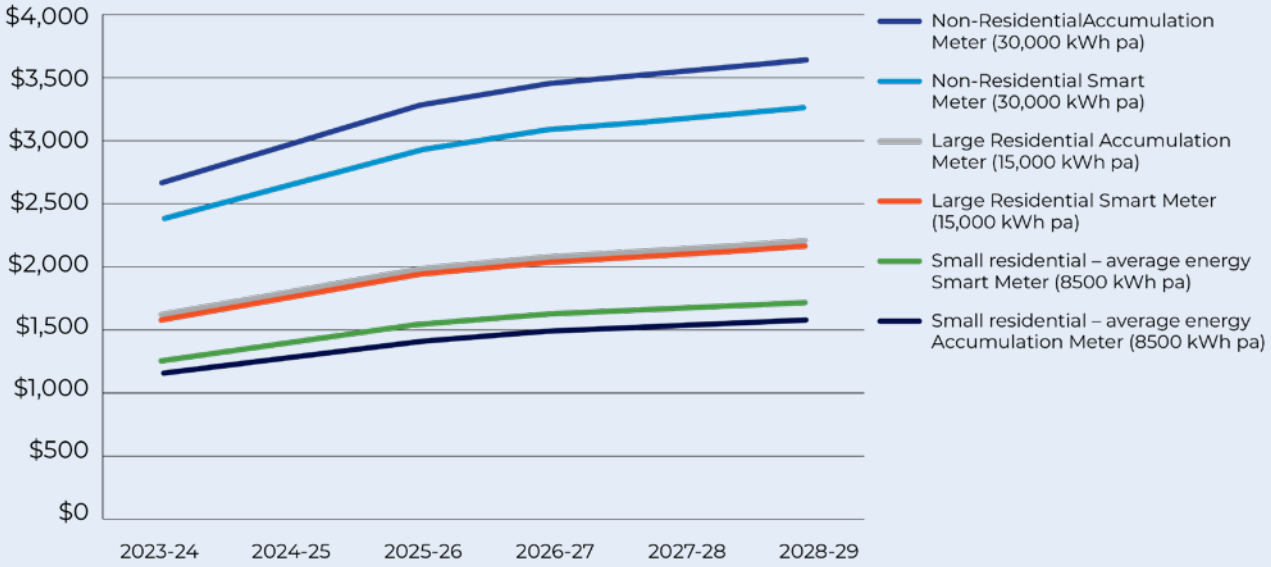
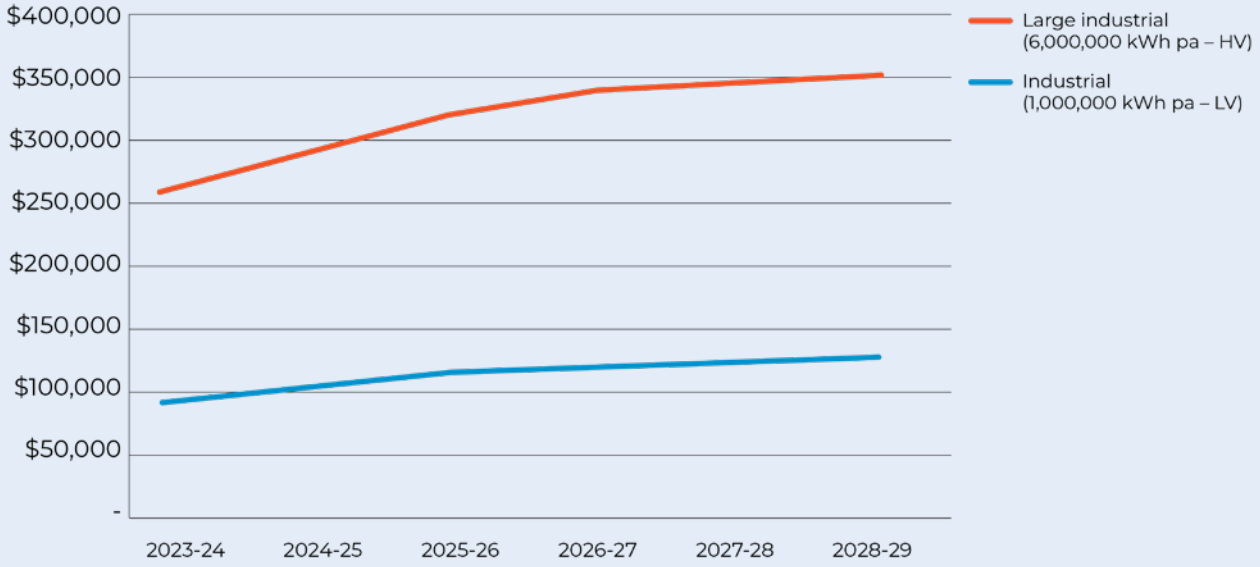


Figure 50 – Indicative impact of 2024-29 network revenue on larger non-residential customer's annual electricity bill ($, nominal)



Customer examining materials at our People's Panel

Key Questions for stakeholders in Chapter Six

Do you consider the customer preferences should be re-visited in light of the higher than anticipated forecast revenue?

Do customers consider that short term affordability should be prioritised over long-term sustainability?

7. Metering services

For the 2024-29 regulatory period, we are proposing to continue installing smart meters for all new and replacement installations, including the ongoing replacement of our mechanical meters that have exceeded their operational life. Our proposed metering expenditure seeks to develop a smart meter fleet that facilitates our customers' choices to install renewable energy installations on the network, while addressing condition, accuracy and reliability issues associated with our current mechanical meters.

Our metering service is an alternative control service where we identify an individual charge for the service separate to the standard service.

Our electricity meter population is about 87,500. Of these, about 24,250 are smart meters. Our current non-smart meter population are mostly very old, mechanical meters which have accuracy issues and are close to or beyond their economic life as illustrated in **Figure 51**. To address this, we are proposing to continue our progressive rollout of smart meters which is underway in the current regulatory period.

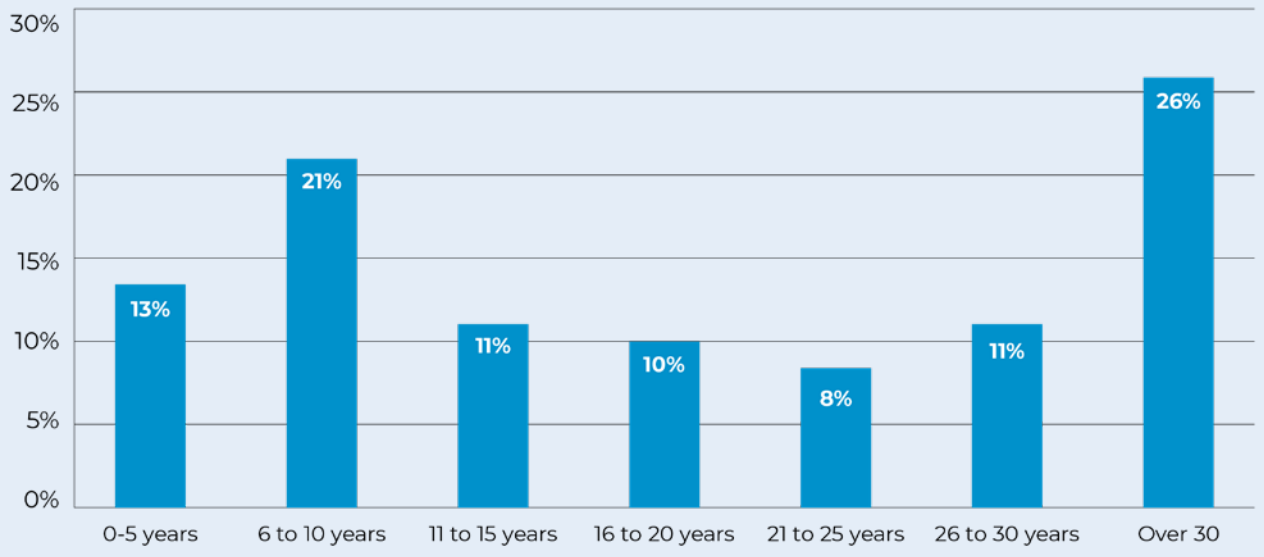
The move to smart meters is consistent with national trends and customer preferences. Our investment in smart metering has generally been supported by our customers, as it removes the need for manual reads. Smart meters also enable us to facilitate growing solar and battery connections on our distribution network as well as prepare for customer uptake of electric vehicles. As noted in the next chapter, smart meters are a prerequisite for implementing more efficient tariffs that incentivise customers to use appliances in off-peak periods.

Other benefits from smart meters include better network fault identification, more accurate meter reads, and the ability to better comply with stringent metering requirements under the national electricity rules.

Our progressive rollout is planned as follows:

- Of our 63,250 non-smart meters, 21,000 will be replaced or upgraded to smart meters in the remainder of the current regulatory period.
- Half of the remaining 42,250 are proposed to be replaced with smart meters over the 2024-29 period.

Figure 51 – Proportion of meters by age



7.1 Metering capital expenditure

Our metering capital expenditure forecast of $36.0 million (2023-24 real dollars) for the 2024-29 regulatory period is consistent with our aim of a progressive rollout of smart meters. This represents a decrease of nine per cent over the forecast expenditure of $39.8 million in the 2019-24 period, and an increase of 19 per cent over the regulatory allowance of $30.3 million. This is shown in **Figure 52.**

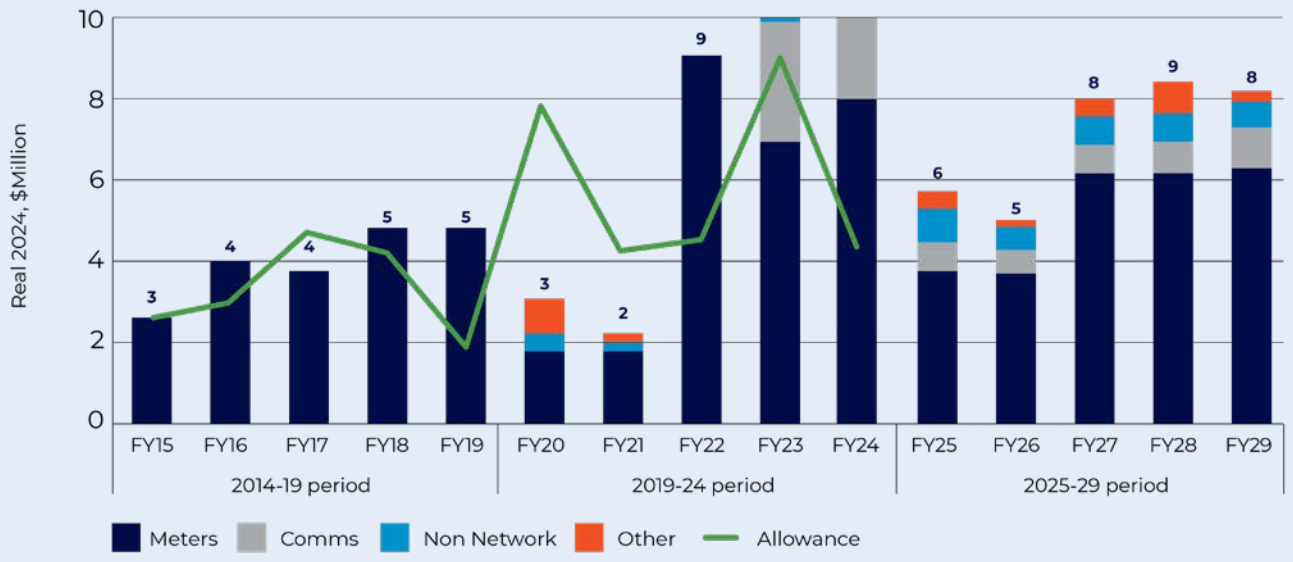
Our capex forecast for 2024-29 is founded on a proposed acceleration of the meter and modem replacement program over the last two years of the current regulatory period. Our planned meter and modem replacement programs for 2019-24 have been delayed because our metering IT systems were unable to manage the increase in data from the planned works. With these constraints now addressed, we expect to ramp up this program from 2022-23.

We considered both a slower and a faster smart meter rollout as part of our preparation for our initial regulatory proposal. We are proposing a middle option of a progressive rollout to balance costs for consumers, resourcing needs and compliance issues. We believe the capital program provides the most appropriate and sustainable transition to a safe, accurate, and reliable meter population going forward.

Other points of note regarding our metering capex program are:

- The overall meter population is less than stated at the last regulatory determination. Several thousand customers have three meters, which are used as a single meter for billing purposes. We have now changed this to be a single meter in our metering register and have undertaken a significant data cleansing exercise in our billing system, resulting in a more accurate (and lower) count of meters. The combination of these issues has caused significant under-recovery of metering costs in the current regulatory period.
- An additional driver of capital expenditure is an allocation of approximately $6 million to replace asbestos meter panels on customer premises where it is unsafe to replace the meter on the existing panel. This is a continuation of a program that was approved in the last determination.
- There is a dip in capital expenditure in the first two years of the regulatory period. The rationale for this is that we have a significant population of unregulated meters (around 15,000) that we are responsible for. These meters form part of various isolated systems in the NT that are not connected to the regulated networks. Similar

Figure 52 – Metering capital expenditure ($m, real 2024)



to the wider, regulated meter population, many of these meters are at the end of their useful life and require upgrading. Funding for these upgrades is separate to the AER process and approval is currently being sought. Pending this approval, it is expected that this work will be undertaken in 2024-25 and 2025-26. This will mean resources will be redirected to this work, necessitating a reduction in the replacement program for regulated meters for this two year period.

7.2 Metering operating expenditure

Our metering operating expenditure relates primarily to costs associated with reading meters and maintaining meter data. Opex is derived via the Base Step Trend method and is forecast to be $31 million over the next regulatory period, an overall decrease of 14 per cent relative to actual forecast expenditure and 1.3 per cent relative to the regulatory allowance for the current regulatory period, primarily driven by:

- The application of overheads to direct expenditure costs.
- Escalation factors applied to the base year operating expenditure.
- Increases in our meter testing and inspection rates to comply with the requirements of Chapter 7A of the NT NER.

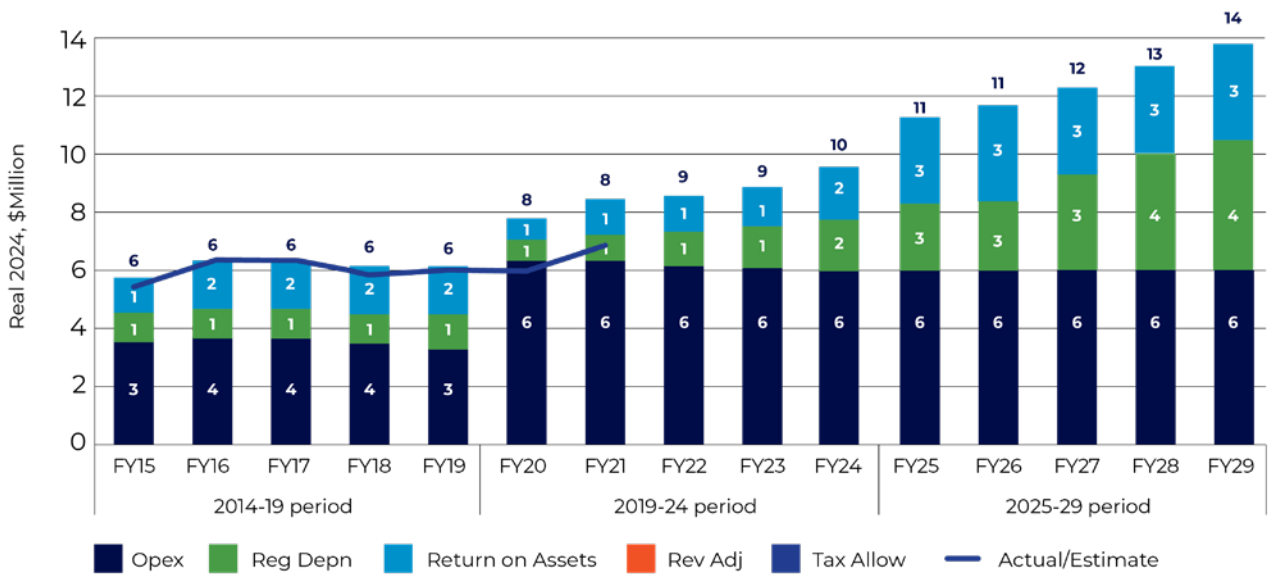
7.3 Revenue impacts from metering expenditure

The expenditure proposals outlined above result in a revenue requirement of around $11.0 million in the first year of the regulatory period, rising to $13.8 million by year five. The correction of current under-recoveries, along with the increased capital program, result in an increase in annual metering charges to customers of 43 per cent as a one-off in 2024-25, followed by smoothed price increases of 1.34 per cent in subsequent years. For a small customer with a single phase meter this is an increase from $67 to $101 in year 1. The revenue outcomes can be seen in **Figure 53.**

The major driver of revenue increases is the increase in capital expenditure relative to the capital expenditure allowed in the current regulatory period. In particular, our meters were almost fully depreciated by the start of the 2019-24 regulatory period, so as our meter replacement program progresses, the metering regulatory asset base will grow, in turn increasing the return on and of capital.

We also propose a change in the way our metering services are currently categorised to more correctly apportion costs between customers, particularly for low voltage CTs and HV customers.

Figure 53 – Metering revenue ($m, real 2024)



Power and Water staff discussing options at our People Panel

Key Questions for stakeholders in Chapter Seven

Do customers consider we have the right pace of smart meter rollouts?

8. Tariffs for a new age

We set network tariffs each year to collect the revenue allowance set by the AER. In the current 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 want to consult with customers on the need for further tariff changes. Our proposed changes seek to reduce future costs through tariff structures that encourage customers to shift consumption and solar exports to periods when the network has spare capacity.

In Chapter Six, we described the process for how the AER places a ceiling on the revenue we can collect for our network services based on expenditure plans and previous investments. To collect the revenue, we set network tariffs based on a customer's connection, energy and demand for our network services. Importantly, the network tariff is charged to the retailer rather than the customer.

Our network 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 related objective is tariffs that encourage customers to best utilise the capacity of the network for example by shifting demand to off-peak periods. This improves affordability for all customers by improving utilisation, a strategic focus that we outlined in Chapter Three.

The NT NER requires us to develop network tariffs that align with Pricing Principles that relate to economic efficiency. Under the Pricing Principles, we must set tariffs to recover the expected future costs of building new networks. This involves setting a charge that reflects the long run marginal cost (LRMC) of our network services. Any residual costs should be recovered by tariffs that collect revenue from customers in the least distortionary way.

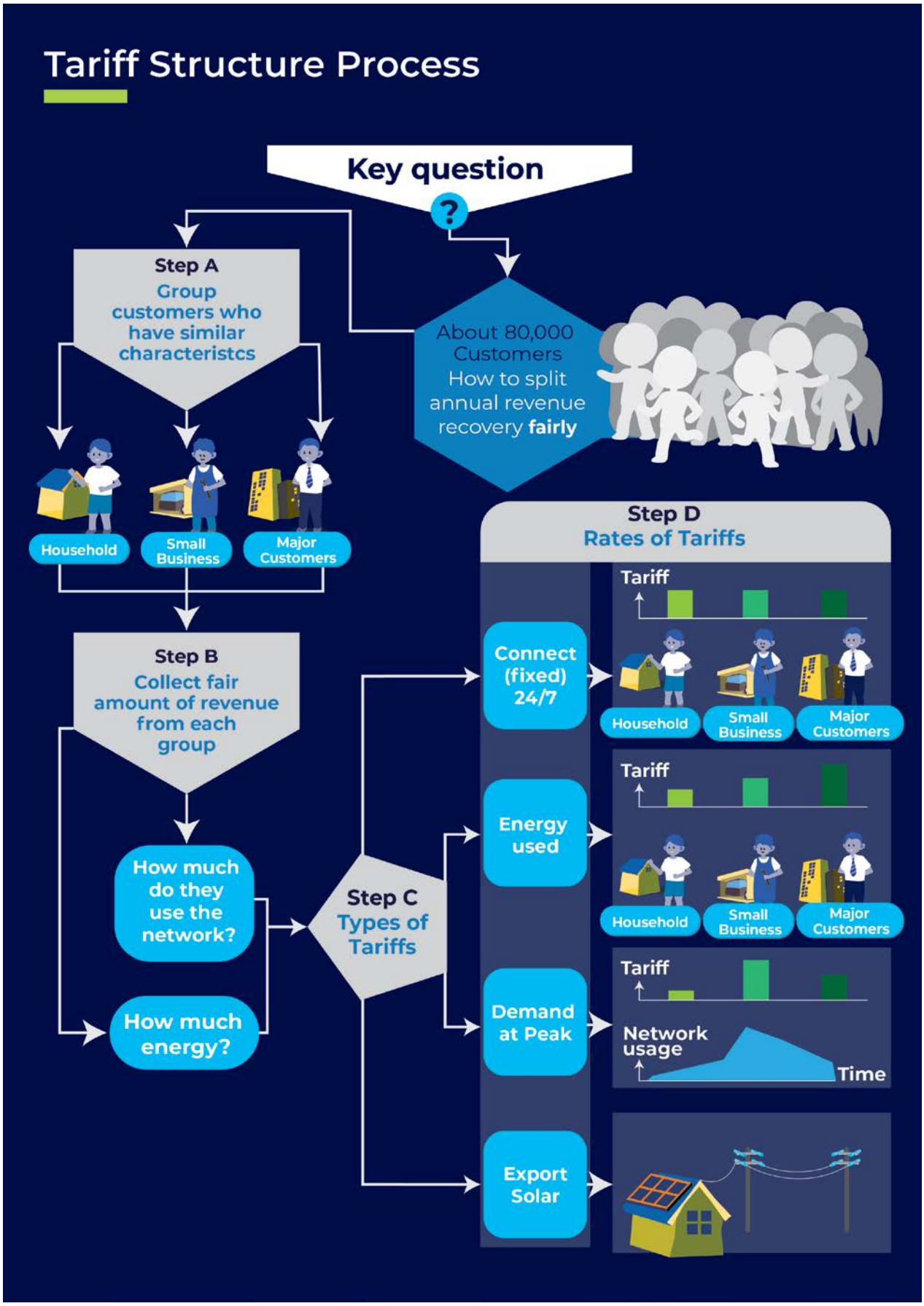
Figure 54 describes the key steps in setting network tariffs.

- Step One is developing tariff classes based on grouping customers into tariff classes and segments. This recognises that it would be administratively difficult to establish a price for each individual customer. The process instead seeks to group customers based on similar characteristics, usage of the network, and meters. For example, we group our customers based on whether they are residential, non-residential or a major energy user. We also develop our groupings based on consumption, and whether the customer connects to our high or low voltage network. Finally, we have separate tariff groupings for smart meter customers.
- Step Two is to collect revenue from these customer groupings in a way that reflects the fair share of their use of the network. This is based on factors such as where customers connect to our network, and how much energy and peak demand is dedicated to the customer group.
- Step Three is to identify the mix of tariff types that should be used to set tariffs. The process is based on developing a mix of efficient price signals that result in customers paying a fair share based on how they use the network. This includes fixed charges, energy consumption, and peak demand charges that may vary based on the time of day or season.
- Step Four is to develop rates for each of these tariff components that result in collecting our annual revenue, based on the optimal allocation of revenue among each of the tariff components.

Limitations of network tariffs in the NT

In our discussions with customers, we have noted that our network tariffs are not passed through to the customer by the retailer, and this limits the ability of our network tariffs to provide a direct price signal to customers. For small customers, the retailer must use the tariffs in the NTG Pricing Order. These tariffs do not have a specific network component, nor are the charging parameters the same. For larger customers, the retailer has the option of directly passing through our network tariff.

Figure 54 – Process for setting network tariffs



8.1 Network tariffs in the current period

In the 2019-24 period, we made significant changes to our network tariffs. The key driver of change was the application of the national framework for regulation. A further driver of change was stakeholder feedback particularly from the AER on driving more efficient tariffs.

In response, we made four key changes in the 2019-24 period. Firstly, we simplified our tariff structures to limit the parameters. Secondly, we shifted to peak demand pricing structures rather than rely predominantly on energy consumption charges. Thirdly, we had sought to re-balance revenue between different tariff classes to better align costs of services with revenue collection. Lastly, we sought to implement a power factor correction trial to reduce energy losses.

At the time, our meter fleet was largely accumulation meters. Customers that had this type of meter could not effectively transition to more efficient tariffs. For this reason, we had proposed a progressive rollout of smart meters to ensure that more customers had more efficient tariffs.

Our proposed changes to network tariffs was largely accepted by the AER in the 2019-24 determination. Our customers are currently grouped into seven tariff classes with assignment based on whether the customer is residential or non-residential, the annual energy consumption, the type of meter, and whether they are connected to the high or low voltage network.

There are only three types of charges. The System Access Charge (SAC) is based on the days a customer is connected to the network. The Anytime Charge is based on total energy consumption. The Peak Demand Charge is based on the maximum demand of the customer within in a month in the peak period. The peak period is 12pm to 9pm on weekdays. For smaller customers with smart meters, the peak period is between 1 October and 31 March each year and for larger customers it is all year round. The tariff classes and charges are set out in **Table 6** below.

Table 6 – Tariff parameters approved by AER

Tariff	System Access Charge (SAC)	Anytime kWh (c/kWh)	Peak Demand ($/kVA)
Tariff 1 Residential customers consuming <750MWh with standard accumulation meters	×	×	-
Tariff 2 Non Residential customers consuming <750MWh with standard accumulation meters	×	×	-
Tariff 3 LV Smart Meter consuming <750MWh with smart meters	×	×	×
Tariff 4 Unmetered Supply (for connections without metering such as traffic lights and streetlights)	×	×	-
Tariff 5 LV>750MWh Customers connected to the LV network consuming >750MWh	×	×	×
Tariff 6 HV<750MWh Customers connected to the HV network consuming <750 MWh	×	×	×
Tariff 7 HV>750MWh Customers connected to the HV network consuming >750MWh	×	×	×

While the AER accepted our network tariff proposal, it requested improvements in our approach. Specifically it noted the need to:

- Establish a more robust approach to energy forecasting, consistent with system demand forecasting approach and needs to consider a number of variables that may impact prices in a 12-month period.
- Investigate and refine our methods for estimating long run marginal cost.
- Further investigate the timing of periods of our peak period window.
- Provide further justification of the need for individually calculated tariffs and the need for a power factor correction tariff.

8.2 Case for more efficient tariffs

In our 2024-29 regulatory proposal, we will publish a Tariff Structure Statement (TSS) that describes any changes we are seeking to make to our current arrangements. The AER will make a determination on whether to approve or seek changes to our TSS.

As noted in Chapter Three, our network is facing rapid global and local changes that will influence our future costs. A key strategic focus for us moving forward is to improve the utilisation of the network by delivering more energy and solar export capacity, while minimising new network investment. We see that network tariffs will play a key role in activating this strategy by providing customers with price incentives to use our network in off-peak periods.

In our consultations with customers, we noted how our future costs could be minimised through tariff reform that better manages when customers use our network.

Managing peak demand in the evening

Peak demand growth across our network has been relatively flat over the last decade. Due to the extreme heat, demand for electricity is highest in the middle of the day in the October to April period.

Over the last five years, we have seen less demand for electricity from our network in these peak periods. This has largely been a result of customers using their own solar panels to energise their homes and businesses. Demand for electricity from our network has shifted to the early evening period when the sun is no longer shining. **Figure 55** 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.

We are also seeing a significant uplift in customer numbers in the 2024-29 period including major residential and industrial developments. This will accelerate demand for our network services, adding to demand at peak times. Post 2030, we expect an acceleration in electric vehicles in the Northern Territory. Electric vehicles 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.

Managing solar in the day

Our future network strategy is directed at a hosting solution that helps us more clearly identify opportunities to unlock solar securely without causing network voltage or system inertia issues. However, with a doubling of rooftop solar forecast by 2030, we expect that some exports will need to be ramped down or curtailed. **Figure 56** shows the minimum demand day on the Darwin-Katherine electricity system. There is a significant decline in demand for our network electricity between 2017 and 2021 in the middle of the day.

Network tariffs could incentivise customers to use more of their own solar, rather than exporting into the grid during these 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.

Currently, our demand charge in summer is set from midday onwards, which does not 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.

Figure 55 – Maximum demand day profile (MW)

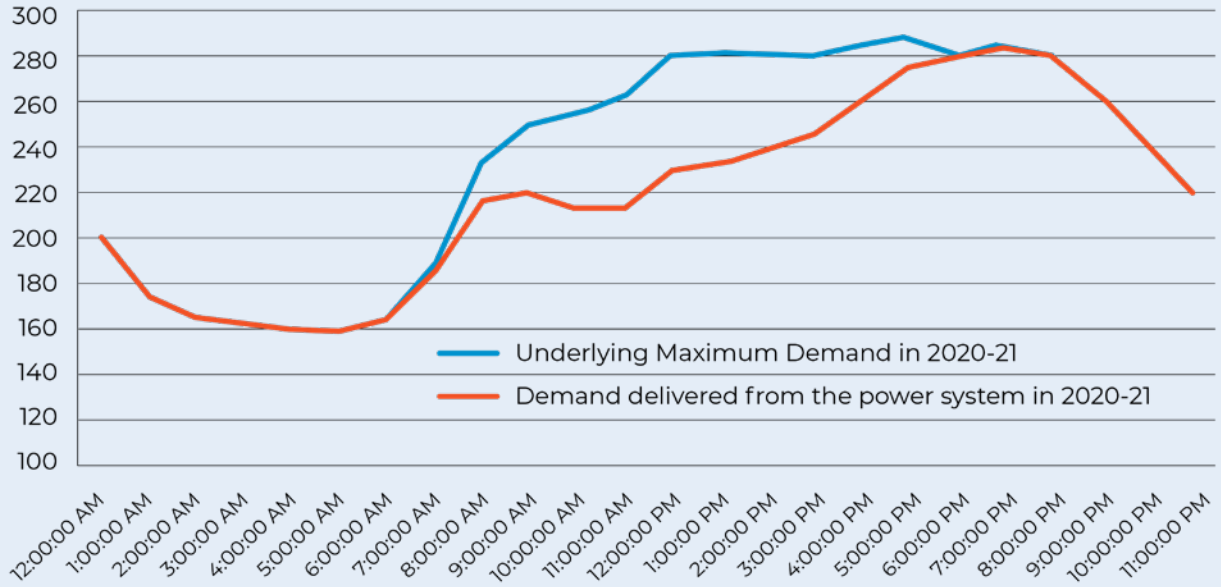
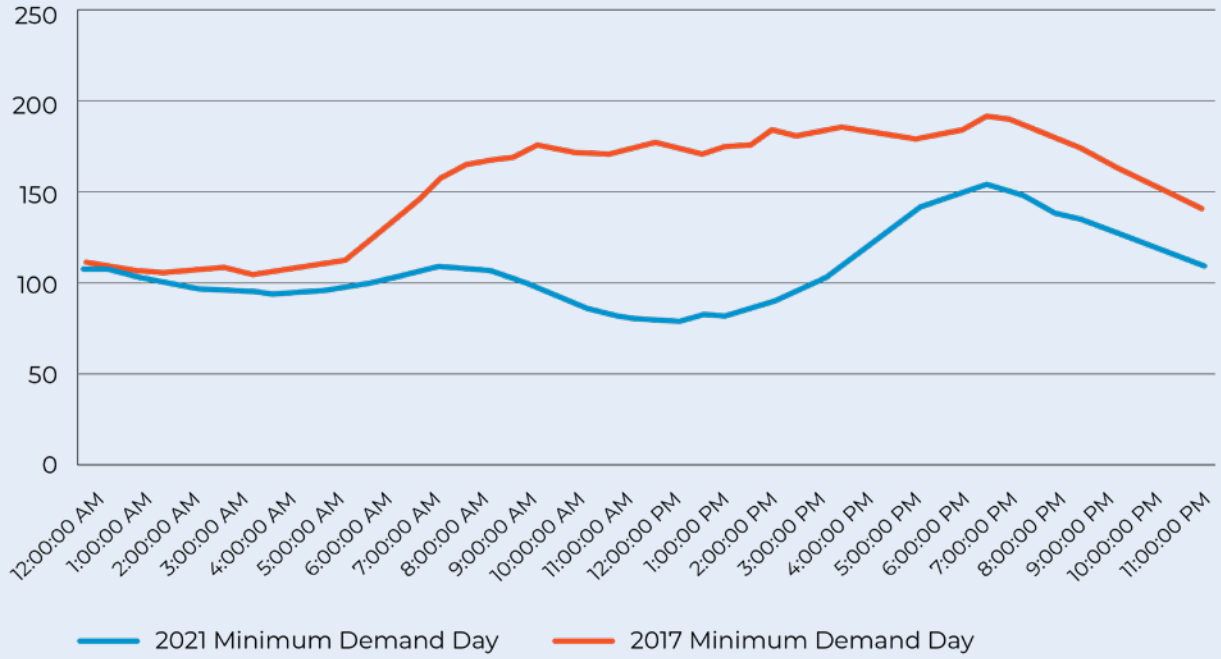


Figure 56 – Change in the profile on the minimum day in the Darwin-Katherine system in FY2021 (MW)



8.3 Strategy and principles for tariff reform

Our strategy has focused on changes in tariff reform that responds to the network impact of rising peak demand in the afternoon/evening periods in summer and solar in the middle of the day. We have been discussing our strategic thinking and options for pace of reform with stakeholders, and this has influenced our position in this Draft Plan.

Principles underlying tariff reform

There are four key principles behind our thinking on efficient tariff reform. Firstly, we see a need to keep our structures simple. This is because we understand that pricing signals need to be clear and understandable. Secondly, we have considered whether changes could lead to unmanageable bill impacts, particularly to our larger customers who are likely to have the network tariff applied directly to them. Thirdly, we have considered equity issues particularly between customers with different meter technology, noting that there should not be a wide gap between customers with similar usage patterns. Fourthly, we considered practical constraints such as billing systems and time to communicate new tariffs to customers and retailers.

Our starting point 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. As a result, we have continued to apply a fixed daily rate charge rather than something more complex such as a daily rate based on maximum demands. 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.

Strategic direction

At a high level, we see that the tariff reform applied in the 2019-24 period provides a solid foundation for further tariff reform. We note that tariff reform is enabled by smart meters, and that the continued rollout of smart meters is integral to implementation in the future.

We consider that the current tariff classes and segments are simple and effective at grouping customers with similar characteristics and use of network services. Our strategy identifies minor changes to separate segments of our existing tariff classes could help strengthen the price signal and also assist with retail competition in the future.

Under changes in the NT NER, we require a new type of tariff for customers that export solar through our network. This is consistent with our need to manage solar in the middle of the day and to meet growing peak demand through stored solar.

A key strategic change is the refinement of time of day pricing. This includes tightening the peak period to align with the time and seasons when our network experiences the highest demand. This includes tightening the peak period to align with the time and season when our network experience 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

Our proposed strategic direction is to place greater emphasis on demand rather than energy charges, particularly for larger customers. This includes adjusting the rates to more reflect the long run marginal cost.

Feedback from stakeholders

We are mindful that our consultation on tariff reform has been relatively limited to discussions with retailers and with the People's Panel in Darwin. We recognise that this is an issue that requires more consultation with customers, retailers and broader stakeholders.

Our consultation on tariff reform has been predominantly with Retailers operating in the Northern Territory. It is retailers who see our network charges and bundle these charges with other costs to separately bill customers. We have also engaged broadly with residential customers on pricing arrangements in the Territory.

Our People's Panel in Darwin noted the limitations of reform given that the tariffs of small customers are set in the NTG Pricing Order and do not align with network tariff structures. However, the Panel wanted Power and Water to develop network prices that made it easier for retailers (and government) to pass better price signals. Most Panel members preferred 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.

In our options we also discussed the pace of reform. Our customers were mindful that changes in tariffs can have an affordability impact on vulnerable customers who cannot change their energy usage patterns, or were not provided with communications. They asked us to think about introducing reform at a slower, incremental rate.

8.4 Proposed changes to Tariffs

In the following sections, we discuss the key changes we are proposing to make in the 2024-29 period.

Step One – Proposed changes to how we group customers

We currently have seven tariff classes, with no further segmentation. We are not proposing any changes to our tariff classes, but we are considering introducing further segmentation to provide a more targeted price signal based on the characteristics of the customer class.

We are planning to separate the existing tariff class for small customers with smart meters (Tariff Class 3) into two segments. Under this plan, customers consuming less than 100MWh will be assigned to Tariff 3a and customers consuming between 100MWh and 750MWh will be assigned to Tariff 3b. This follows retailer feedback on how to encourage and expand retail competition in the future.

In respect of other potential changes, we are examining whether the benefits of an additional tariff segment for our largest customers who may have different characteristics when setting the peak charge. It is also likely that we will also introduce a new class for generation customers including battery operators.

Step Two – Proposed changes on allocation of revenue between customer groups

We are currently analysing whether any changes are required in how we allocate revenue among customers. This issue is also dependent on any changes to our calculation of long run marginal cost and its application in changes to tariffs.

Step Three – Types of tariffs and charges

Under our AER approved TSS, customers in each tariff segment are subject to a range of different components to which a charge is applied. This includes a fixed charge for daily system access, an energy charge, and a demand charge for customers with smart meters. We are proposing to make the following changes subject to further consultation with customers.

a. Time of day – energy consumption charge

Currently, we have a single 'anytime' charging parameter for the energy consumption component of tariffs, even if the customer has a smart meter.

We are proposing to apply an energy charge based on the period and time of day when energy is consumed. This would only apply to customers with smart meters as accumulation meters do not provide this level of data. We consider that the change 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. The high price period for energy replaces the maximum demand charge for most customers. **Figure 57** conceptualises the key change we are proposing to implement.

The periods and rates are described in the next section on charging periods and rates.

b. A new export charge

Under the new NT NER Rules, we have an obligation to consider whether rooftop solar customers should pay a charge for using our network to export energy if this leads to higher costs for all customers. As noted in the previous section, our future network strategy is aimed at unlocking household solar through a hosting solution where we can demonstrate a benefit to all customers through lower electricity costs. This recognises that solar is lower cost than other sources of energy in the NT, and that unlocking more solar can lead to improved affordability for all customers.

There will still be periods in a day when our network cannot securely meet the export demand of customers without jeopardising the security and quality of network services, or high costs of new infrastructure.

To ensure fairness for all customers, we are consulting on potential export charges that provide price signals to efficiently manage solar on our network. This includes a tariff charge in periods where our network has difficulty managing exports, and a rebate when the network requires an injection of energy during peak demand times. We consider this provides household customers with the right incentives to export solar when there is capacity on the network, and to use batteries and other technologies to capture excess solar and discharge in the evening peak periods. This is conceptualised in **Figure 58.**

Figure 57 – Time of use pricing relativity for consumption of energy

Figure 58 – Time of use pricing for export of energy

Given the magnitude of the change, we propose to introduce new export tariffs from FY2026 onwards. The time periods where charges and exports would occur are discussed in the next section on charging periods and rates.

Demand charge parameters

We currently apply a demand charge to all customers with a smart meter. For the new segment of smart meter customers consuming less than 100MWh, we are proposing not applying a demand charge and only applying energy consumption charges.

For customers consuming more than 750MWh, we are considering the introduction of a charge reflecting the average of KVA demand in the peak period applied as a daily rate. Residual costs will be recovered by a fixed charge and an off peak monthly demand.

Step Four – Charging periods and rates

Currently, we have a peak period of 12pm to 9pm on weekdays. For larger customers this is all through the year, and for smaller customers it is between October and April.

For smaller customers with smart meters consuming less than 750MWh, we are proposing to narrow the hours of the peak period. This reflects the analysis presented in the last section that shows that our peak demand is shifting to the evening when the network cannot rely on solar to help meet underlying demand. This provides a sharper signal on the drivers of future costs for the network. 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. The new periods are:

- Peak congestion (busy) period: From October to March, weekdays between 3pm and 9pm. The long run marginal cost will be allocated to these periods.
- Super off-peak (easy) period: Every day of the year between 9am and 3pm. It is proposed that little or no charges will accrue to customers in this period to encourage consumption to soak up excess rooftop PV.
- Off-peak (light) period: All other periods. Residual costs will be allocated to this period (in addition to the standard access daily fixed charge).

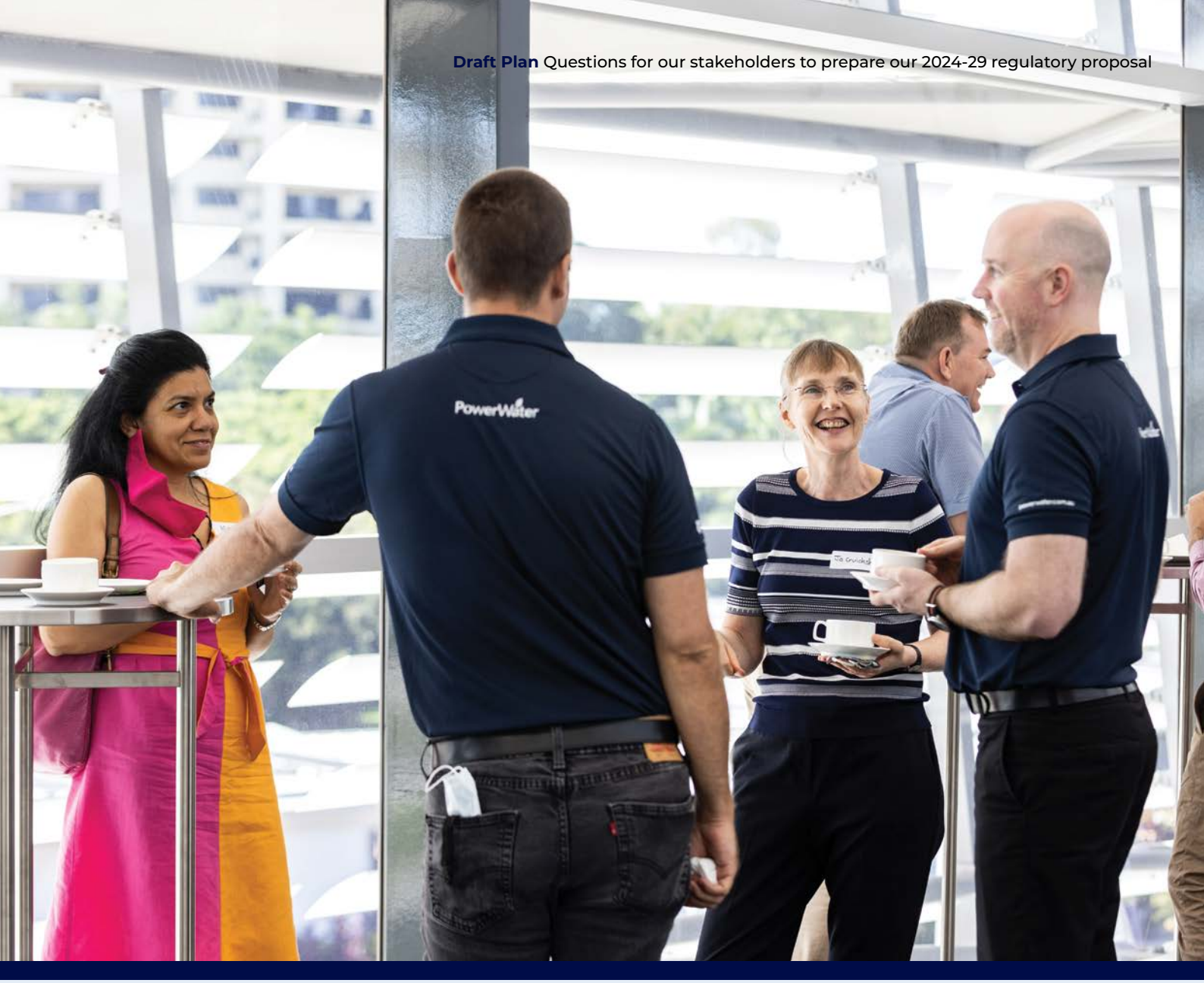
Further analysis of some LV and HV customers is required to determine if all customers will transition to the same peak window, or whether a different segment will be created for some customers reflecting their ability to create a new asset peak due to their size.

We propose to move away from a using a single period maximum (kVA) window to apply LRMC charges. Instead, customers using less than 750 MWh will be charged kWh rates in the peak period. For customers consuming less than 100MWh, residual costs will be recovered via the system availability (daily fixed) charge and kWh rates in the off-peak period. For customers consuming more than 100 MWh and less that 170 MWh there will be the option for a maximum demand (KVA) charge in off-peak periods. However, this is likely to occur during the period.

Table 7 shows the types of charges we intend to apply in the 2024-29 period.

Table 7 – Tariff changes proposed

Network Tariff	Tariff Class	Fixed	Energy Consumption Charge				Energy Demand Charge	Energy demand at peak charge	Export charge	Export Tariff
		Fixed ($/day)	Anytime (c/kWh)	High Period (c/kWh)	Mid Period (c/kWh)	Anytime (c/kWh)	Highest recorded demand in month ($/kVA)	Average of all recorded demand in high period in a month ($/kVA)	Export price period (above threshold)	Export rebate period (c/KWh)
Tariff 1	Residential	Yes	Yes	-	-	-	-	-	-	-
Tariff 2	Non-Residential	Yes	Yes	-	-	-	-	-	-	-
Tariff 3a	Res + Com with a smart meter	Yes	-	Yes	Yes	Yes	-	-	-	Yes
Tariff 3b	Res + Com with a smart meter	Yes	-	Yes	Yes	Yes	Yes	-	-	Yes
Tariff 4	Unmetered Supply	Yes	Yes	-	-	-	-	-	-	-
Tariff 5	LV >750MWh	Yes	-	-	-	-	Yes	Yes	Yes	Yes
Tariff 6	HV <750MWh	Yes	-	-	-	-	Yes	Yes	Yes	Yes
Tariff 7a	HV >750MWh	Yes	-	-	-	-	Yes	Yes	Yes	Yes
Tariff 7b	HV >750MWh	Yes	-	-	-	-	Yes	-	Yes	-



Future Network Forum in Darwin

Key Questions for stakeholders in Chapter Eight

To what extent should tariffs reflect the costs different customers impose on the network?

Are there specific aspects of our proposed tariff structure that you support, oppose or want more information about?

PowerWater

Power and Water Corporation

Level 2, Mitchell Centre
55 Mitchell Street, Darwin
Phone 1800 245 092

powerwater.com.au

@PowerWaterCorp