Transmission and Distribution Annual Planning Report

2022

@PowerWaterCorp

Transmission assets, Berrimah

About this report

The 2022 Transmission and Distribution Annual Planning Report (TDAPR) provides information to our stakeholders on Power and Water Corporation's plans for its electricity networks in Darwin-Katherine, Alice Springs and Tennant Creek.

The report provides stakeholders with information on our network performance, demand forecasts, system limitations, and proposed projects.

Detailed information on asset numbers, voltage regulation, system limitations, and contingency scenarios have been published as a separate Appendix in excel format to this report.

We have recently launched our new Rosetta Portal. Information contained in the portal is intended to supplement this report and contains maps of our network and other key data to signal where there is spare capacity on the network and where there maybe opportunities for demand management solutions.

All dollars are presented in real 2022 dollars. We note that our upcoming regulatory proposal will present projects in real 2024 dollars. Further, the regulatory proposal is only for the 2024-29 regulatory period, while the TDAPR is for the period 2023-32.

Contents

Acknowledgment of Country

Power and Water acknowledges the Traditional Owners of the Country on which we work and live. We recognise their continuing connection to the land, waters and community. We pay our respects to Elders past, and present.

People's Panel member, Alice Springs

Chief Executive Officer – Key Message

I am pleased to present the 2022 Power and Water TDAPR.

This year's TDAPR is aligned to our upcoming 2024-29 regulatory proposal which seeks funding for our forecast capital and operating programs.

The timing of our regulatory proposal has provided a unique opportunity to engage more broadly and deeply on our future network plans, resulting in a richer and more meaningful TDAPR.

In August this year, we published our Draft Plan. This set out the key challenges and opportunities facing our network over the coming years and our initial thinking on the expenditure needed to operate more dynamically to respond to change and better meet customer expectations.

Hearing directly from our customers on what matters most, their values, preferences, and pain points has significantly shaped the development of our future network strategy and where we need to improve.

Customers have told us that they want a greener and more productive Territory that has cheaper bills, reliable electricity, is future ready, and supports greater customer choice and equity. They want us to be more innovative, look for ways to improve affordability (both in the short and long term) while thinking ahead and looking towards the future.

In response to this, we have developed a Future Network Strategy that sets out the key focus areas and initiatives for supporting the Territory's transition to renewable energy and uptake of customer energy resources.

We have looked harder at our expenditure plans to see if there were opportunities to defer investment to deliver better affordability to customers. I am pleased to report that we have found ways to bring our expenditure down through further analysis of our demand forecasts and use of our new risk prioritisation procedure. We have also identified alternative methods and initiatives for addressing customer pain points and improving customer service at a lower cost.

A key feature of this year's report is setting out the key focus areas, initiatives, and systems for transitioning to an efficient and agile network of the future. Also included is our performance over the past year. The report also details our progress in uplifting our network planning, asset management, and demand forecasting capability. It discusses the benefits that this will deliver to customers and where we are heading next over the coming years and into the 2024-29 regulatory control period.

Djuna Pollard
Chief Executive Officer

Hearing directly from our customers on what matters most, their values, preferences, and pain points has significantly shaped the development of our future network strategy and where we need to improve.

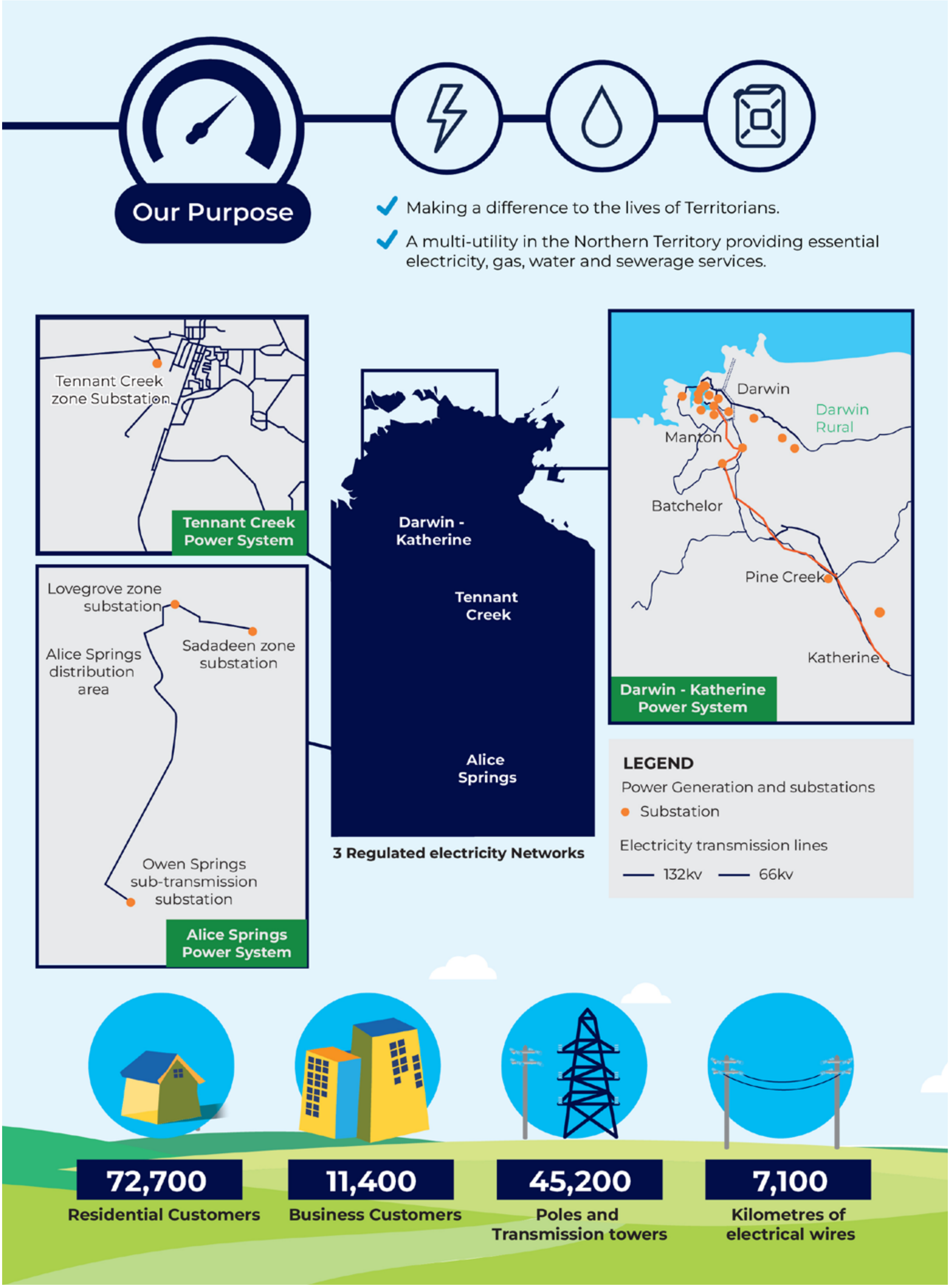
1. Summary

We are adapting to significant global changes impacting our regulated networks in Darwin-Katherine, Alice Springs and Tennant Creek. Our network lies at the heart of the Northern Territory's (NT) transition to a renewable power system as we accelerate to a 50 per cent renewable energy target by 2030. This provides both opportunities and challenges. In this year's TDAPR we outline our Future Network Strategy which has incorporated the feedback of our customers and stakeholders. The strategy outlines how we will continue to safeguard our current reliability performance, while leveraging opportunities to drive down electricity and transport bills in the NT. We also outline emerging constraints and our 10-year investment plan that will shortly be subject to regulatory review as part of our 2024-29 regulatory proposal.

This summary provides a quick overview of our future plans, including:

- **Our network and customers** – In our engagement sessions, stakeholders have wanted to understand how our networks fit into the electricity system, and how our network is facilitating the transition to renewables. Stakeholders also wanted to understand regional differences, including customer attributes and how this is reflected in our network planning and investment decision-making. To address this, we have included more visually rich material on the role our network plays in the energy system in the Northern Territory (NT) and more information on our customers in each region. **Figure 1** on the next page provides a snapshot of our network and customers, with more information provided in Chapter 2.
- **Future Network Strategy** – Following extensive consultation with our stakeholders, we have developed a comprehensive strategy to guide our transition to a clean energy future and address other emerging challenges. Our Future Network Strategy sets out our key objectives including facilitating lower electricity and transport bills, a reliable and secure electricity system, **and a** greener and more prosperous NT characterised by greater customer choice and equity. We identify focus areas including facilitating small and large-scale renewables, encouraging scale and utilisation and re-designing the grid to lower future network costs. Further information is provided in Chapter 3.
- **Current performance** – We continue to provide our customers with a reliable service that meets service targets set by the Northern Territory Utilities Commission. We still have plans to address network issues impacting customers in rural areas who receive disproportionately long outages. Despite increased solar penetration we are also meeting our voltage performance targets, except in Katherine where we are undertaking works to improve performance. This is discussed further in Chapter 4.
- **Asset management approaches** – In this year's TDAPR we discuss key improvements we have implemented to guide our 10-year planning approach. This includes a new risk quantification procedure that has enabled us to identify material risks, and defer projects where the risks can be managed. We have also implemented a new demand forecast approach. This is discussed in Chapters 5 **and** 6.
- **10-year investment program outlook** – Our analysis of constraints and investment programs for the 2023 to 2032 period reflects a deeper level of business case assessment and application of top-down checks. This is because the program outlined in this year's TDAPR will be subject to review by the Australian Energy Regulator (AER) as part of our 2024-29 regulatory determination process. Our 10-year program reflects a higher level of expenditure on replacement projects, and much lower levels of augmentation (new assets). Our replacement and augmentation projects are discussed in Chapters 7 and 8. We are also making investments to facilitate renewables consistent with our Future Network Strategy.

Figure 1 – Snapshot of Power and Water's electricity network



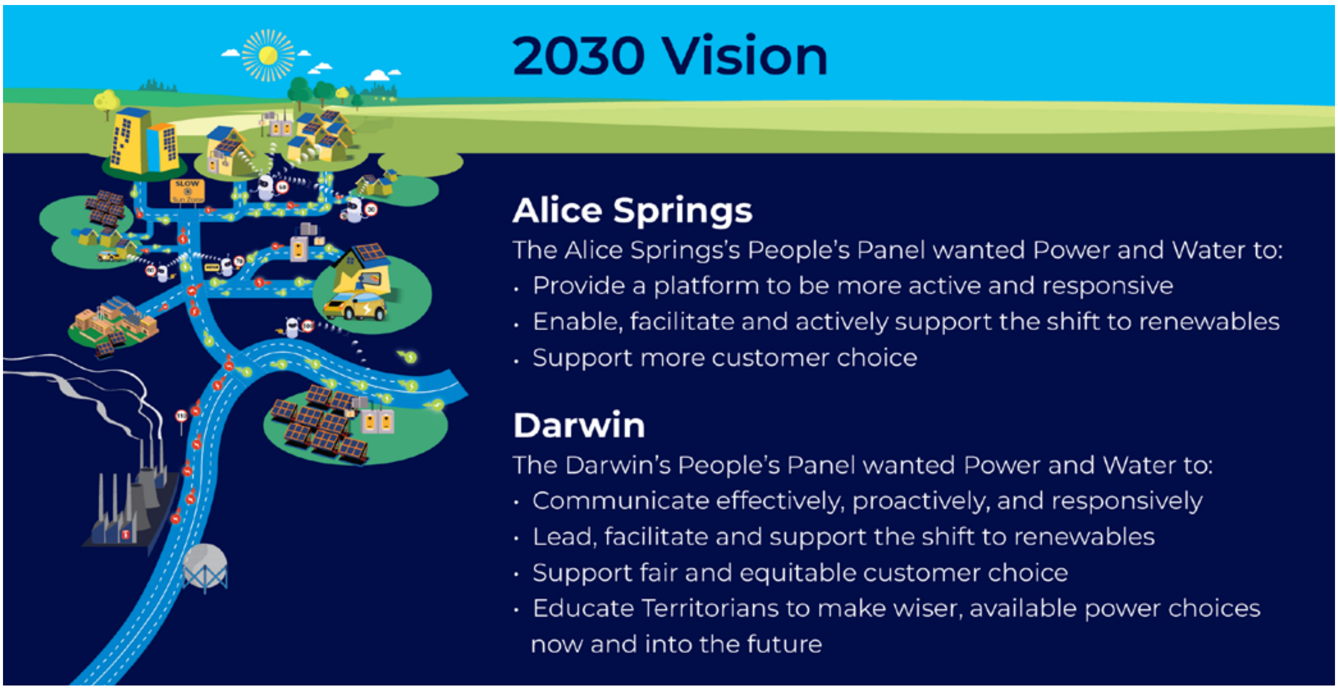
1.1 Future Network Strategy

Our customers want us to facilitate and actively support the transition to renewables. Our Future Network Strategy has pieced together key future changes impacting our business and the vision set by our customers. We have identified key benefits of actively planning ahead including lower electricity and transport bills, environmental and economic benefits for the NT, and opportunities for customers to benefit from investments in renewable technology.

Our Future Network Strategy identifies solutions to the challenges of facilitating renewables, managing an ageing asset base and meeting higher demand for electricity. In Chapter 3, we identify four focus areas aimed at:

- **Unlocking small scale renewables** – Our strategy strikes a balance between facilitating the maximum 'low cost' generation from rooftop solar, with the need to manage exports during periods when the security of the energy system is at risk. This includes an innovative technology to communicate to solar panels to reduce exports when there is a risk to system security.
- **Efficiently planning and investing in the transmission network to deliver large scale renewables** – Our strategy provides a blueprint on how our transmission network can cost-effectively deliver renewable generation from large scale solar farms. This includes relieving existing transmission constraints, building new renewable hubs, and actively planning for a transmission network that can connect new sources of generation in the future.
- **Scaling-up to best utilise the NT energy system** – Growing our energy system provides a great opportunity to lower electricity costs for all customers. Higher population growth, new industry and electric vehicles will help deliver scale to our small energy systems over the next 20-years. Our strategy is directed at minimising the costs of meeting higher demand by encouraging customers to use energy in off-peak periods. We show the importance of tariff reform and orchestrated charging for electric vehicles. We also identify opportunities to improve energy efficiency for low-income households.
- **Re-designing the grid to reduce network costs** – We face significant cost drivers over the next 20-years as we manage our ageing assets and increased extreme events from climate change. Our strategy focuses on methods to reduce our costs including extending asset lives, utilising new technology to optimise the grid, and improving the resilience of our network to extreme conditions.

Figure 2 – Future Network Vision from our Darwin-Katherine and Alice Springs People's Panels



66kV Isolator at entry to Owen Springs transmission substation

1.2 Performance in 2021-22

Power and Water has continued to provide reliable services to customers in 2021-22. On average, our reliability has improved from the previous year with customers experiencing 115 minutes of outages (29 minutes less than the previous year) and slightly less outage events. While weather can impact year to year performance, this continues our positive performance over the last eight years as seen in **Figures 3** and **4**.

Reliability performance varies considerably across our customer base with outage length and frequency much higher for customers in rural areas of the network. Power and Water is striving to improve the performance for customers in more affected areas while balancing our costs.

Power and Water is also managing to maintain voltages within reasonable levels. This is increasingly challenging as more rooftop solar is being exported back into a grid that was designed for one-way flow.

For most of our network, we are operating within the standards of voltage quality. However, the Katherine network continues to experience voltage issues. We will be addressing this issue by installing switched reactors at the zone substation to absorb reactive power from solar.

Chapter 4 of this document outlines our 2021-22 performance in more detail, including specific programs to improve reliability and voltage quality and our performance by network region.

1.3 Forecast 10-year program

We have identified capital expenditure over a 10-year horizon for both our transmission and distribution networks.

This will help customers and stakeholders engage more readily with our upcoming regulatory proposal for 2024-29. It also provides stakeholders with more time to put forward alternatives to network investment.

Below, we summarise our forecast of key constraints on the network that give rise to replacement and augmentation projects. We also identify major projects over $15 million, including uncertain projects which we identify as 'contingent' upon the occurrence of a trigger event. A detailed description of system limitations and proposed solutions is set out in Chapter 7 and 8.

Replacement capex to address asset condition

Replacing our ageing network assets will be the primary driver of capital expenditure over the next decade. A large cohort of our network assets will be over 50 years old by 2025. Our asset management planning is directed at keeping these assets in service through targeted maintenance and robust risk management. Our targeted programs will replace assets that pose material reliability, safety or environmental risk. We have also applied age-based modelling to forecast the volume of assets likely to fail in service.

The three major replacement projects or programs over $15 million include:

- Berrimah zone substation ($28.7 million) – We are in the early stages of replacing the current substation due to multiple condition issues. The project is already underway and will be completed in 2025-26.
- Darwin high voltage cables ($46.4 million) – We are replacing a portion of cables in the northern suburbs of Darwin due to insulation and sheath issues from water ingress. This program is already commenced and will continue over the 10-year planning period.
- Alice Springs corroded poles ($19.5 million) – We are refurbishing poles that are corroded and which may lead to safety issues. The program has already commenced and will continue over the ten-year planning period.

Augmentation capex to address capacity limitations

Augmentation capex is forecasted to be well below past levels of capex. While we forecast strong demand growth in our three regions over the next decade, our analysis suggests that no major projects will be required. However, there are three potential new developments in Darwin that may give rise to the need for new zone substations. These uncommitted developments include the Northern Territory Government's plans for a new large land development near Palmerston and new industrial sites at East Arm and Middle Arm. Each of these 'contingent' projects would likely require a new zone substation. We will keep our stakeholders informed of these developments in future TDAPRs.

The minor planned augmentation programs include managing overloaded 11kV and 22kV distribution feeders, maintaining reliability for worse performing feeders, and managing voltage issues. We also are investing in the establishment of Dynamic Operating Envelopes (DOEs) which will allow us to communicate with rooftop solar panels when there is a transient constraint with exporting solar to maximise the output of rooftop solar within the limits of our current network design.

We also have two other major projects where there is uncertainty on scope, timing, costs and funding. These are projects directed at maximising renewable electricity from large solar farms. The Renewable Energy Hub project will build transmission infrastructure to meet the Northern Territory Government's plan for a large solar farm complex. We also plan to assess solutions to unlock more generation from existing solar farms. Both of these projects are likely to be material. We will inform stakeholders of the progress of these projects in subsequent TDAPRs.

Figure 3 – Average duration of interruption per customer

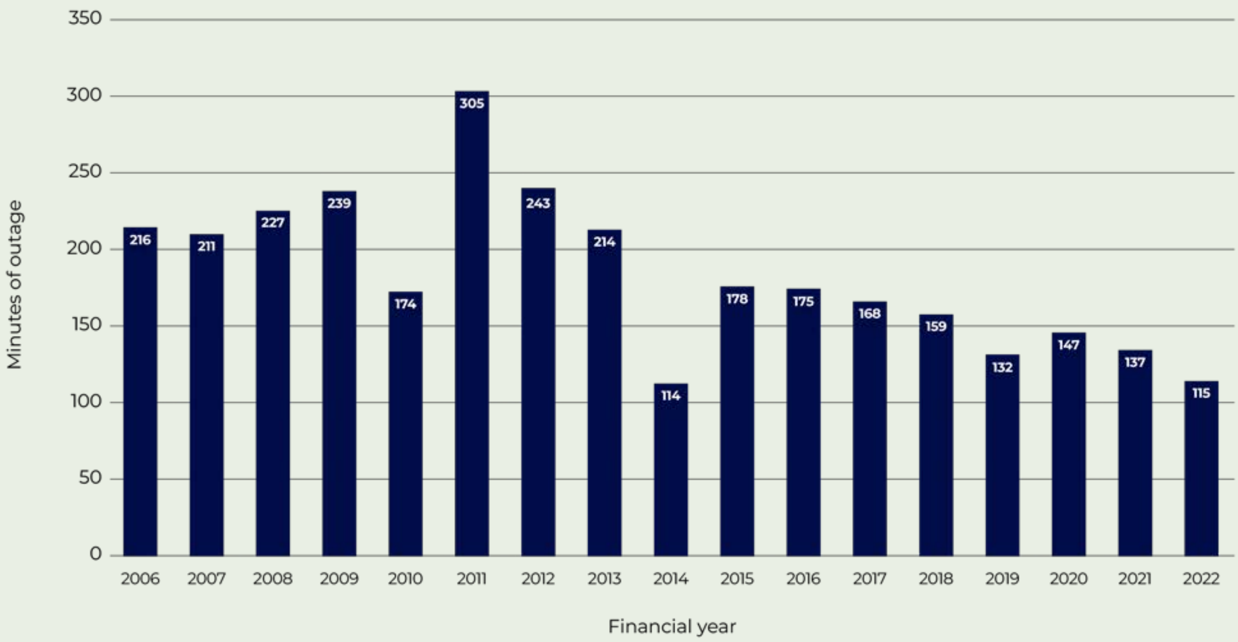
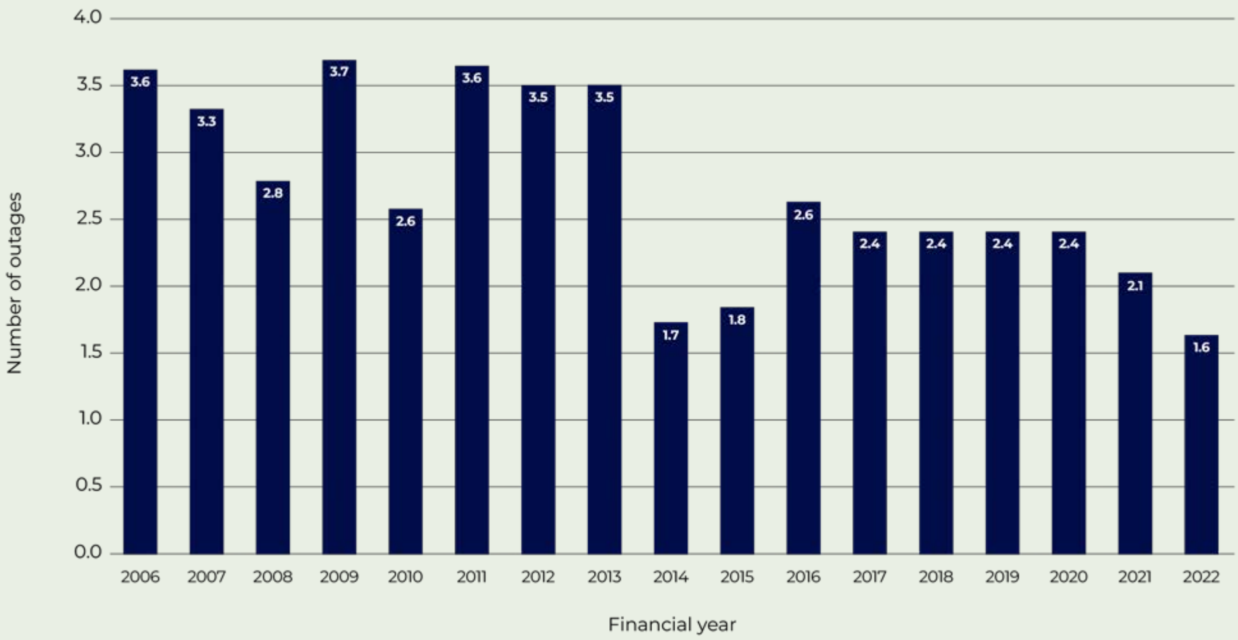


Figure 4 – Number of interruptions per customer



2. Our network

We provide electricity services to more than 90 communities in the Northern Territory over a landmass of 1.3 million square kilometres. We operate three stand-alone electricity networks in Darwin-Katherine, Alice Springs and Tennant Creek which are regulated by the Australian Energy Regulator. These networks transport about 1700GWh of energy to close to 73,000 residential customers and 11,000 businesses across these regions. Each of our networks are unique, operating under different designs and environments. These characteristics necessitate the need for a flexible network planning approach that allows for tailoring to suit the different network drivers and characteristics of each of our regions.

2.1 Power and Water's role

Power and Water is a Northern Territory Government owned corporation that provides electricity, water, sewerage and gas to our customers.

In Australia, it is unique to provide such an array of essential services. This reflects the small scale of the Northern Territory compared to other states and territories. Providing a pool of corporate and system services helps deliver services at a lower cost, helping us mitigate some of our scale disadvantages.

The Power Services division of Power and Water plans, builds, operates and maintains our distribution and transmission electricity networks.

Our role in the electricity supply chain is shown in **Figure 5** and depicts our electricity network. We transport energy produced by large scale gas and solar generators using our poles, cables, conductors and transformer assets to residential and business customers.

In recent times, our role has further expanded to include transporting energy which has been exported back onto the grid from our smaller customers who produce solar behind the meter.

Over the coming years, we anticipate customers will continually evolve how they use and consume energy as new technology and service offerings become available. We expect that this is likely to change significantly once our smart meter rollout is complete and the costs of home batteries and electric vehicles becomes more affordable – resulting in a greater electrification of businesses and customers' daily lives.

The advent of these changes is likely to encourage greater retail competition, new entrants to the market and the emergence of new product offerings. These changes will provide customers with better choice and control around how they use their energy and will help place downward pressure on electricity prices.

It is important that we keep abreast of these changes and incorporate them into our thinking so that we design, plan, and operate our networks in a manner which is fit for purpose and is able to meet the changing needs of our customers.

We will closely monitor new market developments and advances in technology. This will help to ensure that our networks adapt and evolve so that we continue to deliver valued services to customers both now and into the future.

Further information on our key plans and initiatives for transitioning to a more agile network of the future are described in Chapter 3.

Figure 5 – Our role and network

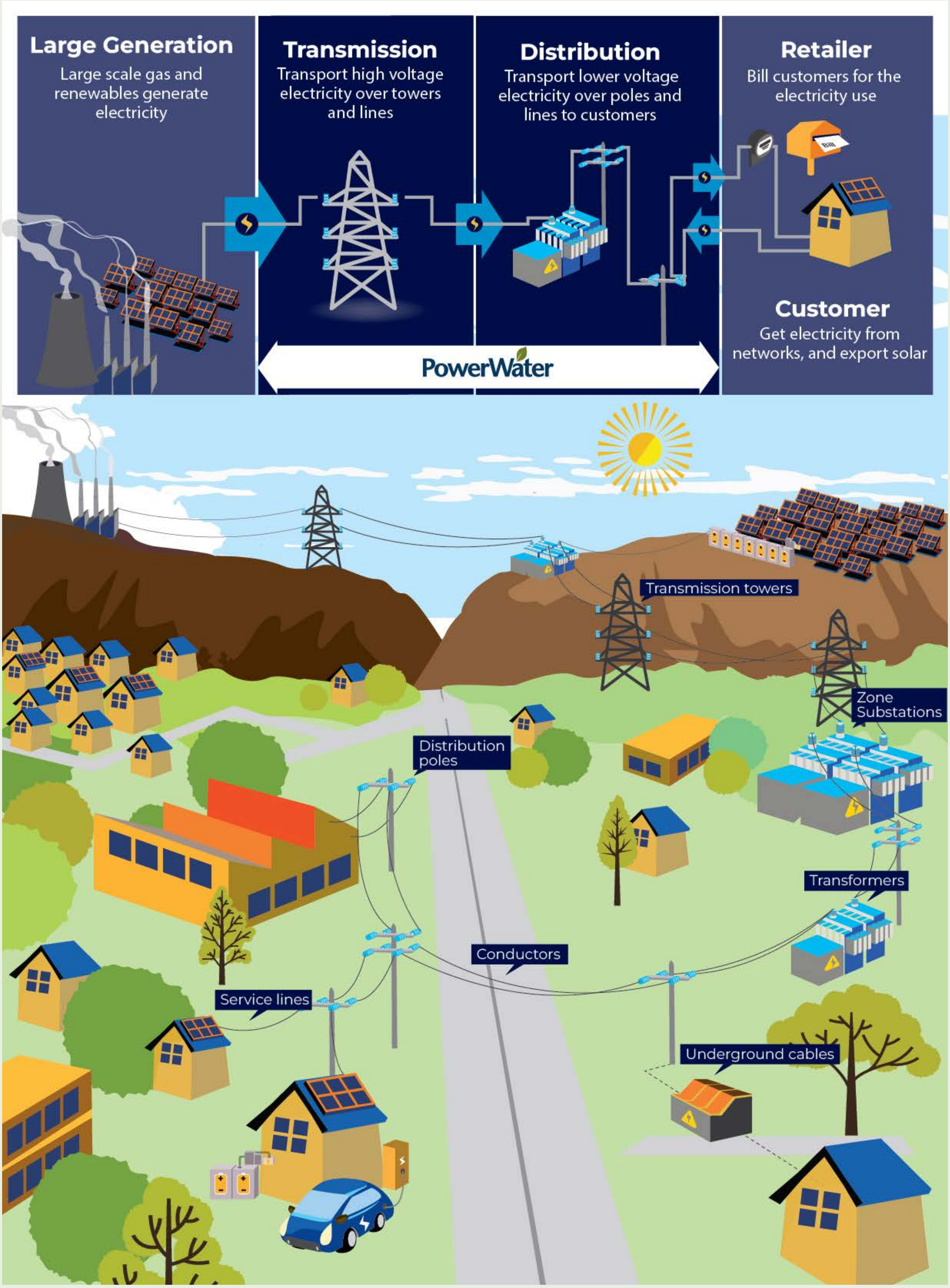
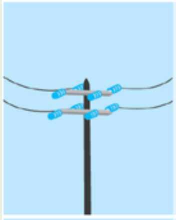
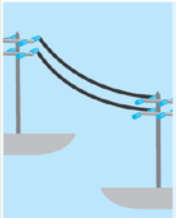
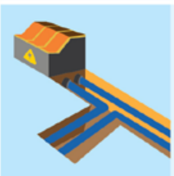


Figure 6 – Overview of key assets

Asset Category	Asset Type		Region: Darwin-Katherine	Region: Alice Springs	Region: Tennant Creek	Total
	**Transmission towers** Support the conductors that transport electricity at 132kV from generators to transmission substations.	132kV towers	854	0	0	**854**
		66kV towers	2,127	217	0	**2,344**
	**Distribution poles** Poles support the conductors that transport electriciy at 22kV and 11kV, and other assets including transformers and switches that enable us to control the network	11kV poles	4,523	1,250	0	**5,773**
		22kV poles	17,689	2,672	2,262	**22,623**
		Low Voltage poles	10,197	2,249	880	**13,326**
	**Conductors** Overhead lines that conduct electricity throughout the network. The voltages can range from 132kV down to 400V (low voltage)	132kV overhead (km)	354	0	0	**354**
		66kV overhead (km)	339	33	0	**372**
		Distribution feeder - overhead (kms)	2,628	504	340	**3,472**
		Low voltage - overhead (kms)	1,016	124	44	**1184**
	**Service Lines** The final connection from our network to customers premises. These are normally at 240V	Service lines - residential	15,078	3,261	992	**19,331**
		Service lines - commercial	4,035	464	247	**4,746**
	**Underground cables -** Conducts electricity throughout the network and are installed underground	66kV underground (km)	25	14	0	**39**
		Distribution feeder - underground (kms)	789	98	3	**890**
		Low voltage - underground (kms)	607	98	1	**706**
	**Transformers -** Transformers convert electricity from one voltage to another. For example, at zone substations they convert 66kV to 22kV.	Transmission substations	3	2	0	**5**
		Zone substations	19	1	1	**21**
		Distribution substations	4,207	561	130	**4,898**

Power and Water staff member in Alice Springs. 22kV network and Macdonnell Ranges in the background.

2.2 Understanding our networks

Some of our electricity network services are regulated by the AER under the NT National Electricity Rules (NT NER).[1] A key reason for regulation is that customers have very limited alternatives for getting electricity. Regulators protect customers by reviewing our expenditure plans to ensure they are prudent and efficient, and setting a cap on the amount of revenue we can collect.

The networks subject to AER regulation, and which are not physically connected due to distance, include:

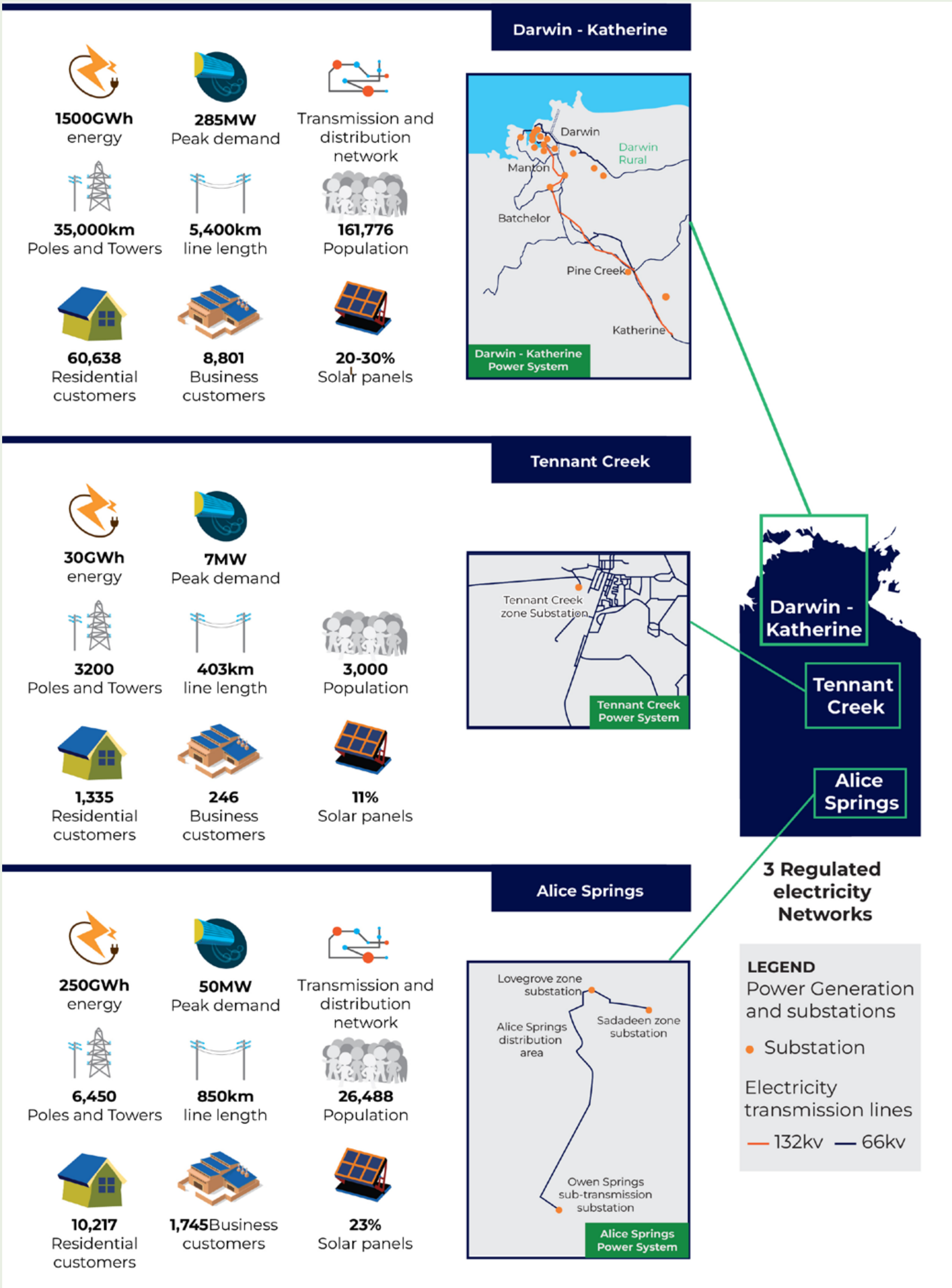
- The Darwin–Katherine network supplies the city, suburbs and surrounding areas of Darwin and Palmerston, the township of Katherine and its surrounding rural areas.
- The Tennant Creek network supplies the township of Tennant Creek and surrounding rural areas from its centrally located power station; and
- The Alice Springs network supplies the township and surrounding rural areas from the Ron Goodin Power Station and the Owen Springs Power Station.

We operate a transmission network in Darwin-Katherine and Alice Springs only. Our zone substations are the connection point between our transmission and distribution networks. The zone substations transform electricity from 66kV into 22kV and 11kV voltages before they are transformed to lower voltages via our distribution substations.

Information on each of our major asset classes and their population by region is summarised in **Figure 6**, with more detailed information provided in Appendix A. **Figure 7 provides a snapshot of our regulated networks, including the location of transmission and distribution lines.** The Rosetta portal accompanying this report provides an interactive map to these locations and indicates where there are existing network constraints.

[1] Power Services also provides electricity services to customers in remote and regional areas of the Northern Territory. These parts of our network are unregulated and not subject to AER oversight.

Figure 7 – Regulated areas of Power and Water's electricity network



2.3 Our customers and community

Power and Water's purpose is to make a difference to the lives of Territorians.

Our electricity networks provide essential energy to about 84,000 customers across our three regulated networks. We deliver almost 1700GWh of electricity to power homes and businesses.

More than 85 per cent of our customers are residential, requiring electricity for essential appliances such as fridges, air conditioning, cooking. Many of our residential customers have rooftop solar. As active participants in the energy market, our customers want the ability to connect solar and transport excess solar back onto the grid or store their solar for use at a later time.

Electricity is also a vital input for all NT businesses and is a critical input for some of our larger industries. While businesses customers only represent a small portion of our customer base (approximately 15 per cent) they account for 70 per cent of energy consumption as shown by **Figure 8**.

Listening to our customers

Over the past year we have continued to ramp up our engagement in the lead up to submitting our regulatory proposal to the AER in January 2023.

During this time, we have undertaken numerous engagement activities to reflect the different voices of our customers in our decisions and plans. This has been an iterative process to provide customers with the opportunity to test and provide feedback on our expenditure plans.

We have launched an extensive engagement program to ensure the voice of customers is reflected in our decision making.

Key engagement undertaken with our customers this year includes:

- **People's Panel –** Throughout March, April and August, our leadership team met with a representative group of customers in Darwin and Alice Springs to hear their experiences of our network, what we should be prioritising, and capturing feedback on our strategic direction and initial expenditure plans.
- **Reset Advisory Committee (RAC) –** Throughout March to July our leadership team met fortnightly with representatives from our People's Panel, industry, business customers, and customer advocates to provide direction on the issues and areas Power and Water should be seeking customer feedback on in its Draft Plan.
- **Future Network Forum –** In June our major customers and broader stakeholders provided feedback on initiatives and topics that have helped to inform the development of our future network strategy.
- **Focus Groups –** Several focus groups were held in March, May and September to capture feedback from our cultural and linguistically diverse (CALD) customers, youth, and business customers on the changing energy landscape, renewables, the future of our electricity network, and opportunities to improve and better target our communication with customers.

As active participants in the energy market, our customers want the ability to connect solar and transport excess solar back onto the grid or store their solar for use at a later time.

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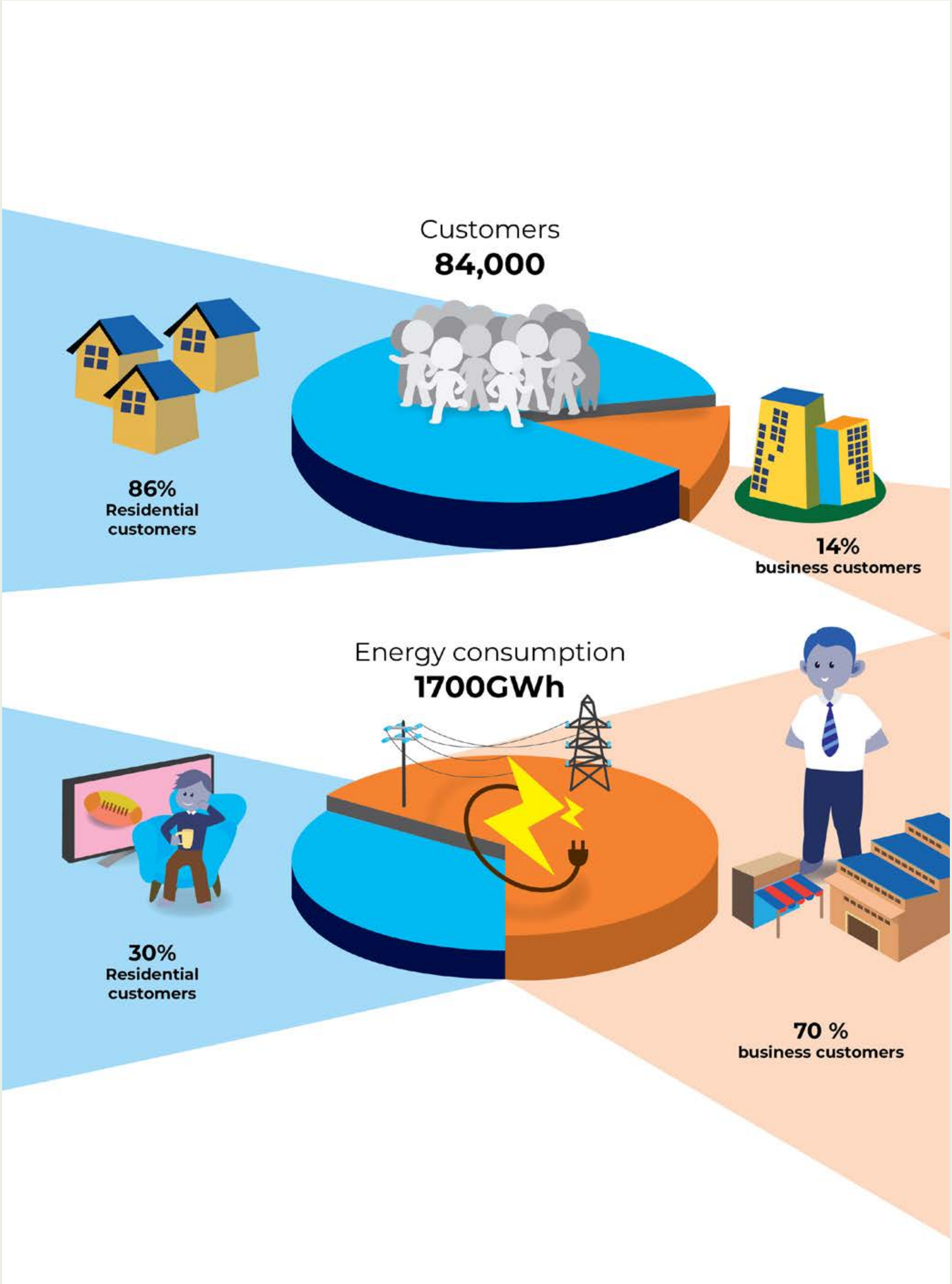
Figure 8 – Breakdown of energy consumption



Channel Island to Hudson Creek 132kV transmission towers, Middle Arm

Framing our conversations

Engagement requires Power and Water to understand the world from the eyes of the customer, and for customers to step into our world. This has been the lens we have tried to bring in framing our discussions with stakeholders.

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 in the lifecycle:

- **Connecting –** When customers are connecting to our network, they want fast and easy connection. This is a period when customers actively engage with us and want us to partner with retailers to make the process seamless.
- **Connected –** When customers are connected, they want reliable energy at a fair price. Customers felt that meter reading and billing were vital to ensuring 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 such as tree trimming and wanted to ensure that we are taking adequate action to ensure the greenness of the landscape.
- **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 – whether this be via the phone, social media or 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 want to move out indicated that prompt timing and reconnection were vital to their experiences. Customers also want accurate metering reads, and prompt billing at the end of having their electricity service disconnected.

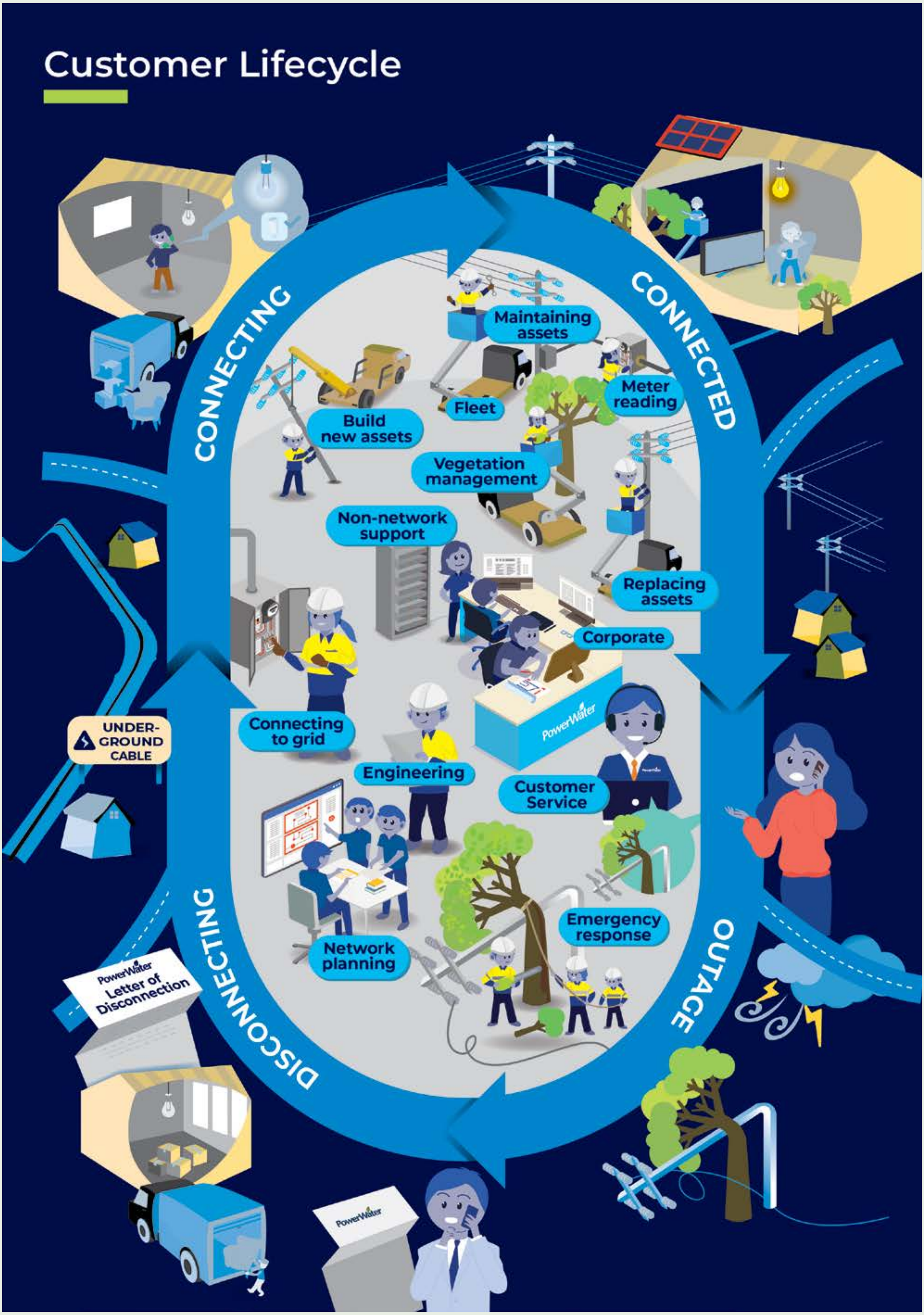
What we have heard so far

The key messages we have heard from customers so far is that we need to:

- Enable more renewables but be sensible by assessing the costs and benefits.
- Test how we perform against other networks using sensible benchmarks, but make adjustments for the unique operating circumstances in the NT.
- Avoid price shocks and reliability incidents by planning and managing our assets from a long-term perspective.
- Provide more information and awareness to help customers make more informed decisions about their energy usage.
- Be more innovative by undertaking trials and pilots of new technologies to increase learnings and develop a range of fit for purpose solutions that can be scaled up.
- Think ahead and make smarter more efficient decisions in managing the network to support the community now and into the future.

We have been reflecting on this feedback and have sought to reflect this in our expenditure plans that we submit to the AER in January 2023 and our future network strategy.

Figure 9 – The Customer Lifecycle



2.4 Our operating environment

Our network has many unique characteristics that impact on the way we operate the business.

Small scale

We have the smallest electricity network compared to other networks in the National Electricity Market (NEM) on measures such as customers, energy volumes and peak demand. This can be seen in **Figure 11** which shows that Power and Water has significantly less customers than other networks.

Our lack of scale leads to a cost disadvantage when compared to other networks in the NEM. **Figure 12** shows that Power and Water needs to construct more metres of line per customer. We also have to meet the same regulatory obligations as larger networks but have less customers to spread the costs of meeting these obligations.

Transmission network

While our customer and energy volumes are small relative to other network businesses, our transmission network in Darwin-Katherine and Alice Springs covers a large geographical area with more than 700 kilometres of transmission line, 3000 towers and five 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

Power and Water operates in extreme environments, particularly in Darwin which has sustained high humidity in the wet season and is prone to destructive cyclones and frequent tropical storms. We also have extreme heat compared to other places in Australia as seen in **Figure 10.**

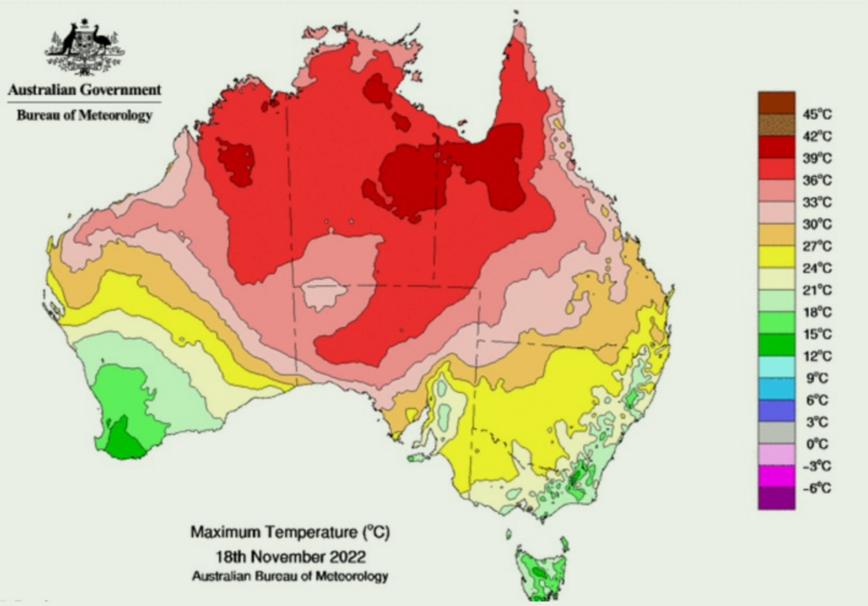
These conditions tend to increase our emergency management costs compared to other networks and can lead to more wear and tear of our network assets. Weather also impacts on labour productivity in humid weather, with our field crews' productivity impacted by the extreme conditions.

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:

- Travel to and from sensitive environmental areas requires mitigation practices which increases time and cost to undertake network activities.
- The NT 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.

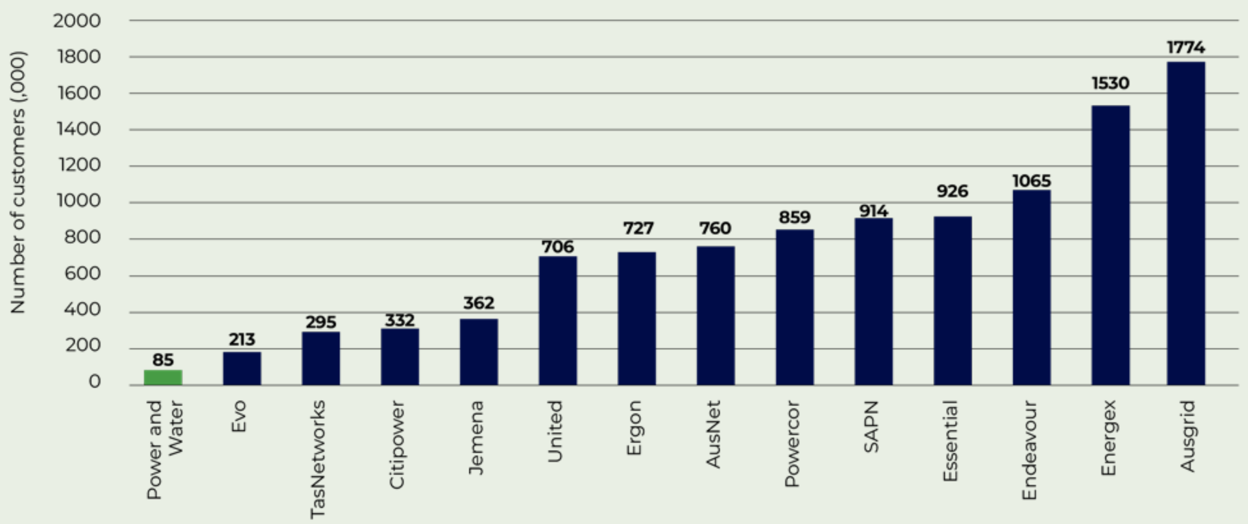
Figure 10 – Extreme heat areas in Australia[2]



The NT has extreme heat conditions which means our customers use more energy in the day for air conditioning. It also means that our workforce need to work in extreme heat conditions, impacting productivity and safety.

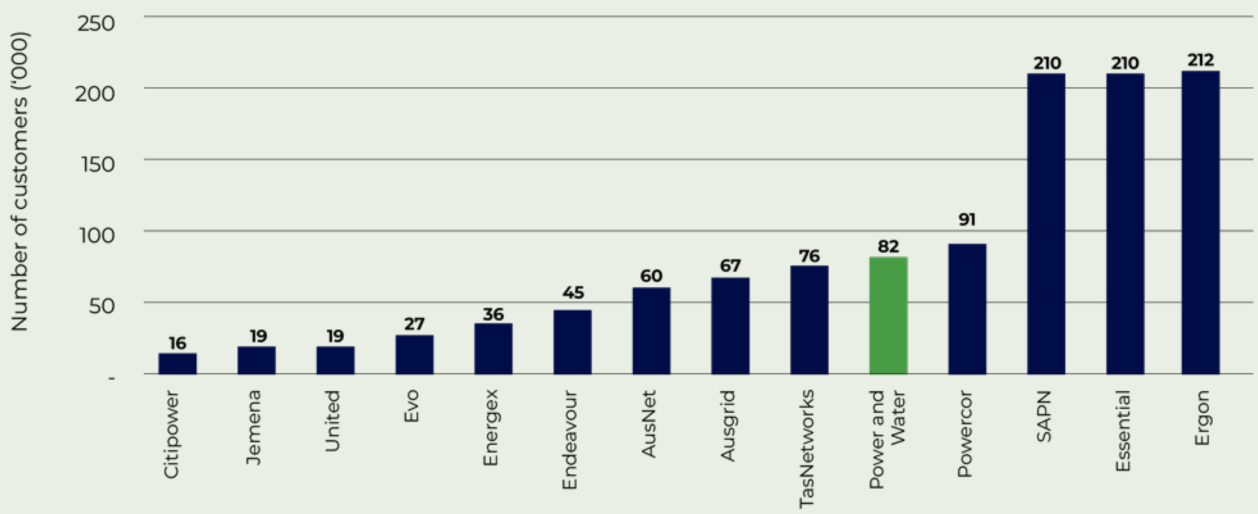
[2] Australian Government, Bureau of Metrology – Daily maximum temperature for Australia

Figure 11 – Customer numbers by distribution network



Power and Water has the lowest number of customers in the National Electricity Market. The second smallest network is Evo Energy which has 2.5 times as many customers. Ausgrid, the largest network, has 20 times the number of customers as Power and Water.

Figure 12 – Total metres of line per customer by distribution network



Power and Water has to build significantly more network (cables and conductors) to provide electricity to each of its customers. This means that while we service a capital city (Darwin) our network is more similar to a rural network, which has diseconomies of scale from having to build longer networks.

3. Future Network Strategy

In last year's TDAPR, we identified key challenges and opportunities to support the NT's transition to a clean-energy future. We also identified emerging issues such as ageing network assets, and the potential for higher peak demand from electric vehicles and new industrial load. Based on feedback from our stakeholders, we have developed a comprehensive Future Network Strategy that identifies key focus areas over the next 20 years. Our strategy aims to embrace a clean energy NT, lower electricity and transport bills and maintain a secure and reliable electricity system.

The purpose of this chapter is to provide a summary of our Future Network Strategy. The strategy provides a blueprint to efficiently support the NT's transition to a clean-energy future. It also identifies opportunities to lower electricity and transport bills of our customers, while safeguarding the reliability and security of electricity in the NT.

3.1 Drivers of change

Over the last year, we have spoken to our People's Panels, business customers and our broader stakeholders about the future of our network. While these discussions have been centred on our three regulated networks, they have also involved consideration of our unregulated networks across the NT.

Our discussions have focused on key changes impacting our networks. Our small network is being disrupted by global and local change factors, as identified in **Figure 13.**

Over the coming years key global change factors affecting our operations include:

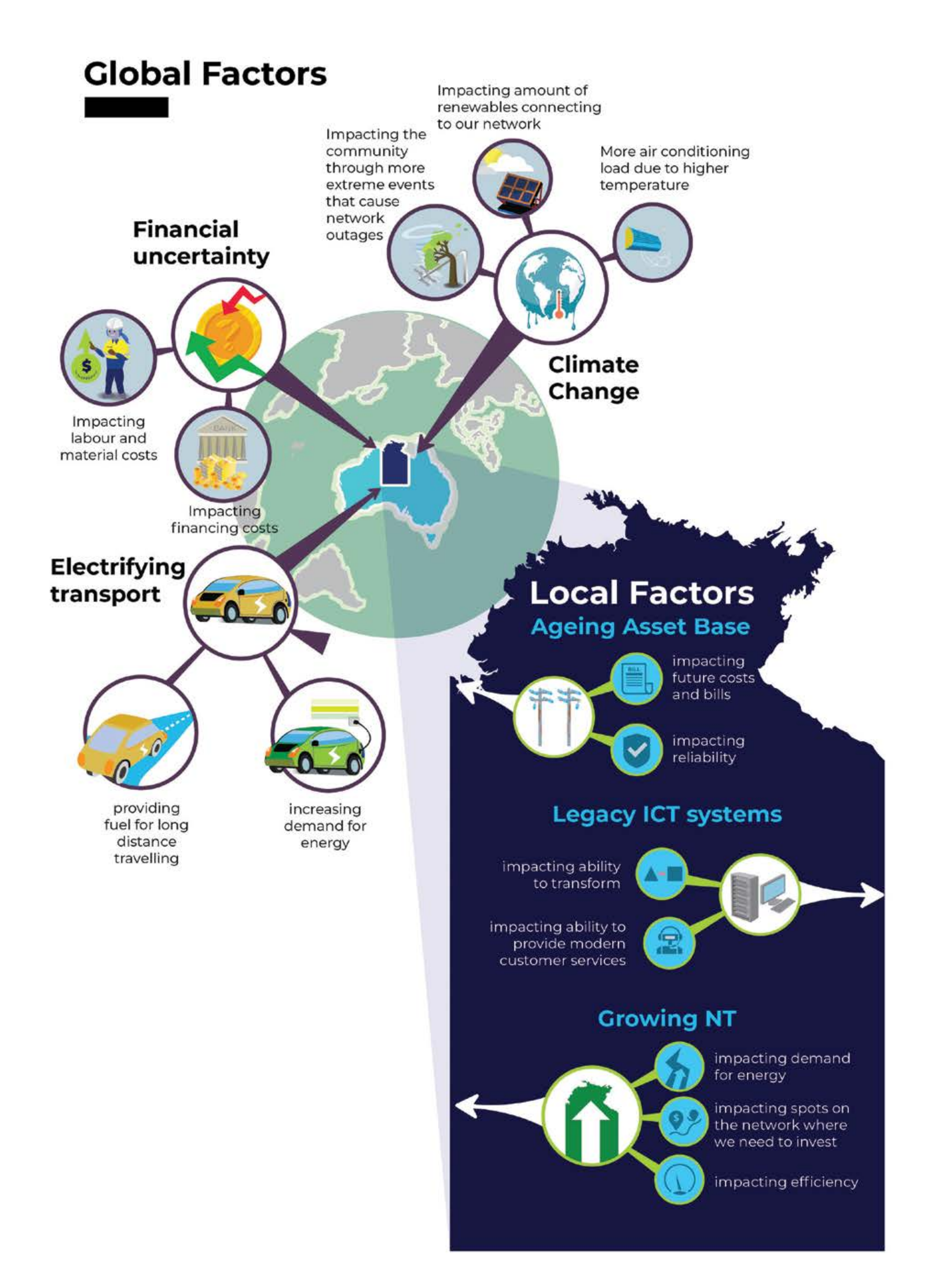
- **Shift to renewables** – The impact of climate change is becoming more prevalent. This has led to a shift to renewables in our energy system, that will accelerate markedly under the Northern Territory Government's 50 per cent renewable **energy** policy by 2030. We expect that our energy system will further push to 100 per cent renewables by 2040. Our network is the vital link to delivering renewables to customers.
- **Electricationoftr ansport and businesses** – The growing uptake of electric vehicles in the NT is likely to also have a significant impact on consumption and demand. Our customers' charging patterns will have considerable impact on the level of new investment we need to make.
- **Financial uncertainty** – Higher inflation and interest rates will impact our borrowing costs, which influences the revenue we recover from customers for our services.

Key local factors driving the need for network change include:

- **Ageing asset base** – Over the next two decades, a large cohort of assets built after Cyclone Tracy in 1974 will reach or exceed their expected asset life. We will need to prudently manage these assets and ensure that we do not face a spike in our replacement levels.
- **Refreshing ageing ICT system** – Some of our existing fleet of ICT systems have not been refreshed for a generation, with the exception of our metering and billing systems. This impedes our ability to adapt and respond to change and limits our ability to provide modern services expected by our customers.
- **Growing the NT** – the Northern Territory Government has set an ambitious target of creating a $40 billion economy by 2030. Several major infrastructure projects have already been announced and we anticipate increased connections from large users over the coming years together with higher population.

The advent of these changes places growing importance on our ability to adapt and respond to change. It presents both challenges and opportunities that need to be carefully managed through a cohesive strategy.

Figure 13 – Global and local change factors impacting our network



3.2 Future Network Strategy Objectives

The objectives of our Future Network Strategy have been framed around the feedback of our customers and stakeholders. While our customers wanted us to embrace a clean energy future, they also wanted us to consider affordability, reliability, impact to the NT more broadly, and customer choice and equity. **Figure 14** sets out the key objectives of the Future Network Strategy.

Lower bills

A key objective of the Future Network Strategy is to facilitate lower electricity and transport bills for our customers. Our strategy identifies three opportunities to drive lower prices. Firstly, we see an opportunity to reduce the network portion of the electricity bill by facilitating an increase in electricity consumption in the NT and by incentivising customers to use energy in off-peak periods. This should help to overcome our scale disadvantages while minimising investment in new network infrastructure to meet demand.

Secondly, our strategy has looked at how we can facilitate lower generation costs in the NT. The Darwin-Katherine Electricity System Plan showed that transitioning to low-cost renewables from high emission technology has significant cost savings. This can be seen in **Figure 15** which shows that pursuing 50 per cent renewables by 2030 results in significant savings compared to re-investing in today's emissions technologies. Our network will play a vital role in ensuring that low-cost renewables can be transported to customers with minimal constraints, thereby minimising the generation costs borne by customers.

Thirdly, our analysis shows that electricity is far cheaper than petrol or diesel to fuel vehicles. This will have a material impact on lowering transport bills for households and businesses in the NT.

Reliable and secure electricity

Our customers have told us that we need to safeguard the long-term reliability of the network. They understood the engineering challenges entailed in transitioning to a renewable energy system. Customers were also conscious that our asset base will rapidly age over the next 20 years, and that the network will need to adapt to increasing climate change events. In this context, our Future Network Strategy is premised on safeguarding the security and reliability of the network.

A green and prosperous NT

Our strategy considers the environmental and economic value of facilitating growing renewables in the NT energy system.

Climate research shows that the NT environment will be impacted significantly by climate change events. This includes persistent hotter temperatures and more extreme weather events. Our customers considered it vital that we play our local part in abating climate change by supporting a transition to clean energy.

The benefits of greener energy systems will also provide economic benefits to the NT. With our abundance of resources and our proximity to international markets, we have a great opportunity to grow our export market. International markets will place a higher value on products developed in a renewable energy system.

Customer choice and equity

Our customers have led the way in decarbonising our energy systems. About 20 per cent of our residential customers have a rooftop solar connection. Over the next two decades, we also expect customers will install more home storage batteries and drive electric vehicles. A key objective of our strategy is to limit constraints on how customers use their technology.

Our People's Panel also emphasised that our decisions must consider equity between customers. In particular, we should more directly consider initiatives that improve the experience of low-income households.

For this reason, a key objective of our strategy is to promote customer choice in how they use technology and improve the experience of all customers, including low-income households.

Figure 14 – Objectives of the Future Network Strategy

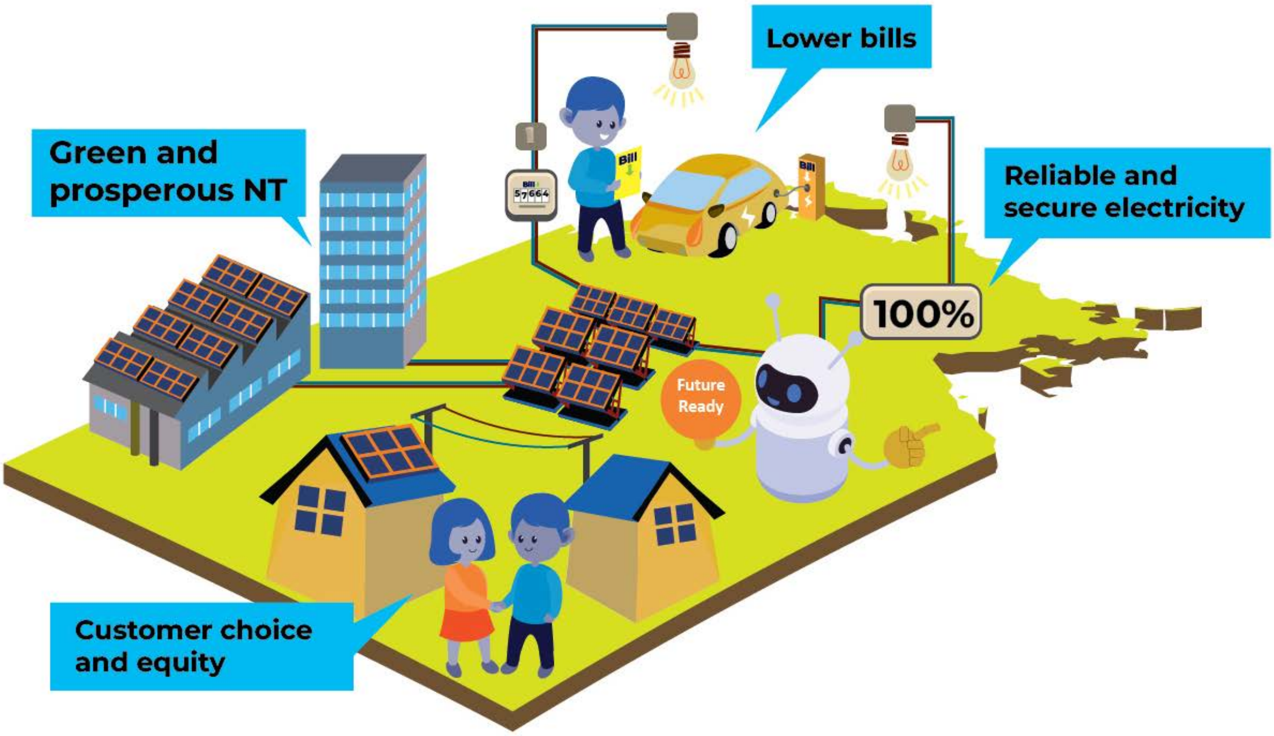
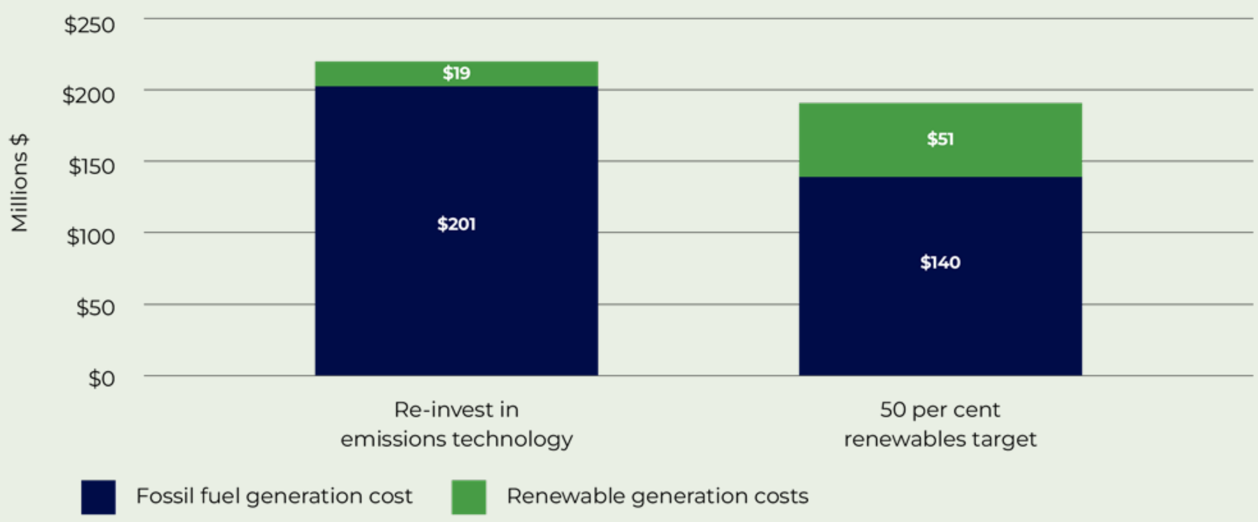


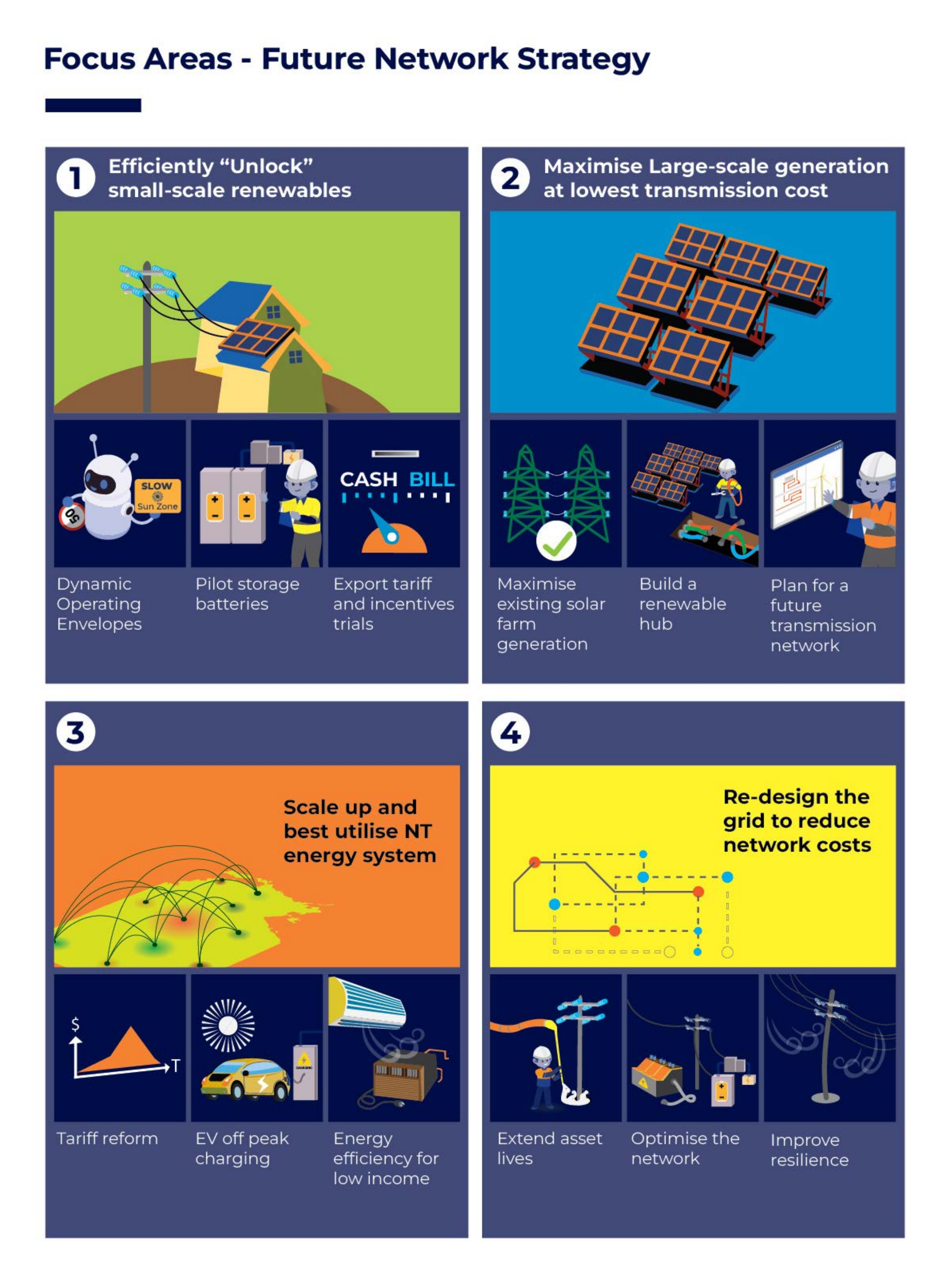
Figure 15 – Comparison of costs of renewable generation compared to re-investing in emissions technology



3.3 Focus areas of the Future Network Strategy

The Future Network Strategy identifies key 'focus areas' over the next 20 years that would enable us to achieve the objectives. This is set out in **Figure 16** below and discussed in the following sections.

Figure 16 – Focus Areas



Communications mast and Power and Water work vehicle near Alice Springs

Focus area 1 – Efficiently unlock small scale renewables

Over the last five years there has been significant growth in small-scale (rooftop) renewables on our network. In 2022, more than 10 per cent of underlying energy consumption was produced by rooftop solar with more than 18,000 customers having a rooftop connection. By 2030 we expect that more than 20 per cent of energy will be delivered via rooftop solar.

Small scale solar has fundamentally changed the role of our distribution network. Traditionally our network has been designed and configured to convey electricity one-way from generators to customers. However, the advent of renewables has now meant that our network must be capable of delivering energy from generators and absorbing and transporting energy from customers.
To date, our network has been highly adaptable to these changes with minimal need to apply any constraints on our customers. This has meant that we have been able to dispatch low-cost renewable generation to our customers.

However, our network is starting to face emerging constraints as small-scale solar increases on the network. **Figure 17** shows actual and forecast residential solar connections from 2017 to 2050. This shows that small scale solar connections will continue to increase over the forthcoming decades, driven by new residential precincts and a higher proportion of existing homes connecting solar.

The most pressing challenge is the security of the network on low demand ("minimum demand") days. This occurs on sunny and mild days when household solar is largely meeting the low energy demands of customers. Maintaining system security requires a minimum level of thermal generation, but if rooftop solar continues to increase there is insufficient demand for the thermal generators to meet, and limited means to constrain the solar production in the absence of batteries. We expect minimum demand constraints to occur in the next five years in all our regulated networks, and the problem will amplify in coming years. **Figure 18** shows that we will experience more minimum demand "events" over the next 20 years as solar penetration increases.

We also expect localised voltage constraints to increase in future years, but we have limited visibility to understand the extent of the issue. Voltage issues occur when network infrastructure cannot manage reverse power flowing back onto the network from small scale solar exports.

Our Future Network Strategy has identified efficient solutions to help manage transient constraints related to small-scale solar while still providing for maximum low-cost renewable generation.

Dynamic Operating Envelopes

As further discussed in Chapter 8, we will be investing in a new technology termed "Dynamic Operating Envelopes" (DOEs) that communicate to customers' solar panels when there is a constraint on the network to maximise the amount of solar that customers can put back onto the network without damaging it. At all other times, customers can export their solar back into the grid. This avoids the need to place static export limits on our customers all year round, and in turn provides a market benefit to all customers through access to lower cost generation. The DOE solution will be implemented in 2028 to coincide with the expected constraints on minimum demand days across our three networks. As discussed in focus area three, DOEs can also be used to charge electric vehicles at off-peak times.

Pilot battery storage

Home and distribution batteries provide a means of capturing excess solar in the day and exporting in the night. This lessens the need to constrain solar during minimum demand days, and to inject low-cost renewables in the evening peak period. Currently, the costs of batteries are quite high, but we expect that prices will fall over the next 20 years. In our strategy, we identify an opportunity to trial distribution batteries through our Demand Management Innovation Allowance to provide insight on feasibility and operability of batteries in the future.

Trial export tariffs and incentives

We are considering innovative trials that would place a disincentive to export at minimum demand times but provide strong incentives for battery owners to feed-in energy in peak periods.

Figure 17 – Number of residential customers with solar installed

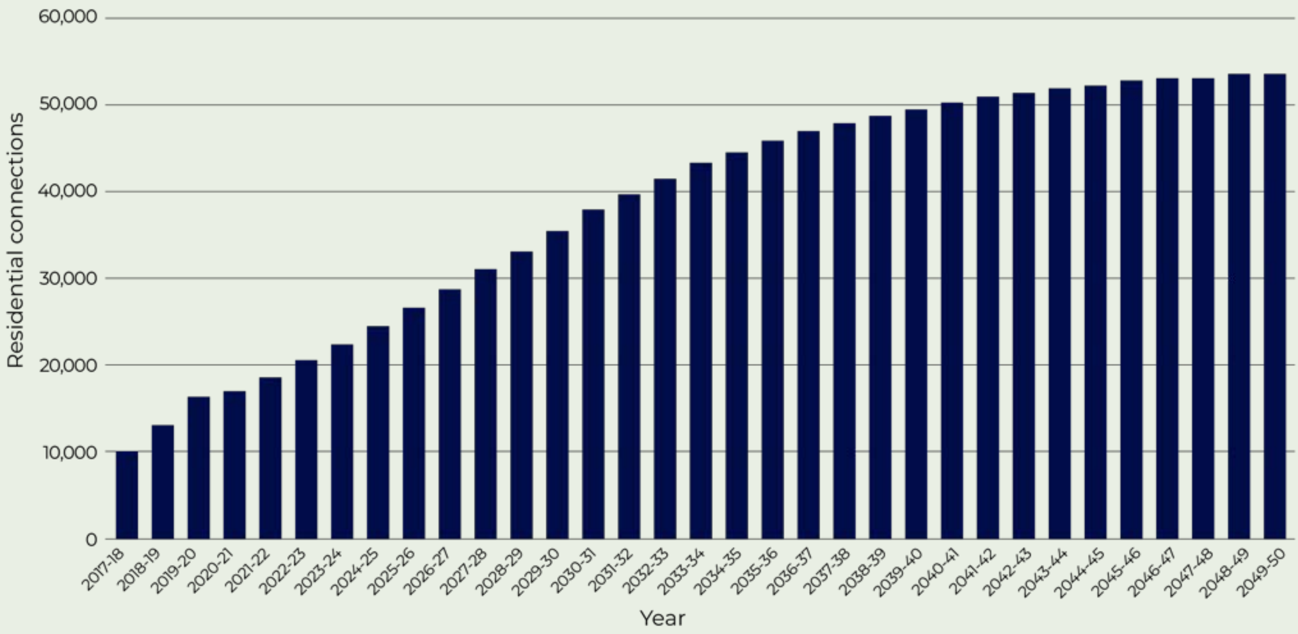
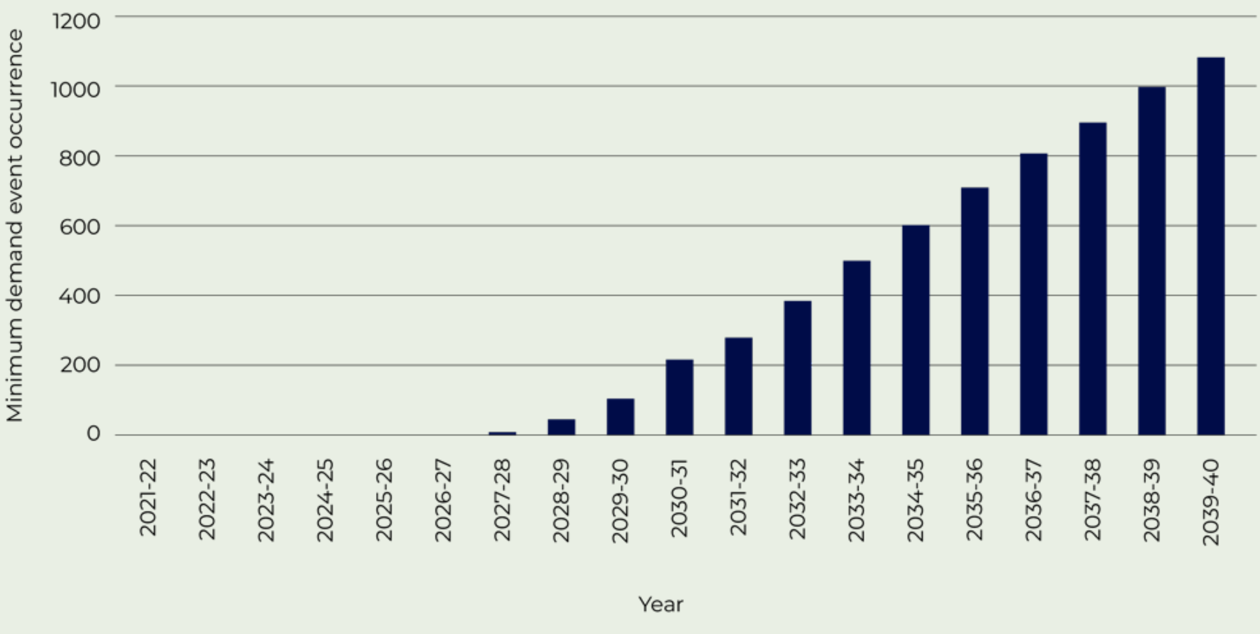


Figure 18 – Forecast minimum demand 'events' on Darwin-Katherine by year



Solar panel, Darwin

Focus Area 2 – Effi ient transmission network to deliver large scale renewables

In recent years, we have connected a significant amount of large-scale solar farms to our Darwin-Katherine transmission network. The Darwin-Katherine Electricity System Plan (DKESP) indicates that large scale renewable generation and battery storage will deliver about 30 per cent of underlying demand by 2030. The DKESP also indicates significant growth in large scale renewables after 2030 as we move towards net zero emissions. This includes potential for new technologies including mass solar farms, wind, and hydrogen.

Large scale renewables are significantly lower cost than replacing the existing stock of thermal generation. Large scale renewables can also be more easily controlled during times of constraint on the network.

Our transmission network provides a vital link for transporting large scale renewable energy to our customers. We see opportunities to reduce our transmission costs by encouraging proponents to locate close to spare transmission capacity, which allows us to securely deliver renewable generation to customers. We also see a role in planning in advance for new sources of generation beyond 2030.

Our future network strategy identifies three initiatives that would help maximise renewable generation at least cost to our transmission network.

Increase dispatch of existing renewable generation

We see an opportunity to increase generation of existing large-scale renewables in Darwin-Katherine. A key issue is that the generators have located south of existing thermal generators on the Darwin-Katherine transmission line (DKTL). The security limit into Darwin from the DKTL is currently lower than the full potential of renewable generation, due to system limitations and the line being a single contingency risk. We see an opportunity to relieve the constraint on the transmission network through procuring services of new technologies such as grid scale batteries. As noted in Chapter 8, we are advancing a contingent project as part of our 2024-29 regulatory proposal that would secure funding for this initiative on the condition that we can demonstrate a market benefit to consumers.

Support development of a renewable hub

We are working with the Northern Territory Government on its initiative to locate a renewable energy hub close to our existing transmission network. The hub would co-locate solar farms and large-scale batteries, enabling more efficient dispatch into Darwin. The hub would deliver about 200MW of renewable generation to the Darwin - Katherine network by 2030. We would need to extend our transmission network to connect the hub to our existing transmission network, but we would have spare capacity to transport the generation. Due to the uncertainty in scope and costs, we will be seeking funding for this project through a contingent project in our 2024-29 regulatory proposal as discussed in Chapter 8.

Plan a transmission network beyond 2030

We will devote more resources to planning for an efficient and secure transmission network to meet future sources of renewable generation beyond 2030. This includes considering the likely sources of new generation, identifying areas where generators may co-locate, and developing transmission rings that provide for capacity and security of supply.

Our transmission network provides a vital link for transporting large scale renewable energy to our customers.

Focus Area 3 – Scale up and best utilise the NT energy system

Our regulated networks are relatively small compared to other places in Australia, limiting our ability to capture economies of scale in our service delivery. This has been a key impediment to lowering electricity costs in the NT, as we have a small customer and consumption base to spread our fixed costs.

We see an opportunity to increase the scale of our energy systems over the next 20 years. A combination of population growth and large industry will significantly increase energy consumption. Further, we expect an acceleration of electric vehicles from 2030 onwards that has the potential to materially increase the average consumption of electricity used by our customers. Our strategy is focused on facilitating greater electricity uptake in the NT and encouraging use of electricity in off-peak periods that reduce electricity costs.

We see that a mix of innovative tariffs, automated EV charging, and targeted energy efficiency incentives are instrumental to improving the utilisation of the energy system.

Tariff reform

In the 2024-29 period, we will be proposing significant reforms to our network tariffs. This includes a super user tariff that encourages large industrial users to locate in the NT. This recognises that complex tariffs can be a barrier for mass industry locating in the NT. Our super user tariff provides a simple design that will encourage new industry to connect to parts of our transmission network with spare capacity. Super users will greatly increase the scale of our business and will provide opportunities to lower our cost to serve for all customers.

We will also be introducing a 'time of use' design tariff for our residential customers. The tariff provides very low prices in the day to encourage customers to shift their use of energy appliances to the middle of the day. This is when there is ample capacity on the network and greater access to low-cost solar generation. Tariffs are set higher in the evening in summer when our network faces high demand. A key element of our strategy is to work with the Northern Territory Government and energy partners on mechanisms that allow the customer to respond to our network tariffs. We will also be rolling out more smart meters to ensure that innovative tariffs can be applied.

EV off-peak charging

EVs are a key focus of our Future Network Strategy. A customer can significantly save on travel costs from using electricity to fuel their cars as can be seen in **Figure 19.** EVs also provide a great opportunity to lower average electricity costs if charging occurs in off-peak periods. Each EV adds about 30 per cent more consumption to a typical household. We see that tariffs will be vital to incentivising customers to use electricity in off-peak periods in the day rather than the evening peak. Automated charging using the DOE solution discussed in Focus Area 1 provides further opportunities for customers to shift charging to the daytime. **Figure 20** shows how time of use tariffs and automated charging can shift consumption to the middle of the day.

Energy efficiency for low-income households

Our strategy has also identified future opportunities for innovative demand management schemes. In particular, we see an opportunity for energy efficiency schemes targeted at low-income households. In our engagement sessions, stakeholders noted that low- income households often reside in rental accommodation with poor insulation and inefficient cooling appliances. This is leading to high electricity bills for customers on low budgets. Our strategy identifies opportunities to use Demand Management schemes that may provide incentives for energy efficiency in rental properties, particularly if this assists in helping us manage constraints on the network in the evening peak.

Figure 19 – Savings from EVs

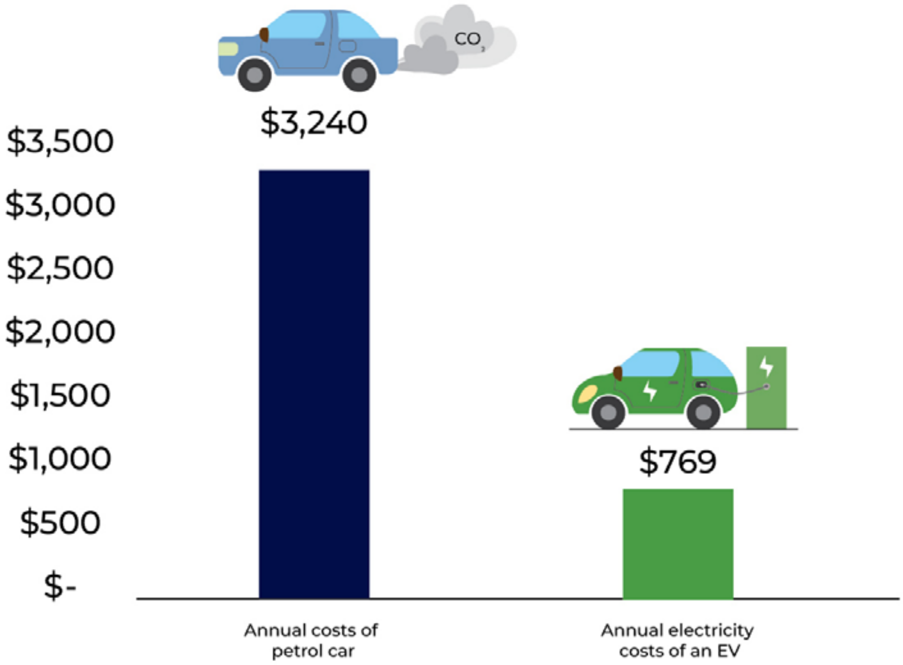
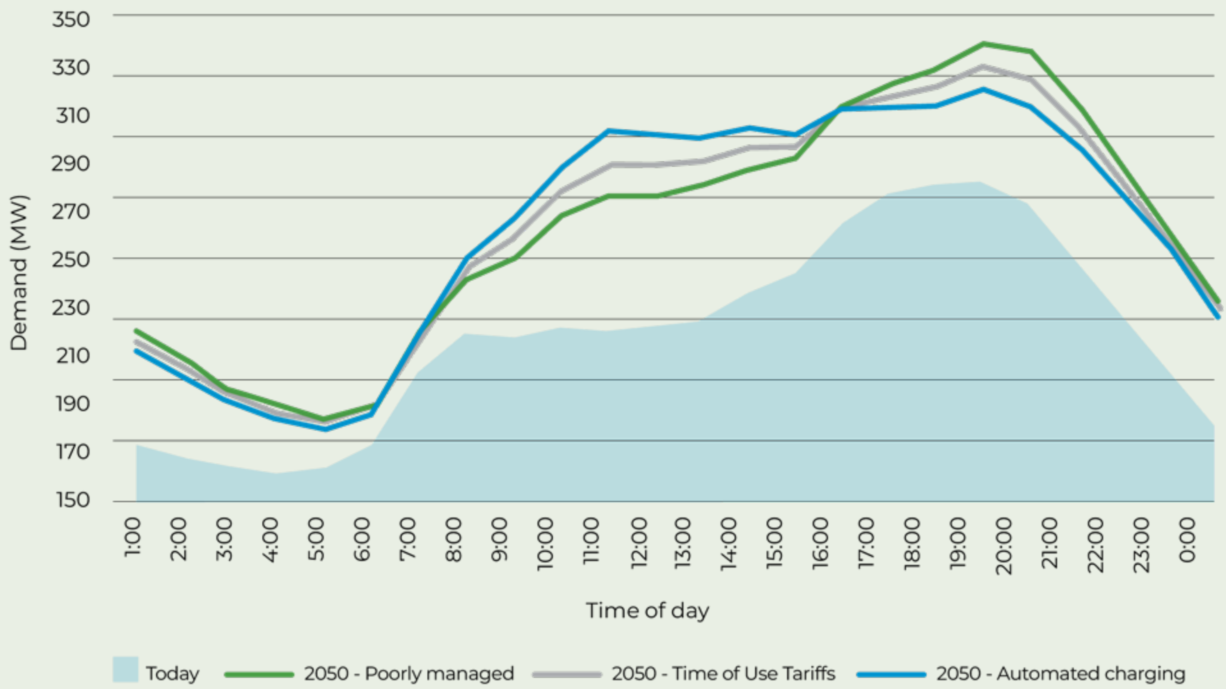


Figure 20 – EV charging scenarios



Focus Area 4 – Re-design the grid to reduce network costs

We will face a significant challenge over the next 20 years to minimise our capital and operating expenditure. A large proportion of our assets were installed at the time of Cyclone Tracy about 50 years ago. This cohort of assets is likely to face condition issues when operated beyond their technical life. This will place upwards pressure on our replacement and maintenance costs. We also expect to face increasing emergency response costs associated with tropical storms and cyclones, as climate change events become more pronounced.

Our customers have been leading the discussion on how new technology and thinking can help us mitigate the expected increase in our operations. Based on these discussions, our Future Network Strategy has identified key initiatives to re-design the grid.

Manage ageing assets

Our peer networks in Australia have been operating their assets well beyond their technical life through improved asset management strategies and ICT systems. The NT's extreme climate means that our assets are subject to more wear and tear over their lifetime, but we still see a role for similar strategies to extend asset life. This will have the effect of dampening and smoothing an expected increase in replacement over the next 20 years.

Over the next 20 years, we will invest in systems and expertise to help us extend the lives of assets. This includes maintenance strategies and systems that provide visibility on condition and performance issues and allow for corrective maintenance and life extension. We will also continue to apply our new risk quantification procedure that can help understand the relative risks from deferring replacement. This approach has underpinned our upcoming replacement program over the next decade as discussed in Chapter 7.

De-scale the network

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 looking at microgrid solutions for some parts of our unregulated areas rather than re-building existing infrastructure. The learnings will be applied to more isolated parts of our regulated network, where there may be opportunities for stand-alone power systems.

We will also consider opportunities provided by solar and batteries in our distribution system to reduce the capacity of replacement assets. Over time, there may be a role for customers' technologies to be used as a back-up (redundancy) for the network, rather than re-building additional network infrastructure.

Improve resilience to climate change events

We have extensive experience with restoring power to our customers after cyclones and major storms. The predicted increase in extreme weather increases the risk of outage time to our customers and higher safety risks. We will undertake resilience studies to understand the types of risks we will face in upcoming years and the optimal mitigation strategies. This may include smarter asset design and operation and safeguarding critical assets.

Power and Water network planners assessing network map

4. Network Performance in 2021-22

Over the last decade, Power and Water has significantly improved our reliability performance. In the 2021-22 period, we were able to meet all our reliability performance targets. In terms of voltage performance, we have improved the overall quality while continuing to support an increase in solar on the network. Actions to address voltage issues in Katherine during 2020-21 have proven effective with high-voltage events halving in the 2021-22 reporting period.

The TDAPR provides an opportunity for our stakeholders to assess the performance of our network on an annual basis. The typical measures of network performance include reliability and quality of supply.

4.1 Reliability performance

Our customers expect us to minimise the frequency and duration of power interruptions. In this section, we report our reliability performance against key metrics set out in our regulatory requirements.

The Northern Territory Electricity Industry Performance Code (EIP Code) is the applicable regulatory instrument for setting our reliability metrics and targets. The EIP Code provides a framework for setting reliability measures and standards for Power and Water's regulated network, as well as reporting our performance to the Northern Territory Utilities Commission.

Below we describe how Power and Water performed in 2021-22 against the key metrics in the EIP Code, including reliability performance by feeder category and worst performing feeders.

Power and Water is not subject to the AER's Service Target Performance Incentive Scheme (STPIS) for the 2019-24 period. For this reason, we do not report or forecast our performance against the scheme.

While we report our reliability performance as part of our response to the AER's Regulatory Information Notice (RIN), it is important to note that reporting definitions are slightly different in the EIP Code and RIN. Consequently, our performance data differs in each of our regions.

Feeder performance in 2021-22

The EIP Code requires Power and Water to propose reliability targets for each regulatory control period for approval by the Utilities Commission.

This includes targets for System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) by feeder category on the distribution network.[3] SAIDI is the average minutes off supply per customer, and SAIFI is the average number of interruptions experienced per customer.

Our annual performance can differ markedly from year to year due to weather and other unpredictable activity.

Table 1 reports our aggregate 2021-22 SAIDI and SAIFI performance by feeder category against the targets approved by the Commission under the EIP Code.

[3] In calculating the performance metrics, the Code requires that all transmission networks are classified as distribution networks and their performance is reported as for the distribution network. For clarity, any reference to the distribution system also includes the transmission system in the remainder of this section.

Our performance in 2021-22 was significantly better than the previous eight years. The improvement was observed predominantly in reduced asset failure and secondly in reduced external impacts (third parties and flora and fauna).

Performance by region

Each of our three network regions – Darwin-Katherine, Alice Springs and Tennant Creek – have very different performance characteristics.

While we have targets set for each feeder category, we do not have a target for the whole of network or for each individual region. Performance by region is assessed through our annual EIP Code reporting and provides insights into performance to ensure our customers are receiving an appropriate level of service regardless of their region.

Figures 21 to **22** below show the performance of SAIDI and SAIFI by region. The three charts show that as the network size decreases, the volatility of the performance increases as a result of the proportionally higher impact of each outage on the total.

The long-term average shows that Darwin and Tennant Creek are showing improving trends, while Alice Springs is remaining fairly constant. Katherine is showing a deteriorating trend in both SAIDI and SAIFI. This is largely driven by transmission outages and recent surges in bat activity in the rural areas of Katherine. Our poor performing feeder program has focussed on protection of our pole tops from fauna in recent years, with more planned in coming years to avoid similar large spikes in outages associated with migrating bats and birds. Our project to replace legacy protection and control systems on the Darwin-Katherine transmission line is also well underway and will enable a faster response to transmission faults affecting the Katherine region.

This information is an input into our investment decision making, along with performance against feeder category targets and analysis of the worst performing feeders and quality of supply obligations, which are discussed below.

Table 1 – 2021-22 Reliability performance compared to approved target in EIP Code

	Adjusted SAIDI[1]			Adjusted SAIFI[1]		
Feeder Category	**Performance Target**	**Actual Performace**	**Performance**	**Performance Target**	**Actual Performace**	**Performance**
CBD	4	0.223	Target met	0.1	0.003	Target met
Urban	140	70.815	Target met	2	1.258	Target met
Rural short	190	133.232	Target met	3	1.823	Target met
Rural long	1500	831.082	Target met	19	8.745	Target met
Whole of network[2]	175.8	114.524	Target met	2.6	1.627	Target met

[1] The recorded data is 'adjusted' to remove excluded events consistent with the reporting requirements in the EIP Code.

[2] The EIP does not specify 'whole of network' targets. We derive a 'whole of network' target based on our feeder category targets.

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Figure 21 – Darwin reliability performance

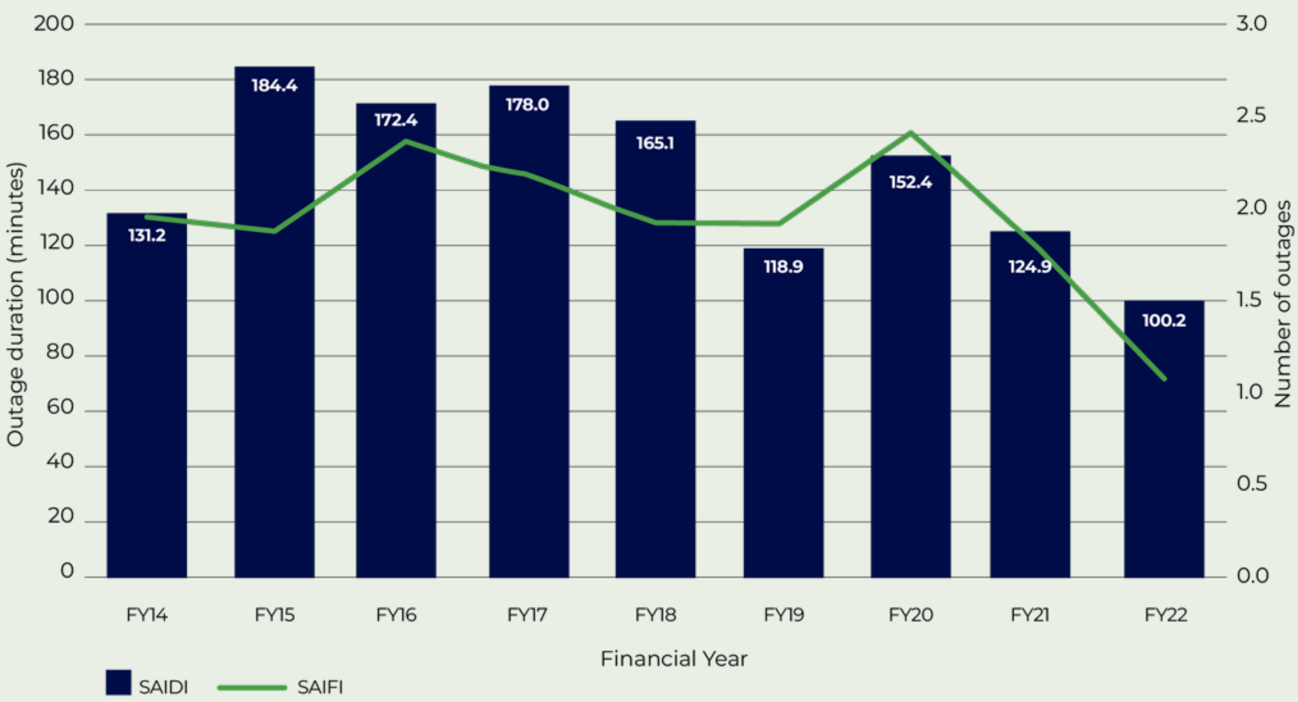


Figure 22 – Katherine reliability performance

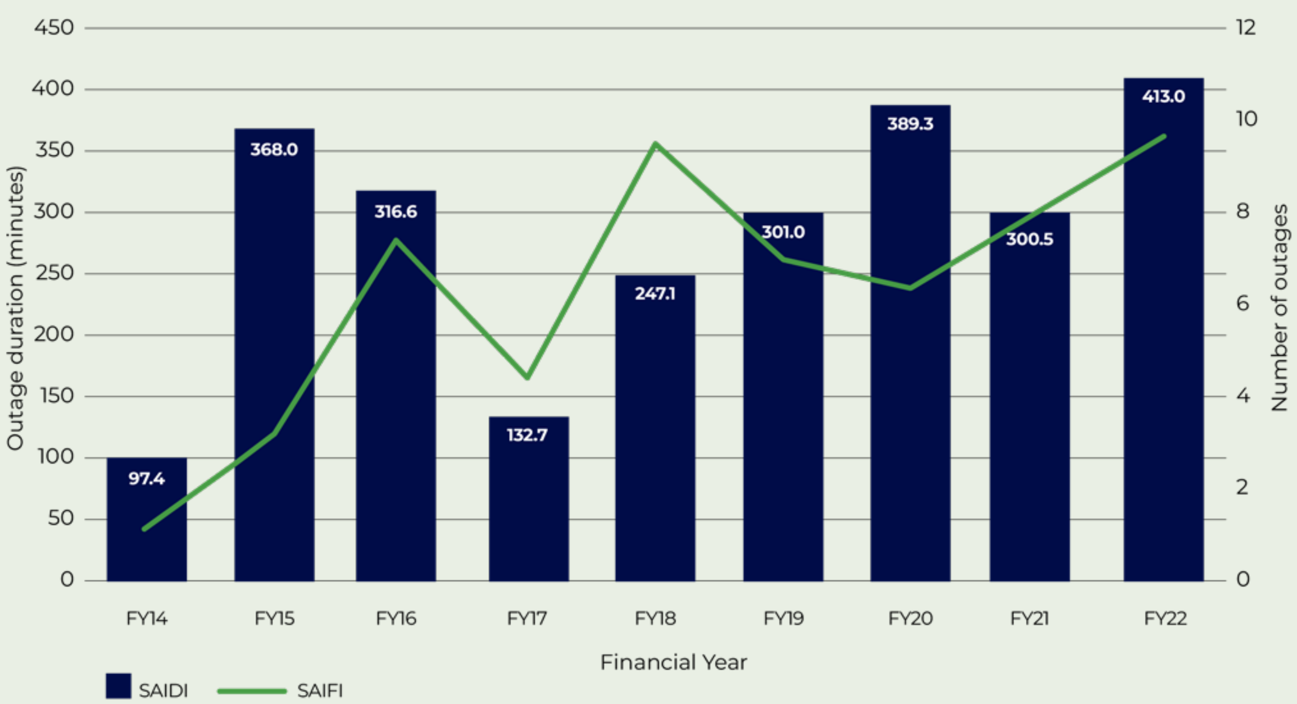


Figure 23 – Alice Springs reliability performance

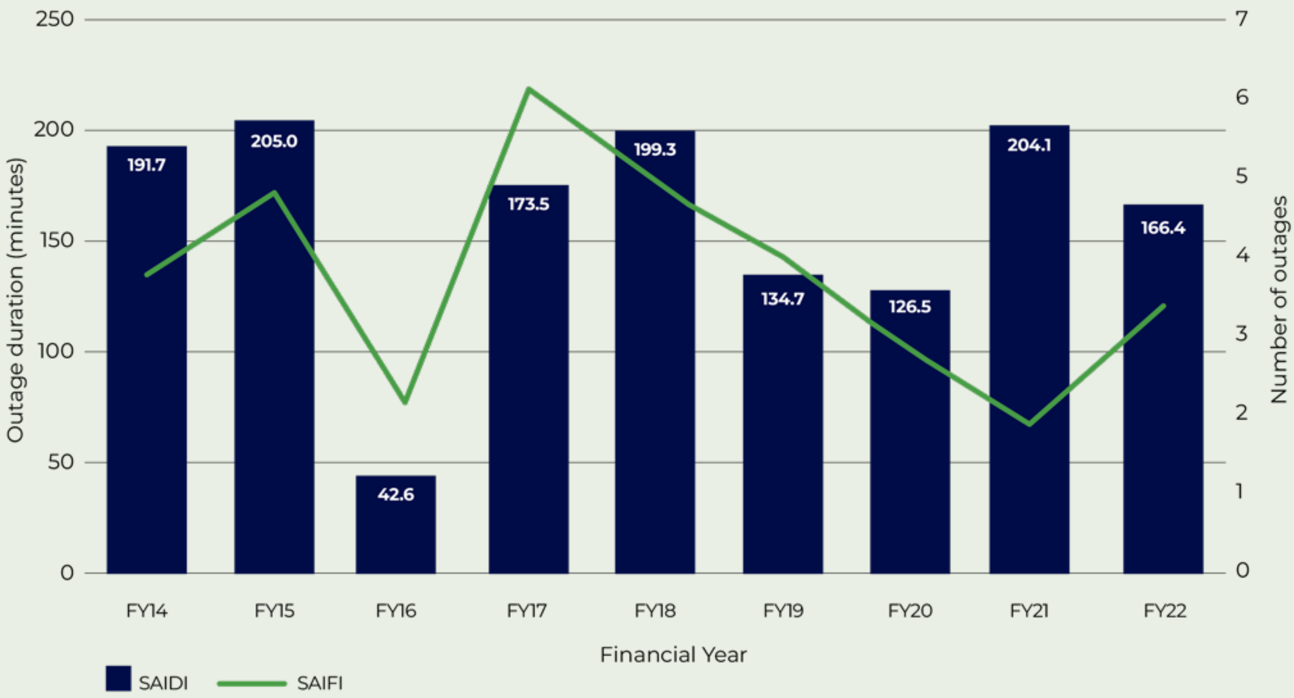
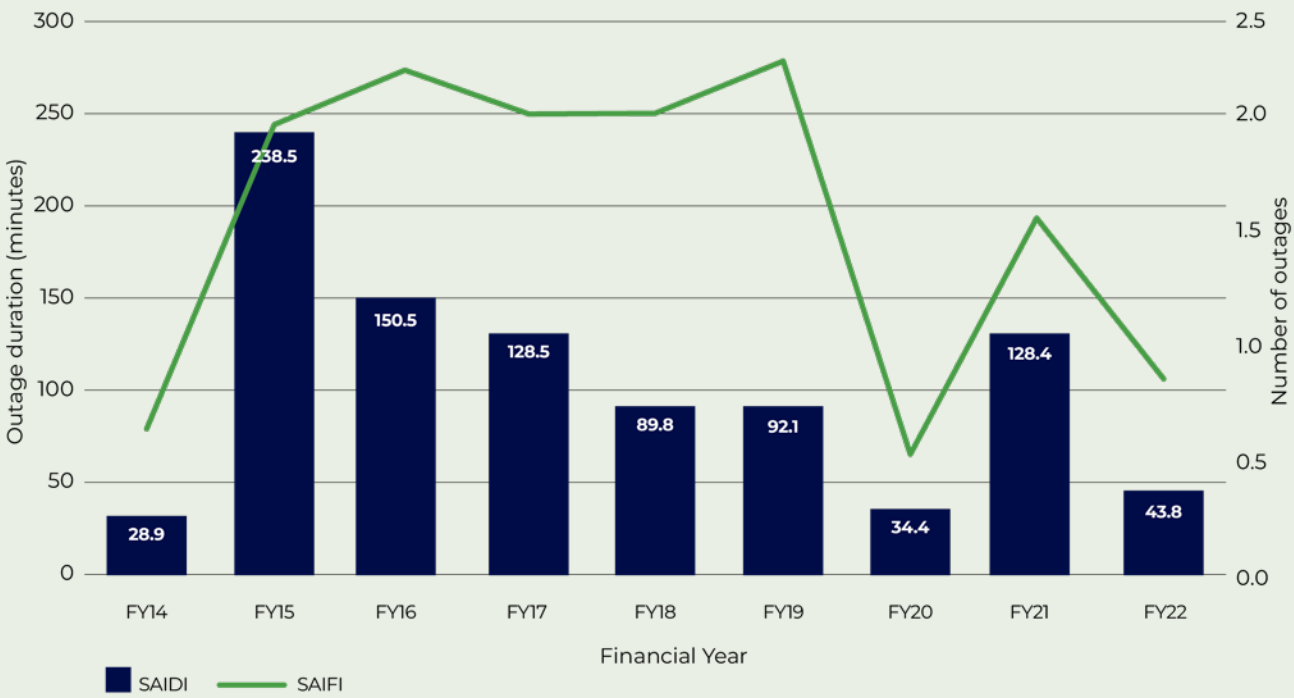


Figure 24 – Tennant Creek reliability performance



Worst performing feeders in 2021-22

The EIP Code also requires us to measure and report on the five worst performing feeders in the CBD, urban, and short and long rural categories.[4] This recognises that some of our customers receive worse reliability than others and we should improve performance if cost-effective.

Table 2 sets out our five worst performing feeders by category for 2021-22. We outline the dominant causes of interruptions and its impact on SAIDI for the feeder. We also identify if the same feeder was identified as worst performing in 2020-21.

Customers connected to our rural feeders experience significantly worse reliability than customers connected to our CBD and urban feeders. This is due to limited interconnection to transfer load from an adjacent feeder. The length and location of the route means it takes longer to find the cause of the issue.

Last year, in response to the worst performing feeders we identified projects to address the performance. This year, only three of those feeders remain on the list (excluding Rural Long which are always reported) demonstrating our actions have been mostly effective in resolving the issues.

Improving reliability performance

Our reliability improvement program focuses on areas of the network where customers consistently receive poor service, and where there are cost-effective ways to materially improve performance.

Based on our performance in 2021-22, we will not undertake specific reliability works in the CBD. Our performance has generally met the targets in previous years. Further, our planned replacement program over the next 10 years should contribute to improving CBD performance. In particular, we are planning to replace distribution substations to improve fault level capacity as outlined in section 8.4 of this report.

For urban feeders, we have implemented solutions for each of the recent specific drivers of poor performance on the worst performing feeders. In Katherine, we installed new protection against outages caused by bats on sections of the network frequently affected. We will continue to monitor the performance and take further action if required.

To improve reliability performance on the worst performing short rural feeders (based on the identified causes) we have undertaken the following work:

- On the Florina feeder, we installed new protection against bats on frequently affected lines.
- On the Lambells feeder, we replaced the defective cross arms and on the Acacia feeder we installed a recloser and five smart fuse switches in the affected areas to improve restoration times.
- On the Herbert and Middle Point feeders we have targeted the problem areas by focusing and increasing our normal vegetation management program to minimise disruption caused by trees close to the power line.

For long rural feeders, while we have achieved our targets, we have also implemented the following:

- Dundee – We installed a remotely controlled switch to enable rapid restoration of supply after a reliability event. We also installed protection equipment to mitigate damage caused by animals.
- Mataranka – We replaced a failed recloser and installed an additional one to improve restoration times.
- Ali Curung – we installed animal guards and improved animal protection on transposition poles.

Improving reliability performance on worst performing feeders requires specific solutions to address the unique causes of outages. We will continue to monitor feeder performance and implement solutions as needed.

Many of our projects will help ensure the ongoing reliability performance of our network. In addition, we have a dedicated reliability performance improvement program (NMF) to ensure we are able to make prudent and efficient investment to improve reliability where required.

The implementation of our new Vegetation Management Strategy that began in 2019 is also enabling us to better target trees that are in poor health and pose a risk to the network, particularly during storms. We plan to conduct a comprehensive review of this strategy in 2023 to ensure that the efficiencies achieved are sustainable and to identify further opportunities for improvement, particularly with respect to network resilience and reliability.

[4] We have only three rural long feeders on our regulated network. For this reason, these will always be reported as worst performing feeders.

Table 2 – Worse performing feeders by category

Category	Feeder Name	SAIDI	Cause and impact on reported minutes	Same as previous year
CBD	11WS02 LITCHFIELD	0.8	All CBD feeders met the category target.	No
CBD	11DA04 WEST BENNETT	0.7		No
CBD	11WS11 MANTON ST	0.6		No
CBD	11ML09 DALY	0.6		No
CBD	11MS02 SMITH	0.5		No
Urban	22KA22 KATHERINE	430.4	Bats and vegetation contacting overhead lines during March and April, contributing 155 minutes.	Yes
Urban	11PA08 YARRAWONGA	412.9	Mainly due to a single outage caused by an insulator failure, contributing 256 minutes.	No
Urban	11WN13 GOYDER	372.5	Mainly due to a single outage caused by the failure of a HV link, contributing 256 minutes.	No
Urban	11WH02 BLESSER CREEK	298.2	Mainly due to a single outage caused by the failure of a lightning arrestor, contributing 198 minutes.	No
Urban	11WN22 LUDMILLA	308.3	Trees blowing into power lines and an ABS defect also contributed to 49 minutes of feeder SAIDI.	Yes
Rural Short	22KA03 FLORINA	1357.7	Bats contacting overhead lines during March and April, contributing 313 minutes.	No
Rural Short	22HD402 LAMBELLS	953.1	A HV crossarm failure during a heavy storm, contributing 728 minutes.	No
Rural Short	22MT07 ACACIA	923.7	A conductor failure and a fuse saver defect, contributing 477 minutes.	No
Rural Short	22SY11 HERBERT	809.9	Weather related outages including trees blowing into powerlines and lightning arrestor, contributing 674 minutes.	Yes
Rural Short	22HD403 MIDDLE POINT	787.2	Trees that fell onto a power line, two separate events, contributing 721 minutes	No
Rural Long	22KA10 MATARANKA 1	1476.8	Met category target. Failure of a recloser, vegetation and bat activities. Contributed 980 minutes.	Yes
Rural Long	22TC01 ALI CURUNG	1050.1	Met category target. Failure of a HV Bridge, recloser and weather related outages. Contributed 549 minutes.	Yes
Rural Long	22SY04 DUNDEE	589.7	Met category target. Weather related events contributed 326 minutes.	Yes

4.2 Quality of supply performance

Quality of supply relates to voltage disturbances that can impact a customer's energy supply and appliances.

Currently, Power and Water's Network Technical Code and Network Planning Criteria is the applicable standard that sets out measures and standards for quality of supply delivered to our customers.

For steady state voltage, we must apply the Australian Standards for our low voltage and high voltage network.[5] The standards set out requirements for voltage fluctuations, harmonics and voltage unbalance.

We monitor power quality issues by analysing customer complaints and actively monitoring voltage levels at our substations. We have permanently installed monitoring equipment in all zone substations and use portable equipment to undertake cyclic monitoring of distribution substations.

We use power quality and geographical data to develop electrical models of low voltage so we can better predict power quality issues. We also regularly review solar installation specifications.

We investigate cost-effective options to resolve identified quality of supply issues. Options include distribution transformer tap adjustments, upgrading or installing additional distribution transformers, segmenting the local low voltage network between transformers, upgrading the capacity of conductors, and phase balancing.

Low voltage quality audits

We conduct regular audits of low voltage quality, using a random sample of customers. In 2022, we continued to use data obtained from smart meters to assess power quality. The meters measure and record voltage information for a period of 90 days, with measurements averaged over 10-minute intervals.

Table 3 identifies the percentage of time that voltage was above or below the limits prescribed in our regulatory obligations. The key findings for this year are:

- Darwin and Tennant Creek are not showing any issues with voltage quality based on the sample size.
- Alice Springs has had some infrequent high voltage events, suspected to be driven by solar PV uptake. We are installing reactors to manage this issue and will continue to monitor voltage quality to assess if this addresses the issue.
- Katherine is above the limits for a significant proportion of the time. However, this has reduced by about 55% compared to 2020-21. This improvement is due to two reasons. Firstly, the voltage sampling was undertaken at an earlier time of the year resulting in higher minimum demand which had the effect of a lower voltage. Secondly, Power and Water received customer complaints regarding high voltages which were addressed by changing distribution transformer tap positions to reduce the network voltage. Therefore, the high voltage issue is still present on the network and is expected to be resolved by the new reactor planned to be installed by 2024.

We note that the low voltage quality audits are only one aspect of understanding the extent of issues with the quality of power supply. Customer complaints provide another means of identifying issues with power quality.

Table 3 – Voltage performance by region

Voltage zone	Darwin	Katherine	Alice Springs	Tennant Creek
Below limits (<216V)	0.00%	0.01%	0.00%	0.00%
Above limits (>253V)	0.00%	4.00%	0.75%	0.00%

[5] The relevant standards are AS60038 and AS61000.3.100. The range of LV supply is specified in AS61000.3.100 Section 5 and is re-produced in Appendix B.

Low voltage quality audits

In 2021-22 we received 23 complaints about quality of supply from customers compared to 39 complaints in 2020-21. **Figure 25** below compares the number of complaints by category over the last three years.

We investigated each complaint to understand the underlying issue. In 2021-22 the main cause of an identified complaint was related to an issue with customer equipment or was not able to be identified. **Figure 26** compares the underlying causes.

Figure 25 – Quality of supply complaints

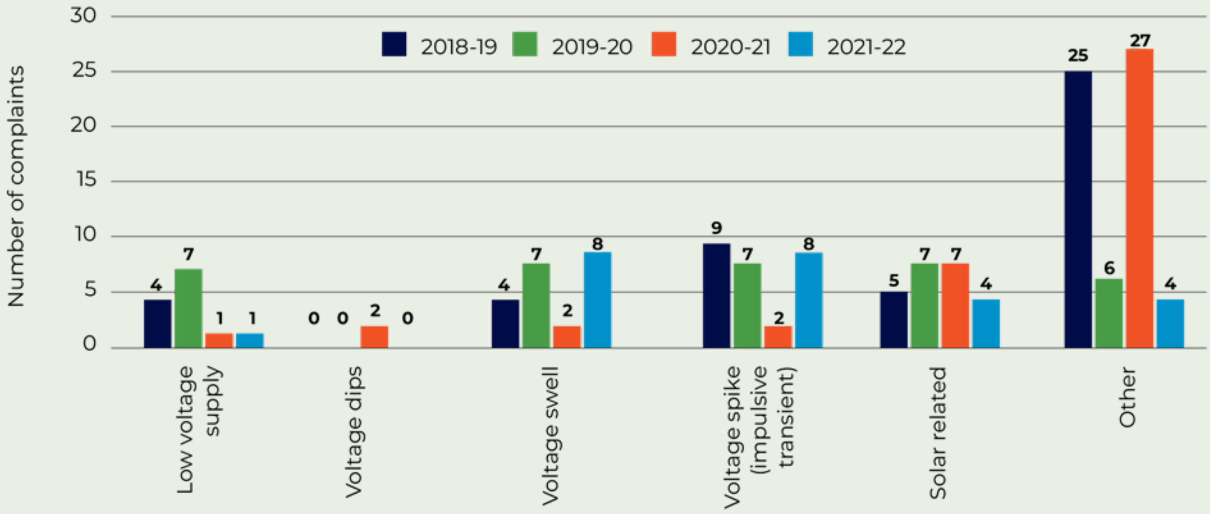
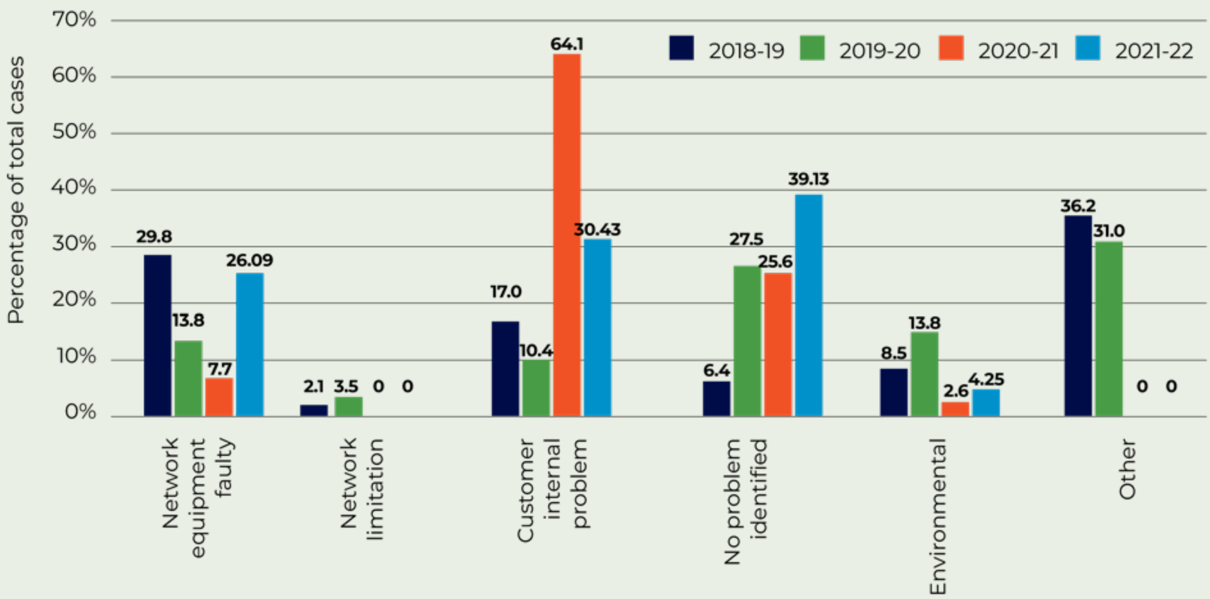


Figure 26 – Quality of supply causes



Power and Water engineers analysing network performance

Improving quality of supply

Power and Water has a quality of supply program for the 2019-24 period that aims to resolve low voltage issues over time. This is discussed in the sections below.

Voltage management studies

We are currently undertaking studies on the optimal voltage management strategies for the Darwin-Katherine Power System (DKPS). This will help us understand the voltage issues that are likely to arise on our distribution and transmission networks, particularly in the context of increasing renewables on the system.

The study should also help us estimate the likely level of services we will need to meet our expected obligations under the new Essential System Services (ESS) framework that the Northern Territory Government is developing to ensure the security of the Northern Territory Electricity Market.

Targeted augmentation

Power and Water also undertakes targeted reconfiguration of the low voltage network in areas that are most impacted. This is likely to be older suburbs where there has been significant new housing development with solar PV.

Dynamic Operating Envelopes

As outlined in Chapter 3, we are focusing on using new technology to help address emerging voltage issues and to avoid unnecessary network investment.

Our planned Dynamic Operating Envelopes (DOEs) solution will enable us to control residential solar PV and other energy resources to more efficiently manage voltage incursions and transient constraints that would otherwise require significant capital investment to resolve.

DOEs are being trialled in Alice Springs until the end of the 2023 - 2024 financial year. Results from this trial will be used to help inform how DOEs can be implemented across our different networks and incorporated into our standard business practices.

Network batteries

We are planning to install two network batteries between 2024 and 2029 as a trial under the Demand Management Innovation Allowance.

Installation of batteries that can be controlled by Power and Water to charge when there is high solar PV generation (i.e. midday) and then discharge during high demand when there is less sun (i.e. evening time) will help avoid the need for investment in new infrastructure to meet growing peak demand and will improve network utilisation.

Building our understanding and capability with these new technologies will help us improve quality of supply at a lower cost to our customers.

4.3 ICT Update

Our Information and Communications Technology (ICT) strategy is directed at supporting key improvements to our business to uplift our core capabilities and strengthen cyber security. This will be achieved primarily by replacing outdated and obsolete assets and systems with modern equivalents. This will provide improved functionality and visibility of our operations that will allow us to enhance the efficiency of our business practices.

Our focus areas include:

- **Driving efficiency to support our Operating Model initiatives** – We have identified key investments to upgrade and implement new ICT systems to improve the efficiency of our services.
- **Improving the way we communicate with customers** – We have identified changes to our customer relationship management system and outage management system that improve our ability to respond to customers' enquiries and to communicate outage times.
- **Improving our asset management and network planning capabilities** – We have recognised that investing in analytics and data can help our network planners to make better decisions. This is particularly important in a more complex network with high penetration of household PV, and greater opportunities for non-network solutions.
- **Assisting our transition to NER compliance in a prudent and efficient manner** – We require systems to keep pace with higher standards and meet new compliance obligations under the NT NER, particularly in relation to metering and connections.
- **Improving cyber security capabilities** – We are increasing our focus on cyber security across corporate and operational networks to meet the requirements of the *Security of Critical Infrastructure Act*. This includes strengthening our cyber and physical defences and closing any capability gaps.

The Meter to Cash program will replace the existing Retail Management System (RMS) to deliver meter data, billing and customer management capabilities including adherence to obligations introduced under the NTESMO Market Communications Guideline. With a planned go-live date in late 2023, the solution is currently under development with functional testing commencing in Q4 2022 and wider industry testing scheduled in Q2 2023 in collaboration with NTESMO and other NT electricity market participants.

We have recently upgraded our health, safety, environment and risk incident reporting system, termed 'HERCS.' This new system will provide improved data and analytics to ensure we are able to identify and manage any emerging issues that may affect our customers.

During the past 12 months we have completed the hardware replacement for our Energy Management System (EMS). The EMS has now moved to a virtual machine configuration, meaning the hardware and software can be replaced or upgraded separately. This provides more flexibility and better functionality as our network needs change and creates greater opportunity for cost savings to customers. We have also significantly progressed the related software upgrade that will have improved functionality to manage the increasing amount of renewable energy generation connecting to the network. This is planned to be completed in 2024-25.

This provides more flexibility and better functionality as our network needs change and creates greater opportunity for cost savings to customers.

5. Asset Management

Power and Water has developed a new strategic asset management system that reflects a 'whole of lifecycle' approach to efficiently manage our assets. As part of the framework, we undertake regular planning reviews to identify emerging system limitations and solutions. A key focus of our planning is working with stakeholders to identify lower cost non-network solutions to address limitations.

The purpose of this section is to describe our planning framework for maintaining assets and planning our network. We provide a brief outline of our key network planning obligations, describe our asset management system, and set out our process for identifying investment need and options.

5.1 Our planning obligations

Power and Water is subject to specific Northern Territory and national regulations that direct and influence the way we manage, operate and plan our network. The key planning obligations that directly influence our planning decisions are described below.[6]

Network Technical Code and Network Planning Criteria

Power and Water must comply with an obligation under the NT Electricity Reform (Administration) regulations to publish a Network Technical Code and Network Planning Criteria. In March 2020, we published a document which combined the two requirements.[7]

The Network Technical Code sets out network performance criteria including frequency, quality of supply, stability, load shedding, reliability, steady state criteria, and safety and environmental criteria.

It also sets out power system security requirements. The Network Planning Criteria identifies the supply contingency criteria that we must use to plan and operate our network. The criteria relate to:

- **Supply contingency –** This is the ability of the supply system to be reconfigured after a fault (contingency) so that supply to customers can be restored.
- **Steady state –** This is the adequacy of the network to supply the energy requirements of users within the equipment ratings, frequency and voltage limits, taking account of planned and unplanned outages.
- **Stability –** This is to ensure the power system can return to a steady-state or equilibrium operating condition following a disturbance.
- **Quality of supply criteria –** This relates to operating the system within the acceptable voltage and current ranges.

[6] Our planning decisions are also based on other regulation such as corporate responsibility, worker safety, and the environment. Further we have a regulatory obligation to adhere to good electricity industry practice when providing network access services and in planning, operating, maintaining, developing and extending the electricity network.

[7] The documents can be accessed on our website at: https://www.powerwater.com.au/developers/power/technical-code-and-planning-criteria

Vehicle driving on dirt road outside of Alice Springs

Northern Territory Electricity Industry Performance Code (EIP Code

The EIP Code applies to our regulated networks of Darwin-Katherine, Alice Springs and Tennant Creek. The Code influences the way we plan the network to achieve reliability targets and address worst performing feeders on our network.

The EIP Code requires us to propose reliability performance targets to the Utilities Commission for the 2019-24 regulatory period. The targets are based on System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) performance standards. SAIDI is an index showing the length of time customers are without power and SAIFI is an index showing the frequency of power interruptions to customers. The Utilities Commission approved our proposed performance targets for the 2019-24 regulatory period.

Power and Water has recently made a submission to the Utilities Commission to amend the targets for the 2024-29 regulatory period. The proposed targets will require improved performance, in line with the average of the past five years.

The EIP Code also requires us to provide an annual report to the Utilities Commission on the five worst performing feeders for each feeder category. This includes information on the SAIDI performance on each of the identified feeders, and a statement that explains the performance and action we intend to take to improve performance.

We discussed our network performance for 2021-22 and outlined our reliability program to address reliability issues in section 4.1.

Northern Territory National Electricity Rules (NT NER

Power and Water is subject to planning obligations under Chapter 5 of the NT NER. This includes obligations to forecast demand on elements of our network, obligations to undertake annual planning and report on outcomes, and specific obligations with respect to connecting large customers and embedded generators. Chapter 5 of the NT NER also requires us to manage, maintain and operate our network to minimise interruptions to connected customers, and restore the network as soon as reasonably practical following an interruption.

Potential new obligations

The Northern Territory Government is continuing to reform the electricity market. A key focus area is improving the efficiency of Essential System Services (ESS) of the power system.

In its draft report in January 2021, the Northern Territory Government indicated that Power and Water will likely have responsibility for locational voltage and system strength requirements. We will report back to customers on how the new framework will impact Power and Water's planning and capital forecasts.

We also note that in March and April 2022, the Australian Government amended the *Security of Critical Infrastructure Act 2018* to apply to electricity businesses, such as Power and Water. This will result in new obligations regarding cyber security, which are being incorporated into our forecast ICT plans that will be submitted as part of our regulatory proposal to the AER.

In February 2022, the National Electricity Rules were amended to allow electricity distribution businesses to implement Stand Alone Power Systems (SAPS). SAPS typically comprise solar panels, batteries and back-up generators. They can include both microgrids and individual power systems and are generally used when it is not economic to build long power lines to connect remote communities.

While SAPS have been classified by the AER as standard control services for our forthcoming 2024-29 regulatory control period, these arrangements have not yet been adopted in the Northern Territory. We will continue to work with the Northern Territory Government to understand if and when these arrangements are likely to be implemented. In the meantime, we will continue to build our understanding of the costs and benefits associated with implementing SAPS solutions in parts of our unregulated network.

132kV Darwin – Katherine Transmission Line in background with distribution poles in the foreground, near pine creek zone substation

5.2 Improvements to capital planning

Power and Water is currently implementing significant changes to our approach to capital planning.

In Chapter 3, we outlined our progress towards establishing a Future Network Strategy that helps us plan for four key challenges – integrating renewables, managing ageing assets, supporting a growing NT and efficient uptake of electric vehicles.

We are also making a number of key changes to our planning approach, which are described in further detail below.

Strategic Area Planning

Area Planning provides an opportunity to efficiently design the network to address multiple drivers of investment, such as demand growth and asset condition.

For example, in Darwin-Katherine we expect large industrial and housing developments to emerge over the next 20 years. This may require an expansion of zone substations and our transmission network. During the same period, high value assets will also reach the end of their service life. Area plans will enable us to align investments and consider non-network solutions to resolve multiple constraints with lower levels of investment.

This will help us to optimise the network over the long-term, provide improved service outcomes and lower costs for customers.

Demand forecast process

We are currently updating our demand forecast methodology to generate more accurate forecasts of solar installation and connections. We will also be able to better forecast minimum demand, which occurs on days when there is high solar production but low demand from customers.

For this year's TDAPR we have continued to apply our current methodology. Over the next six months we will seek feedback from a broad range of stakeholders on our approach. Chapter 6 provides more detail on our demand forecasts.

Risk Quantification

Power and Water has developed a new risk quantification procedure that is aligned to regulatory guidelines and Australian Standards that enables us to consistently assess risk across our assets. This is our first attempt to quantify risk and apply it in economic analysis of projects. We expect the approach to develop and mature over the next few years and potentially lead to the implementation of a new software system.

Risk quantification identifies the probability of an asset failure and its consequence in dollar terms. This is then used in an economic analysis to help us identify if, and when, it is efficient to invest.

The procedure has helped us to develop capital programs that balance safety, network performance and affordability. We have applied this to most assets to develop our forecast program of works for the next regulatory period.

Regulatory Investment Tests

The Regulatory Investment Test (RIT) is an investment justification required under the National Electricity Rules. The RIT has specific requirements relating to customer consultation, consideration of non-network solutions and the type and depth of economic analysis. There are different requirements for distribution and transmission projects, and these are termed the RIT-D and RIT-T, respectively.

Under current regulatory arrangements, RITs do not apply to projects assessed by the AER as part of our 2019-24 regulatory determination. However, they will apply to all eligible projects from 1 July 2024.

To ensure that we are ready for this change, next year we will be commencing work to update our planning processes to incorporate these new requirements.

Contingent Projects

The NT NER requires networks to invest prudently and efficiently to meet reasonable expectations of forecast demand. However, there is uncertainty in all forecasts. The NT NER addresses this uncertainty by including a provision to classify projects as contingent projects.

A contingent project must meet defined criteria regarding project requirements, timing and cost. It must also have a defined ‘trigger event’ that will cause the project to be required.

Once the trigger event has occurred, the electricity business must follow an application process and the regulatory allowance is adjusted to include the additional expenditure. If the project is not required, there is no cost to customers.

Power and Water has identified five projects that will be included in the upcoming regulatory proposal to the AER for the 2024-29 period as contingent projects. These are discussed in Chapter 8.

Power and Water engineers looking at asset management plans

5.3 Asset management framework

Our asset management strategy seeks to efficiently provide a safe, secure and reliable electricity network service to our customers.

To meet this objective, we have developed a new Strategic Asset Management System (SAMS)[8] that draws on industry best practice and international standards to set out how Power and Water will manage our assets and the key artefacts that will document and communicate it.

The Asset Management Policy sets out the guiding principles for applying the SAMS. It also demonstrates the commitment of our senior leadership to effective asset management.

The Strategic Asset Management Plan (SAMP) aligns our corporate objectives to our asset management objectives. The SAMP reflects a 'whole of lifecycle' approach to asset management through planning and design of new assets, maintaining and operating existing assets, and renewal and retirement of assets. The SAMP also describes challenges being faced at a network level and management strategies.

Asset Management Plans (AMPs) describe how each individual asset class contributes to achieving the asset objectives. The AMPs assess asset condition, specific performance issues and asset challenges and describe the identified plans to address any gaps compared to the asset objectives and to achieve the required performance.

Asset maintenance

Our maintenance activities seek to cost-effectively ensure assets remain in functional service. Routine activities include inspections, patrols, surveys, testing, repair of assets and switching activities. Non-routine activities are predominantly directed at restoring asset condition or performance, or rectifying defects.

Our approach to routine and non-routine maintenance is based on the principles of objective need and risk management. Our goal is to optimise maintenance by prioritising activities based on asset condition.

The intensity of maintenance activities for each asset class is dependent on several factors including the existing condition and performance of the assets, operating environment, location of asset, and demand profile. Appendix C identifies our maintenance strategies for each asset class.

Over the last decade, we have made significant improvements to our asset maintenance framework. The recent roll-out of mobile field devices for maintenance work has enabled asset information to be captured and entered directly into our asset management system. This initiative has been critical to improving our understanding of asset condition and performance.

We are also reviewing and developing online monitoring techniques to improve asset reliability and maintenance efficiencies.
Our inspection and condition monitoring practices have evolved and will continue to be optimised through maturing risk management practices.

Over the last decade, we have made significant improvements to our asset maintenance framework. The recent roll-out of mobile field devices for maintenance work has enabled asset information to be captured and entered directly into our asset management system.

[8] Power and Water, Strategic Asset Management System, August 2022, CONTROL0548. The SAMS is a framework that sets out the information and documentation required for Asset Management. It does not refer to a software system.


Transmission towers, Berrimah

Asset renewal and retirement

We apply an economic assessment as part of our risk quantification procedure to identify the optimal time to retire or replace assets.
Our framework considers the asset's condition and failure modes, the likely risks of failure on safety, security and reliability of services to customers, and the relative maintenance and capital costs. In some cases, our decision making will be influenced by demand growth or customer upgrade requirements. Essentially, our decision making is based on an economic assessment of risks, costs, and benefits.

Our approach recognises that the criticality and consequence of asset failure varies among different network assets. For this reason, we apply different strategies to our asset classes based on risk profile, capital value and criticality to reliable and safe operation of the network.
The replacement strategies include:

- **Replace on failure (Functional failure) –** This is where the asset has low criticality, and where asset condition information is difficult or costly to gather. In these cases, it is more economical to keep the asset in service provided the maintenance costs do not justify replacement.
- **Condition-based (Conditional failure)–** This is where the function provided by the asset is critical and the cost of risk exceeds the replacement cost. In these cases, we need a clear measure that the asset is not providing the level of service required.
- **Planned (Proactive replacement) –** This is where there are emerging risks such as safety or environmental risks, change in technology, or legislative and compliance changes. In these cases, asset condition may be measurable and can be used to prioritise replacements or spread replacement activity over longer timeframes to eliminate significant spikes in expenditure and associated resources.
- **Demand-driven –** This is where we identify that existing installed capacity is insufficient to supply the forecast demand. This recognises that there may be synergies in the timing of replacement to meet a demand driver.
- **Customer-driven –** This is where the individual customer requests new or increased capacity. Similar to above, this recognises there may be synergies in retiring an existing asset in degraded conditions at the time of an upgrade.

5.4 Methodologies for planning the network

Under our asset management framework, we undertake regular reviews of our network to determine emerging issues and solutions. As we operate standalone transmission and distribution networks in our regulated areas, we have no joint planning requirements or activities.[9]

In 2021, we extended the outlook from five to 10 years for our distribution network. This aligns our transmission and distribution networks, and is a sensible approach given the need for long term planning. We have retained the 10-year planning horizon for both transmission and distribution in this year's TDAPR.

Our planning process seeks to identify system limitations including:

- **Capacity constraints –** On an annual basis, we forecast projected maximum demand for distribution feeders, zone substations, and transmission lines. The demand forecasts reflect recent trends in maximum demand, forecast major connections, and forecast major embedded generation. Our planning process considers if there is likely to be thermal constraints on our equipment, with reference to the network planning criteria.
- **Condition of assets –** Using a risk-based approach, we identify assets that should be replaced, retired, or more intensely maintained. The condition of assets is influenced by age, previous maintenance, environmental conditions such as exposure to salt and humidity, proximity to animals, and extreme weather events.
- **Quality of supply issues –** We monitor power supply issues based on customer feedback, and monitoring data from meters and zone substations. Quality of supply is impacted by a generator tripping or transmission fault, switching of network equipment such as reactive plant, installation and switching of customer loads, and embedded generation such as solar rooftop installations.
- **Fault levels –** We regularly review whether the fault levels remain within our asset's fault level ratings and if the asset ratings comply with those prescribed in the Network Technical Code. Fault levels are impacted by changes in the configuration of the network particularly with the addition of generators, embedded generation, power transformers and large motors.
- **Distribution losses –** We monitor the extent of distribution losses on the network and identify if action is required to minimise losses.

Once a system imitation has been identified, we analyse whether it gives rise to an investment need. The first internal gateway for the creation of a project is the Business Needs Identification (BNI). The purpose of the BNI is to demonstrate the investment need and supporting evidence with reference to the risk to reliability, security or safety of services.

The Preliminary Business Case (PBC) process analyses a range of feasible options to determine the most prudent and efficient investment to meet the need identified in the BNI. We identify and analyse project risks and develop the scope and requirements for the preferred option. Depending on the value of the project, we may also develop a more detailed business case before the project is implemented. This is to ensure sufficient project analysis and development prior to seeking approval to proceed.

We are looking to uplift our demand management capability to better embed consideration of non-network solutions as an efficient means for deferring network investment. This, coupled with better awareness and education on energy efficiency, will play a critical roe in helping to improve customer affordability.

After the completion of the project, we conduct a Post Implementation Review (PIR) to confirm whether the expected benefits have been delivered by the investment to inform continual improvement of the process.

[9] The NT NER requires that a network's TDAPR specify joint planning obligations and activities.

6. Demand Forecasts

Power and Water has a rigorous method to forecast maximum demand on our transmission and sub transmission lines, zone substations and distribution feeders. Our method relies on annual reviews of recent demand data, and projections of new customer connections and embedded generation. At the system level, solar PV is causing minimum demand to occur during the middle of the day and is expected to continue decreasing, while maximum demand is occurring in the evening when solar PV generation is not available.

Demand forecasts are a key part of our planning process, helping us establish whether any element of our network will face a capacity limitation.

Power and Water undertakes an annual review of demand forecasts commencing in April of each year. The timing of the review allows us to incorporate the most recent data on maximum demand which generally peaks in the November to March period. This coincides with the wet season in Darwin-Katherine and summer in Alice Springs and Tennant Creek.

Our demand forecasts are prepared on a locational basis, which are often termed 'spatial' forecasts. We prepare spatial forecasts for individual network elements including our transmission and sub transmission lines, zone substations, modular substations, and distribution feeders. The information is used to determine whether there are capacity constraints emerging on the network.

In summary, our process identifies the underlying trend in demand based on the last six years of historical data, including the most current data. We extrapolate the underlying trend and incorporate the impact of any significant new connections and embedded generation. In sections 6.2 to 6.4 below, we explain the specific approach for forecasting demand on our distribution feeders, zone substations and transmission lines.

In section 6.5 we provide an overview of how network constraints and opportunities are identified, what information is available to customers and where it can be found.

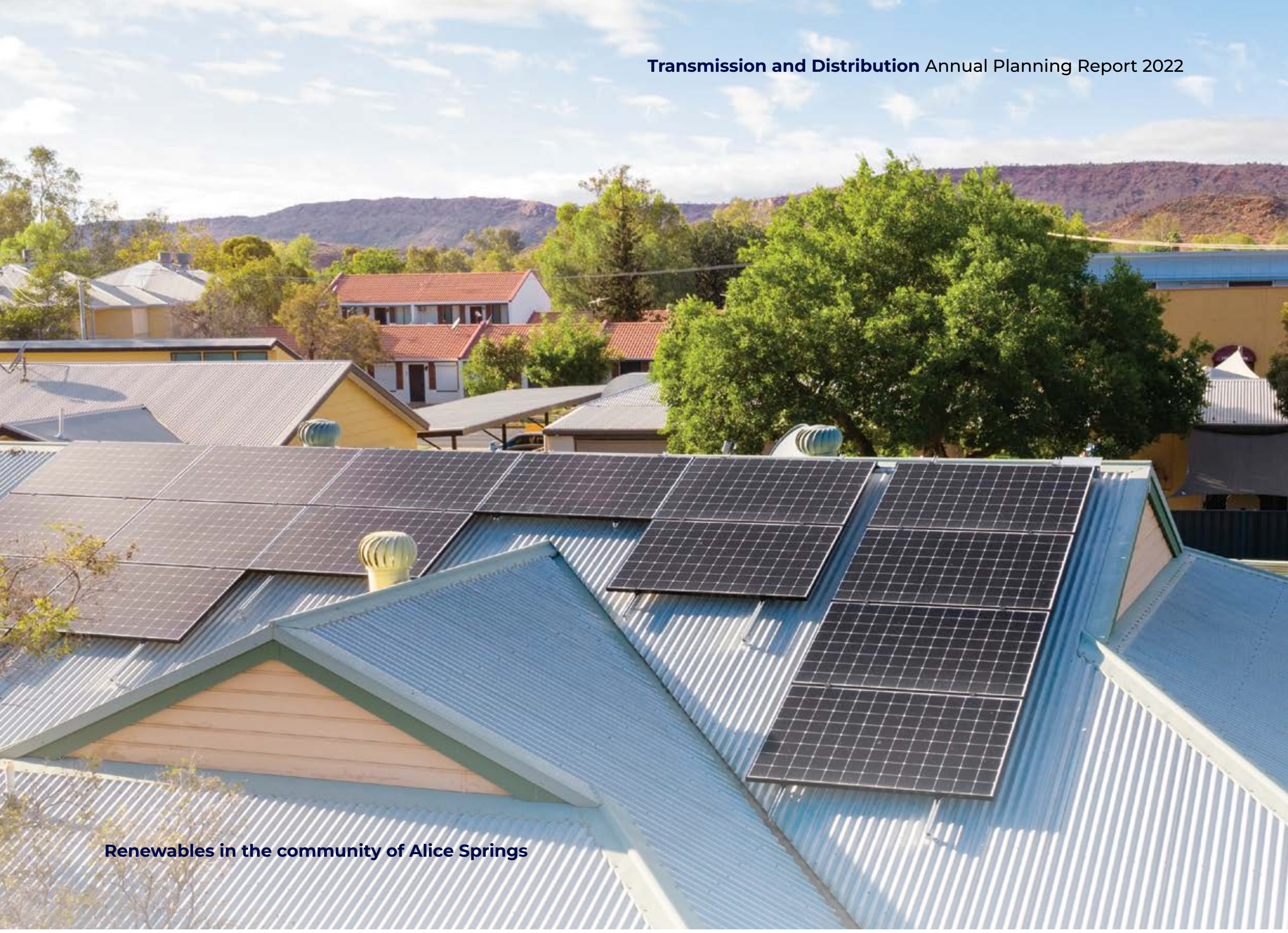
In recent years we have improved our approach to forecasting solar PV, batteries and electric vehicles which are expected to have an increasingly large impact on demand.

During the next year, we plan to make further improvements to align our forecasting methodology between all levels of the network, from HV feeders to zone substations and regions. We will also include the impact of solar PV generation into our weather normalisation approach, improve granularity of our spot load analysis, and add in export forecasts (i.e. generation by residential solar PV that is sent into the network) to improve our ability to target investment for export services.

6.1 Regional outlook

Power and Water has continued to provide a maximum and minimum demand forecast at a regional level for the Darwin-Katherine, Alice Springs, and Tennant Creek networks as shown in **Figures 27** to **32**.

We compared our forecast to the Utilities Commission's Northern Territory Annual Electricity Outlook report. The 2021 outlook report suggests that maximum demand will remain relatively flat on all three networks. This differs with our forecast that shows an increasing demand on all networks. The reason for this difference is that the Utilities Commission does not specifically account for spot loads as they consider they are implicitly included within the population growth forecast. Spot loads are a critical consideration in our forecasts due to the potential for these to significantly impact on our relatively small networks.



Renewables in the community of Alice Springs

In Darwin-Katherine and Alice Springs, the Utilities Commission is forecasting a decline in minimum demand. This is consistent with our forecast and largely relates to increased solar installations which reduce demand in the middle of the day.

In Tennant Creek, the Utilities Commission is forecasting a f at minimum demand, which differs to our forecast of a decreasing minimum demand. The minimum demand is driven by increased generation from solar PV during the middle of the day, to the point where there will be more solar PV generation than demand. This is shown in **Figure 32** as a negative demand.

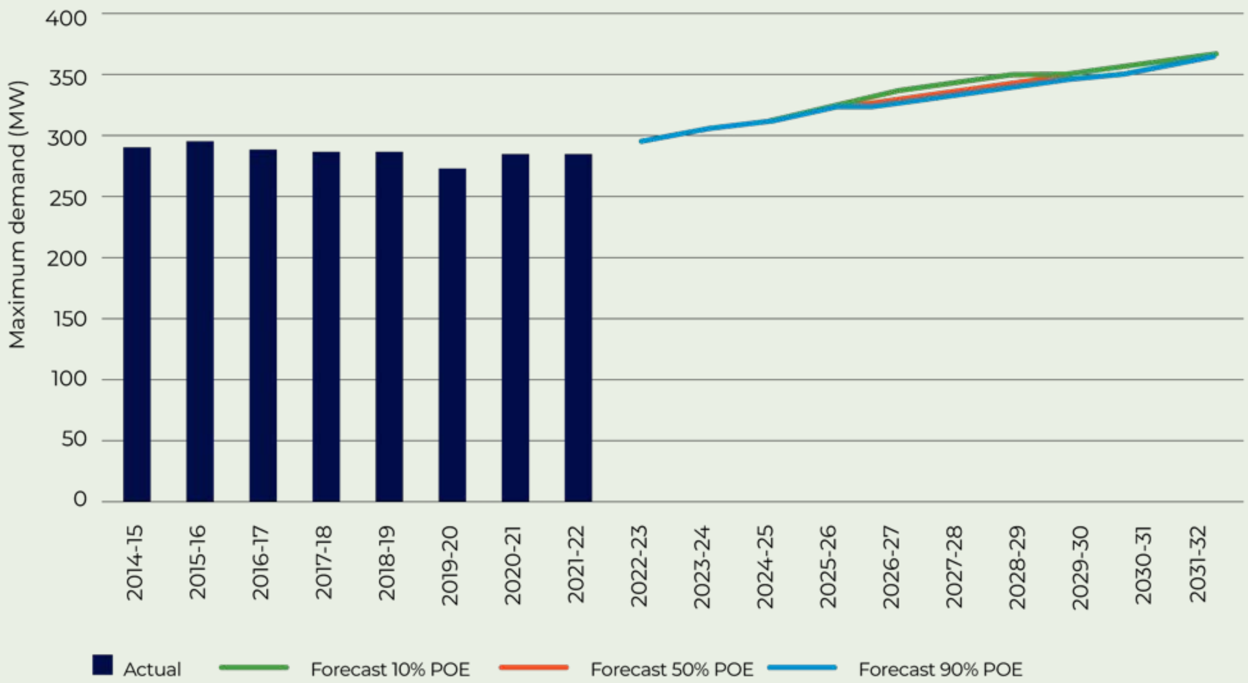
In practice, as minimum demand continues to decrease the voltage should rise in localised areas and cause the inverters of residential solar PV to disconnect to self correct the imbalance.

However, minimum demand could also impact how generators can be operated as generators typically need to be operated above a minimum output threshold. In the worst case, if the demand decreases below the minimum threshold there could be a system black event. Other issues that are likely to be encountered as minimum demand decreases are managing voltage, system strength and inertia (ability to ride through faults and maintain frequency).

To address this scenario, Power and Water has established a Future Network Strategy. This will help to assist in managing periods of minimum demand, particularly through the implementation of our dynamic operating envelopes initiative. The Future Network Strategy is described in further detail in Chapter 3.

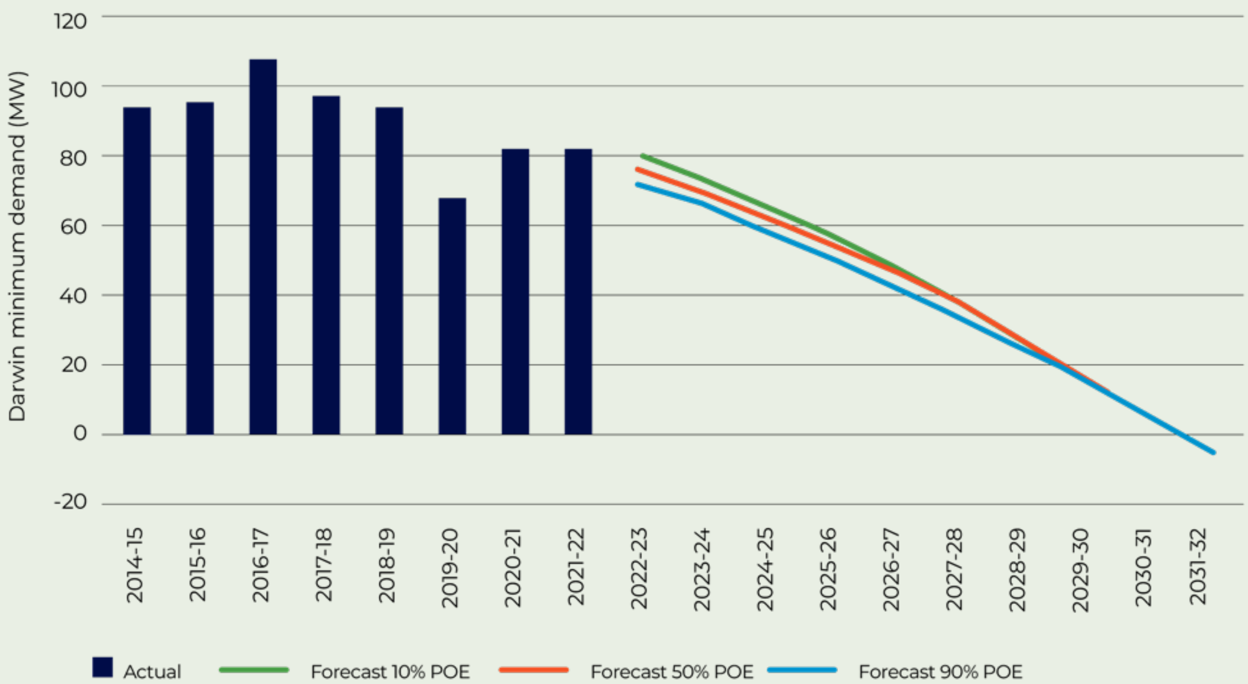
The issue of minimum demand overlaps with the responsibilities of other Market Participants. Power and Water will work closely with Territory Generation and NTEMSO to achieve an effective solution for our customers and maintain appropriate levels of service.

Figure 27 – Darwin-Katherine maximum demand forecasts



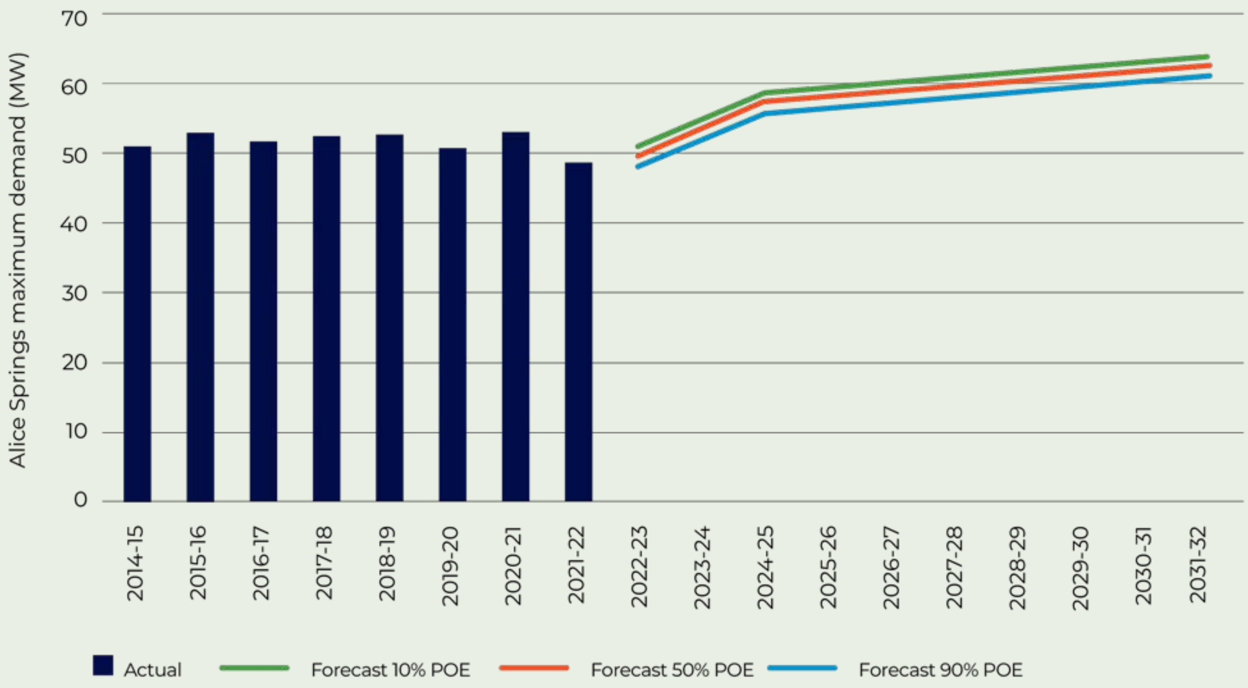
Maximum demand in Darwin-Katherine remained consistent with the previous year, and is forecast to grow by close to 25% over the next decade.

Figure 28 – Darwin-Katherine minimum demand forecasts



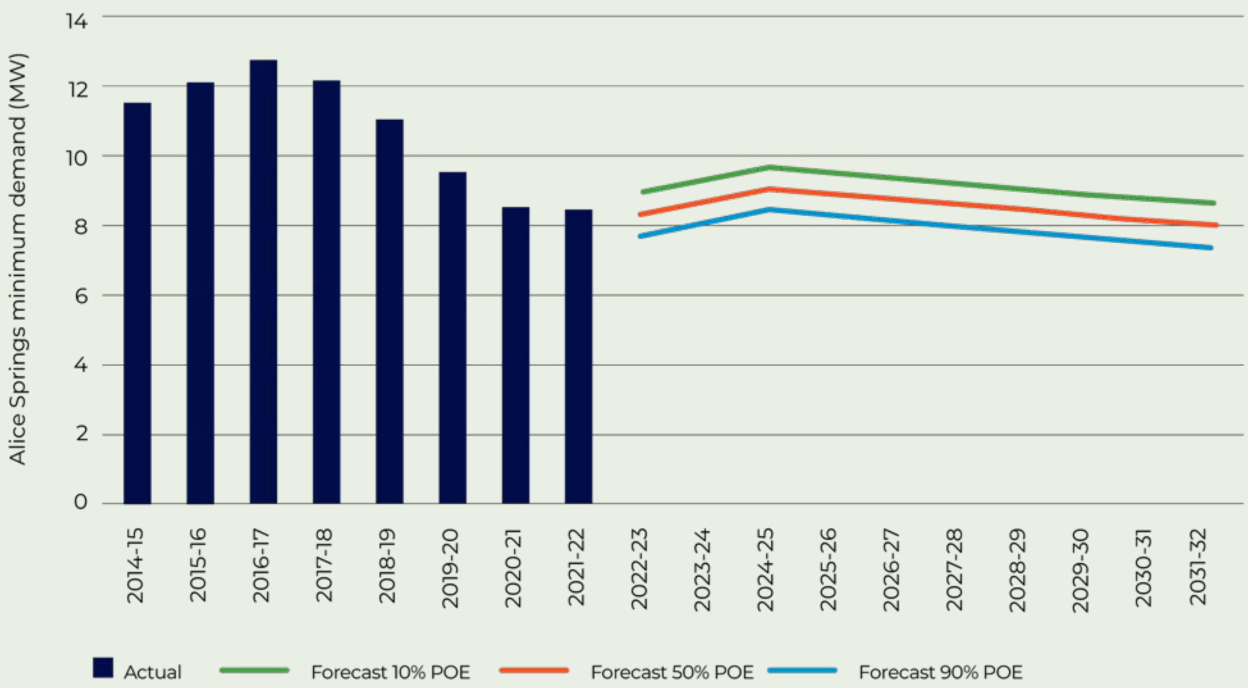
Minimum demand was consistent with last year in Darwin-Katherine, however, as solar installations continue to grow, minimum demand is expected to fall.

Figure 29 – Alice Springs maximum demand forecasts



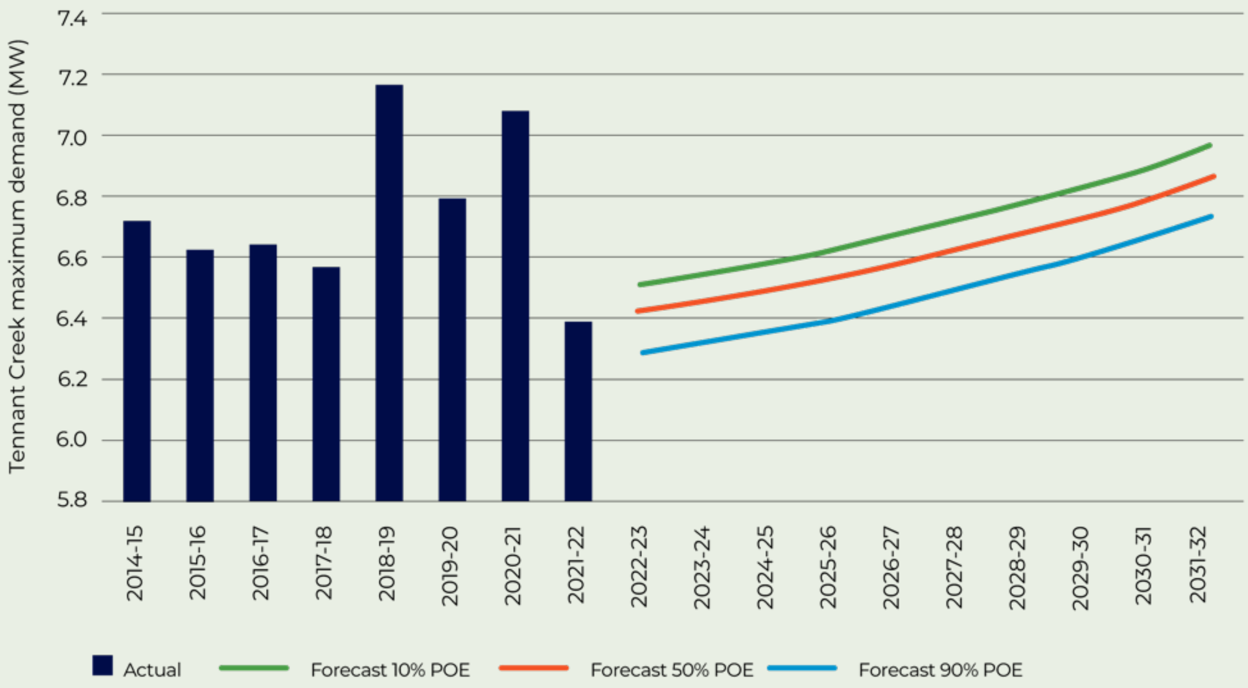
Maximum demand in Alice Springs slightly decreased in 2021-22 but is forecast to increase by approximately 15% over the next decade. The forecast shows a new spot load connecting in 2024-25.

Figure 30 – Alice Springs minimum demand forecasts



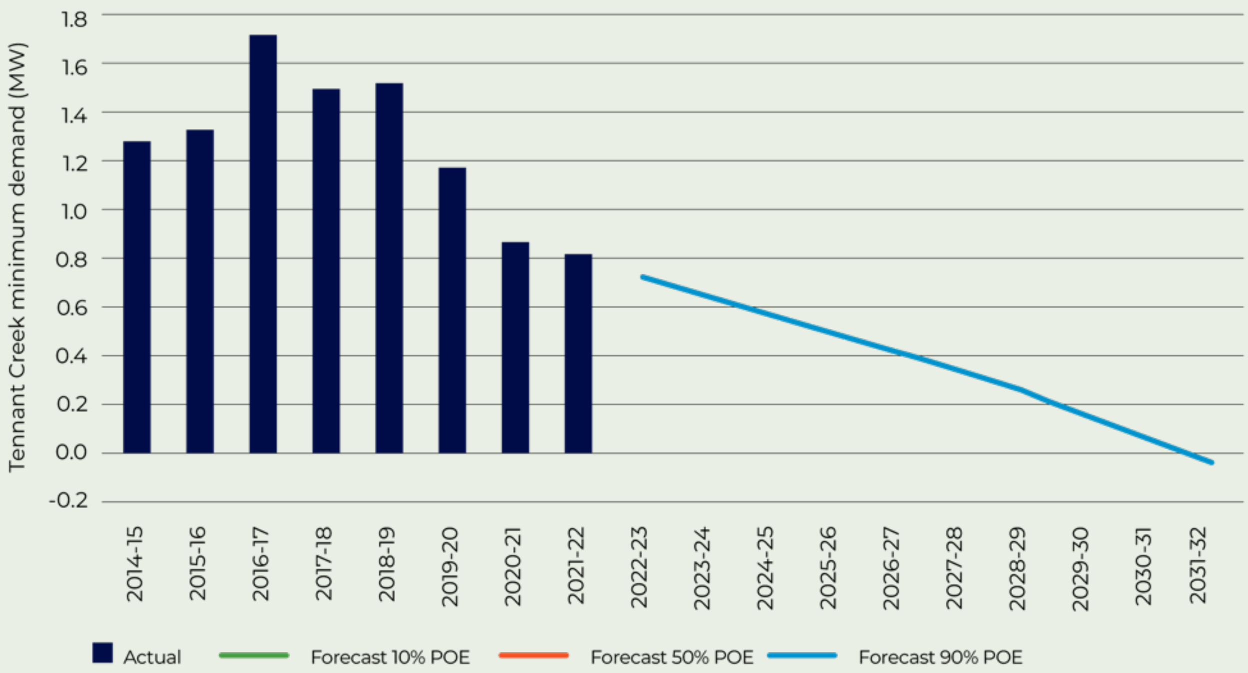
Minimum demand in Alice Springs remained consistent with last year but is expected to decline slightly during the next decade but not as signi icantly as the other two regions.

Figure 31 –Tennant Creek maximum demand forecasts



Maximum demand in Tennant Creek is projected to decrease compared to last year but is projected to increase across the next decade by approximately 7%.

Figure 32 –Tennant Creek minimum demand forecasts



Historical minimum demand in Tennant Creek was revised to correct data errors. The revised profile shows that demand in 2021-22 was similar to last year and that the long term trend is forecasted to decrease to zero in 2031-32.

6.2 Distribution feeders

We forecast maximum demand on each distribution feeder on our network. The first step of the process is to identify the underlying trend in maximum demand growth on the feeder. We examine six years of demand, including the current year, using 30-minute interval SCADA data excluding the impact of new spot loads,[10] embedded generation and temporary transfers. A linear regression is undertaken to determine the underlying trend (rate of growth).

Our next step is to adjust the 'base value' in 2021-22 to incorporate the impact of permanent new connections, embedded generation, and permanent transfers that occurred in that year. The adjusted base value is then extrapolated from 2022-23 to develop a forecast trend for each feeder for the next 10 years. We then add the expected load from committed new connections and subtract the load from expected large scale embedded generation. We also incorporate the impact of permanent load transfers between feeders. In this way, the method reflects the underlying trend in demand, and the expectations of new load and embedded generation.

Our demand forecast has not identified anyfeeders with overloading issues. However, the study only considers the backbone of the feeders and we expect minor overloading issues to occur in some locations due to localised demand. As discussed in Chapter 8, these limitations will be addressed through several approaches including load transfers from adjacent feeders with spare capacity and a dedicated program to address localised overloading.

6.3 Zone substations

Power and Water has 25 zone substations and one modular zone substation[11] that connect to distribution feeders. Zone substations meet the definition of the connection point between our transmission and distribution networks, as defined by the NT NER. Our forecasts for zone substations extend for 10 years, with this year's TDAPR providing a forecast of maximum demand for 2022-23 to 2031-32.

We forecast maximum demand for zone substations using the general approach described for distribution feeders as set out in section 6.2 but with two key differences. Firstly, we use weather to correct the recorded maximum demand to normalise the impact of varying temperature across years. Secondly, we apply a diversity factor to spot loads to account for the different load profiles and time of day where individual peak demand occurs for each spot load.

Our approach to weather correction has been improved to provide a more accurate forecast. The first step in our weather correction process is to record the temperature of the day when maximum demand occurred each year. This is used to establish a relationship between maximum demand and temperature. Using the derived relationship, weather-corrected maximum demand is calculated for each region based on the temperature that has a 50 per cent probability of exceedance (PoE) and 10 per cent PoE for each regional reference weather station.

We identify the linear underlying trend for each zone substation at 10 per cent and 50 per cent PoE using weather-corrected maximum demand for the preceding six years[12] (including the current year). We then include the impact of committed connections and embedded generation.

The actual demand for 2021-22 and forecasts to 2031-32 for each zone substation are set out in Appendix F, together with information on existing capacity under different contingencies. The information identifies the zone substations where a system limitation has occurred under 10 per cent or 50 per cent PoE forecasts.

There is a material difference in our demand forecasts compared to last year, largely driven by our expectation for fewer spot loads in particular areas and a downward revision of the rate of connection growth in existing sub-divisions.

[10] A spot load is a term used to describe large individual customers, typically HV customers and subdivision.

[11] The modular substation is known as the 'Nomad'. It is comprised of a transformer and switchgear in a standalone container that can be easily transported to address constraints as needed. It is currently deployed at the future Wishart zone substation site.

[12] The number of preceding years may need to be adjusted if there is a significant load increase or drop in load during a particular year.

Zone substation, Pine Creek

6.4 Transmission lines

Power and Water has transmission lines in Darwin-Katherine and Alice Springs that transport generation to our zone substations. We forecast demand on transmission lines for a period of 10 years. For this year's TDAPR the forecasts are for 2022-23 to 2031-32.

Our forecast method relies on zone substation and generation connection point forecasts. Our approach is to use the 50 per cent PoE zone substation forecasts described above, with an adjustment for load diversity. We also forecast generation at each of the existing and new connection points to the transmission network, together with any new load or embedded generation connecting to the transmission network.

Similar to zone substations, we are expecting lower demand than forecast in our TDAPR last year. The forecast demand reduction is an outcome of the revised forecasting methodology that has been applied. We are also reporting the 50 per cent PoE demand rather than 10 per cent PoE demand.[13]

In the 2021 TDAPR, we identified the Hudson Creek to Archer sub transmission line was overloaded during a scenario when the Hudson Creek to Palmerston sub transmission line is out of service (and vice versa). This year, due to the lower forecast demand the modelling shows that under the same scenario, the line is loaded to approximately 50 per cent of its capacity in 2026-27. We expect that this loading will continue to increase and will require investment to mitigate the risk to supply.

The scenario above assumes that 100 per cent of the Weddell power station is available. If one of the three generators at Weddell power stations is out of service, then the loading on the transmission line increases to 95 per cent in 2026-27.

Projects to address the system limitations emerging out of the transmission line demand forecasts are discussed in Chapter 8.

The demand forecasts for transmission lines are provided in Appendix D and shows the expected utilisation per year for a 10-year horizon.

We note that results are only provided up to 2026-27 as the 2021 NT Electricity Outlook Report identified the retirement of four generating units at Channel Island Power Station, resulting in a generation shortfall. The shortfall shows the forecast Unserved Energy increasing from less than 0.0001 per cent in 2025-26 up to 0.7 per cent in 2030-31. With insufficient generation available, we are not able to complete our load flow analysis beyond 2026-27.

[13] A 10 per cent PoE means that the demand forecast is expected to be exceeded once in 10 years. A 50 per cent PoE means the demand forecast is expected to be exceeded once in two years. Hence a 10 per cent PoE forecast is higher than a 50 per cent PoE forecast.

6.5 Constraints and opportunities

To assist our current and potential future customers, we identify locations on the network where there are constraints or available capacity under different possible network configurations, such as credible network outages.

We provide this information in spreadsheet format in Appendix F that can be downloaded from our website and also accessed via an interactive Geographical Information System (GIS) based system, the Power and Water Rosetta Data Portal.[14]

The information provided includes:

- A 10-year forecast of maximum demand, asset capacity and identified constraints for:
  - > Each individual zone substation
  - > Each of our 29 transmission lines
- 20 contingency scenarios for our transmission lines in the Darwin-Katherine region and four scenarios in Alice Springs. These scenarios identify the available capacity over a 10-year forecast in the event of a transmission line outage and highlights any constraints. These constraints are then assessed by Power and Water for possible solutions, including potential non-network solutions that can be provided by interested parties.
- A list of distribution feeders that are expected to exceed their capacity within a 10-year forecast period.

This information is integral to Power and Water's planning processes. It helps to ensure that any emerging issues are identified early to allow sufficient time to engage with proponents on our Demand Side Engagement Register on the viability of using non-network solutions to address identified constraints. This can assist in reducing the cost of electricity to customers by identifying lower costs alternatives for addressing the identified network need.

More generally, it can also assist customers in identifying locations that have sufficient capacity for loads or local demand for generators, minimising the cost of connection and benefiting the security of the electricity network.

[14] [Power and Water Corporation - Rosetta Data Portal (powerwater.com.au)]

7. Programs to address asset condition

Replacing our ageing network assets will be the primary driver of capital expenditure over the next decade. A large cohort of our network assets will be over 50 years old by 2025, reaching the end of their technical life. Our asset management planning is directed at keeping these assets in service through targeted maintenance and robust risk management. Our targeted programs will replace assets that pose material reliability, safety or environmental risk. We have also applied age-based modelling to forecast the volume of assets likely to fail in service.

In this section we identify system limitations related to asset condition. When our network assets fail, they can lead to outages, safety incidents, non-compliance and environmental risks.

Over the 10-year planning horizon, we see that more of our assets will be at, or approaching the end of their technical life. In part, this is due to the wave of asset investment in the wake of Cyclone Tracy in 1974. These assets will be approaching 55 years of age by 2030. Given these assets have operated in the harsh NT climate, we expect some assets to reach the end of their serviceable life before 2030.

In developing our forecast of transmission and distribution replacement, we have continued our practice of deferring replacement until absolutely required.

Our targeted projects and programs look to replace assets in poor condition before they fail, based on an assessment of the reliability, safety and environmental risks. As noted in Chapter 5, we have applied a new risk quanti ication tool ahead of our upcoming 2024-29 regulatory proposal to improve the consistency and precision of risk calculations.

We have also developed an age-based model of likely asset failures to 2030, assuming the targeted programs are in place. Our modelling suggests that our networks will continue to age despite our targeted programs, and this will result in considerably more assets failing in service over the 10-year planning horizon.

We will continue to explore options to address asset condition, including non-network alternatives and look forward to stakeholders offering ideas we have not considered.

Overall, we expect to incur materially more capex on our distribution network assets compared to our transmission assets. As seen in **Figure 33**, about 48 per cent of replacement expenditure over the planning period relates to the top five planned material programs and projects, with 21 per cent relating to reactive projects, and 31 per cent on remaining projects.

Based on the AER's categories, we expect that underground cables will be the dominant driver of capex over the next 10 years. This relates to two major replacement programs in Darwin.
We also expect to incur significant capex on our communications and protection assets as we replace obsolescent technology and improve the cyber security of our communications.
Our breakdown of capex by AER replacement category is set out in **Figure 34.**

In the following sections, we set out our replacement capex by AER category including our planned programs and projects, and our forecast of reactive volumes based on our aged-based modelling.

All dollars are presented in real 2022 dollars.
We note that our upcoming regulatory proposal will present projects in real 2024 dollars. Further, the regulatory proposal is only for the 2024-29 regulatory period, while the TDAPR is for the period 2023-32.

Figure 33 – Split of major, reactive and remaining programs

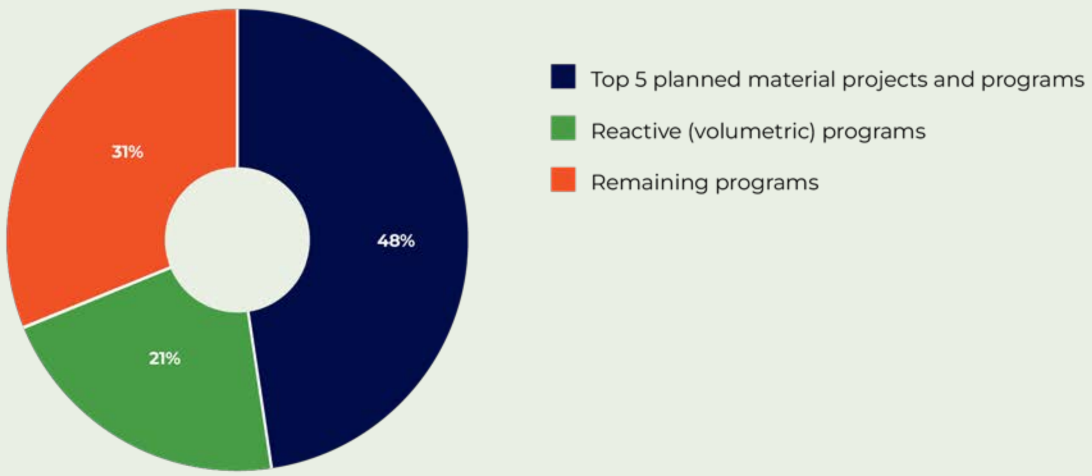
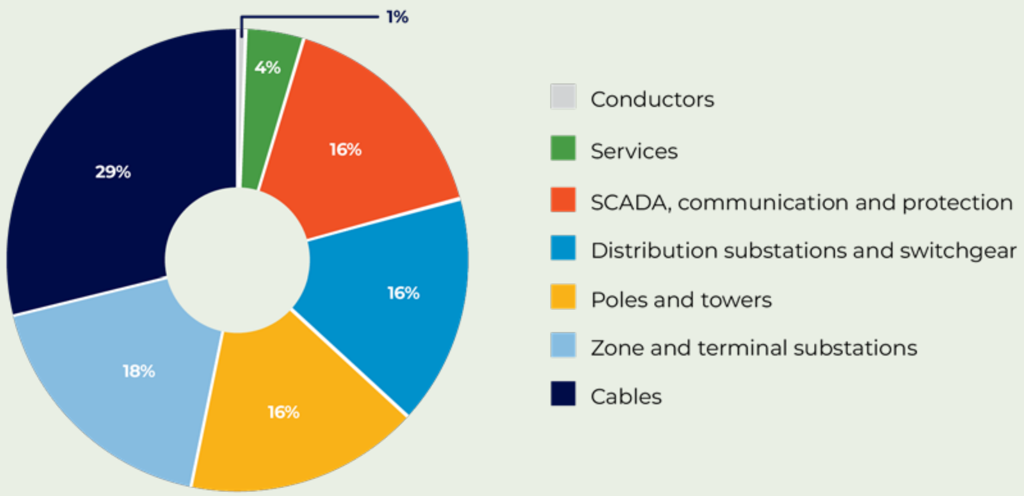


Figure 34 – Breakdown of planned projects and programs by asset class over the next decade



7.1 Transmission towers and poles

Power and Water has about 3,200 transmission towers and 42,000 poles across our regulated network. These assets keep our overhead wires (conductors) at a safe height from the ground to ensure the safety of our community. Due to the harsh environment, Power and Water relies on steel as the primary material in our poles and towers. The dominant cause of failure of steel poles and towers is corrosion due to soil conditions.

Below we have identified asset condition limitations which give rise to a targeted program of more than $5 million across the 10-year planning horizon. We have also identified minor programs and the estimated replacement volume of other poles and towers based on high level modelling.

Alice Springs corroded poles ($21.2 million)

We are currently undertaking a major planned program to rectify corroded pole issues in Alice Springs. Over the 10-year period, we forecast to refurbish 180 poles annually (1,950 poles in total) at a total cost of $21.2 million. The program was identified in last year's TDAPR, but the volume and costs have changed as a result of more detailed business case analysis.

The underlying need relates to corrosion of the pole due to exposure to high salinity and alkalinity. Corrosion causes a loss of thickness in the base of the pole, and this can lead to structural issues with supporting the weight of conductors and transformers (termed 'tip load'). The consequences of pole failure include safety to the community and workers, outages to customers, property damage and the higher costs involved in reactive replacement of the pole.

We assessed five credible options using our risk quantification framework. The least cost option was a targeted replacement program directed at highest risk poles in the population. This is our current approach, which relies on replacing poles within high-risk areas identified through analytics. The schedule of replacement is based on a criticality analysis that augments the risk score determined by the GIS analysis with an assessment of the tip load of each pole.

Importantly, our approach has focused on refurbishment as the preferred method to address the issue, which is a much lower cost than replacing the pole. Prior to 2019, we replaced corroded poles but we have subsequently implemented an innovative new approach that can keep the existing pole in service. This involves re-butting which is a process of removing the bottom section of the pole, welding on a new section and re-installing the pole in the ground. Historical data shows that about 3 per cent of poles cannot be re-butted and require full replacement due to the assets attached to the pole or co-location of other underground utilities.

Unit costs for the program are based on historical costs for refurbishment or replacement, with an additional allowance for more complex poles that we expect to encounter moving forward.

Transmission line pole top corrosion program ($4.1 million)

We currently have a program to replace insulators and cross arms on transmission towers in our Darwin-Katherine transmission network. This program was identified in last year's TDAPR but the volumes and costs have been more precisely estimated. The project will be ongoing over the next decade and beyond.

Our transmission towers are subject to extreme tropical weather and some are located in inter-tide mangrove areas. This has resulted in corrosion on the insulators and cross arms of the towers, commonly termed the 'pole-top' components. Similar to Alice Springs, this approach extends the asset life of the transmission tower by addressing components that have failed rather than replacing the tower.

Our analysis shows that the underlying cause for corrosion in insulators is due to current leaking through the insulators where they connect with conductors (the "hot" end), particularly when wet. The corrosion of the insulator leads to mechanical failure of the insulator strings due to compromised strength and potential for flashover (sparks that damage the asset). For cross arms, we consider that the use of an ungalvanized hollow box section steel creates a humid 'micro-environment' which exacerbates corrosion. Corroded cross arms can lead to mechanical failure with the potential for the live conductor to fall to the ground.

Rusted poles, Alice Springs

Our analysis identified three key risks with pole-top failures. The key risk is safety of our staff who may be impacted by the structure or elements falling while inspection or maintenance is undertaken. While the towers on the Darwin-Katherine transmission line are located in more regional areas, there is also a safety risk to the public. Finally, there are reliability risks from the failure of the asset given that transmission lines supply power to all the zone substations.

We identified three options to address the issue including run to failure, inspection and replacement of defect items, and a targeted proactive replacement **program**. The targeted program was considered the option that was least cost given the quantified risks with the 'run to failure' option, and the high operating costs entailed in inspections. This is consistent with our current approach where we identify the insulators and cross-arms at most risk based on analysis that takes into account recent data, structure age, and criticality of assets for reliability. The program has a total cost of approximately $4.1 million to replace 610 insulators and cross arms.

Several learnings from the current program have been considered in our approach to undertaking replacement of pole-tops. This includes that 'live line' work is more expensive, using polymer rather than porcelain insulators results in a lower lifecycle cost, and using galvanised steel to replace bare cross arms is a better design option.

Darwin transmission – earthing program ($1.1 million)

We have a program to address earthing issues with our transmission towers. Earthing mitigates voltage issues when lightning hits a transmission line. Our analysis suggests the earthing is not performing due to physical damage and corrosion.

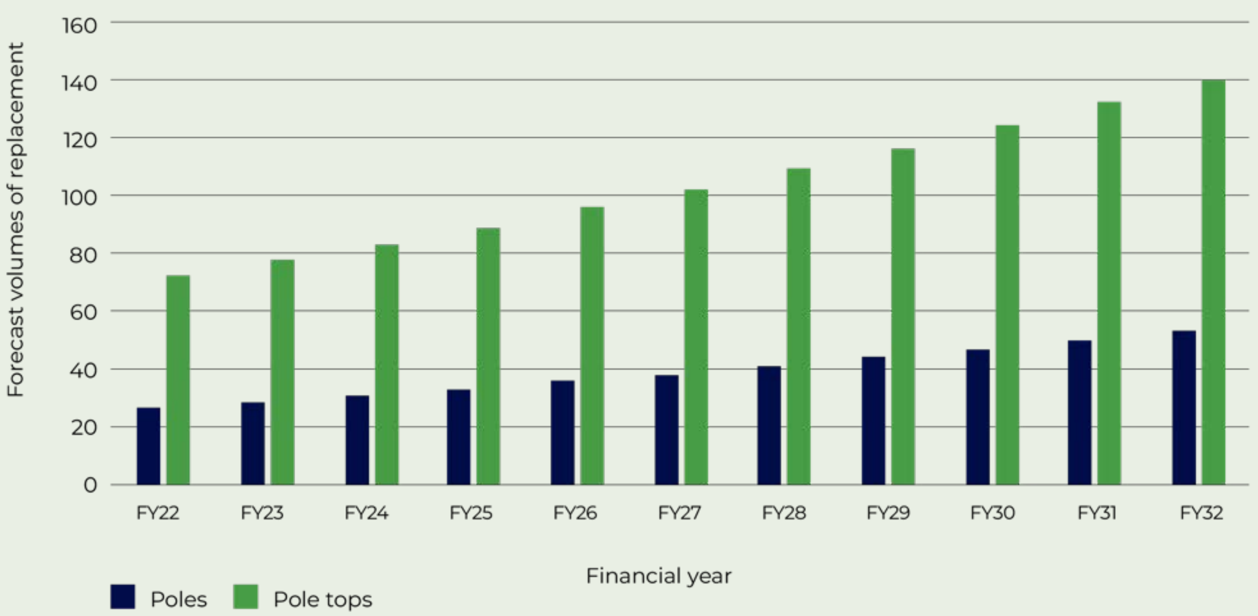
Inadequate earthing creates a safety risk for our staff working near the asset, and for the public located close to the asset. Further, the assets are crucial for the security of the network.

Our options analysis identifies refurbishing the tower earthing components as the least cost option. The project will end in 2024.

Reactive replacement volumes

Our volumetric modelling forecast excludes the population of poles that are already included in the planned programs identified above. Our forecast is $2.92 million for poles and $3.62 million on pole tops. The forecast quantities for poles and pole tops are set out in **Figure 35.** Due to the ageing of assets, the model predicts increasing replacement volumes for each category.

Figure 35 – Forecast volume of pole replacements (excluding targeted programs)



7.2 Conductors

Conductors are the wiring infrastructure that transports electricity above ground through poles and transmission towers. We have about 5,100 kilometres of overhead conductors comprised of about 700 kilometres of transmission lines (132kV and 66kV), 3400 kilometres of high voltage distribution feeders and 1200 kilometres of low voltage conductors.

Below we have identified asset condition limitations which give rise to a targeted program of over $5 million. We have also identified minor targeted programs, and estimated replacement volumes of other conductors using high level modelling. We generally replace portions of conductors.

We note that in last year's TDAPR we forecast a small gauge replacement project, predominately in Tennant Creek. Further investigation found that we had insufficient data to conclude that there is an issue with these conductors. We are now undertaking a data gathering and analysis program to improve our knowledge of these assets and determine if this project is required. The program has been excluded from our forecast in the 10-year horizon pending improved information.

Darwin – Cockatoo conductor replacement program ($7.6 million (Previously Lake Bennett feeder replacement

We are currently undertaking a program to replace the Cockatoo type 22kV conductors in the Lake Bennett and Manton Dam rural area to the south of Darwin, consistent with our 2019-24 regulatory proposal. The project was included in last year's TDAPR as the Lake Bennett feeder replacement, but has been re-examined and expanded to include all Cockatoo type conductors in the area based on updated business case analysis. The project is expected to continue over the 10-year planning horizon.

Due to implementation issues, we will only complete 27 kilometres of the expected 40-kilometre section of the feeder by the end of the current 2019-24 regulatory period. Our forecasts for the 2024-29 period include replacement of the residual 13 kilometres of the Lake Bennett feeder together with the replacement of 18 kilometres of a feeder around the Manton zone substation, where the same type of Cockatoo conductor is installed and has similar condition and operating risks.

The need for replacement arises from three issues. Firstly, the type of conductor is an imperial gauge "Cockatoo" type, which gives rise to complex challenges. The conductor is showing condition issues such as broken strands and conductor damage due to burning and are difficult to repair due to the weight, gauge, high stringing tension and equipment required. This has led to deteriorating and relatively poor reliability outcomes for customers in the area, given the radial nature of the line where there is no alternative source of supply when the conductor fails in service. Secondly, the Lake Bennett feeder fails to meet compliance standards for clearance to ground. Thirdly, the bat protection we use on the conductor is deteriorating due to extreme weather, leading to corrosion and risk of the conductor breaking and falling to the ground.

Our analysis quantifies the risks with retaining the Cockatoo conductors in the Lake Bennett and Manton zone substation areas. There are compliance and safety risks with not addressing the mandated clearance issues. This is hard to mitigate given that approximately 65 per cent of the conductor spans over road crossings are non-compliant. Further, we expect reliability to further decline for customers connected to the feeders. Our quantification analysis indicates that reliability is the most material of risks, followed by compliance penalties.

We examined three credible options to address the risks. This included replace on failure, install mid-span poles and install new feeder sequentially, and a complete line re-build. The analysis indicated that installing mid-span poles and re-conductoring was the least cost option to address the needs. The run to failure option resulted in high risks that would continue to grow over time. A complete line re-build had much higher costs to reduce the risks compared to mid span poles and re-conductoring.

The scope of the least cost option is to replace 31 kilometres of Cockatoo conductors in the first three years of the 2024-29 regulatory period, along with the installation of 182 mid span poles and 219 pole tops.

Strangways to Mary River ($5.5 million)

This is a major committed project that will commence in FY23 and be completed by FY26. The project seeks to increase clearance of the 66kV transmission line between Strangways and Humpty Doo to the east of Darwin. The project was in last year's TDAPR but was named "Darwin – 66kV transmission clearance project".

The need for the project arises from two issues. The primary issue is that many of the 118 spans that comprise the length of the 22-kilometre conductor. do not meet clearance requirements introduced retrospectively in 2010. To address these risks, we had been operating the line at a lower capacity of 7MW, which means less spans are non-compliant. Nevertheless, the radial line connects to three zone substations along the Arnhem Highway, and provides a degree of continued risk.

The second issue is higher demand in the Humpty Doo area, which now requires us to operate at a higher capacity, resulting in much higher levels of non-compliance

Our business case assessment considered that a prudent solution to address the two issues was to undertake immediate works on 48 of the highest risk spans with very low clearance over the road, dirt road crossings and ground. The total forecast capex was estimated at $4.7 million, with $3.23 million expected to be incurred in the first year of the 2024-29 regulatory period.

Clearance compliance programs ($3.5 million

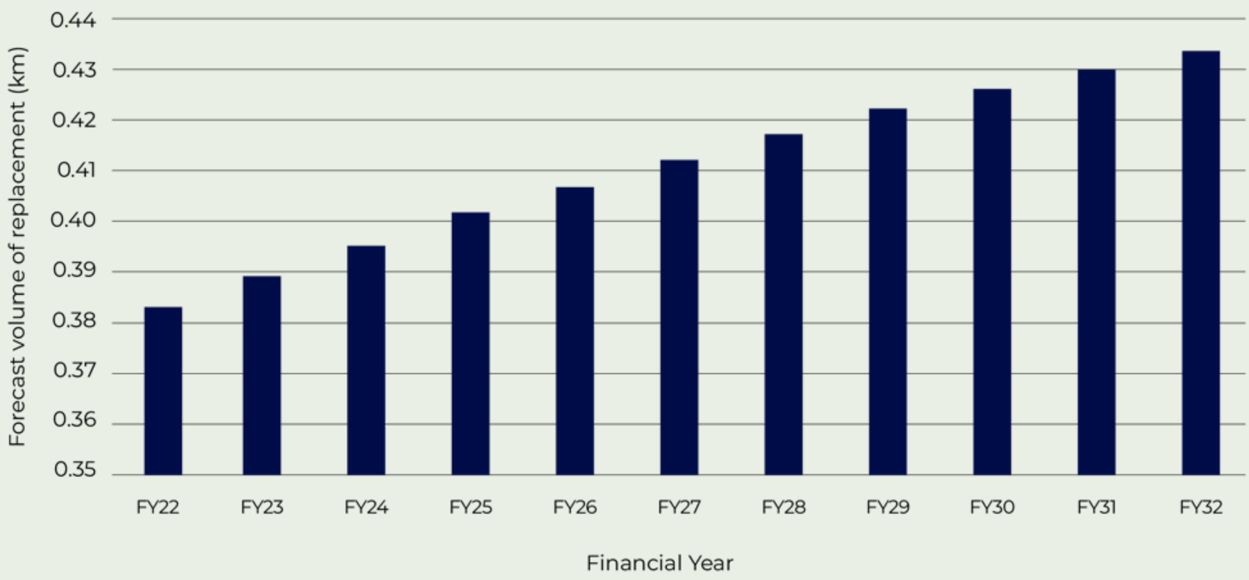
We have also forecast an additional $3.5 million to address compliance issues with clearance height on conductors, based on historical trend data.

In addition to our targeted program, our aged based modelling suggests that we will need to replace significantly more kilometres of conductors over the next 10 years, as seen in **Figure 36**. This is due to the ageing of conductors with a significant proportion older than their technical life by 2031-32.

Reactive replacement volumes

Our volumetric modelling forecasts excluded the population of conductors related to the Lake Bennett and Manton conductor program and the Strangways to Mary River conductor replacement programs. We are forecasting a steady rate of reactive replacement of conductors, which is relatively low in value. We note that the replacement is based on the impacted span as measured in metres, rather than replacement of the whole length of conductor. This is a very small fraction of the conductor population.

Figure 36 - Forecast volume of conductor replacements (km, excluding targeted programs)



Transmission lines, Wishart

7.3 Service lines

Service lines are wiring infrastructure that connect to a customer's premises. We have about 57,000 service lines, including 24,000 conductors (above ground) and 33,000 cables (underground).

We forecast capex of about $8.7 million due to a new planned program in Darwin which is comprised of $8.6 million. The residual forecast capex is for our volumetric forecasts of service line replacement of $0.1 million. This is discussed further below.

Service lines planned program ($13.1 million

Previously, Power and Water has only replaced service lines when they fail in service, particularly after tropical storms or cyclones. Until recently, our maintenance strategies did not include inspection of services so there was limited data on the condition of service lines. However, two recent safety incidents involving condition issues with our overhead service lines, including a fatality in our unregulated region, has prompted a change in our asset management approach for service lines.

Following the fatality in 2020, NT WorkSafe instructed Power and Water to initiate an inspection program, including in our regulated networks, and to undertake a review of maintenance strategies. Our initial inspection program subsequently found a significant number of defects on overhead service lines in our regulated region which has necessitated a revision to our maintenance strategies, including an ongoing cyclic inspection program.

The inspection program has identified several condition issues with overhead service lines. We found that the insulation for the service conductor has deteriorated in many of our service lines due to prolonged exposure to UV radiation (sunlight) and moisture ingress, leading to direct exposure of the wiring. We also found that a high proportion (about 25 per cent) of service lines were close to vegetation creating a risk that impact by the vegetation could result in live conductors falling to ground or touching a conductive surface. Additionally, we found instances of failure in the service clamp that attaches the wiring to the pole that could lead to the apparatus becoming energised and being touched by our workforce or public.

The overriding risk from these condition issues relate to worker and public safety due to the proximity of service lines to people and the way in which they fail. The quantified risk of reliability associated with the failure of service lines is relatively low, as the failure only impacts the individual house rather than the street or suburb.

Our options analysis examined two credible options. The 'run to failure' option is consistent with our historical approach to managing service lines where we only replace service lines on failure, which has generally been during storms and cyclones. The second option was targeted replacement where we identify defects during a cyclic inspection and proactively schedule replacement. This includes addressing the backlog of defects from our current inspection program. The second option was the least cost due to the higher quantified safety risks under the run to failure option.

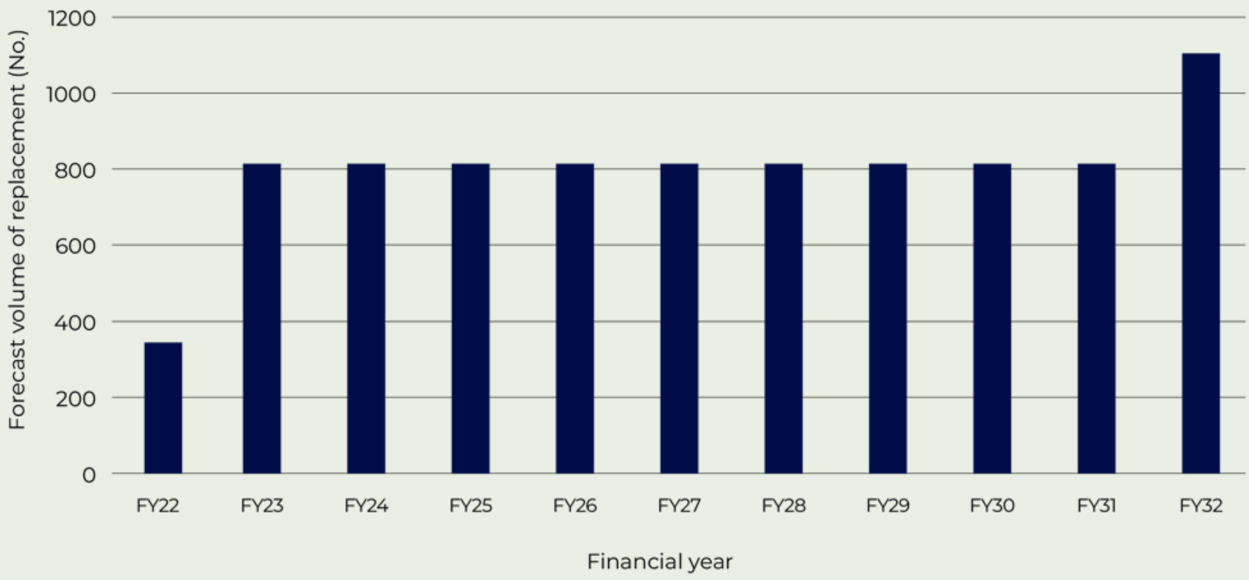
The proposed scope of the project in the 2024-29 period is to replace 4,000 service lines (800 a year) at an average cost of $2,000 based on previous expenditure data. The forecast level of service lines has been based on defect data established in the 1000 inspections to date.

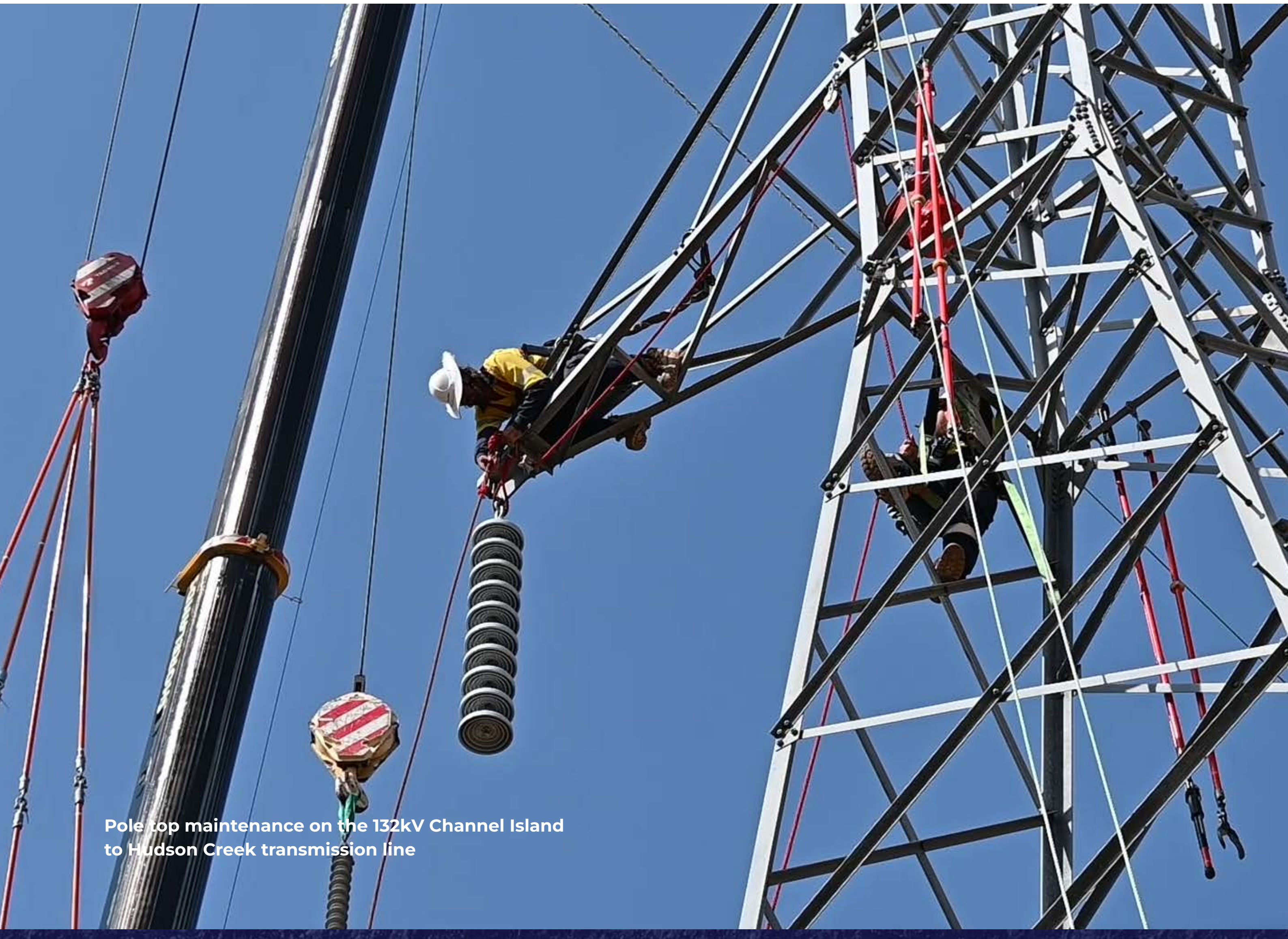
Reactive replacement volumes

Reactive replacement volumes are forecast using the volumetric model which is adjusted to exclude the targeted replacement program for overhead service lines and takes into account underground services. It uses historical failures and the asset age profile to predict a very low level of replacement of $0.1 million for reactive replacement of overhead and underground service lines.

Figure 37 shows the quantities of service lines forecast for the 2024-29 period.

Figure 37 – Forecast volumes of service lines replacement





Pole top maintenance on the 132kV Channel Island to Hudson Creek transmission line

Pole top transformer, Darwin

7.4 Cables

Underground cables are wiring infrastructure constructed below ground often through ducts or tunnels. We have about 1,640 kilometres of underground cable, comprising of about 40 kilometres of transmission, 890 kilometres of high voltage distribution cables, and 710 kilometres of low voltage cable.

Below we have identified asset condition limitations which give rise to a targeted program of over $5 million in the 10-year planning horizon. We have also identified minor programs, and the estimated replacement volume of other cables based on high level modelling.

Similar to conductors, we generally replace segments of underground cables.

Darwin Northern Suburbs High voltage cable replacement ($51.4 million

In the 2019-24 period, we have been progressively replacing high voltage cable in the Darwin northern suburbs with about 25 kilometres undertaken by the end of the period. We are forecasting to replace an additional 37.5 kilometres in the 2024-29 period.

The underlying need for the project is the condition of cables installed in the area. About 146 kilometres of XLPE type cable was installed in the late 1970s and early 1980s. The XLPE cables installed at the time have undergone a degradation process that leads to water ingress, resulting in accelerated corrosion of the neutral/earthing screens when exposed to moisture and electrical stress. A compounding factor is that the cables installed in the northern suburbs have an aluminium screen which oxidises in the presence of water, causing the screen to turn into a powder and become electrically discontinuous (open circuit). The oxidisation process also increases the volume of the aluminium, causing the cable to swell and deform, and is a likely factor in the insulation failures. Together these issues increase the risk of cable failure and impaired operation of the earthing system.

We have extensive condition data and outage data to show that a large proportion of the assets are at the end of their serviceable life. By using population sampling statistical methods, we have determined that between 54 per cent and 79 per cent of the cable is very highly likely (95 per cent confidence) to have reached the end of its serviceable life. This is likely to grow over time.

The risk analysis shows that reliability is the dominant quantified risk. While the northern suburbs cables account for only 16 per cent of the cable fleet, they contribute an average of 47 per cent of the cable outages as measured by SAIDI and SAIFI. This risk will grow over time as the probability of failures rise. While the consequences of health impacts are significant, the probability of them materialising is very low and we have no historical data to use, so we have relied on probabilities suggested by Ofgem as documented in our Risk Quantification Procedure.

Our options analysis shows that a reactive run to failure model results in deteriorating network performance and increasing safety risk to both the public and workers. Further there is a higher cost of reactive replacement. The preferred option is consistent with our current approach to target cable replacement where we use testing results and criticality based on demand and proximity to the public to identify the highest risk cables.

As part of our options analysis, we considered the optimal timeline to replace the cables from 1 year to 20-years. The analysis demonstrates that a 16-year replacement is optimal. On that basis, we have identified that we should undertake about 7.5 kilometres of cable replacement each year. The unit rate has been derived based on recent cable projects undertaken under the new contracting arrangement in the Northern Suburbs.

Underground cables are wiring infrastructure constructed below ground often through ducts or tunnels.

Cullen Bay to Bayview ($6.7 million)
We currently have a program to replace low voltage cables in the Cullen Bay and Bayview areas of Darwin. By the end of the 2019-24 period, we will have undertaken 4 kilometres of replacement. We are forecasting a further 8.8 kilometres of cable replacement in the 2024-29 period.

The cables were initially installed in the 1990s when the suburbs were first developed. Poor installation techniques have led to water ingress in the cables. The water is reacting with compounds in the cable insulation leading to calcium adipate that damages the cable insulation. Calcium adipate also expands cable joints and lugs (connects the cable to the terminal) and eventually leads to failure of the cable. Calcium adipate is also conductive when wet, elevating the risk of electric shock to field crews. In addition, the neutral earthing system in Cullen Bay is inadequate and elevates risk to field crews through potential rises when disconnecting neutral cables to work on the assets. This is compounded by the high soil resistivity that results in poor earthing performance.

The key risks arising from the condition issues include worker and public safety risks particularly arising from the inadequate neutral earthing system, but also from the risk of conductivity due to calcium adipate. While reliability issues have not been material to date, the continued degradation in the condition of the cables gives rise to increasing risk of cable failure. Further, when an unplanned outage arises, it could lead to extended outages for customers due to the difficulty in locating the fault from widespread degraded insultation.

Our options assessment examined three options, of which only two were feasible. This included run to failure, and a targeted proactive replacement and refurbishment. The latter option is the current approach. Our options analysis confirmed that proactive replacement is the least cost approach to addressing the risks with the cables. The run to failure option has higher costs due to the complexity in identifying the location of the fault, the difficulty of accessing the fault due to footpaths and other underground services (which have been directly buried), together with the high risks of keeping the assets in service.

Under the recommended proactive replacement option, we would prioritise cable replacement based on evidence of condition. The approach also lowers the present cost of the program by performing the replacement over many years, rather than a single year. The option also presents an opportunity to outsource the works to a contractor, improving the deliverability of the capex program.

East Arm – Replacement of feeder
In last year's TDAPR we identified the need to replace an underground cable that runs from Berrimah zone substation to East Arm. While the cable is younger than its expected life, the original installation of cable and joints was poor, which has led to severe insulation issues. The cable has a high cost of repair together with increased fault restoration time. Our risk analysis demonstrates that replacement of the cable is the most prudent and efficient option.

Further analysis has demonstrated that all the outages were occurring in the first half of the cable (between Berrimah ZSS and the railway line) and currently there is no indication of poor condition of the second half. We suspect that different installation methods may have contributed to the difference in condition and performance. We will continue to monitor and test the second half of the cable but there are no longer plans to replace it within the TDAPR's forecast horizon.

The replacement of the first half will be aligned with government road works along Berrimah Road. By doing this, the government will contribute to the civil works required to relocate and replace the cable, reducing the cost to Power and Water and our customers.

Due to the reduced scope and contribution from government, the project timing and cost is significantly lower than forecast in last year's TDAPR.

Darwin CBD cable tunnel ($0.9 million
The Darwin CBD is supplied by cables which are installed in underground tunnels. The tunnels are typically more than 30 years old and built of reinforced concrete. The need for the project arises from the condition of the tunnels. The issues include cracks that allow water to flow through the tunnel causing flooding, attracting snakes, rats and breeding insects. While there are sump pumps in place these are failing from blockages and over-use. The tunnel structure is also damaged from tree roots and modifications to install more cables. Finally, there is notable obstruction in the tunnels from unorthodox installation of cables in the past.

There are risks to our workers from the current condition of the tunnels including the risk of injury due to debris that is hidden under water when field crews are working underground, danger from snakes and other animals that may be attracted to the water and shelter, and obstruction of exit routes due to poor installation practices.

Our options assessment shows that there are material risks of doing nothing. The preferred option is to remediate and refurbish the tunnels including sealing the joints between prefab panels to prevent water ingress and tree roots entering the tunnel, replacement of sump pumps and refurbishing drainage systems, and refurbishment of cable racks.

We forecast the costs of undertaking the works at $0.9 million in the 2024-29 period.

Darwin to Frances Bay 66kV Transmission cable ($4.7 million)

The Darwin to Frances Bay cable is part of the sub transmission system connecting zone substations and is therefore critical to the security of the network.

Testing has identified that there is a minor partial discharge which indicates that the insulation has deteriorated slightly. The deteriorated section is planned to be addressed through minor repair works and the cables is expected to remain serviceable until FY30. Testing will be undertaken periodically to monitor the condition of the cable.

While only 0.75 kilometres in length, it has high costs due to its location in an urban setting. The need arises in 2030, so we have not progressed our options analysis.

Casuarina to Leanyer ($9 million)

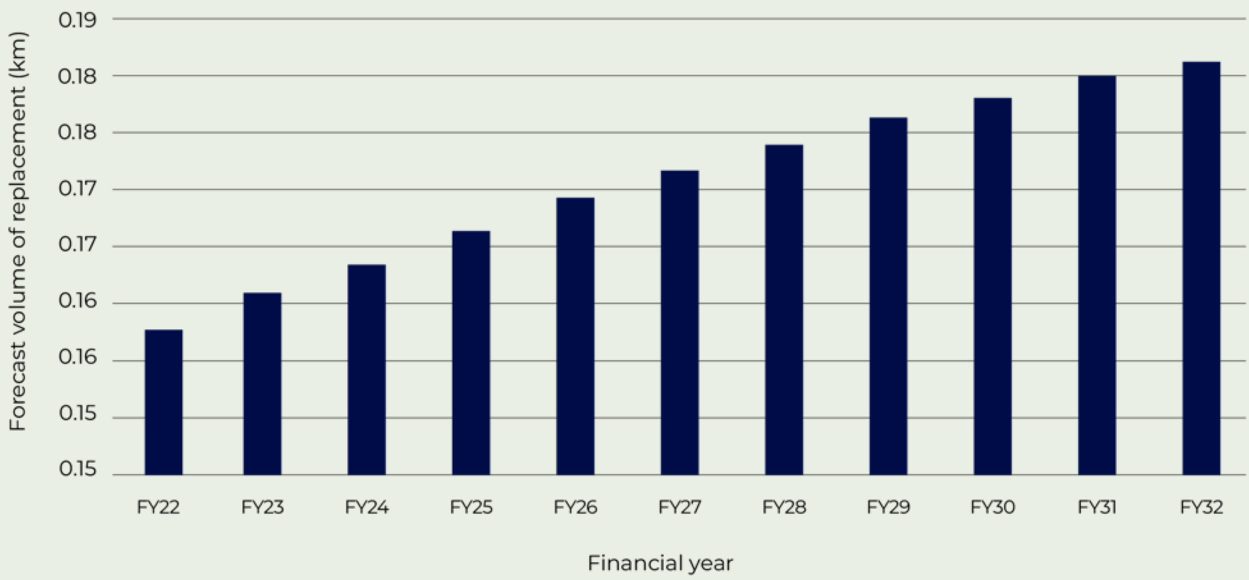
The Casuarina to Leanyer cable is part of the sub transmission system connecting zone substations and is therefore critical to the security of the network.

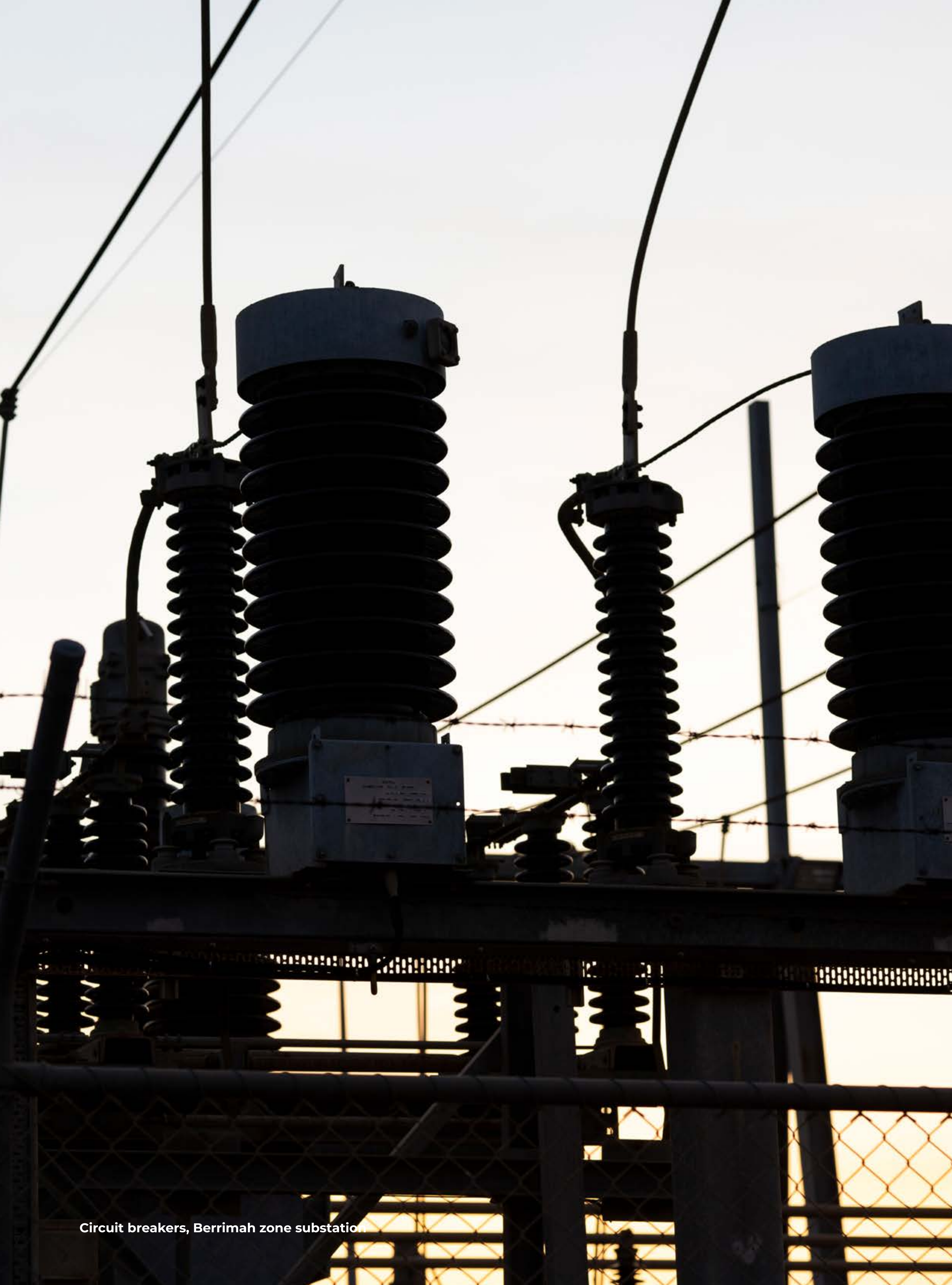
The cable was installed in 1982 so is now 40 years old and will be approaching the end of its expected technical life in 2030. While test results show it is currently in good condition, we will continue to monitor it through periodic testing and expect it will require replacement around 2032. We note that it will only be replaced on a condition and risk basis.

Reactive replacement volumes

Our volumetric modelling forecasts exclude the population of assets related to the cable replacements in Darwin's northern suburbs and in Cullen Bay and Bayview. The results show that cable refurbishment will increase over the 2024-29 period, consistent with the incremental ageing of the population. **Figure 38** identifies the quantities of replacement by metres, noting that the usual practice is to patch the fault which only requires replacement of 10 metres of cable on average. This is a very small fraction of the cable population.

Figure 38 – Forecast volume of cable replacement (km, excluding targeted replacement)





Circuit breakers, Berrimah zone substation

7.5 Transformers

Transformers step-down voltage as energy flows from large scale generators through our network. Electricity is transported over long distances at high voltages (132kV or 66kV on our network) as it reduces the electrical losses and makes the network more efficient. However, our customers require energy at lower voltages to safely meet their needs, so the voltage is progressively stepped down using transformers.

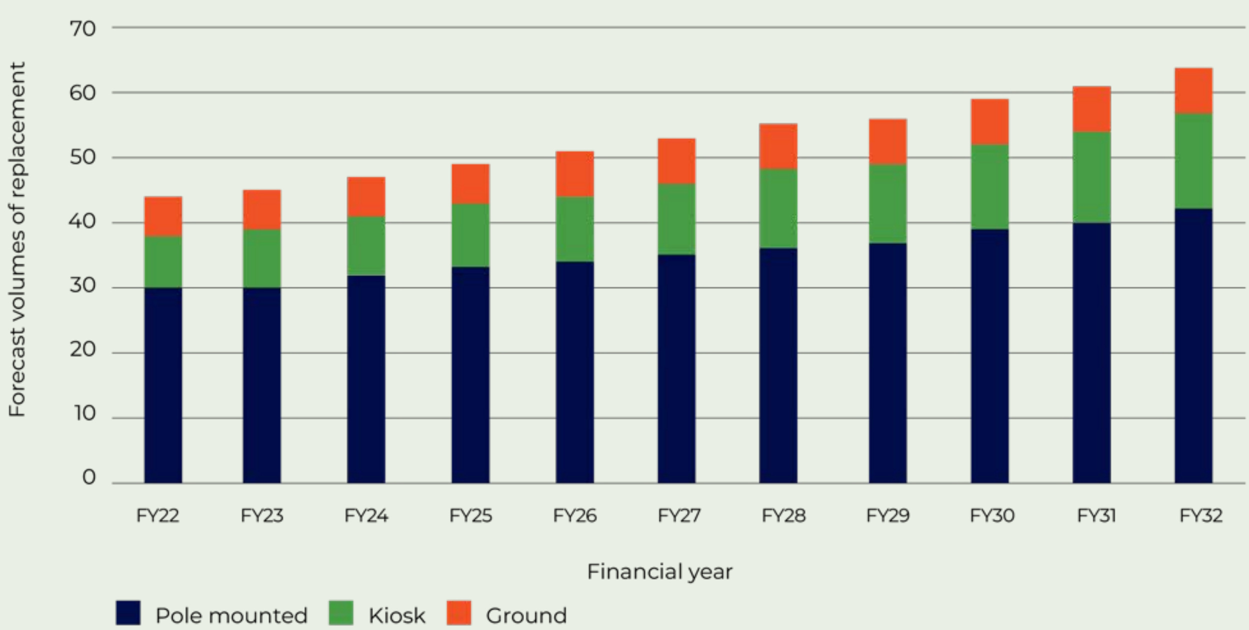
The first voltage transformation occurs at our zone substations where energy is transformed from 132kV or 66kV from our transmission network to either 22kV or 11kV which is used on the distribution network. Zone substations are secure compounds with a significant amount of assets inside. Distribution transformers that you can see attached to poles or in enclosers on the ground then convert the voltage from 22kV or 11kV to low voltage which is supplied to customers.

In total we have **five** sub-transmission substations, 25 zone substations, one modular zone substation, and 4898 distribution substations. The volume of replacement for each asset type is provided below in **Figure 39.**

Since 2008, we have been progressively addressing condition issues with our zone substations in the aftermath of the zone substation failure in Casuarina.

We are forecasting $30.4 million on replacing transformers in the 2024-29 period. The majority relates to a major committed project to replace the existing Berrimah zone substation ($18.6 million). There are no other planned programs. Our volumetric model predicts that we will need to incur an additional $11.8 million on replacing distribution transformers. These programs are discussed below.

Figure 39 – Forecast volume of distribution substations (excluding targeted replacement)



Berrimah zone substation ($28.4 million)

The Berrimah zone substation was a material project assessed by the AER in our 2019-24 proposal, with the project expected to commence early in the 2019-24 period. However, the project has only substantially commenced in FY23 with a cost of $1.2 million incurred to date. There is about $9.7 million of expenditure committed for the last year of the 2019-24 period. We are forecasting that the remaining capex of $18.6 million will occur in the first two years of the 2024-29 regulatory period.

The approved business case for the project notes the underlying condition issues at Berrimah zone substation.

- Five of the six 66kV circuit breakers in the switchyard together with one of the transformers are likely to fail in the short term. Failure of these assets during operation will result in significant outages and loss of substation capacity for extended periods of time.
- While the building structure itself is in relatively good health, the auxiliary systems including air conditioning, fire systems and auxiliary supplies are expected to fail in the short term. Most of these systems were original units installed in 1981 and there are on-going issues which require regular repair.
- The majority of protection relays are over 15 years old with a significant number over 25 years old. Most of these relays are no longer supported and spares cannot be sourced from the original equipment manufacturers.
- The 11kV switchboard was installed as part of the original substation. Over the years, the switchboard was extended and the original bulk oil circuit breaker trucks were replaced by compatible vacuum circuit breakers, reducing the risk of fire and explosive failure. The main concern with this switchboard is that it is does not have appropriate arc-fault containment and there is inadequate protection to quickly isolate the bus in the event of a bus fault.
- Frame Earth Leakage is used on similar switchboards in Power and Water to provide arc fault protection. However, this has been disabled at Berrimah due to the degradation of panel insulation and subsequent spurious bus trips that resulted in widespread outages.

Our options analysis considered the feedback of the AER at the time of the 2019-24 regulatory determination. The AER considered that we had demonstrated that a green-field option (that is, re-building a new zone substation on an adjacent site), which maintains the capacity of the current zone substation reasonably reflects the efficient costs that a prudent operator would incur.

Consistent with the preferred option, we will replace the existing Berrimah substation with a new substation initially configured with two standard sized transformers with provision for a third transformer circuit. The firm transformer capacity will have a minimum of 41MVA once the new substation is commissioned. In the future, there will be options to increase firm capacity by installing a third transformer at Berrimah or proceeding with the development of a permanent zone substation at Wishart.

In the future, there will be options to increase firm capacity by installing a third transformer at Berrimah or proceeding with the development of a permanent zone substation at Wishart.

Berrimah zone substation

Nomad zone substation, Darwin

Single phase substation refurbishment and replacement program ($6.3 million

The program commenced in the 2019-24 period to resolve corrosion issues with the enclosure and tank of single-phase underground distribution substations in Darwin's northern suburbs. By the end of the period, we expect to have refurbished 91 and replaced 32 substations. In the 2024-29 period we forecast that a further 115 substations will be refurbished and 20 replaced altogether.

The need for the project was established in our 2019-24 regulatory proposal where there was evidence of significant corrosion of the external tank leading to oil leaks and failure, as well as deterioration of the internal components required for operational switching. The deterioration of the substations is strongly related to age, with most of the substations being installed in the early 1980s, and their continued exposure to tropical weather in Darwin over the life of the asset. This also relates to the design and location of the asset where the substation is mounted on concrete in residential gardens, allowing the water to pool. An additional issue that has been identified during the current program is the need to upgrade earthing of the unit to align with newer standards.

The dominant risk relates to health and safety of the public. The substations are installed in the front yards of residential properties in four of the northern suburbs of Darwin. The primary mode of failure is oil loss leading to internal flash over (arcing). Since the older transformers in corroded condition are not arc-flash rated, the assets pose a risk of the substation catching on fire or exploding and not being contained by the corroded enclosure. The second risk is environmental damage from leaking oil close to residential areas. Reliability is a lower quantified risk as a failure of an individual substation will lead to outages for only a small number of customers.

We directly examined three options in our business case. It should be noted that preventative maintenance was a non-credible option as previously we found that measures such as removing debris, soil and water was ineffective in most locations as the materials build up in a short timeframe due to high vegetation growth rates and wet season conditions. The first credible option of reactive replacement leads to significantly high quantified risks. The second credible option was to continue the existing proactive replacement and refurbishment program where we target substations through normal inspection processes and address the issues through either replacement or refurbishment. This option was preferred as it has the highest net present value. We also explored a third option of accelerating replacement but considered this was not economic.

The forecast scope of the program is to replace 20 substations and refurbish 115 substations. At the time of replacement or refurbishment, we will also ensure the earthing meets new compliance standards. The unit cost estimates have considered previous costs in the 2019-24 period, and reflect the relatively low cost of refurbishment compared to replacement.

Hudson Creek spare transformer ($2.2 million

Hudson Creek substation is critical to the Darwin-Katherine System. It is the location where the 132kV transmission network connects from the Channel Island generation and is converted to 66kV for our sub transmission network.

The transformers at Hudson Creek are currently around 35 years old and have had some issues in the past with oil leaks and water ingress.

Due to the size and voltages of these transformers, they have a very long lead time of approximately two years from placing an order to delivery.

To manage risk to network security as these transformers approach the end of their expected serviceable lives, we will purchase a spare transformer so we can rapidly replace a transformer if one should fail.

Replace Cosmo Howley ($0.6 million)

Cosmo Howley is a zone substation that supplies an industrial customer. The zone substation has reached the end of its technical life and requires replacement.

However, our customer notified us that the intended operations have changed and will only require 0.7 MVA, which we are able to provide through a micro substation rather than a full substation. This has significantly reduced the cost compared to what was reported in last year's TDAPR.

Centre Yard zone substation ($0.8 million)

The Centre Yard zone substation is located on the Cox Peninsula and supplies power at 11kV to the local community.

The transformer at the zone substation is in poor condition and requires remediation while the remainder of the zone substation assets are also close to end of life. There is low demand in the area and uncertainty of any future development or load growth.

We assessed a number of options to manage this network constraint, including:

- 'Do nothing' and allowing it to run to failure, which would result in a prolonged outage while replacement assets were deployed
- Replacing the zone substation with modern equivalent assets.
- Establishing a Stand-Alone Power System and suppling via a new feeder or repurposing existing subsea cables.

The preferred option was to repurpose the existing 66kV subsea cables by operating them at 11kV and directing connecting to the 11kV network with only distribution switches to provide isolation capability. A back-up generator will also be installed. This approach enables us to retire the existing zone substation and minimise cost to customers. This project will be completed by mid-2024.

However, this is a temporary solution (expected to last up to 10 years) as the subsea cables are close to end of life and have a number of condition and installation issues. We are currently assessing long term permanent options, including:

- A new mine is being established on the Cox Peninsula that requires a new feeder to be constructed. We are assessing the economic benefit of extending this feeder to the Centre Yard zone substation.
- We are also undertaking further assessment of a Stand-Alone Power Supply to assess if it will be more economic in the long term, particularly with the transition to renewable energy.

We currently expect an alternative option will be required in early 2030.

Palmerston Zone substation Transformer 2 and 3 replacement ($18 million)

The Palmerston zone substation is located in the northern region of Palmerston and supplies customers at 11kV. It has expanded over time and has an unusual arrangement as it is comprised of three transformers that convert electricity from 66kV to 11kV and one transformer that converts from 11kV to 22kV, primarily as a back-up supply to the Palmerston hospital.

There are several condition issues at Palmerston zone substation:

- Transformers 2 and 3 have both been assessed to be in deteriorated condition. Based on the internal insulation condition, we expect they will require replacement in 2030.
- The 11kV to 22kV transformer is a non-standard configuration and puts operational constraints on the 11kV switchboard.
- Three of the four switchboards are over 40 years old and approaching the end of their technical life. So far they are not exhibiting any significant deterioration indicators but we will continue to monitor them.
- The building that houses the switchgear and protection systems is in poor condition and the roof leaks. The roof will be repaired in the next regulatory period to enable us to defer any significant replacement works.

With the construction of Archer zone substation completed in 2011, the capacity constraints at Palmerston were resolved and now only condition-based issues remain.

We have developed an area plan to ensure prudent and efficient long term investment decisions are made. We have found that aligning works with the potential future Holtze-Kowandi zone substation will enable us to simplify and standardise Palmerston zone substation by reducing it to a two transformer substation with provision for a third based on demand growth. The 11kV switchgear and buildings would be replaced at the same time.

The plan will reduce overall cost to customers and provide real options for future growth. The plan is subject to Holtze-Kowandi proceeding and will be reassessed periodically.

Zone substation, Humpty Doo

Reactive replacement volumes

Our volumetric modelling forecast excludes zone substation transformers. The modelling forecasts that we will incur a total of $11.7 million for distribution transformers, comprised of $3.4 million on pole mounted substations, $4.6 million on kiosk mounted substations, and $3.7 million on ground mounted substations.

We have developed an area plan to ensure prudent and efficient long term investment decisions are made.

7.6 Switchgear

Switchgear enables elements of the network to be turned off to assist with fault management, undertake planned maintenance, and to ensure safety. We have 300 high voltage switchgear, 1730 distribution switchgear and 3645 distribution pillars.

Below we have identified asset condition limitations which give rise to a targeted program over $5 million in the 10-year planning horizon. We have also estimated replacement volume of other switchgear based on high level modelling.

Distribution switchgear condition and fault-based program ($6.9 million)

This is the continuation of an existing program that seeks to address asset condition issues and increases in insufficient fault level ratings with a type of distribution switchgear (Magnefix). These switchgears are operating in areas with fault levels that are close to or above its fault level rating. This poses a risk to the safety of the public and our workers.

An increasing number of the population have been failing in service. The main failure modes are deterioration of the switchgear insulation and terminations, due to harsh service conditions, which can lead to explosive failures. In addition, development of the network over time has resulted in an increase of system three phase fault levels above 14.4kA in some areas of the distribution network. Currently the network contains 29 Magnefix switchgear installations where the system fault levels exceed or are encroaching on the equipment rating.

The key risk with failure of the substation relates to worker safety. There are no protective barriers present between the operator and the switchgear in the event of a switchgear failure or incorrect operation. All operations can only be performed manually with the operator standing directly in front of the switchgear. In addition to worker safety, many of these installations are in public areas and present an elevated safety risk to members of the public.

We have three recorded instances of explosive failures, underscoring the risk to safety posed by the assets. There are also reliability risks when a distribution substation fails including significant outage time for a large number of customers. For example, in one incident about 600 customers experienced an outage of 5.5 hours.

Our options analysis shows that run to failure results in high residual risks compared to other options, and would not be prudent given our recent experience with explosive failures.
The preferred option is to target replacement on high-risk switchgear based on asset condition, and prioritised based on the fault level and the proximity of the location to the public.
A third option is to alleviate fault levels through operational configuration; however, splitting bus configuration can lead to greater risk of outages for customers and therefore is less economical than targeted replacement.

The scope of the project is to replace nine of the high-risk switchgear installations during the current regulatory period and the remaining 20 in the 2024-29 period. Each asset will require replacement of the padmount/package substation containing the switchgear, civil works and re-termination of the cables. The cost of the project has been based on recent replacements.

Distribution pillars ($4.8 million

This is a new planned program that we forecast to commence in the first year of the 2024-29 period and is expected to be an ongoing program. Each year the project will replace 56 and rectify 200 distribution pillars through operational repairs. These assets are part of our underground network, effectively distributing power to typically four to eight customers.

The need for the program arises from the deteriorated condition of the covers, outer enclosures and foundations in the base. This is due to the operating environment of the asset in particular prolonged exposure to heat and UV light, infestation of pests and dirt, subsidence of ground, and a humid environment accentuated by water sprinklers in garden beds. Our inspection data of about 5000 pillars over the last five years has identified about 20 per cent have a defect, of which approximately 25 per cent are critical to public safety. Our analysis also shows that a large proportion of pillars were built at the time of Cyclone Tracy (47 years old today) and that these assets are expected to further decline in condition as they continue to age beyond their expected operating life of 35 years.

The predominant risk associated with deteriorated pillars are health and safety of the public, given the proximity to our customer's properties.

In particular, damaged coverings expose or enable access to 'energised' elements of the asset, leading to potential for electric shocks. We have had three recent events where customers have been exposed to live parts, and one of the incidents led to an electric shock.

We examined four options in our business case. The option to replace on failure resulted in unacceptably high quantified risks due to the relatively high probability of a safety event. We also analysed the net present value of our current approach of replacing about 20 pillars each year and corrective repairs on about 110 pillars. We found that the expected decline in the condition of assets would mean that safety risks would significantly increase at this level of investment. The third option was to develop a targeted replacement and repair program that prioritise assets where there is high foot traffic, high population density or close proximity to critical infrastructure such as schools. This would increase replacement volumes to 56 pillars per year and repairs to 200 per year. This was the option that maximised net present value. A fourth option to only replace assets was deemed not economic.

The costs of undertaking 56 replacement and 200 repairs was estimated at $0.6 million per year based on historical costs.

Darwin – Channel Island 132kV GIS circuit breakers

We have 14 outdoor circuit breakers at Channel Island. The switchgear is critical to ensuring secure power from our largest generation point.

The assets are currently undergoing scheduled refurbishment to ensure we can keep the asset in service. The refurbishment will likely conclude in FY24. Accessibility for refurbishment is challenging to the connection of critical generators at Channel Island Power Station.

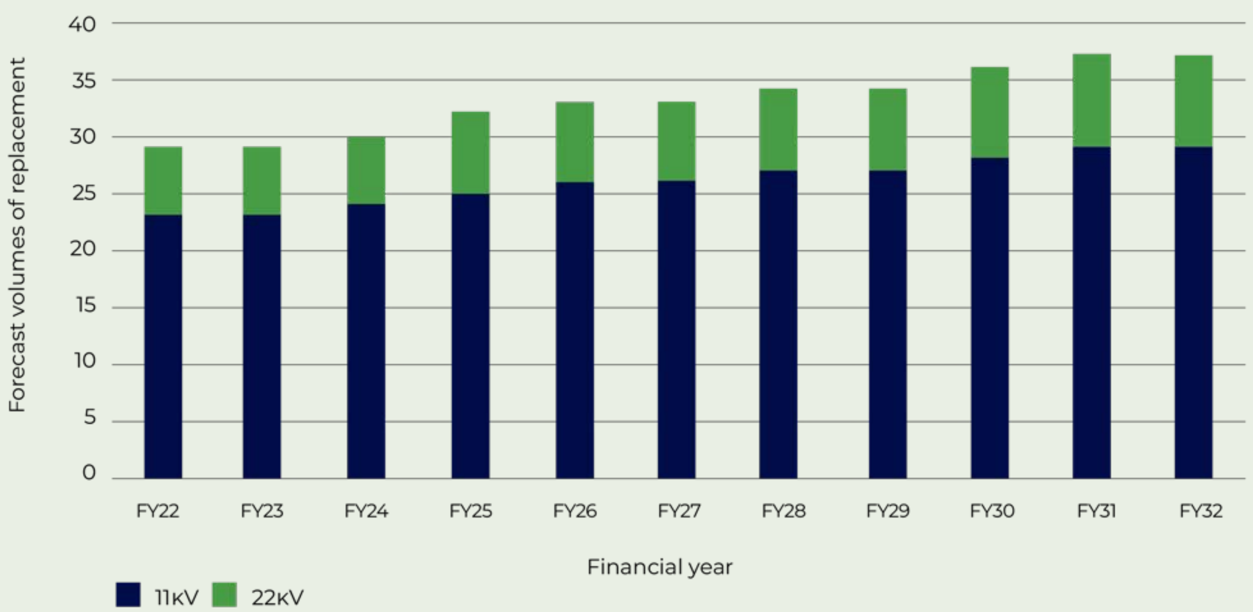
The expected end of life of these assets is in 2035 and condition and risk assessments will inform the actual timing of replacement. Based on this expected end of life, Power and Water will commence planning from 2030 to undertake studies, design and construction prior to retiring the asset.

The studies will include the network need at that time based on the expected development of the renewable energy hub which will change the generation mix. This may result in a reduced replacement project and therefore reduce costs.

Reactive replacement volumes

Our volumetric modelling forecasts excluded distribution pillars. The modelling forecasts that we will incur $7.7 million on distribution switches, and $3.3 million on circuit breakers. The volume of replacement for each asset type is provided below in **Figure 40.**

Figure 40 – Forecast volume of distribution switchgear (excluding targeted replacement)



7.7 SCADA, Communications and Protection

The network requires control systems, communication networks and protection equipment to manage the network securely and safely.

Electricity networks require an ecosystem of secondary assets to keep the network secure. This includes SCADA which gathers, processes, and displays information about the status of the network and provides control of the network. It also includes protection relays which detect and keep the network safe in the event of a fault. Finally, it includes communication assets such as data networks, microwave radio, optical fibre network and pilot cable network. This connects network assets to the SCADA system and sends protection signals across the network to ensure protection operates as quickly and accurately as possible to maintain system security and safety.

Below we have identified asset condition limitations which give rise to a targeted program over $5 million in the 10-year planning horizon.

Protection relay replacement program ($17.5 million

Protection relays monitor network voltages and currents. They protect assets against damage and the public from injury when operating conditions are abnormal or unsafe. We currently have more than 1350 protection relays on the network, of which about a third relate to older electromechanical and static (first generation electronic relays) technologies. We have been progressively replacing our electromechanical and static relays over the past decade with intelligent digital technology.

The drivers of the program relate primarily to the poor functionality and obsolescence of remaining electromechanical and static relays on the network. Lack of vendor support exposes Power and Water to increasing risks due to inability to source spares or repair following asset failure and cyber vulnerabilities.

The relays on our 66kV transmission network have compliance issues with the Technical Code around redundant (X-Y) protection schemes needed for equipment operating at 66kV and above. The Technical Code requires independent, duplicate protection schemes on equipment operating at 66kV and above. We have identified that eight static protection relays operating at 66kV are non-compliant. While the reliability of these relays has enabled us to manage the risks of non-compliance over time, there is new information suggesting physical signs of degradation and investment can no longer be deferred.

Further, there is a new requirement for more rapid reporting of faults and other events which can only be achieved through improved recording capability at these locations.

In addition, the remaining electro-mechanical relays on our distribution network are out of vendor support, do not enable us to comply with more stringent reporting conditions, and have higher failure risks. Unlike digital relays, they do not leverage the network flexibility benefits of remote management, which is becoming of increasing value as our network seeks to facilitate growing renewables.

We examined three options in our business case. Run to failure with spares as a mitigation was not the preferred option on the basis that it does not address the current non-compliance issues. We expect further degradation in the condition of the assets which will increase risk over time and does not provide for improved network flexibility. We also considered run to failure and replacement with a modern-day equivalent but this had similar issues and higher costs. The preferred option was to replace obsolete relays on a targeted basis over time with modern, faster acting and more configurable relays.

Under the preferred option, we will replace a total of 69 relays representing about 15 per cent of the existing static relay population over the 2024-29 period. We consider this will need to be incrementally uplifted in future regulatory periods as at this rate of replacement we would still have electromechanical relays in operation beyond 2050.

The scope of the project involves replacing the identified eight relays on the Channel Island to Hudson Creek transmission network that are non-compliant. We would also replace 61 distribution protection relays in Darwin urban areas, Batchelor, Weddell and Alice Springs. In addition, we would install a data recorder in eight locations.

Zone substation assets, Berrimah

Energy Management System replacement ($9.0 million)

This is a SCADA project that is already underway and will be largely complete by the end of the 2019-24 period, except for residual capex of $1.5 million in the first year of the 2024-29 period. The EMS allows us to perform remote switching and identify and respond to network outages and is also important to support the transition to renewables. The purpose of the project is to ensure the EMS remains in a fully supported state for all hardware and software, is appropriately sized, and to improve cyber security.

MPLS migration ($10.7 million)

Consistent with our regulatory obligations, we operate a communications network that provides information and control signals between our SCADA and network assets and protection signalling. The communication devices currently rely on multiplexors, which combine or split out the signal from our population of communication devices.

The types of multiplexors currently in use on the Power Services electricity network are old technology and have been superseded by Multiprotocol Label Switching (MPLS) devices. MPLS is designed to operate in a virtual environment and therefore provides more flexibility as the switching and throughput can be made without physical changes to the network.

The underlying need to transition to MPLS in the 2024-29 period is that multiplexors are being phased out by vendors as evidenced by End of Life and End of Support notices. In addition to the primary driver of obsolescence, a critical router of the Digital Mobile Radio network is close to end of life, and new routers are only compatible with MPLS. Further there are advantages of using MPLS to overcome functionality issues with our existing substation LAN. Finally, there are operational benefits of migrating to MPLS in terms of network control.

We examined two options to address the obsolescence issue with end of support multiplexors. In both options we would replace the 210 multiplexors with an MPLS solution, replace the 22 digital radio switches, upgrade LAN at 10 substations, develop a testing facility, and purchase critical spares. The difference in options related to the type of MPLS used. The MPLS-IP was preferred to MPLS-TP due to its additional functionality.

This program is a continuation of our existing condition and obsolescence based replacement program, but with a focus on transitioning to a new technology rather than a 'like for like' replacement.

Other minor programs less than $2 million ($5.1 million in total)

There are five other minor planned programs in this asset class. This includes:

- Communication battery replacement ($1.5 million) – The communications network is reliant on battery systems to ensure that communications are not interrupted during power outages. Analysis shows that many of our communication batteries are beyond their expected life, and are subject to high temperatures which further reduce life expectancy. Our options analysis showed that run to failure has high risks, and that a proactive replacement program is preferred. Under this option we would replace 43 communication batteries in the 2024-29 period focusing on batteries that are older and have been exposed to higher temperatures.
- Code compliance and safety program ($1.4 million) – This project ensures the communications remains compliant with the requirements of Power and Water's Network Technical Code and Planning Criteria. The program is based on historical expenditure to address compliance breaches as they are identified. This includes rectification of single points of failure, separation of assets to ensure full redundancy, and security hardening of legacy network devices.
- Microwave systems retirement ($1.3 million) – The microwave communications systems clears electrical faults in remote locations where fibre is not economical to install. The key driver of this project is obsolescence. The vendor has issued 'End of Support' notices for 30 of our 64 microwave terminal units, meaning that technical assistance, replacement assets and software and firmware patches will no longer be available. We examined three options. Run to failure with replacement of spares was high risk due to network performance decline and cyber security risk. Proactive replacement with a modern equivalent that is compatible with MPLS was the preferred option compared to replacing with fibre. This was due to the lower cost and strategy alignment with MPLS migration (see project above).
- Dense Wavelength Division Multiplex (DWDM) retirement ($0.5 million) – DWDM systems are used to increase the data carrying capacity of optical fibre cables. The technology is vital to provide a link between the Hudson Creek Control Centre and the Disaster Recovery Control Centre in emergency situations such as cyclones. The vendor has already issued an end of support notice that commenced in 2019. The risk of retaining these assets on the network will increase over time as they deteriorate with age and possibly become vulnerable with respect to cyber security. Our options analysis shows that it will be lower cost to install 12 kilometres of fibre to connect the two centres, leveraging other planned projects that utilise fibre, and then retire the DWDM system.
- Communication huts refurbishment ($0.4 million) – Communications huts contain critical communications assets. Our analysis has identified that eight communication huts are in deteriorated condition from degraded roof seals and water proofing, deterioration of paint which makes corrosion more extensive and severe, and inadequate power supply. The 'do nothing' option increases the risk that the communication assets will fail in service. The preferred option is to undertake works to remediate the huts including regalvanising metal surfaces and structural steel, repaint the hut to prevent further corrosion, replace the roof seals and ensure the hut is waterproof, and migrate power source from Telstra to Power and Water owned assets.

The communications network is reliant on battery systems to ensure that communications are not interrupted during power outages.

Communication tower, Darwin

7.8 Other

The AER recognises that a network is likely to have programs of works that do not align neatly with the definitions used for the RIN. We have identified three programs that relate to 'other' network assets.

Below we have identified asset condition limitations which give rise to a targeted program over $5 million in the 10-year planning horizon.

Zone substation minor works program ($8.1 million

Zone substations receive electricity from bulk supply substations and transform the energy to a lower voltage for distribution along powerlines to distribution substations. A zone substation includes transformers and high voltage switchgear identified in the AER's RIN categories, but also includes a range of other assets including buildings, civil and grounds, instrument transformers, outdoor disconnectors and busbars, components of power transformers, and substation auxiliary plant.

We currently have an ongoing program to maintain and replace assets within a zone substation based on a well-established and detailed maintenance strategy. This comprehensive and regular monitoring and maintenance strategy allows condition, compliance and risk issues associated with zone substation minor assets to be accurately assessed in a timely manner.

We assessed two options. The first option was a run to failure approach, which showed a significant increase in risk over time predominantly relating to worker safety from operating assets that can fail in service. The second option was to continue our current practice of condition-based replacement and refurbishment. The costs were based on historical trends by type of asset, but adjusted downwards to account for the impacts of other zone substation works in our forecast. Option 2 was shown to result in increasing risk over time, but much less than Option 1. We considered that the higher short-term risks could be tolerated without increasing the forecast capex.

Based on the adjusted historical average, we expect to undertake about 60 projects to replace or refurbish zone substation assets at a cost of $8.1 million in the 2024-29 period. The majority of forecast capex relates to the building, amenities, civils and grounds.

Darwin – Upgrade transmission secondary systems ($5.7 million

The Darwin-Katherine Transmission line is the main supply for the townships of Pine Creek and Katherine.

The secondary systems in the terminal substations on the line at Manton, Batchelor, Pine Creek and Katherine have exceeded their operational life and technical support. The equipment is experiencing increasing failures, and without support are technically and economically difficult to repair. This has led to a high number of unplanned outages.

Our analysis identified replacement as the most economical option. We did not identify any viable non-network options. Work has already commenced and will be complete by 2024.

Road access to transmission network and communication hubs ($2.5 million

Many of our transmission lines and communications huts are located in remote locations. To access these assets, we need access to safe and reliable roads that can carry heavy machinery where network assets require rectification, or be accessible by four-wheel drive for communications assets.

The condition of many of the current access routes are inadequate to enable staff to safely travel to remote areas, particularly during or immediately following tropical storms and severe wet weather. They are also not equipped to transport heavy vehicles and equipment such as transmission and communication towers. We have identified 24 road sections in the Darwin-Katherine area that service overhead transmission assets and an additional four road sections that service communications huts which are in poor condition.

Our options analysis shows that doing nothing results in poor and declining accessibility to address faults and asset failures, undertake maintenance and will pose an increasing risk to field crew safety. We assessed the difference between undertaking a program to rectify the roads to different design lives, namely 5-years and 20-years. The longer design life requires more construction work and materials and is therefore more expensive. The analysis found that undertaking the works to a level of quality required for a 5-year design life maximised the net present value.

Fountain Head track before rehabilitation

Fountain Head track after rehabilitation

The forecast works will cost $1.7 million over the 2024-29 regulatory period. This will improve access roads from Batchelor to Adelaide River, Adelaide River to Pine Creek, Pine Creek to Katherine and Leanyer Swamp. We will also undertake works for access to communication huts including Lake Bennett, Hughes, Pine Creek, and Mount Bundy.

Minor programs in substations ($1.4 million)

There are two minor replacement programs in our zone substations relating to compliance obligations. These includes:

- Zone substations fire replacement systems ($1.1 million) – Fire suppression systems are required to be installed at all zone substations and comprise a fire indictor panel for monitoring and control, and a gas system to suppress the fire. The run to failure option was not preferred as it increases the risk to the network and to field crews if a fire were to occur. The preferred option is to undertake planned replacement of the fire systems components as required based on condition, age, obsolescence and testing requirements for pressure vessels. The forecast capex relates to replacement of 13 Fire Indicator Panels and 118 gas cylinders for the suppression system at 12 zone substations.
- Zone substation DC replacement ($1.3 million) – Zone substation switchgear and protection systems require DC supply (i.e. battery systems) to ensure operation during loss of network supply. Due to the ageing of the battery systems, there is a need to manage assets which reach the end of their serviceable life during the 2024-29 regulatory period. Our analysis has found that battery systems will reach end of life at 16 substation locations in the 2024-29 regulatory period.

Alice Springs network re-configuration ($TBA)

Alice Springs is supplied from two main zone substations, one at Lovegrove and the other at Sadadeen. The area north of The Gap is supplied at 11kV while the area south of The Gap is supplied at 22kV. Electricity is generated at the Owen Springs Power Station and transmitted to Lovegrove at 66kV where it is stepped down to 22kV to supply Sadadeen zone substation and then to 11kV to supply the distribution network.

This is a complex arrangement that is the result of organic growth of the network and the location of the old Ron Goodin Power Station, which is located adjacent to Sadadeen zone substation.

Changes to the location of the generation source and planned retirement of Ron Goodin Power Station have changed the way power flows on the network, and therefore the functional requirements of the assets. Currently, technical constraints make it difficult to restart the network if there is a system black event.

In addition to the change in power flows, many assets are in deteriorated condition and are expected to require replacement between 2025 and 2035. These include:

- the 22kV switchboard at Sadadeen which has reached the end of its technical life and is being carefully managed to remain in service until it can be decommissioned in 2025.
- four of the six 22kV to 11kV transformers are expected to require replacement based on condition between 2032 and 2035.
- the 11kV switchboard at Lovegrove is expected to require replacement based on condition in 2030.

Power and Water has undertaken an extensive analysis of the network and consultation with Territory Generation and Northern Territory Electricity System and Market Operator (NTESMO) to identify all the assets requiring replacement and identify other constraints and considerations.

We have developed a long-term plan that will avoid stranded assets and provide real options. The plan will be adjusted periodically as new information arises or asset condition changes at a different rate than expected without creating stranded assets.

Our plan has considered the retirement of Ron Goodin Power Station, the co-located battery system, Uterne solar farm, evolution of the network with solar PV and electric vehicles, and expected growth areas.

Zone substation, Pine Creek

The initial action is to install two cables from the 22kV switchboard at Lovegrove zone substation that will connect to an existing cable near The Gap. These will provide a 22kV supply from Lovegrove directly to the 22kV network south of The Gap. Concurrently, the two 22kV express ties between Lovegrove and Sadadden will be disconnected from the Sadadeen 22kV switchboard and reconnect directly to the transformers. This will enable the 22kV switchboard to be decommissioned, rather than replaced, without restricting investment options or creating stranded assets. The retirement of the Sadadeen 22kV switchboard resolves the immediate risk on the network.

The cost of this is forecast to be $4.2 million, compared to an estimated $10 million to do a 'like for like' replacement of the 22kV switchboard.

The next steps are to progressively replace assets (as they reach their end of life) in a way that will result in our planned optimised network.

While further analysis is required and new information will need to be considered over the entire period of the area plan, the long term approach is to simplify the network by:

- removing 22kV assets from Lovegrove and Sadadeen so north of The Gap is only 11kV
- establishing a zone substation south of The Gap that will supply at 22kV.
- deferring expenditure at each step as long as possible so we can avoid stranded assets and be adaptable in case new options arise or network needs change.

This will take up to 20 years and be dependent on load growth. We have identified a series of steps to enable this transition with minimal investment, while managing risk, until the new zone substation is required.

The cost of the full reconfiguration is still being developed and the full cost estimation will be provided in next year's TDAPR.

8. Programs to address capacity, voltage and fault limitations

Recent analysis shows that our investment in growth capex over the next decade may be lower than historical levels. This reflects that we largely completed major projects in the period prior to 2019 and that there is mostly sufficient capacity on the network to meet peak demand. Our program reflects continued investment in reliability and compliance programs together with new investment to address condition and risk issues. It also reflects a new type of investment on our network to facilitate growing small-scale renewables. We have not identified any credible non-network solutions for addressing constraints through this year's planning processes. However, we welcome stakeholder ideas and feedback on solutions we may not have considered.

In the following sections, we identify our constraints that give rise to new investment on the network. These include capacity constraints, reliability and quality of supply constraints, and faults and non-compliance. We outline our forecast capital programs to address these constraints including on our transmission and distribution network. This year we have also forecast a program to increase the capacity of our network to facilitate increasing distributed energy resources.

8.1 Program overview

The level of augmentation capex to address constraints is forecast to be significantly lower than last year's TDAPR and very low compared to historical levels. This can be seen in **Figure 41.**

This is largely attributable to our assessment of capacity on the network at a spatial (local) level compared to peak demand growth forecasts.

Our peak demand growth forecasts are increasing in most areas of our network in the 2024-29 regulatory period. While there are differences between each of our regions, aggregate growth in zone substation forecasts in the 2024-29 period is not forecast to exceed network capacity. The growth is largely attributable to 'spot loads' on the network particularly in Archer, Humpty Doo and Strangways. This also reflects that solar is not having the same impact on curbing peak demand growth, as we have shifted to an evening peak.

A key change from last year's TDAPR was a change to our current approach to estimate 'spot loads'. We found that the timing and magnitude is likely to over-forecast the load that connects on the network. As a consequence of applying lower spot loads, demand growth is far less in each of our zone substations than the 2021 TDAPR.

Consequently, all of our large substations and transmission lines would be able to accommodate the forecast peak demand growth due to existing capacity and opportunities to transfer load under contingencies. We note however that there are some capacity constraints at zone substations that we will need to address (such as the capacity of cables from transformers to the switchboard or instrument transformers with inadequate ratings). We will also need to upgrade our 11kV feeders leading to two small programs in the 2024-29 period.

While demand driven capex is lower, we have identified a new project that seeks to facilitate growing **distributed energy resources** on our network. Implementation of dynamic operating envelopes is aimed at flexibly managing minimum demand issues on our network, without imposing static limits all year on export capacity.

In respect of other drivers, we expect to incur similar levels of expenditure as the current 2019-24 period on maintaining our jurisdictional reliability standards, ensuring compliance with our voltage performance standards, and ensuring we comply with conductor clearance standards.

We also have two specific programs that commenced in the 2019-24 period that upgrade assets on the network to meet compliance and risk drivers. This includes a program to upgrade our transmission lines and a program to replace specific distribution substations in Darwin CBD that will also address rising fault issues (discussed in section 7).

We also have five major projects that are uncertain in terms of scope, costs and timing. These include:

- **Renewable Energy Hub –** The renewable energy hub is part of the Northern Territory Government's plan to meet 50 per cent of renewable **energy target** by 2030. The premise of the project is that lower cost renewables could be dispatched through centralising production close to the existing transmission infrastructure. The project will require Power and Water to build a new transmission line to the hub, and a substation to inject generation to the existing transmission network. Latest costings from Northern Territory Government suggest a range of between $65 million to $130 million based on the assessment of seven options. Significant costing and funding uncertainty means that we are classifying this as a contingent project.
- **Unlocking existing large scale renewable generation on Darwin-Katherine Transmission Line –** Many large solar generators have located south below Darwin. There are transmission constraints on the Darwin-Katherine transmission line due to power security issues that result in curtailment of generation. The Darwin-Katherine System Plan noted mechanisms to improve the dispatchability of this existing generation, including procuring services of grid scale batteries. However, there is considerable uncertainty on technologies available, and the level of market benefit. We consider a RIT-T would provide a means of testing if there is a solution that maximises market benefit. Due to the level of uncertainty associated with this project we are classifying this as a contingent project in our 2024-29 regulatory proposal to the AER.
- **Holtze-Kowandi land release –** The Northern Territory Government has announced the release of land **near** Darwin called Holtze-Kowandi. This is a significant land release that would entail the need for a new zone substation if housing and commercial demand occurs in the 2024-29 period. However, there is uncertainty on exact timing of when the load would materialise, hence the construction of the new zone substation has been included in our 2024-29 regulatory proposal to the AER as a contingent project.
- **Commercial development in Middle Arm –** A new industrial zone will likely attract significant demand for electricity from large, new non-residential customers. There is uncertainty on how many industrial customers may seek connection and the resultant demand for grid services. It is likely that a significant load would require a new zone substation. Due to this uncertainty, the new zone substation has been included in our 2024-29 regulatory proposal to the AER as a contingent project.
- **Development in East Arm –** An industrial precinct at East Arm may require significant investment in a new Wishart zone substation. Due to the uncertainty around the timing of this development, the new zone substation has been included in our 2024-29 regulatory proposal to the AER as a contingent project.

Figure 41 shows the categories of our augmentation program for the next decade. This is discussed in the following sections

This year we have also forecast a program to increase the capacity of our network to facilitate increasing distributed energy resources.

Figure 41 – Forecast augmentation capex

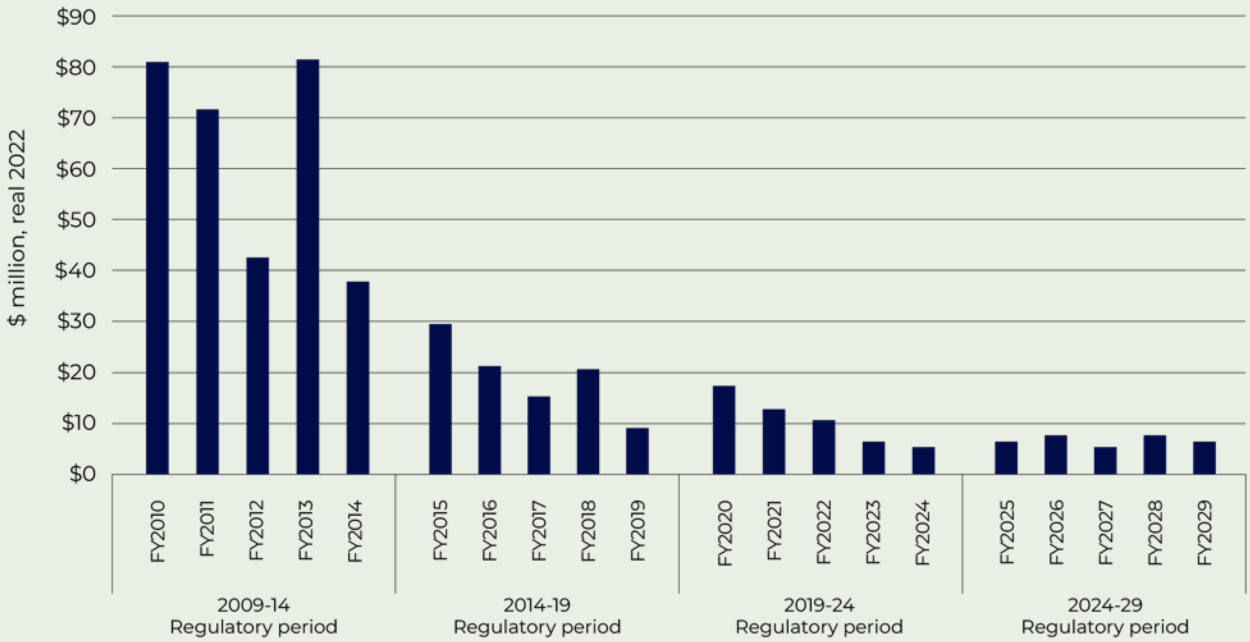
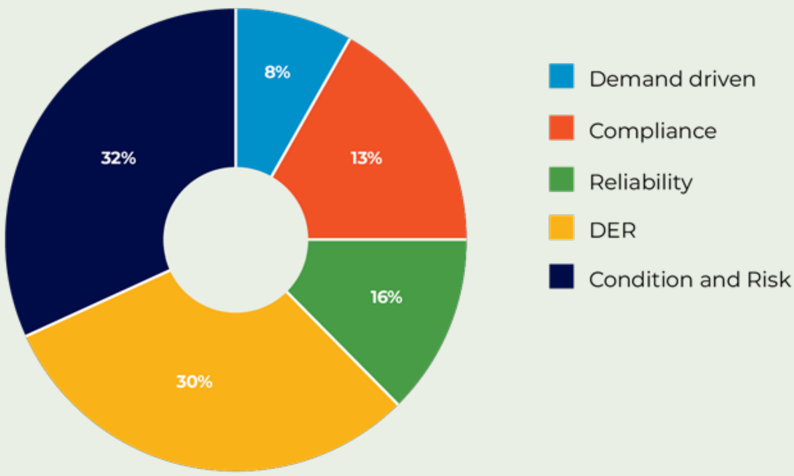


Figure 42– Categories of augmentation



8.2 Capacity

We upgrade or build new infrastructure when our assets cannot securely meet peak demand in an area of the network. This is termed demand driven capex.

We have not identified constraints on any of our main distribution feeders, but have identified constraints on some tee offs in localised areas. Our approach has been to examine the capacity of each of our high voltage distribution feeders compared to the forecast demand growth in the area. We have applied the relevant contingency criteria to assess if there is sufficient capacity available on the distribution feeder. Where there is insufficient capacity we have considered options to address the shortfall.

We also note that the NT has a number of potential large projects that may lead to significant spot loads in pockets of our network. At the time of our proposal, there is no committed load, and therefore these projects have been excluded from our capex forecast for 2024-29. The projects which are probable but uncommitted have been included as contingent projects.

Tindal zone substation upgrade ($11 million)

Tindal zone substation is located in the Katherine region of our network. It is currently supplied by two 22kV distribution lines and has a firm capacity of 5.5MVA. Due to forecast demand growth, we plan to increase the zone substation firm capacity to 13.5MVA and build a third 22kV feeder to strengthen the resilience and security of supply to this substation.

The scope of the project is to rebuild part of the zone substation including replacing the existing transformers with two larger ones, replacing all the switchgear, protection and upgrading the buildings.

The project commenced with preliminary design in 2020 and will be completed during the 2024-25 financial year.

Overloaded feeder program ($6 million)

Under our Planning Criteria regulations, we have an obligation to adhere to time limits for power restoration during contingency events. This varies by type of feeder. For urban areas with between 5MVA and 50MVA of demand, we must restore load within 60 minutes and this typically is achieved via distribution transfer capacity (DTC) to contiguous feeders and or substations to assist with restoration.

In the current period, we addressed overload issues with feeders on the network through multiple solutions including activities such as improving the capacity through increasing transfer of load, increasing the size of network cables, and enabling higher transfers through operational switching.

Our business case has identified a need to undertake augmentation works to address seven cables in the 2024-29 regulatory period. This was based on an analysis of the capacity of each high voltage feeder under an N-1 contingency and reviewing whether a capacity constraint arises due to an increase in peak demand growth.

We analysed two options, utilising our new risk quantification approach that provides a specific value for customer reliability. We analysed the relative risk of discontinuing our practice of addressing overloaded feeders. This increased the quantified risk of outages particularly in commercial areas. The second option was to continue our current practice of undertaking augmentation on feeders that are high risk (ie: in commercial areas). We found that the second option provides for the highest net present value.

The scope of works addresses seven feeders in the Darwin-Katherine network. We have identified specific works for each feeder including intra-feeder interconnectivity and improved switching capability to transfer loads within a feeder system during contingency conditions. The unit costs have been based on previous costs incurred.

8.3 Small scale renewable hosting (distributed energy resources capex) In Chapter 3, we discussed our Future Network Strategy that includes a focus on unlocking low-cost renewable energy from our customers' solar panels. This has led to a rigorous business case
to understand the constraints of our network in hosting solar exports, and identifying efficient solutions. This follows on from last year's TDAPR where we noted key challenges and potential solutions.

The business case shows that our three regulated networks will not be able to accommodate a forecast increase in the uptake of rooftop solar, based on an assessment of our network hosting capacity. The analysis shows that our networks face an emerging constraint over the next five years termed 'minimum demand' events. This is when there is insufficient demand available for thermal generation to keep the system secure, leading to the risk of system black start events. The problem is a result of low demand being met by rooftop solar, with no ability to constrain solar output in these periods.

Our options assessment looked at alternative solutions to address the minimum demand issue. This included stricter static exports that apply all year-round, not just during the infrequent periods in which minimum demand threatens system security. We tested whether a new type of technology termed 'dynamic operating envelopes' (DOEs) which automatically curtail solar exports at times of minimum demand but allow customers to export at all other times of the year. We also examined alternative network and non-network solutions such as network upgrades, rebalancing feeders and transformer tap changes. Each of the network engineered infrastructure solutions provide limited benefits by managing some characteristics of the distribution system. However, despite these potential benefits, many of the infrastructure solutions and technologies lack an ability to future proof the network for the continued uptake of distributed energy resources technologies.

The preferred option was DOEs. DOEs curtail solar exports at times of minimum demand but allow customers to export at all other times of the year. The prevailing advantage of DOEs is that they allow for maximum use of low-cost renewable energy. They also provide the capability for our network to better manage electric vehicle charging in the future, which is consistent with our strategic priority to better utilise the network and electricity system.

The preferred DOE investment is projected to result in at least $128.9 million in gross benefits over a 30-year period. This compares to a cost of $92.7 million over the same period. Nearly three quarters of the quantified benefit is attributable to avoided solar export curtailment, or increased solar exports. It also addresses the preferences of our customers to leverage new technology to unlock more solar and enable flexibility for the future.

Further data on forecast hosting capacity constraints for our Darwin-Katherine network are provided in the appendices together with a description of our methods.

8.4 Reliability

Chapter 4 discusses our program to meet our EIP obligations. As part of this year's TDAPR we have undertaken additional analysis of forecast reliability capex over the next decade.

Worst performing feeder program ($8.5 million)
The NT Electricity Industry Performance Code (EIP Code) sets out requirements to maintain network reliability within defined targets and to report on the five worst performing feeders per feeder category and the actions being taken to manage those feeders.

The need for this program is to ensure that we maintain an adequate level of reliability for customers connected to parts of our network that inherently have low reliability. This is generally in more remote areas of the regulated network where customers receive energy from long, radial lines that are subject to higher risk of outage events and lower back-up in the network. Customers in these areas are disproportionately impacted by outages. A consistent theme in our engagement with customers was the need for Power and Water to consider equity among customers, including issues such as reliability of services.

Over the current regulatory period, we have invested about $0.85 million a year on works directed at worst performing feeders. This includes installing automatic reclosers to clear transient faults in a short period, installing remote controlled switches to isolate the fault location leading to quicker restoration for some customers, localised undergrounding, installing covered conductors and animal protection.

Our analysis shows that our investment has been effective at managing (not improving) performance in rural locations and that lower levels of capex will deteriorate our performance on both short and long rural feeders. We have used our risk quantification procedure to develop a quantified view of the risks of declining reliability, however we note that such analysis does not consider the disproportionate impact on rural customers, which are impacted by much higher levels of outages compared to other customers.

We examined three options. The "do nothing" option assessed discontinuing our current approach to target investment at work performing feeders. We considered this option is likely to result in Power and Water not meeting its rural short and long targets in the EIP Code over the 2024-29 period. The second option was to use historical expenditure as a basis to forecast annual capex in the 2024-29 period. Our analysis suggests that this option would more likely lead to Power and Water meeting its current performance on short and long rural feeders. The third option was to improve our current performance by spending more capex in the 2024-29 period compared to historical averages. We considered this option would lead to a performance in excess of the regulatory threshold and was therefore not justifiable.

The scope of works has not been costed on a bottom-up basis but base on historical levels of capex. The rationale is that our annual program of works takes into account emerging issues that are difficult to forecast ahead of time.

Maximising solar exports, Darwin

8.5 Voltage

We also undertake augmentation works to meet the quality of supply criteria in our Network Planning Criteria.

Voltage rectification – Alice Springs ($2.4 million

This program seeks to rectify voltage issues at the Owen Springs Power Station in our Alice Springs network through the installation of two reactor capacitor banks. However, in the interim Power and Water will look to use load banks as a short-term solution for addressing high voltage issues in Alice Springs.

The need for this program arises from minimum demand days in Alice Springs. This is when high solar PV output coincides with periods of relatively low demand particularly from commercial and industrial customers, and air conditioners for residential customers. These events increase voltage on the network significantly. Our load flow analysis demonstrates that we would not meet our voltage compliance obligations as a result of minimum loads from FY2023 with performance deteriorating over time.

While we are implementing operational measures to manage the short-term risk, such as procuring services of load banks, we note that additional measures will be required in the 2024-29 period as solar penetration increases. Our options assessment considered that doing nothing is not an option as it will lead to repeated non-compliance, and the level of non-compliance will grow over time. We examined a range of solutions to address the issue including stricter static limits, encouraging demand management to activate higher consumption on minimum demand days, load banks that can be procured during a minimum demand event, a battery energy storage system, dynamic operating envelopes, and the installation of reactors at Owen Springs.

We considered that the installation of reactors was the most credible option that maximised net present value. This technology would absorb high voltages on minimum demand days. The option was considered preferable on the basis that it is a simple and proven technology. If the asset were no longer required, for instance when DOEs become operational in Alice Springs, it could be relocated to another location in Power and Water's network.

The scope of the solution is to procure and install two 11kV air-core shunt reactor units with two 3.5MVAr stages with associated switchgear, undertake civil and fencing works, install primary and secondary cables from the reactor units to the new circuit breakers on the 11kV switchboard and install protection and control systems for the operation of the reactor banks.

Power quality compliance program ($7.1 million)

Power and Water must comply with quality of supply (voltage) requirements as defined in the Network Technical Code and Network Planning Criteria. The purpose is to ensure that our customers' electrical equipment is not damaged or suffer a reduction in expected life.

The need for the program arises from specific voltage issues we forecast to occur in the 2024-29 period. Firstly, increased embedded generation and rooftop solar causes higher voltages on the network. In parts of our network such as Katherine, this has led to higher voltage than the prescribed standards. New requirements for inverters to have both 'Volt-Var' and 'Volt-Watt' modes available have helped mitigate over-voltage issues from rooftop solar, but the problem will continue in Katherine due to older solar installations and embedded generation.
A second driver is under-voltage issues in some new residential and commercial developments, which we expect will heighten with electric vehicle charging.

We examined three options to address non-compliance. The "do nothing" option would breach our compliance obligations, increase costs associated with customer claims, and heighten the risk of reputational damage. Reactive replacement involves only acting in response to a customer complaint, however this option does not address the undetected issues with voltage problems and may lead to higher risks in the future. The third option is consistent with our current approach where we proactively identify power quality issues through load flow studies and system modelling, and initiate targeted projects based on the results. The third option is the preferred option due to the ability to target works where there are clear issues.

The preferred option has used historical trends to identify the forecast capex in 2024-29. This is because works are undertaken on a site by site basis, and it is difficult to identify the likely works in advance. The types of work we have historically undertaken include upgrading conductors or overloaded transformers.

Car lodged in transmission tower, Tiger Brennan Drive

8.6 Fault Compliance

Transmission line upratings ($8.1 million

Each transmission line has a specified nominal rating. As more current flows through a transmission line, it heats up and expands, resulting in increased sag which reduces the clearance to the ground or other public assets.

Hence, the rating of a transmission line is usually determined by two factors: the conductor's design temperature and the safety clearance of the conductors from public assets. The conductors on the transmission line are required to operate below a certain temperature to maintain compliance with clearance requirements.

An aerial LiDAR survey of each transmission line (66kV and 132kV) identified clearance issues.

We examined three options to address non-compliance. "Do nothing" does not address the risk and therefore was not accepted. The option to rectify all non-compliances was assessed, but since a large number of the non-compliances occur where there is no public or high vehicle access, they do not present a significant risk. The third option was to do a risk analysis on each span and prioritise them for a targeted replacement program that focused on 12 transmission line sections.

By rectifying the compliance issues, the transmission line can be operated with higher power transfer capacity.

There were no credible non-network solutions identified that would mitigate this network issue.

8.7 Other drivers of network augmentation

Our asset management processes identify emerging condition issues that necessitate investment in new assets.

Low clearance program ($3.5 million)

This is an ongoing program to address compliance issues with our distribution conductors. Throughout the year, conductors that breach requirements for minimum clearance from the ground and structures are identified. A mitigation solution is developed on a case by case basis to meet the specific circumstances of the asset.

We assessed options to efficiently address these non-compliances. In our options assessment, we considered that doing nothing further would be a breach of our compliance obligations, and expose customers and our staff to safety risks. The preferred option was to address the low conductors as they are identified by developing a custom solution.

Since the solutions required vary for each individual conductor, the forecast has been based on the trend of historical expenditure.

Network design and planning project ($3.3 million)

This project addresses minor augmentation at zone substations. These minor projects at major substations address capacity issues or operational flexibility. This includes improving the cyclic rating of power and transformers to avoid overload (e.g. by adding cooling fans), modifying feeder supply arrangements to improve load transfer capacity and increasing the ratings of substation equipment. These projects help to defer major expenditure. We have used historical expenditure as a basis for our forecast capex in 2024-29. This project is likely to cost $3.3 million.

Minor programs less than $2 million (total of $1.8 million)

We have also identified one minor program less than $2 million. The protection of security network infrastructure program arises from the continued occurrence of incidents involving unauthorised access. The project involves upgrading the protective security assets such as fences at zone substations, replacing locks, and improving access control at distribution enclosures. This project is likely to cost $1.8 million.

8.8 Miscellaneous

Darwin CBD transmission protection program ($0.6 million)

In the 1980s, we installed transmission towers on Tiger Brennan Drive, near Darwin's CBD. The 27m tall towers support the 66kV transmission lines that supply the Darwin CBD. There has been substantially increased traffic flow along the road since it was built and a duplication was completed to the Stuart Park section of the road in 2014. This has brought the towers even closer to traffic on the road.

The need for the project is to ensure that the transmission towers are not impacted by vehicles. The lattice structure of the towers typically has relatively low levels of redundancy, and a direct impact to one leg of a tower has the potential to cause collapse of the structure. Very recently, a passenger vehicle travelling at high speed veered off Tiger Brennan Drive, mounted an embankment and became airborne, landing on one of the towers. While the driver did not suffer harm, the tower requires extensive repairs and reinforcement, which underscores the risk of damage to transmission towers posed by traffic.

Our options analysis considered both the risks of safety including potential fatalities, and the probabilities of an outage if the tower was to fail. The preferred option was to install physical protection on towers that were at high risk of vehicle collision. This was considered more economical than an alternative option to relocate the towers or underground the section of line.

Under the scope of works, we would build barriers adjacent to existing roads to protect the towers and deflect vehicle. The costs have been based on materials and labour estimates.

Other minor programs less than $2 million ($5.1 million in total)

There are five other minor planned programs in this asset class. This includes:

- Sadadeen to Lovegrove fibre optic cable replacement ($1.45 million) – the existing fibre optic cable is installed in an arrangement termed a 'folded loop', meaning the same cable is used for communications in both directions and there is no redundancy. There is also a single point of failure on the fibre network that needs to be addressed. Replacing sections of the fibre optic cables and installing in an alternative configuration will resolve these issues.
- Alice Springs to Darwin communications link replacement ($0.9 million) – a critical existing communications link between Darwin and Alice Springs is relied upon for controlling the Alice Springs network. The link has poor availability and reliability that is below industry accepted levels, resulting in a level of risk that is unacceptable. The preferred option is to establish a new link with higher levels of service.
- Antenna monitoring devices ($0.3 million) – antennas are currently only inspected visually and any electrical issues are only addressed reactively. A new monitoring device has been trialled at McMinns zone substation and has provided good condition data that can be used to enhance our asset management of these devices and support improved performance. This device will be installed at 8 critical communications locations.
- Communications hut electrical supply ($0.3 million) – one of our remote communications huts has experienced a high frequency of outages as a result of lightning and electrical surges. This project will investigate the causes and undertake works to resolve the issue.

List of Appendices

We have also published an accompanying Excel databook covering all technical data including asset population, maintenance strategies, and demand forecasts for our transmission network and zone substations. The table below sets out the relevant data.

Appendix Number	Description of data and information in the appendix
Appendix A	Asset count reported in 2020-21 Category Analysis RIN
Appendix B	Voltage regulation standards
Appendix C	Maintenance strategies
Appendix D	Transmission lines – demand forecasts and system limitations
Appendix E	Transmission contingency analysis
Appendix F	Zone substations – demand forecast and system limitations
Appendix G	Distribution feeders – identified system limitations
Appendix H	Maps of the three regulated networks
Appendix I	System limitations template – transmission
Appendix J	System limitations template – distribution
Appendix K	Embedded Generation Connections

Transmission lines, Darwin

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