Transmission and Distribution Annual Planning Report 2020

PowerWater

About this report

The purpose of this report is to provide our stakeholders with information on our plans to manage our regulated electricity network in Darwin-Katherine, Alice Springs and Tennant Creek.

The 2020 report covers a planning period of five years for the distribution network and 10 years for the transmission network. We present information on our network performance, demand forecasts, network limitations, as well as our planned investments.

This is our second Transmission and Distribution Annual Planning Report. We have tried to make improvements to the way information is presented so that our stakeholders can access, interact and engage with the data and analysis. A key improvement is a new visualisation platform (Rosetta Portal) which we will shortly place on our website to accompany this report. This will provide stakeholders with access to data about our network and the constraints. We have also separately published a systems limitation table consistent with the AER's guidelines. Together with Appendices.

Berrimah zone substation.

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Chief Executive key message

In 2020, Power and Water has focused on meeting the needs of our customers during the COVID global pandemic. Looking to the future, I want Power and Water to lead from the front in creating an affordable, reliable, and inclusive energy market in the Territory.

I am very pleased to present our second Transmission and Distribution annual planning report for Power and Water's electricity network. This year we have tried to improve the accessibility of our report to stakeholders. This includes a visualisation platform (Rosetta portal) that we will shortly place on our website which will provide graphics and maps of our network.

2020 has been a very testing year. As a Territory, we have shown resilience and clear thinking in the face of a global pandemic.

As the leader of Power and Water, I have set my staff a central objective through these uncertain times – to be there for our customers, and to be positive about our shared future.

Looking ahead, I am excited about the role Power and Water will play in a dynamic and fast changing energy market in the Northern Territory. Our customers have been on the forefront of a transition to a renewable energy market.

The changes in the energy market will continue to accelerate over the next decade. The Northern Territory Government's Roadmap to Renewables will pivot our energy system to 50 per cent renewables by 2030. In the longer term, we expect our network to deliver more demand to our customers from new industry in the Territory and electric vehicles on the road.

This year's planning report reflects our thinking on the opportunities and challenges that lie ahead. Central to our thinking is a focus on keeping bills affordable; ensuring we maintain service quality; and individualising our services to meet the changing expectations of our customers.

Power and Water understands that we need to adapt to changes. We have been working hard on implementing our new operating model. The new model aims to improve affordability and service delivery to our customers. While there is still plenty to do, our progress has been steady and constructive.

This report sets out the key issues on our network over the next decade, and some of our proposed solutions.

As always, we want your feedback so we can reflect the community's thinking in our plans going forward.

Djuna Pollard
Chief Executive

Berrimah zone substation.

Solar panels in Alice Springs.

Electrical maintenance in Alice Springs.

Looking ahead, I am excited about the role Power and Water will play in a dynamic and fast changing energy market in the Northern Territory.

1. Overview

Power and Water has continued to deliver reliable and safe services to our customers in a difficult year. However, we need to continually evolve to deliver an affordable, reliable and individualised service to our customers in a rapidly changing energy market. In this year's report we have outlined a longer-term perspective on how Power and Water can help the transition to a renewable and customer led electricity market in the Territory.

The 2020 Transmission and Distribution Annual Planning Report (TDAPR) provides forecasts and analysis on key issues facing our regulated distribution networks in Darwin-Katherine, Alice Springs and Tennant Creek. The purpose is to provide our stakeholders with early visibility on key planning challenges, and our thinking on solutions. In turn, this helps customers, energy market participants, advocates, governments, and regulators engage on a shared future pathway for Power and Water.

This is our second TDAPR. Last year, we focused on providing our stakeholders with accurate and comprehensive information. This year we are striving to improve the quality of our communication. We have set ourselves the task of writing a plain English report that provides more context about the challenges and opportunities in a changing Northern Territory energy market. We will also shortly be placing a new visualisation platform on our website called the Rosetta Portal which will allow stakeholders to interact and engage with our network data.

Below, we have set out a short overview of this year's TDAPR for stakeholders with limited time. In the coming months we hope to engage more with our stakeholders on the specific plans contained in this report.

1.1 Meeting the challenges of 2019-20

2020 has been a test of resilience in the face of challenge. The COVID-19 pandemic has caused unprecedented disruption to our daily lives and the economy.

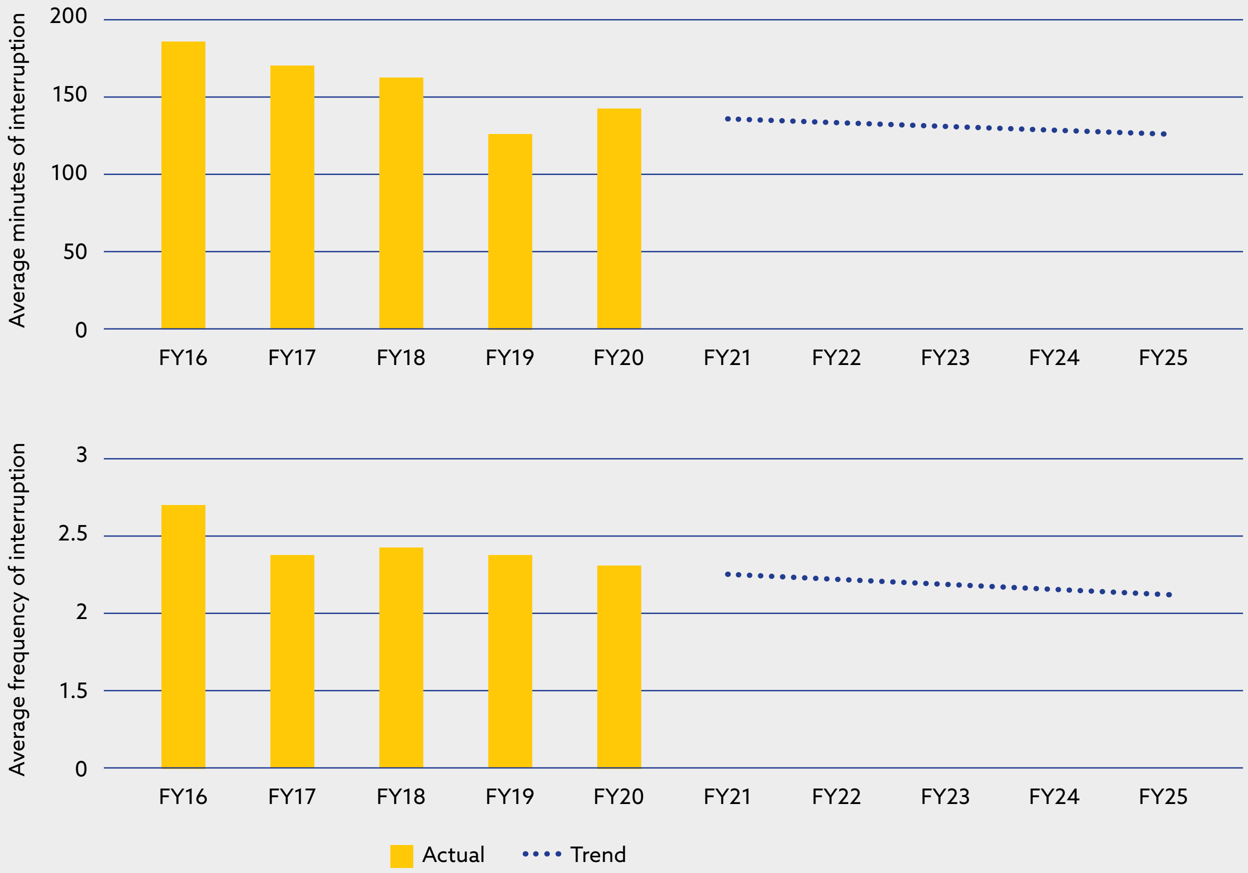
Through this difficult period, Power and Water has focused on being there for our households and businesses. This includes working with the NT Government to ensure a freeze on tariffs until June 2021. We have also established dedicated hardships programs to help vulnerable Territorians facing financial hardship due to the impact of COVID-19. Customers on these programs were not disconnected for non-payment.

COVID-19 has also changed the way we deliver services to keep the network safe and secure. We have implemented strict hygiene and physical distancing activities to keep our customers, crews and contractors safe. Our customers have been working with us through these testing times by informing us when a household is in quarantine and isolation.

Despite a difficult year, Power and Water has continued to deliver reliable services to customers. **Figure 1** shows that over the last 5 years, Power and Water has reduced average outage duration and frequency per customer.[1] In 2019-20 we met the feeder reliability targets approved by the Utilities Commission of the Northern Territory for the CBD and urban areas. However, we fell short of our targets for short rural feeders and the duration of interruptions for long rural feeders. In this year's report, we have identified reliability works that will help us improve reliability in rural areas, focusing on areas where our customers encounter sustained interruptions.

[1] The reported data is based on System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) for the whole of network, based on total sustained interruptions after removing excluded events. Our whole of system target is derived based on our individual segment targets approved by the Utilities Commission of the Northern Territory.

Figure 1: Average duration of interruption per customer (top) and average frequency of interruption per customer (bottom) for whole of system



Implementing a new operating model

Power and Water is progressing our implementation of a new operating model. The objective is to create a high performing organisation that is efficient and effective, and delivers maximum value for the Northern Territory.

An operating model describes how the major parts of a business — the structure, assets, systems and processes — work together to deliver value. The program is focused across the entire business, looking to ensure we have an integrated workforce, with clear accountabilities, supported by properly-functioning ICT systems and streamlined processes that allow efficient work across the business. Implementing the model will be a multi-year journey and once complete, our new Operating Model will deliver:

- A Meter-to-Cash ICT solution that enables compliance with the Northern Territory National Electricity Rules (NT NER) and improved customer billing and service outcomes.
- A one stop customer interface into the business providing a more consistent customer service and trackable customer service requests.
- Improved regional and remote service delivery by enabling sharing of capability, improved asset management practices and better fault response.
- A 24/7 Operations Hub to service the whole of the NT with real-time operations' support, which will provide better fault response and improved customer outcomes.
- Consolidated Asset Management and centralised Capital Project Delivery functions to drive improved and standardised practices and governance.
- Consolidated Service Delivery and Works Management function and system to enable a standard approach to works' planning, scheduling and dispatch and integrated resource planning.

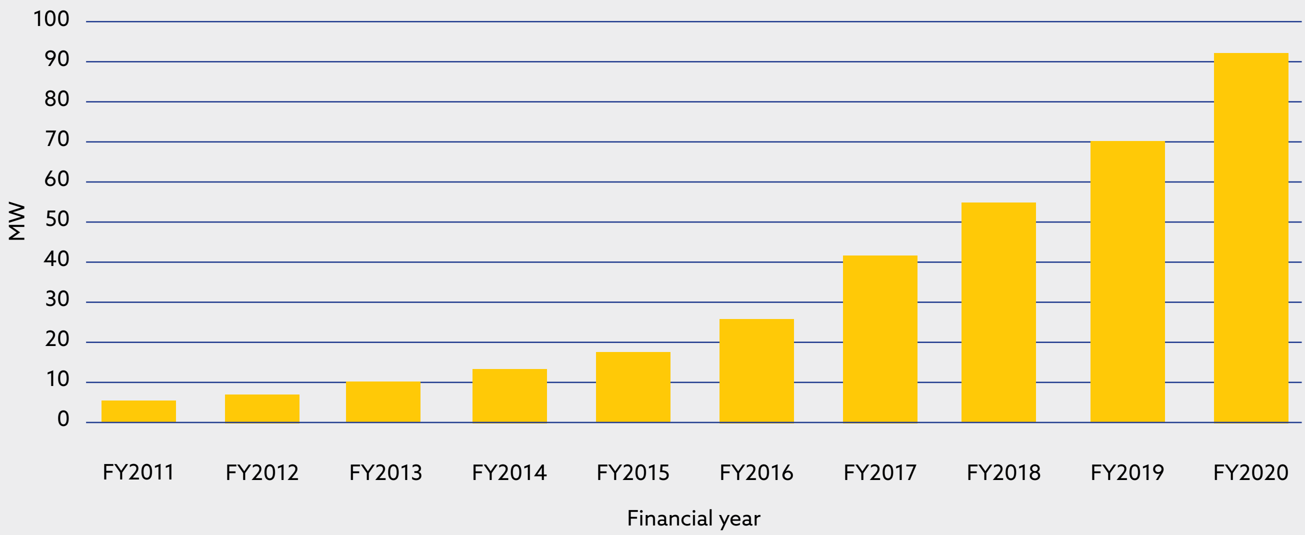
Our Information, Communication and Technology (ICT) program is a key enabler of our operating model. Appendix A provides a summary of our ICT program over the past year, and our plans going forward.

1.2 Pivoting to the future

Over the last decade, the traditional energy market has undergone a monumental shift as renewable energy becomes a larger part of our generation mix. Our customers have been leading the change by installing solar systems to meet their own energy needs and exporting into the grid. About 1 in 6 of our customers now have a solar installation. As seen in **Figure 2**, solar rooftop capacity has grown from 6 MW to 91 MW of capacity over the last decade. Over the last regulatory year, we have seen 21MW of new solar added, representing a growth rate of 30 per cent.

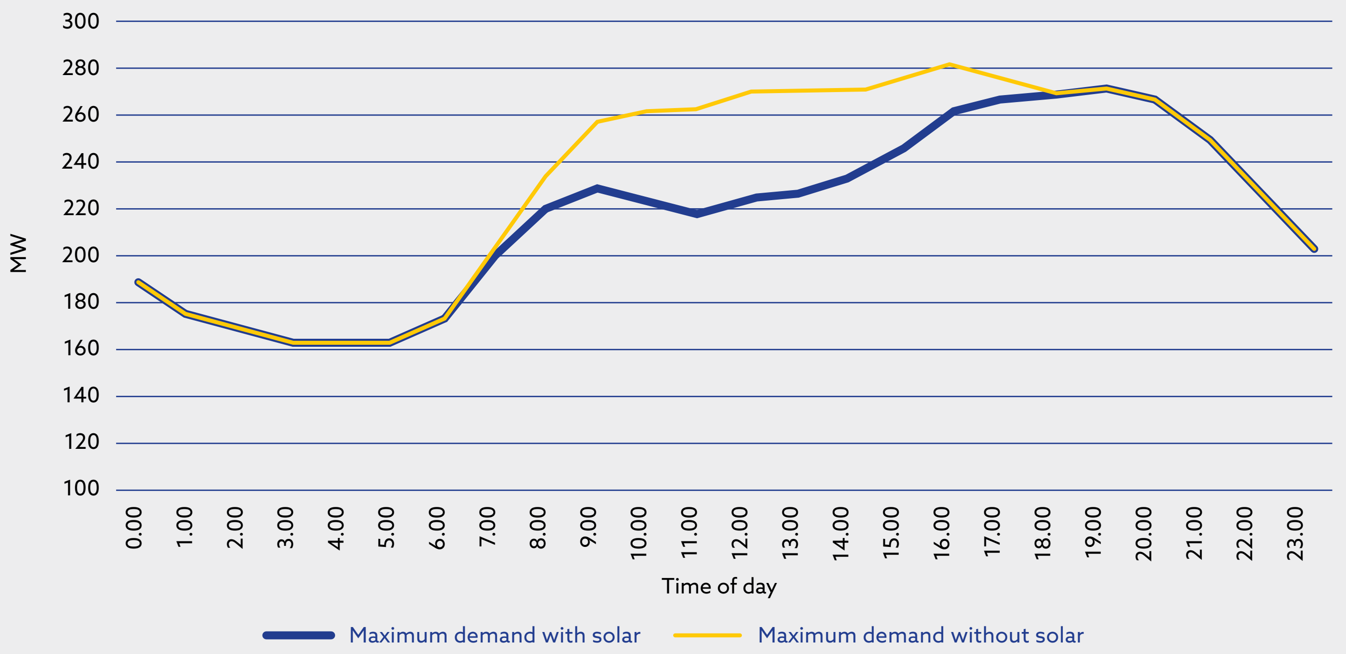
The shift to renewables has been positive for the Territory and the efficiency of our network. Unlike the southern states, demand for electricity in the NT occurs in the middle of the day when solar delivers significant capacity. This has provided our network with significant headroom to meet demand, limiting costly capacity investment. This can be seen in **Figure 3,** which shows that demand for energy from our network has flattened during the day as customers use solar to meet their energy needs.

Figure 2: Installed solar generation capacity on regulated network (MW)



Humpty Doo zone substation.

Figure 3: 2019-20 maximum demand day profile with and without solar – Darwin Katherine (MW)



The NT Government's Roadmap to Renewables will accelerate change in the energy market. The Government's recent report identifies strategies to achieve a 50 per cent renewable target for all electricity consumed from our network by 2030.[2] This will not only boost solar generation in the Northern Territory, but is likely to be accompanied by increasing battery storage to meet demand when the sun is not shining.

At Power and Water, we are embracing a renewable future where more customers actively participate in the market. We recognise that Power and Water need to be leaders in the Territory's transition to a renewable future, by planning ahead and being innovative and agile.

This requires a clear shift in thinking. In the past, we planned the network in a centralised system where our job was to transport large generation one-way to customers. We are now moving to an organic environment where generation decisions are open to our customers and the market.

We understand that a successful transition to a renewable future requires forward thinking on how to bring about an affordable, reliable and individualised service. Below, we identify emerging issues with managing solar on the network that we are currently problem solving. We also identify longer term issues facing our network including managing peak demand and the health of our assets. In the coming months, we want to bring these discussions to our stakeholders so we can integrate community-led problem solving.

Key issue in the short term – Managing solar exports

Our poles and wires network were originally designed to transport energy one-way to our customers, rather than exporting energy back into the grid. While the network has some in-built resilience, we are seeing emerging issues with the rapid growth in solar energy on our network.

The most pressing issue is security of the system when demand for energy is low. This occurs at times of the year when energy consumption is very low, but solar exports are high such as on sunny, dry days when air conditioners are not running. A low minimum demand can cause severe strain on the traditional generators in the energy system, and heighten the risk of tripping.

[2] Further information on the Northern Territory Government's roadmap can be found at: https://roadmaptorenewables.nt.gov.au/

Figure 4 compares the demand at half hourly intervals for the lowest demand day in 2017 and 2020 in Darwin-Katherine. It shows that minimum demand used to occur overnight but now occurs in the middle of the day when customers are using power from their solar rather than the grid. The minimum demand is much lower in 2020 than 2017, reflecting the high level of solar on the network and potentially less demand for energy during COVID-19. We are currently investigating the safe zone for minimum demand, but early indications are a range of between 50 and 65MW.

A further issue with growing solar exports is quality of supply, with reverse flow from exported energy impacting voltage stability. Voltage issues negatively impact customer experience from appliance damage to dips in voltage. In recent years, customers have reported more voltage issues on our network, and our audits also indicate that we are operating the network outside of the preferred voltage limits.

Our network business is working with System Control on investigating options that can help alleviate minimum demand and voltage issues at least cost. We recently produced a new technical specification on installation of solar on our network which sets size limits, and requires new installations to integrate with battery energy storage systems. In the short term, this provides a method to slow the further deterioration in minimum demand and voltage issues by allowing us to manage exports on new solar installations.

A longer-term solution is to improve visibility and coordination of renewable generation within the network. A key initiative we plan to undertake next year is a minimum demand forecast at a local level to help us understand where there are particular issues on our network. This may lead to longer term solutions such as Virtual Power Plants, or community batteries. We recognise that these decisions directly impact the experience of our customers, and for this reason we will be engaging with the community on the solution mix.

Long term planning focus – Flattening peak demand and maintaining ageing assets

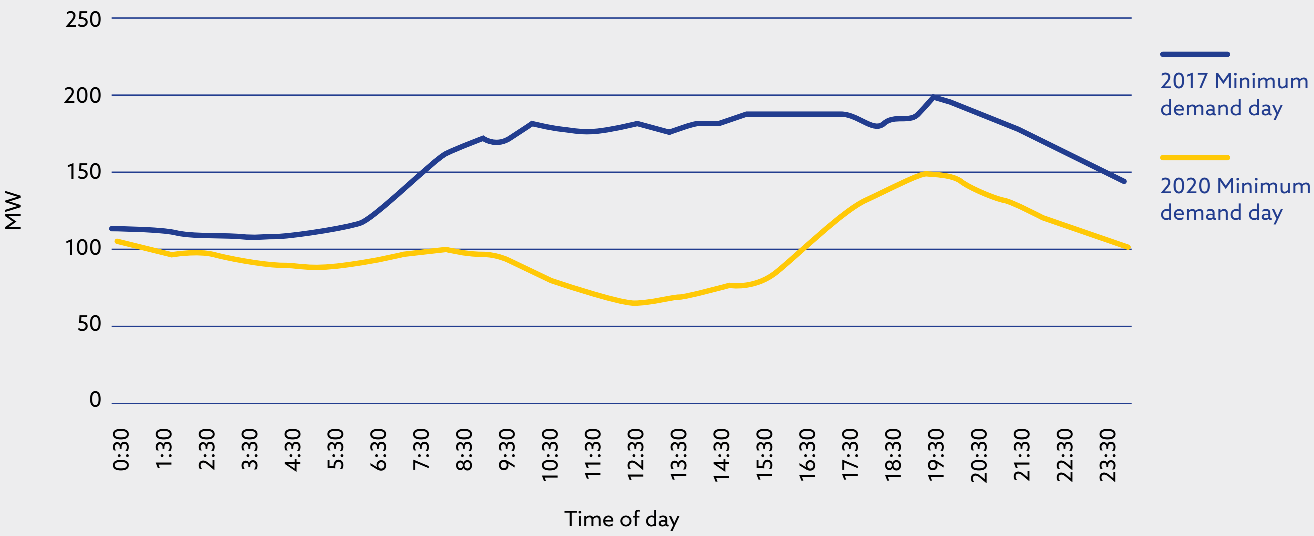
In the longer term, our focus is on managing peak demand growth and minimising the costs of renewing existing assets.

In recent years, we have seen moderate to falling peak demand growth at a system level, meaning that new network investment has fallen significantly. A key reason has been growing installation of household solar, which has helped meet the energy needs of customers at peak times during the day. Peak demand from the grid has now shifted to the late afternoon. This reflects that customers rapidly switch back to the network when the sun loses its potency causing a sharp peak at about 5pm.

In the longer term, we expect to see more industrial and residential customers connect to our network. We also expect to see more electric vehicles on the road in the medium to longer term. This will increase energy consumption and demand at peak times.

In this light, a key long-term objective is to minimise new network investment by shifting energy use to times when the network is under-utilised, and using batteries from stored solar to generate during peak times. This would involve a mix of tariff incentives, and demand management initiatives. **Box 1** on the next page provides an illustration of how electric vehicles would increase consumption and demand for energy from the grid by 2050, and how shifting charging times to the day and overnight can reduce peak demand and increase minimum demand.

Figure 4: Comparison of demand profile on minimum demand day in 2017 and 2020 in Darwin-Katherine (MW)



Box 1 – How will electric vehicles change demand on our network

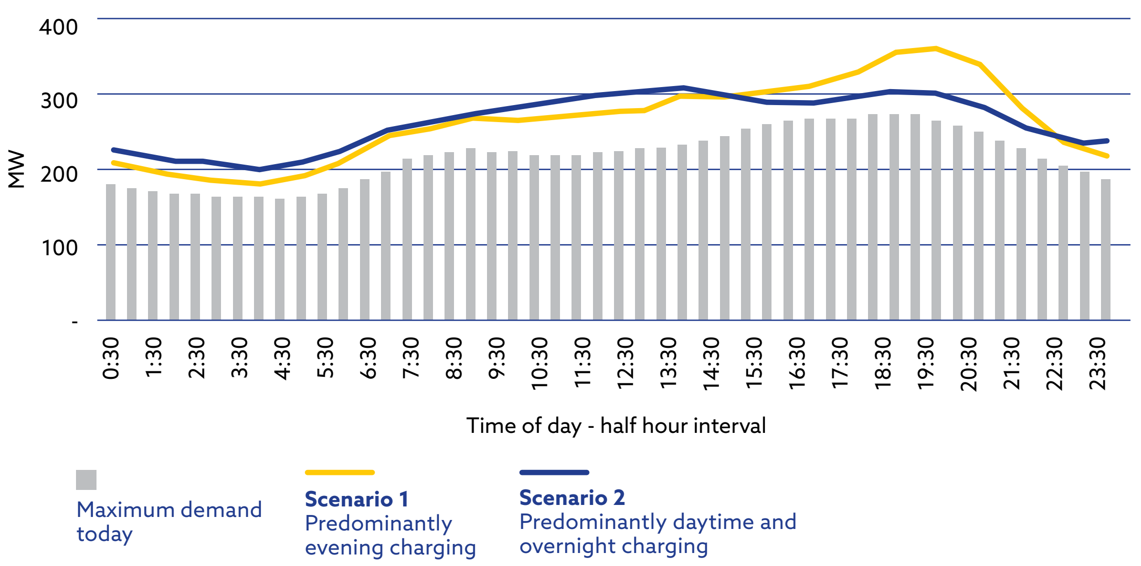
The Australian Bureau of Infrastructure, Transport and Regional Economics forecasts that electric vehicle will comprise 65% of all Australian vehicle sales by 2050.[1] While there are natural barriers to electric vehicles in the Northern Territory, it is possible that 1 in every 2 vehicles may be electric by 2050.[2]

Dynamic Analysis modelled the likely impact of this level of electric vehicles on a maximum demand day in 2050 in Darwin, compared to today (grey columns) based on time of day when customers charge their vehicle.[3] The model results are set out in **Figure 5.**

Scenario 1 (yellow line) is the maximum demand in 2050 assuming today's charging patterns where 40 per cent of owners charge vehicles between 5pm and 9pm. **Scenario 2** (blue line) is where charging occurs mostly in the daytime and overnight, and only 15 per cent of charging occurs between 5pm and 9pm.

Scenario 1 would require extensive investment to meet demand across our network. In contrast, Scenario 2 would shift demand to times when solar is at its peak and overnight when the network is under-utilised. Scenario 2 would improve affordability by minimising the need to invest in capacity, while improving utilisation of assets. The challenge of flattening the curve under high penetration of electric vehicles will require innovative demand management strategies including integration of DER technologies and pricing incentives.

Figure 5: Impact of EV on Darwin-Katherine maximum demand day in 2050 under different charging scenarios (MW)



Notes:

[1] See: Bureau of Infrastructure, Transport and Regional Economics (BITRE), 2019, Electric Vehicle Uptake: Modelling a Global Phenomenon, Research Report 151, BITRE, Canberra ACT at: https://www.bitre.gov.au/sites/default/files/bitre-report-151.pdf

[2] The limited range of electric vehicles presents unique barriers to uptake of electric vehicles in the Northern Territory. These include the vast distances between urban communities and regional centres. This was a key issue raised in a Northern Territory Government consultation on preparing the Territory for electric vehicles. The discussion paper can be accessed at: https://haveyoursay.nt.gov.au/EVdiscussionpaper

[3] This is based on high level modelling, which assumes 50 per cent of vehicles are electric by 2050 with a slow uptake between 2020 and 2030, an acceleration in 2030 and 2040, and slower growth between 2040 and 2050. We have also assumed that energy vehicles improve efficiency by 20 per cent from today's levels by 2050.

A further focus is on ensuring that we minimise replacement and renewal expenditure by extending the life of our assets and identifying lower cost solutions when retiring assets.

Power and Water has made significant inroads into improving reliability over the last decade by implementing a rigorous asset management system. Our system seeks to maintain our assets across the lifecycle and target corrective action on assets that pose the most serious risk to safety and reliability. Our approach has enabled us to keep many of our assets in service longer than their expected life. This is despite the inclement weather conditions in the Northern Territory which place significant wear and tear on our assets.

We are thinking carefully about how to maintain and improve our risk management frameworks to extend the life of our assets. We also recognise that increased solar and battery provide opportunities for demand management to retire rather than replace assets. Further our options analysis examines opportunities to de-scale and better optimise the network as a means of reducing our replacement expenditure.

1.3 Summary of 2020 TDAPR – Material programs

Power and Water's regulated network comprises three stand-alone in Darwin-Katherine, Alice Springs and Tennant Creek. **Figure 6** identifies the major projects and programs with a value greater than $5 million. A detailed description of system limitations and proposed solutions is set out in Chapter 6 of this document. We briefly outline the key limitations and projects below.

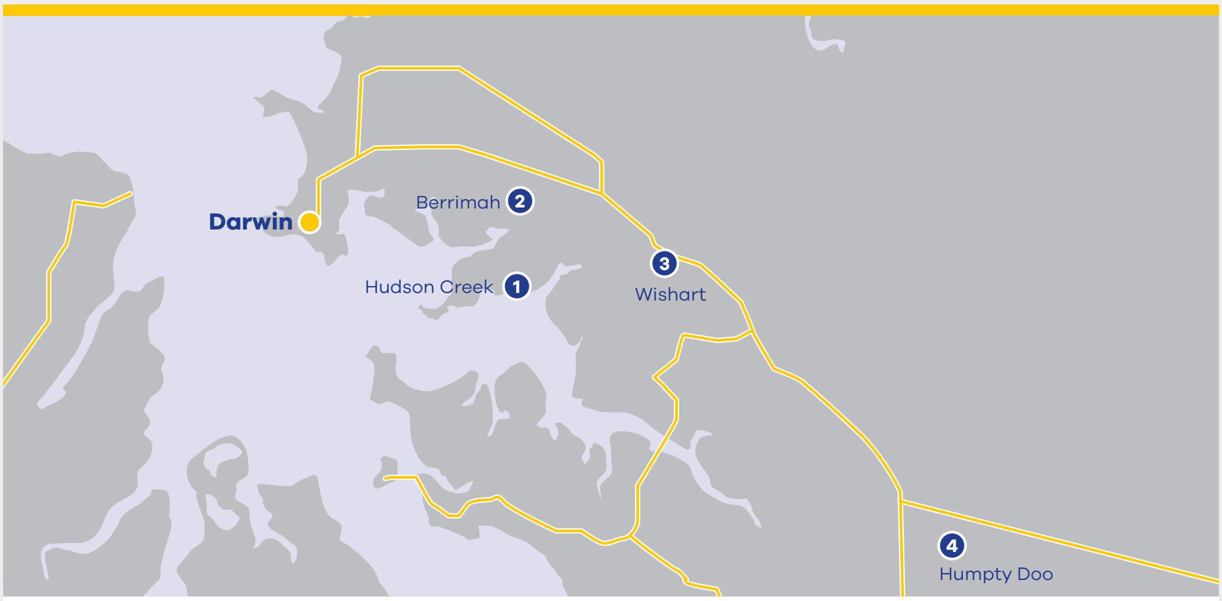
Asset condition limitations

The focus of our forecast investment is managing assets in poor condition that may lead to significant reliability, safety or security risks. There have been no material changes from last year's report.

The major replacement projects relate to zone substations in Berrimah and Humpty Doo zone substations in the Darwin region. Both substations have systematic issues with ageing equipment including power transformers and circuit breakers. We are also replacing our Energy Management System, which is approaching end-of-life and lacks the tools we need in the short term to manage the changing mix of generation sources and their impact on system security. In Alice Springs, the major replacement program is targeted at poles which have structural integrity issues due to corrosion.

Power lines in Alice Springs.

Figure 6: Major projects (over $5 million) over the planning period



1 Replace Energy Management System

Upgrade out of support system

Timing 2024

2 Replace zone substation

Condition issues with transformers and circuit breakers

Timing 2024

3 Non-network and interconnection solutions

Exploring non-network and interconnection options to meet commercial load in area

Timing Ongoing to 2025

4 Replace zone substation

Rural substation has deteriorated transformers and circuit breakers

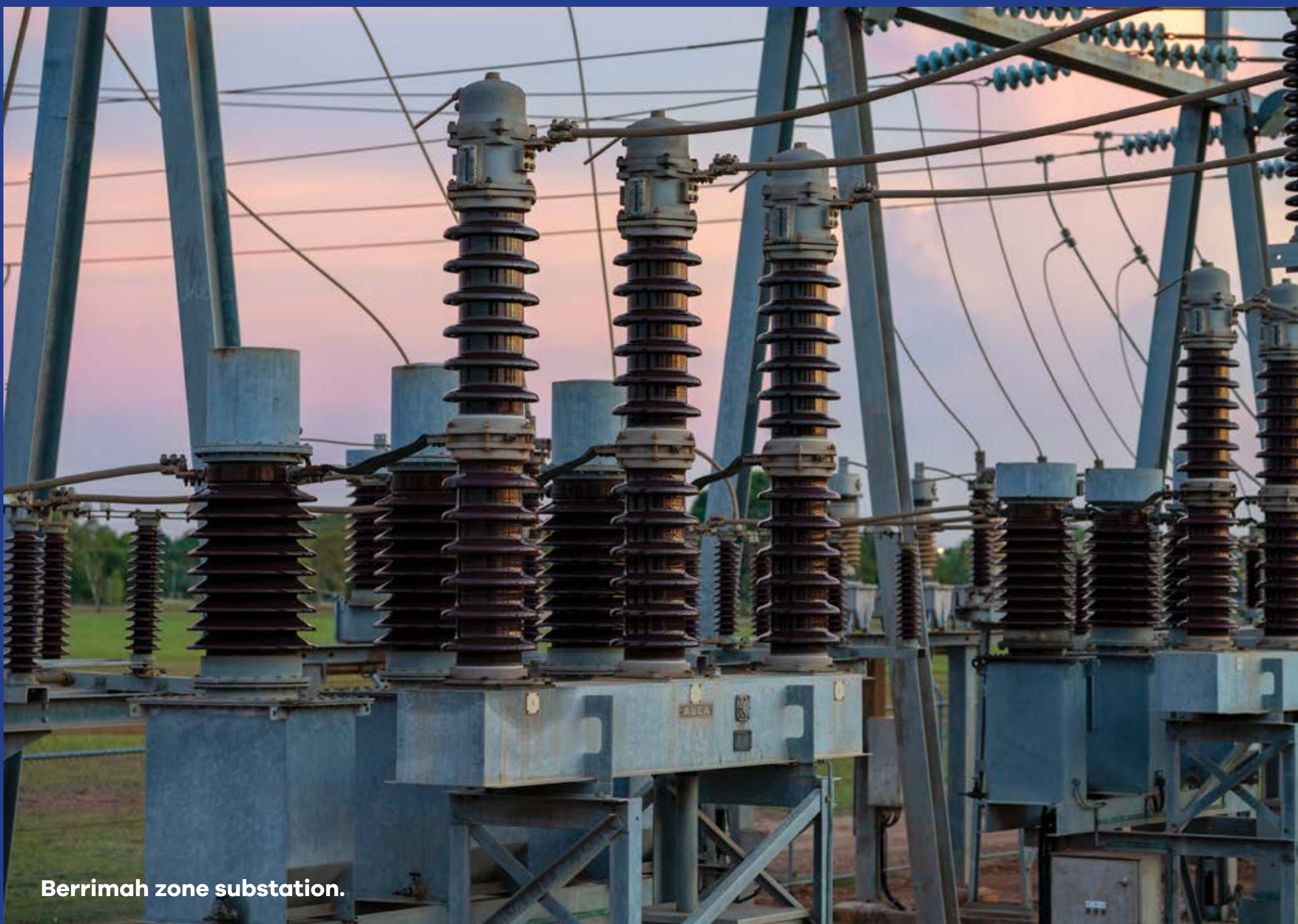
Timing 2023

1 Replace and remediate poles

Replace poles that are corroded from salt exposure and are unsafe

Timing Ongoing to 2025

Power lines at Wishart.

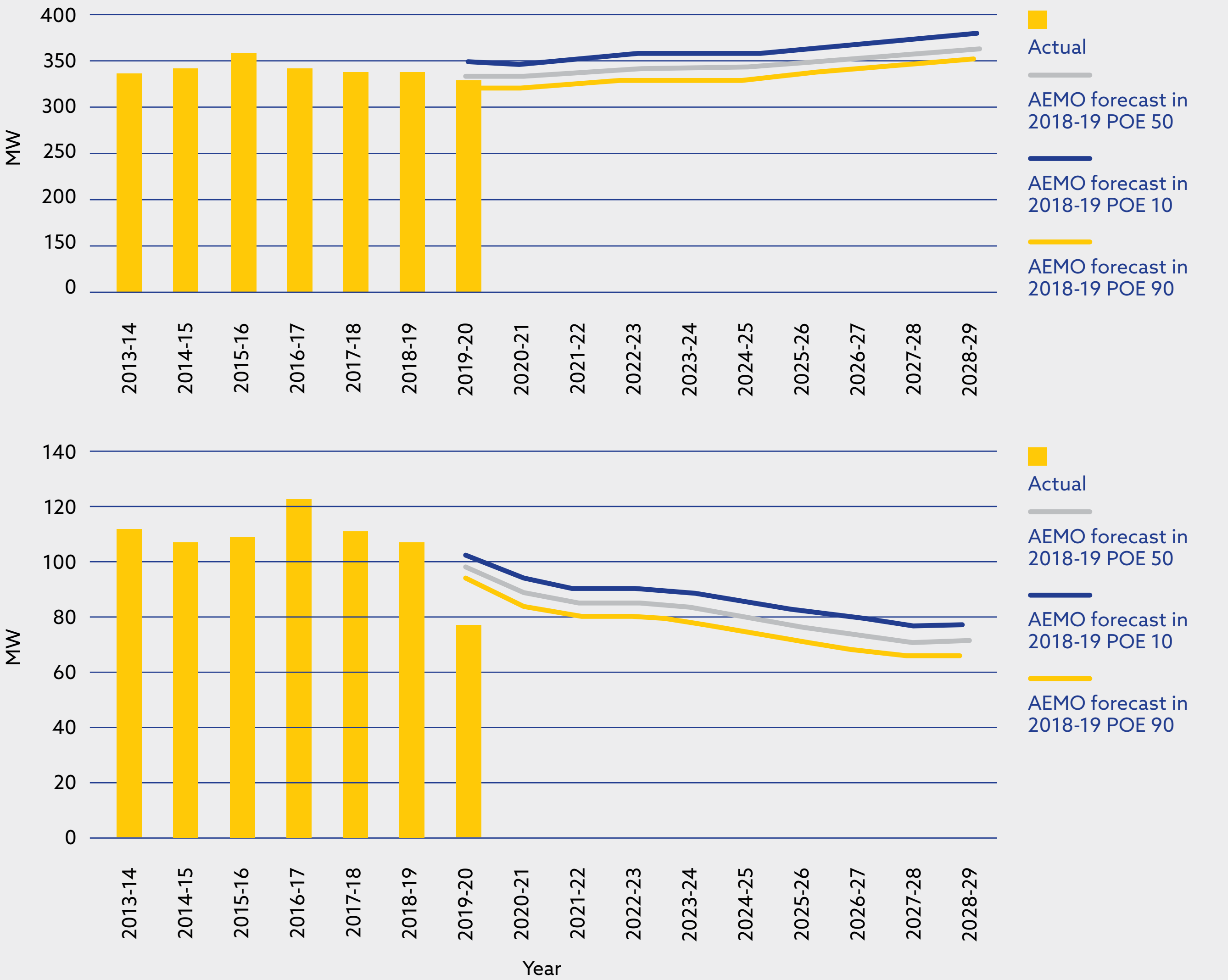


Berrimah zone substation.

Capacity limitations

The 2020 TDAPR identifies that maximum and minimum demand is lower than forecast across all regions. This can be seen in **Figure 7** which aggregates the actual maximum demand (above) and minimum demand (below) for 2019-20 across the regions, and compares this to the forecast scenarios prepared by AEMO for the Utilities Commission last year. The fall in demand has been primarily driven by growing solar from rooftops, lower economic activity, and the impact of COVID-19 on commercial energy volumes. In Chapter 5, we identify demand by region together with our transmission line, zone substation and distribution feeder demand forecasts.

Figure 7: Aggregate maximum demand (top) and minimum demand (bottom) across the 3 regulated networks – Actual and AEMO 2018-19 Forecast



The lower system demand forecasts have not significantly altered the capacity limitations we identified in last year's TDAPR. This is because most of our capacity constraints are driven by major new connections, many of which are forecast to proceed on time.

A key change this year has been forecast load exceeding the capacity of the Wishart modular substation in 2024-25 under normal conditions. Our forecasts of connections indicate that we will have significant new industrial developments in the area in 2024-25. We will be exploring interconnection and demand management options that could meet the forecast load in the short term under a critical contingency, and in the longer term under normal conditions.

Non-network opportunities

In September 2020, we published a Demand Management engagement strategy which aims to galvanise stakeholder insights on non-network options to resolve current and emerging limitations. In Section 4.4 of this year's report we discuss how we think about demand management in our solutions mix, and some of the trials we are currently involved in. Chapter 6 of this year's report also identifies specific projects that may be addressed through a non-network solution such as Wishart and Katherine.

Lake Bennett power lines.

2. Our network

Power and Water provides electricity services to customers in the Northern Territory. Our electricity networks in Darwin-Katherine, Alice Springs and Tennant Creek are regulated by the Australian Energy Regulator. We deliver about 1700GWh of energy to about 85,000 customers in these regions.

The purpose of this section is to describe the network services provided by Power and Water to regulated customers in the Northern Territory, together with information on our operating environment and network assets.

2.1 Power and Water's electricity network Power and Water is a Northern Territory (NT) government owned corporation that provides electricity, water, sewerage and gas to our customers. The Power Services division of Power and Water plans, builds, operates and maintains the distribution and transmission electricity networks that transports electricity between generators and customers. Our role in the electricity network is depicted in **Figure 8** below.

The electricity network services we provide customers in Darwin-Katherine, Alice Springs and Tennant Creek networks are regulated by the Australian Energy Regulator (AER) under the NT National Electricity Rules (NT NER).[3] The 2020 TDAPR focuses on these networks, which are described below:

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

These three networks are not connected to the national grid and operate as three separate stand-alone systems. **Figure 9** identifies the key regions.

Figure 8: Role of Power Networks in the regulated NT electricity market

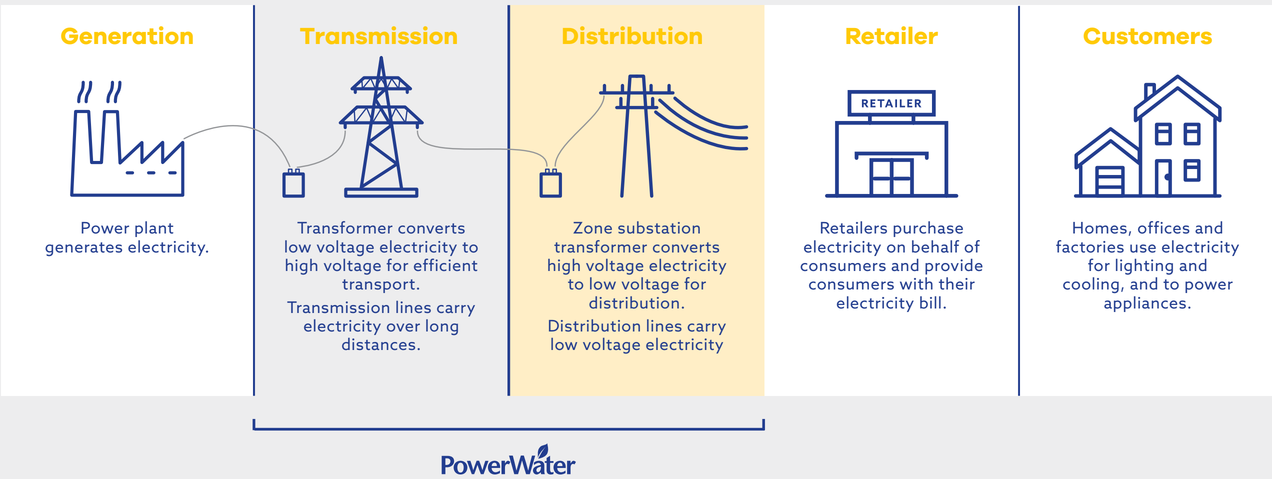
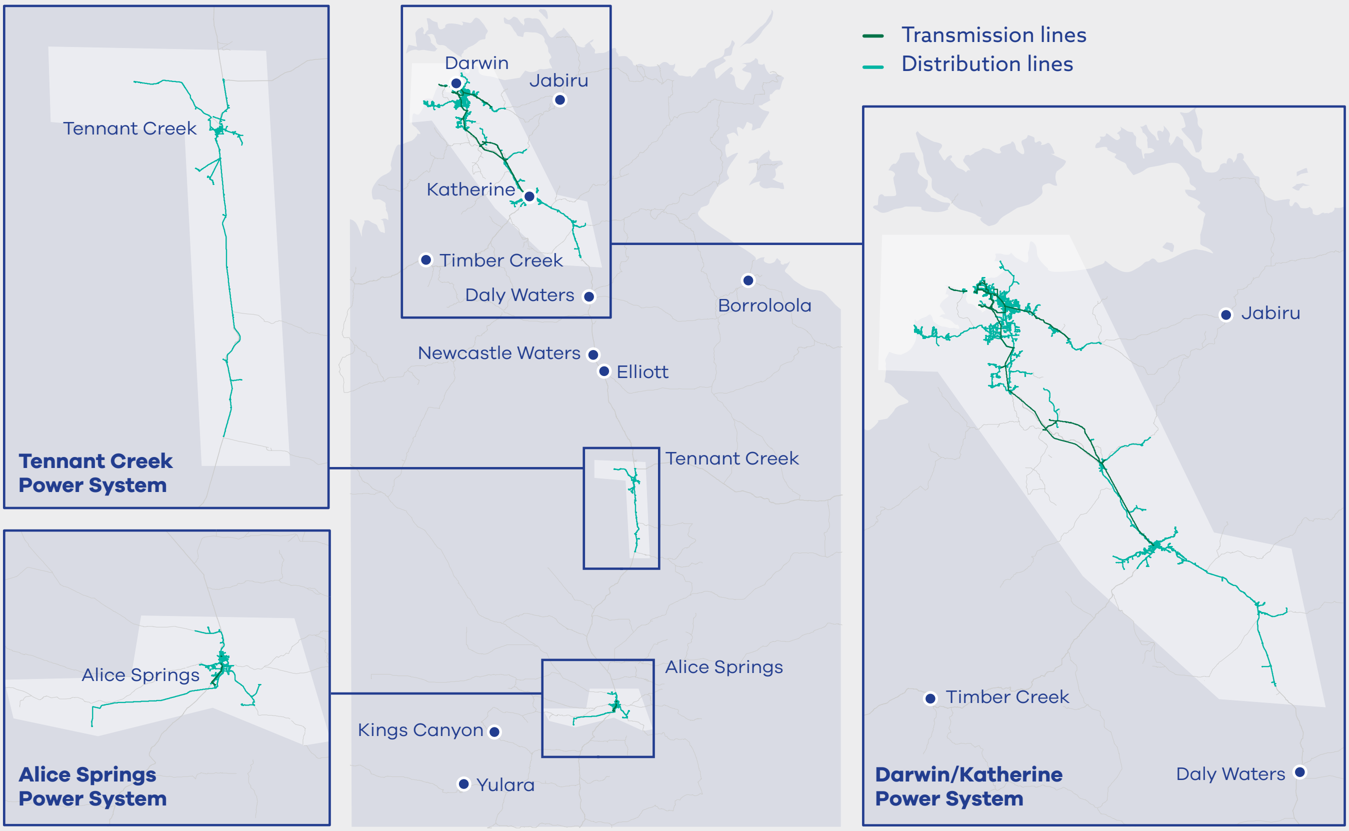


Figure 9: Regulated areas of Power and Water's electricity network



We operate a transmission network in Darwin-Katherine and Alice Springs only. Our zone substations are the connection point between our transmission and distribution network. The zone substations transform the electricity from 66kV into 22kV and 11kV voltages before they are transformed to lower voltages via our distribution substations. **Table 1** provides quantities of assets on our transmission and distribution regulated networks by region, with further details provided in Appendix B of this report.[4]

We also have automatic under frequency load shedding (UFLS) schemes implemented for the Darwin-Katherine, Tennant Creek and Alice Springs networks consistent with our jurisdictional obligations for emergency management.

[3] 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.

[4] In the Darwin-Katherine network, the UFLS is based on a combination of defined frequency settings and rate of change of frequency. In Darwin-Katherine, the system is designed so that under contingency events feeder blocks are progressively disconnected to ensure the system frequency remains above 47Hz. In Alice Springs and Tennant Creek, the UFLS is based on defined frequency settings only. The schemes in these regions are implemented via feeder management relays with each feeder assigned to one of six blocks. We have not identified any new programs in this year's TDAPR.

Table 1: Asset quantities by network type

Network	Asset category	Darwin-Katherine	Alice Springs	Tennant Creek	Total
Transmission	132kV underground (km)	0	0	0	0
Transmission	132kV overhead (km)	354	0	0	354
Transmission	66kV underground (km)	25	14	0	39
Transmission	66kV overhead (km)	343	33	0	376
Transmission	Sub-transmission substations	3	1	0	4
Transmission	Towers	2781	217	0	2998
Distribution	Zone substations	22	3	1	26
Distribution	Distribution feeders – underground (km)	768	97	3	868
Distribution	Distribution feeder – overhead (km)	2610	509	355	3474
Distribution	Distribution substations	4160	561	136	4857
Distribution	Low voltage – underground (km)	596	98	1	695
Distribution	Low voltage – overhead (km)	1012	129	44	1185
Distribution	Distribution poles	32232	6244	3221	41697
Distribution	Service lines – residential	38712	7067	1047	46826
Distribution	Service lines – commercial	8151	1032	291	9474

2.2 Our operating environment

Power and Water's regulated network service operates under national and territory specific regulatory frameworks. We are currently subject to the NT National Electricity Law (NT NER), which is a modified version that allows for staged transition to the national Rules. The AER has responsibility for economic regulation and enforcement under the NT NER. We are also subject to Northern Territory specific legislation and guidelines including the Electricity Reform Act which stipulate that our services must be licenced.

Our network has many unique characteristics that impact on the way we operate our business. We have the smallest electricity network compared to other networks in the National Electricity Market on measures such as customers, energy volumes and peak demand. However, our network extends over a vast area compared to other networks. This can be seen in **Figure 10** which compares Power and Water to other networks.

Our lack of scale leads to a cost disadvantage when compared to other networks in the NEM. Networks are capital intensive, meaning a higher proportion of our costs are fixed. Due to our size, we are unable to spread the cost among our customer base, which can make us look more expensive than our peers on metrics such as cents per kilometre basis.

Power and Water also operates extreme environments particularly in Darwin which has high humidity in the wet season and is prone to destructive cyclones and tropical storms. 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. Further, the extreme humidity means greater use of air conditioners in the peak Darwin wet season.

These geographic and environmental variations influence the design criteria for infrastructure as well as Power and Water's ability to respond to incidents on the transmission and distribution networks.

Figure 10: Comparison of PWC and other networks in the National Electricity Market by customer numbers

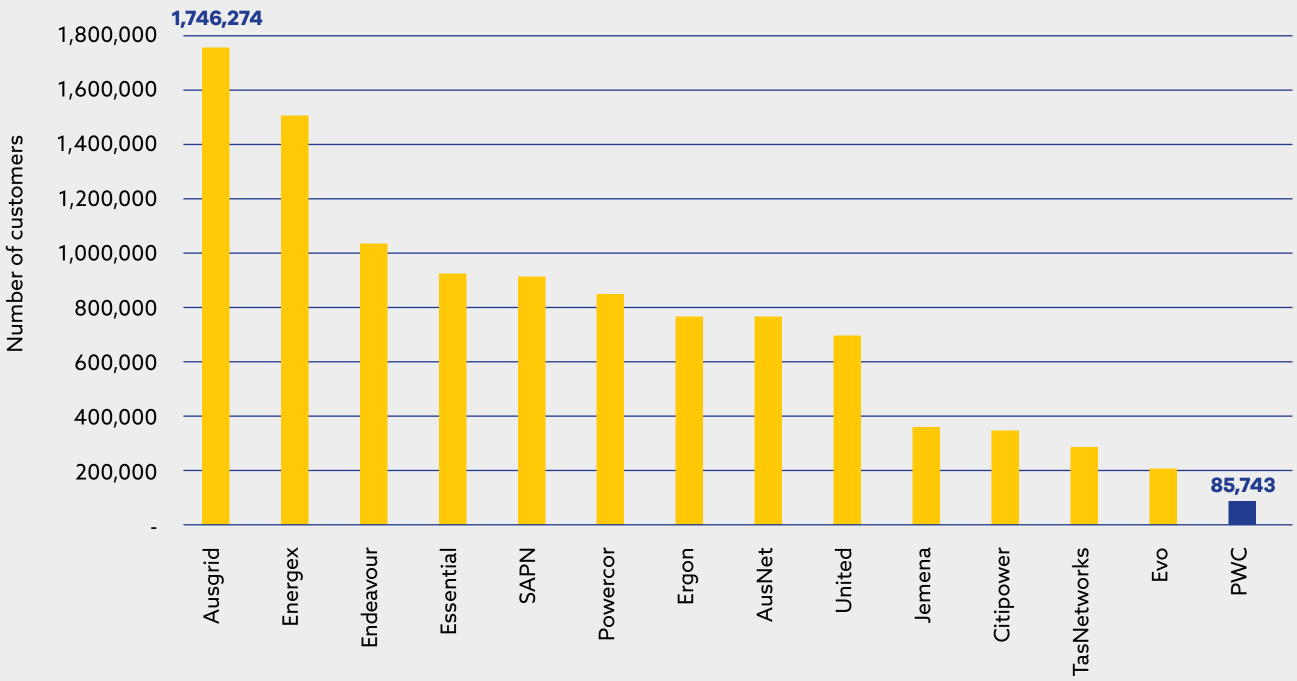


Figure 10: Comparison of PWC and other networks in the National Electricity Market by customer density

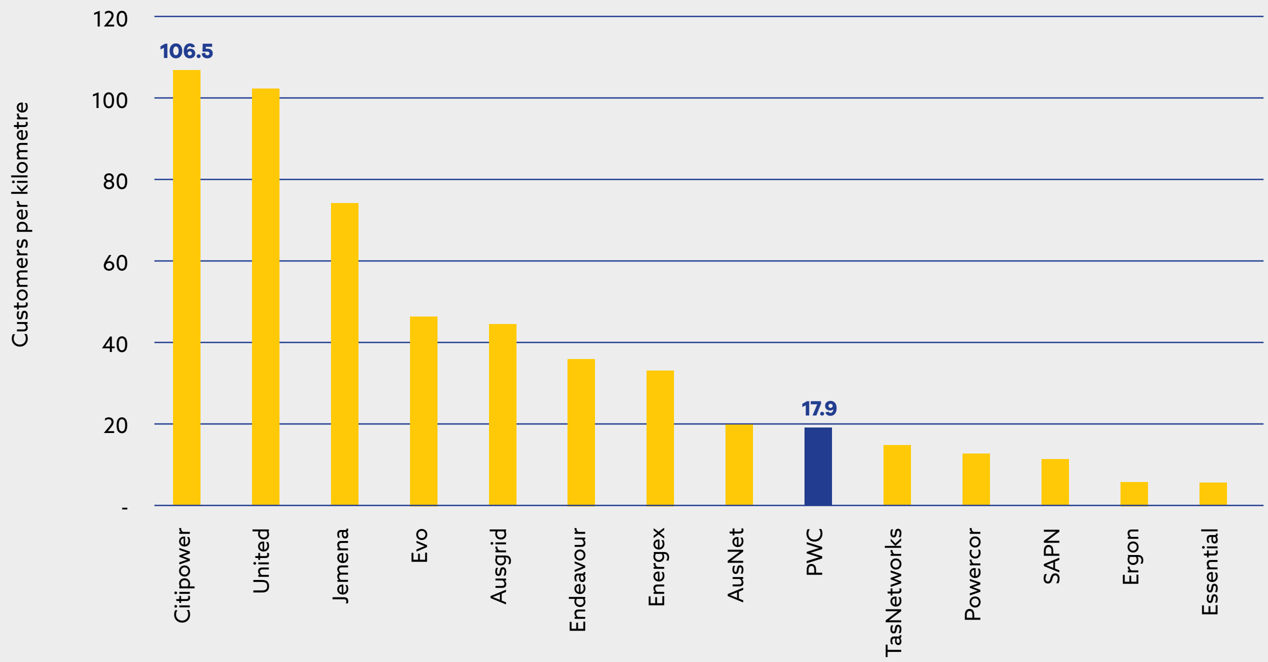


Figure 10: Comparison of PWC and other networks in the National Electricity Market by energy

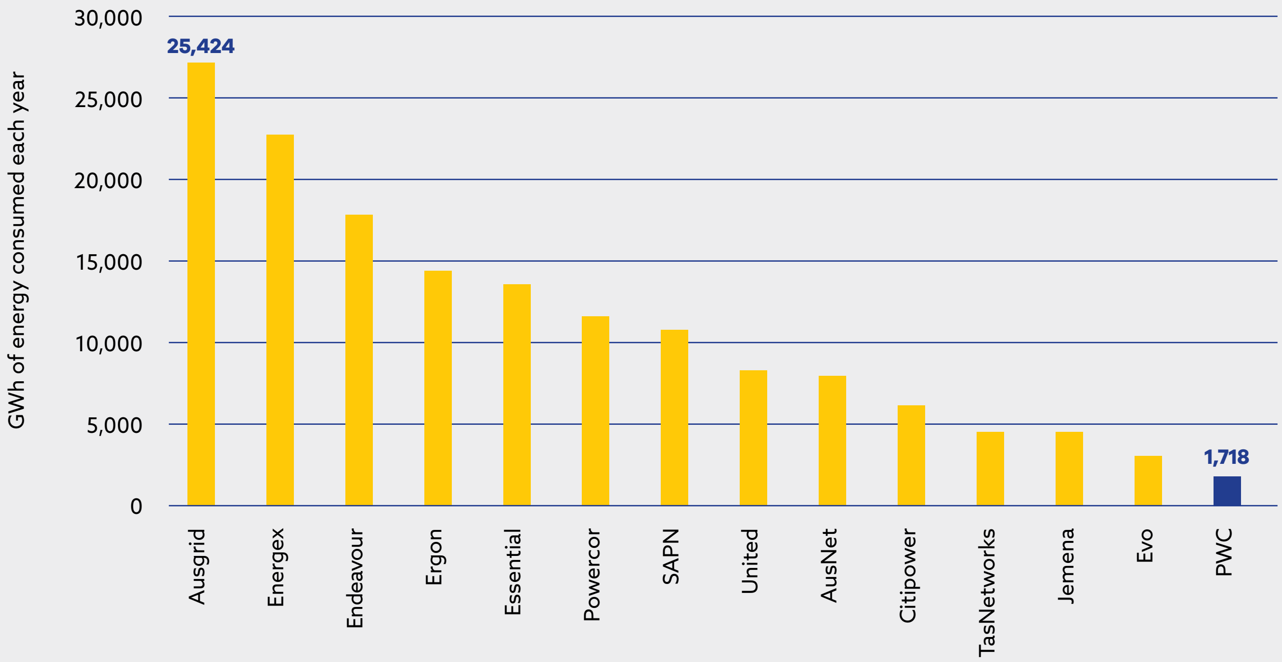
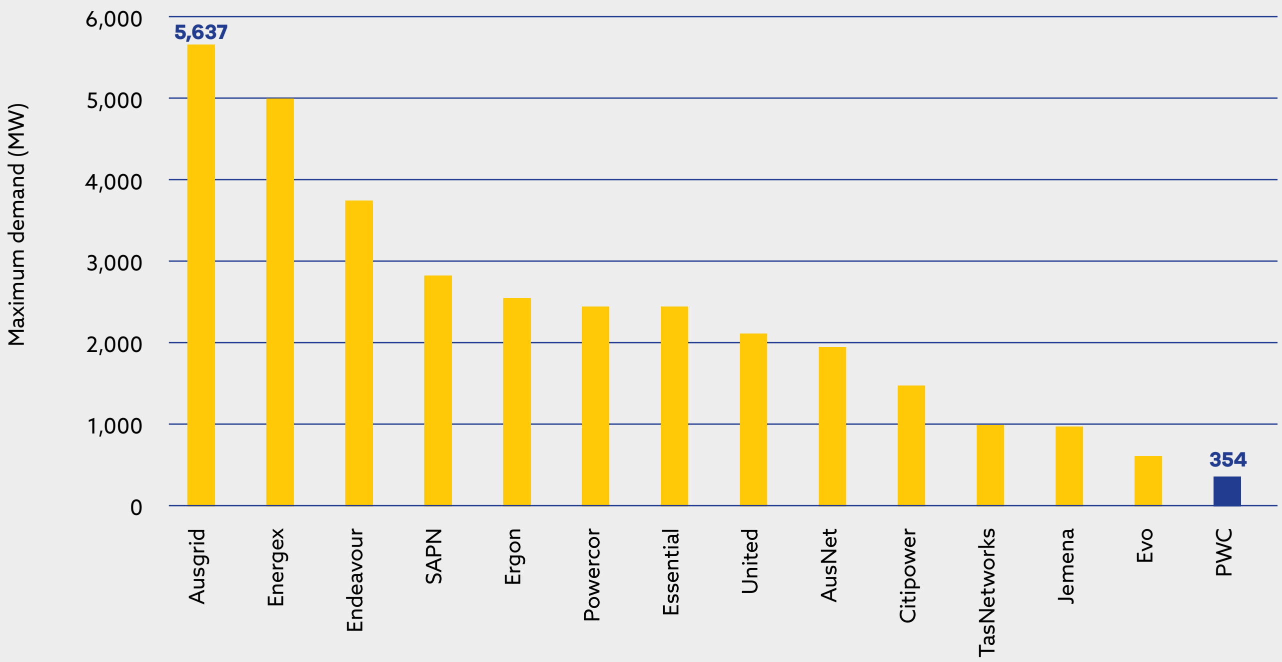


Figure 10: Comparison of PWC and other networks in the National Electricity Market by demand



Rusted power poles in Alice Springs.

Power and Water technicians on the road in Tennant Creek.

Pine Creek zone substation.

Electric car charging.

3. Network Performance in 2019-20

Over the last decade, Power and Water has significantly improved our reliability performance. In the 2019-20 period, we performed better than our regulated targets in the CBD and urban areas, but fell short of some of our targets in rural areas. Quality of supply issues continue to emerge as more customers connect and export solar. Increased solar is also causing challenges with keeping minimum demand at high enough levels to ensure system security.

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, quality of supply, and network security. These issues are discussed in the sections below.

3.1 Reliability performance

Our customers expect us to minimise frequency and duration of power interruptions. The purpose of this section is to report our reliability 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. Below we describe how Power and Water performed in 2019-20 against the key metrics in the EIP Code including reliability performance by feeder categories and improvement of 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 provide a submission to the AER on our performance against the scheme, nor do we provide forecasts of our performance. However, we still report our reliability performance in our response to the AER's Regulatory Information Notice (RIN).

Reliability performance of feeder categories in 2019-20

The EIP Code requires Power and Water to propose reliability targets for 2019-24 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.[5] The SAIDI is average minutes off supply per customer, and SAIFI is the average number of interruptions experienced per customer. **Table 2** below reports our 2019-20 SAIDI and SAIFI performance by feeder category against the targets approved by the Commission under the EIP Code.

[5] 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.

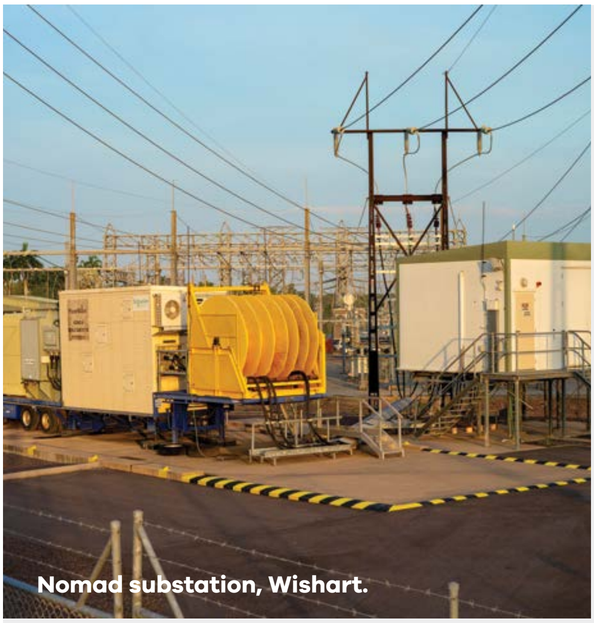
Katherine solar farm.

Table 2: 2019-20 Reliability performance compared to approved target in EIP Code

Feeder category	Adjusted SAIDI[1]			Adjusted SAIFI[2]		
	Performance target	Actual performance	Performance	Performance target	Actual performance	Performance
CBD	4	3.73	Target met	0.1	0.03	Target met
Urban	140	53.4	Target met	2	0.97	Target met
Rural short	190	204.28	Target not met	3	3.38	Target not met
Rural long	1500	1556.6	Target not met	19	15.54	Target met
Whole of network	175.8	147.44	Target met [2]	2.6	2.36	Not applicable[2]

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



Nomad substation, Wishart.

Communications tower, Katherine.

Our annual performance can markedly differ from year to year due to weather and other unpredictable activity. We had relatively mild weather conditions meaning that adverse weather did not impact performance to the same extent as 2016-17 and 2017-18.

Our analysis suggests that asset failures played a more pronounced role in interruption duration in 2019-20, mainly due to several high voltage cable faults. Animal faults also significantly increased compared to previous years, likely due to increased bat activity in the dry season of 2020.

We outperformed our reliability targets for CBD feeders in 2019-20. The CBD category is highly sensitive to one-off asset failures or network operation process errors which usually affect a significant proportion of customers in the CBD. In the CBD, the major cause of recorded outages was a high voltage cable failure in May 2020 resulting in an outage to 29 customers for two hours. Further, there was a loose connection in a low voltage pillar that resulted in failure and loss of supply to customers for several hours.

We also outperformed our targets for urban feeders. Asset failures were also the dominant cause of significant failures including a high voltage cable fault in Parap and a fault on a distribution substation in Alice Springs.

We did not meet our reliability targets for rural short feeders. Asset failures were the most dominant cause of interruptions, largely due to two significant high voltage cable faults. A cable replacement program has commenced in Darwin's northern suburbs which will help mitigate future outages due to cable faults. A further reason for interruptions related to vegetation incidents where large trees fell onto overhead lines.

We met our SAIFI performance target for rural long feeders, but marginally did not meet our SAIDI target. The dominant cause of long interruptions on rural long feeders was adverse weather and asset failure. Distribution substations and surge arrestors continue to be the cause of most asset failures mainly due to repeated stress from lightning strikes and age related deterioration. Rural long feeders take longer to patrol due to their length, which inherently increases the SAIDI impact of sustained interruptions. In many cases, the cause of interruption was unknown, but likely to be caused by vegetation or animals that cause a sustained interruption but fall away from the line prior to the 15 minute reclose.

Worst performing feeders in 2019-20

The EIP Code also requires us to measure and report on the 5 worst performing feeders in the CBD, Urban, Rural-short and Rural-long categories.[6] This recognises that some of our customers receive worse reliability than others, and that we should be continually striving to cost-effectively improve performance for these customers.

Appendix B sets out our 5 worst performing feeders by category for 2019-20. 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 2019-20.

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 feeders, and the long skinny lines which take longer to patrol when there is a weather or environmental event that leads to an interruption.

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 2019-20, we will not undertake specific reliability works on CBD and urban feeders. This is because we are meeting our average performance standards for customers, and performance on worst affected feeders is within a reasonable range.

We plan to undertake reliability improvement works on the following short rural feeders:

- Virginia 22kV feeder – We plan to install reclosers in three locations on the feeder to improve network performance.
- Howard Springs 22kV feeder – We plan to install a new feeder tie, and switch and reconfigure the existing network. We also plan to install reclosers in three locations on the feeder and install animal protection.
- Warrego 22kV feeder – We intend to replace old 'fog-type' high voltage insulators with post insulators, together with installing a new switch to enable faster restoration during outages.
- Florina 22kV feeder – We plan to install reclosers in 5 locations on the feeder to improve network performance.
- McMillans 11kV feeder – We plan to install a recloser and install animal protection.

We note that other capital programs are also expected to support reliability on rural short feeders, such as the replacement of conductor on the Lake Bennett feeder, and the transmission line pole top replacement program. More information on these replacement programs can be found in Chapter 6.

For long rural feeders, we have been improving our diagnostics to reveal locations that contribute the most to interruptions. To improve overall performance on long rural feeders we plan to:

- Increase automation of the network by installing remotely operated switches, automatic reclosers and fused sectionalizes, allowing system operators to isolate faults faster and improve restoration time.
- Install animal protection to prevent faults from occurring.
- Utilise Distribution Fault Anticipation (DFA) systems on feeders to assist in the faster location of faults and more targeted hardware upgrades to reduce the frequency of interruptions, particularly those related to animals.

In terms of specific programs, on the Dundee feeder we plan to install a remote controlled switch to enable rapid restoration of supply during contingencies together with animal protection. On the Ali Curung feeder we plan to install reclosers in two locations, together with animal guards and animal protection on transposition poles.

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.

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

3.2 Quality of supply performance in 2019-20

Quality of supply relates to voltage disturbances that can impact a customer's energy supply and appliances. The supply issues are caused by voltage level disturbance, harmonic distortion, and voltage unbalance.

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 that respectively apply to our low voltage and high voltage network.[7] The standards applied to voltage fluctuations[8], harmonics[9] and voltage unbalance are set out in sections (insert) of Power and Water's Network Technical Code.

Power and Water actively monitors 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.

Customer complaints in 2019-20

Customer complaints are a key source of data to identify quality of supply issues. In 2019-20 we received 29 complaints from customers compared to 47 complaints in 2018-19. **Figure 11** compares the number of complaints by category between 2019-20 and 2018-19.

We investigated each complaint of our customer to understand the underlying issue. In 2019-20 the main cause of an identified complaint was related to faulty network equipment or environmental reason. **Figure 12** compares the underlying cause in 2018-19 to 2019-20.

[7] 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.

[8] A voltage fluctuation is a flicker due to changes in loads connected to the network. As the load increases and more current is being drawn, the voltage level drops (or vice versa).

[9] Harmonics voltages and currents occur when the normally sinusoidal 50Hz fundamental frequency waveform is distorted by the operation of appliances or devices (such as inverters) that draw non-sinusoidal currents from the supply.

[10] Voltage unbalance occurs when the voltage is different on the three phases. This is normally caused by unequal loading of the three phases and primarily impacts customers with three-phase supplies.

Figure 11: Comparison between 2018-19 and 2019-20 of quality of supply complaints by category

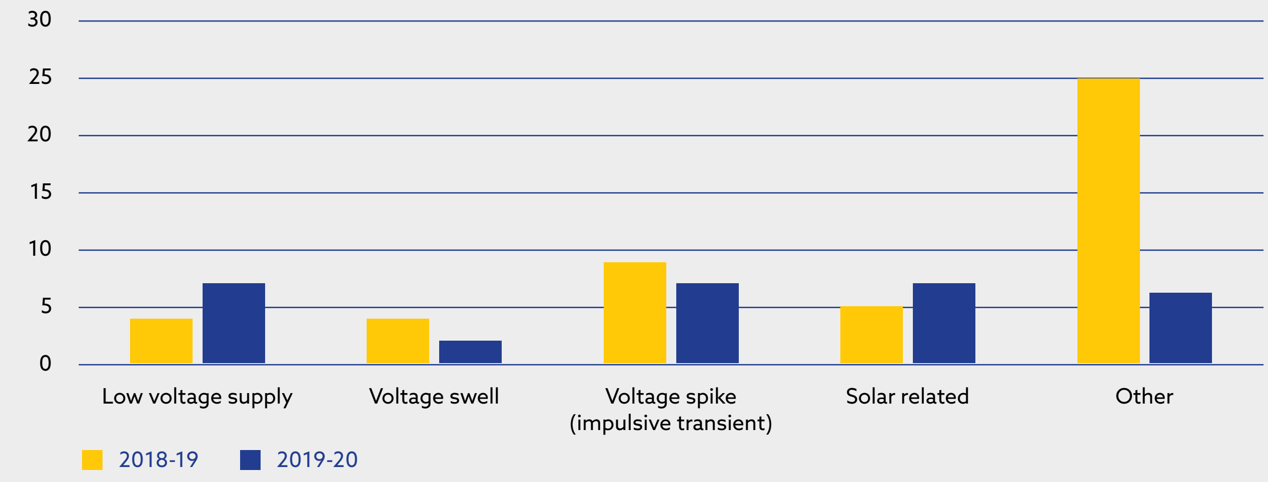
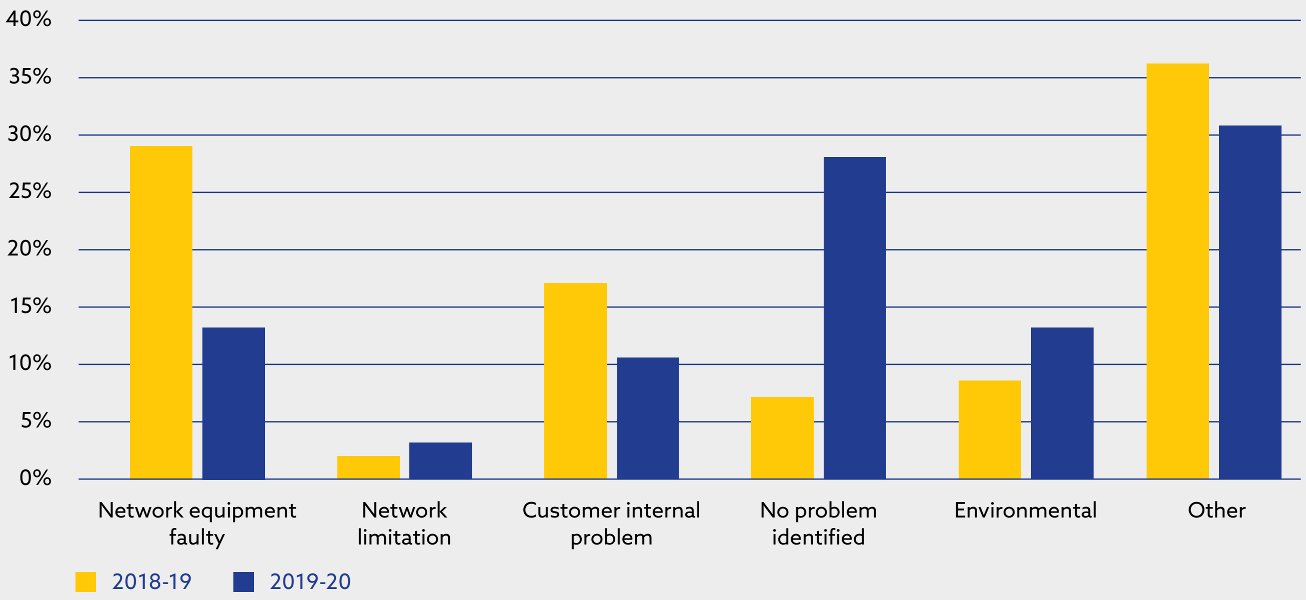


Figure 12: Comparison between 2018-19 and 2019-20 of underlying cause of quality of supply issue



Katherine substation.

Table 3: Voltage assessment performance

Voltage zone	Darwin	Katherine	Alice Springs
Below limits (<216V)	0.00%	0.00%	0.00%
Above limits (>253V)	0.00%	2.94%	0.00%

Low voltage quality audits

We conduct regular audits of low voltage quality, using a random sample of customers. Power quality assessment was performed in 2020 on the data obtained from meters installed at customers' connection points.[11] The meters installed measure and record voltage information for a period of 80 days, with measurements averaged over 10-minute intervals. The outcome of the assessment is shown in **table 3** above.

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. The program includes:

- Targeted augmentation of the low voltage network – This involves targeting areas of the network where voltage issues are most prominent based on customer complaint data and investigations. This is likely to be older suburbs where there has been significant new housing development with solar.
- Reviewing Darwin-Katherine Power System voltage management strategy – We are currently working on a full review of voltage management strategies for the Darwin-Katherine Power System (DKPS), in support of the evolving nature of the system including recent record low day-time system load, connection of large scale renewable generators, change in customer load types and behaviour (eg. more inverter based loads and substantial high behind-the-meter PV update).
- Install inductive compensation – In Katherine, we plan to install switched inductive compensation to lower voltage at the bus in the zone substation, which have the impact of absorbing reactive power. We expect the development stage of this project to be completed by end of 2021.

As noted in the next section, we recently introduced new technical specifications for the connection of embedded generation systems. The specifications include mandatory power quality response modes for all new systems to a

[11] The results are based on the limited sample sizes. We are intending to increase the sample size in our next audit.

3.3 System Security in 2019-20 – Falling minimum demand

Over the past year, we have been considering options on how best to manage the growing number of solar connections on our network.[12] As noted in the overview of this document, growth in installed capacity growing from 70 MW in 2018-19 to 91 MW in 2019-20, a growth rate of 30 per cent over the last year.[13] The key issue is how to manage the security risks with the energy system on minimum demand days when solar output is high, and demand for electricity is low.

In 2020, minimum demand for electricity fell faster than forecast. The rapid change was due to both the growing uptake of behind the meter solar photovoltaic (PV) and the impact of COVID-19 on electricity demand in the Territory. If demand falls below minimum operational levels, this could represent a real risk of the electricity supply being disrupted.

Power and Water, in conjunction with NT Government, is seeking to address issues with low demand periods as a critical step in realising renewable energy targets. We are considering various medium- term initiatives including updating our systems to provide increased visibility and control of behind the meter DER as well as considering centralised solutions such as large scale batteries. However, in the short term, we need to ensure that the issue is not further exacerbated.

In recent public consultations, we have proposed that the current capacity limits for basic micro embedded generation connections of solar only systems will remain in place, and that we transition to a 10 kVA per phase limit. This will help establish the appropriate processes and systems to enable remote monitoring and control of solar systems to maintain system security, or until the issue has been alleviated by other initiatives. Where customers are seeking to install larger systems, they may still make an application to connect under our negotiated connections process.

In addition we are also proposing to mandate the "VPP-ready" requirements for systems that include BESS, by changing Clause 4.11 in our technical specifications from a "should" to a "must". This change will apply to both the Basic and Negotiated EG Technical Specification. Requiring VPP-ready capability will ensure that any BESS installed is able to contribute to alleviating local and system level constraints in the future.

We have also introduced many other changes including updating export limits to be expressed in kW and reducing the ramp rate for a decrease in power to 6 minutes. These changes better reflect the capabilities of existing inverters in the market at this time.

The key issue is how to manage the security risks with the energy system on minimum demand days when solar output is high, and demand for electricity is low.

[12] The NT NER requires that our TDAPR identify key issues arising from applications to connect embedded generating units received in the past year.

[13] Our TDAPR is required to provide a quantitative summary of connection enquiries made under clause 5.3A.5 of the NT NER and applications to connect under clause 5.3A.9 of the NT NER including the average time taken to complete connections. These relate to large embedded generators over 2MW seeking connection to the distribution network. We only had 1 embedded generation enquiry under Chapter 5A.3 of the NT NER in 2019-20. We provided the Preliminary Response for the enquiry however the detailed response has not progressed. There is therefore no metric for days to complete applications to connect.

4. Planning the network

Power and Water has a comprehensive asset management framework 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 on identifying 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 committing to investment and non-network solutions.

4.1 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.

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 combines the two requirements.

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 identify 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.

Northern Territory Electricity Industry Performance Code (EIP Code)

The EIP Code applies to electricity entities operating in the 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 required 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.

The EIP Code also requires us to provide an annual report to the Utilities Commission on the 5 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 2019-20, and outlined our reliability program to address reliability issues in section 3.1.

[14] 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.

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

Pine Creek substation.

Berrimah zone substation.

Solar panels in Alice Springs.

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

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.

4.2 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 develop a Strategic Asset Management Plan (SAMP) that aligns to our corporate 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.

In the SAMP, we group our network assets into common categories including zone substations, transmission lines, distribution assets, and secondary systems. From here we develop specific asset class strategies and plans for these asset groups. We regularly monitor the success of the plans.

We recognise that our asset management strategy needs to continually evolve to keep pace with changes in the energy market and our peers. A key focus in the coming years will be refining our risk frameworks to incorporate deeper quantitative analysis. A further focus will be identifying more opportunities to use non-network (demand management) solutions to defer or avoid replacement of assets such as by utilising micro grids and stored power of customers.

The following sections provide an overview of key activities relevant to achieving the objectives in our asset management strategy.

Planning and design of new assets

We invest in new assets or a non-network solution when maximum demand exceeds the capacity of the current assets, giving rise to a system limitation. Power and Water has a robust demand forecast process that helps us establish when new assets are required for individual areas of our network. We provide more detail on our demand forecast methodology in Chapter 5 of this document, including a summary of the most recent forecasts.

The Network Technical Code is the primary instrument we use to identify when forecast demand leads to a system limitation. The Code describes the required time to restore supply for different network categories under different contingencies.

Asset maintenance

Our maintenance activities seek to cost-effectively ensure assets remains 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 summarises 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 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. The introduction of mobile devices has resulted in significant reductions in our maintenance expenditure by improving the efficiency of our preventative activities.

We are also currently 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.

Table 4: Replacement strategies for specific asset categories

Asset class	Replace on-failure	Condition-based	Planned	Demand-driven	Customer-driven
Circuit breakers		•	•	•	
Power transformers		•	•	•	
Distribution substations	•		•		•
Distribution switchgear	•		•		
Transmission towers		•	•		
Distribution structures		•	•		
Cables	•		•	•	•
Conductors	•		•	•	•
Services	•		•		•

Asset renewal and retirement

We apply an economic assessment framework 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 performing to meet the network need.
- 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 the 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.

Table 4 identifies the key replacement strategies for our asset categories. It shows that we seek to replace critical assets such as circuit breakers and transformers before failure to minimise reliability and safety consequences.

4.3 Methodologies for planning the network

Under our asset management framework, Power and Water undertakes 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.[16] The planning horizon depends on the criticality of the network element. For example, we undertake 10 year planning of our transmission network, but only 5 years for our zone substations and distribution feeders.

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 and forecast major connections. Our planning process considers if there is likely to be thermal and voltage constraints on our equipment with reference to the Network Technical Code and 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, 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 our assets remain within the fault levels in the Network Technical Code and Network Planning Criteria. 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 limitation 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 for the project before the project is implemented. This is to ensure sufficient project analysis and development prior to seeking approval to proceed.

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.

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

4.4 Demand management

An integral aspect of our planning framework is to investigate whether demand management (non-network) solutions can effectively defer or avoid investment. We understand that demand management holds the key to improving affordability for our customers by reducing the cost of addressing network limitations. In the sections below we discuss recent improvements we have made to improve our demand management process, and some of the upcoming projects where we are exploring a non-network solution.

Improving our process to engage with stakeholders on demand management

Our planning process expressly considers whether a non-network alternative is viable to address an identified network need. We recognise that new technology and a dynamic energy landscape will provide more opportunities for innovative non-network solutions that can reduce network costs in the future. For this reason, we have been making improvements to our end to end process to elicit and facilitate viable non-network options.

In September 2020, we published our Demand Side Engagement Strategy. The document describes how and when we engage with stakeholders to garner and unlock demand side solutions. The strategy outlines our approach to engage with a diversity of potential suppliers of non-network solutions including registered participants, customers, and other interested parties such as emerging technology providers. The strategy also provides stakeholders with an understanding of the types of non-network solutions we consider in our project option assessment such as:

- Load curtailment or load shedding – This is where customers agree to reduce or disconnect their load at our request.
- Distributed Energy Resources – This is where a single large-scale embedded generator or multiple small-scale (rooftop) customers invest in hybrid solar PV and battery energy storage systems connected to the same substation to improve security of supply for all customers connected to the substation.
- Micro-grid – This is where sections of the network can be isolated from the network and continue to operate in islanded mode.
- Back-up generation – This is where diesel generators are installed at locations deemed to be at risk to provide capacity support as an interim solution while a long-term solution is developed.

Potential non-network solutions to address system limitations

We are actively investigating potential non-network solutions to address system capacity limitations in the forward planning period. This includes at Wishart modular substation and Katherine zone substation. Further discussion on these specific projects is provided in Chapter 6 of this document.

Potential Demand Management Innovations and Research

We are also actively investigating research and pilots for demand management including:

- Low voltage visibility – We are currently investigating the viability of an innovative research project that would provide us with improved visibility of our low voltage distribution network. The continued roll out of smart meters provides some of the required infrastructure to get visibility of our low voltage network, but only a small proportion of our customers have a smart meter installed. For this reason, we are looking for low cost methods to scale up the visibility of our network by using limited measurement samples from smart meters.
- Aggregation and orchestration of solar and batteries – We are considering pilots that provide our customers with incentives that allow us to access and aggregate their solar in critical locations on our network.
- Microgrid Futures project – We are currently involved in the Northern Territory Microgrid Futures project which examines the viability of using stand-alone networks that operate independently from the grid. We expect that our learnings from these projects will lead to innovative demand management research and pilots in isolated areas of our regulated network.
- Alice Springs Future Grid project – The project is focused on removing barriers to further renewable energy penetration in the Alice Springs power system. We consider there will be opportunities for Power and Water's regulated electricity network to contribute to the success of this project. This could include innovative methods to identify the optimal network location to aggregate batteries to meet peak demand and control voltage on the network.

Humpty Doo zone substation.

5. Demand forecasts

Power and Water has a rigorous method to forecast maximum demand on our 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 a system level, maximum demand is falling, but we face increased demand at specific locations from new housing and commercial developments.

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's undertakes an annual demand forecast review commencing in April of each year. The timing of the review allows us to incorporate most recent data on maximum demand which generally peaks in the October to March period. This coincides with the wet season in Darwin-Katherine and summer in Alice Springs and Tennant Creek. At this time of year, air conditioners are necessary to cope with the hot weather.

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 distribution feeders, zone substations, and transmission lines. The information is used to determine whether we are likely to face a limitation in providing supply under our security criteria.

In summary, our process identifies the underlying trend in demand based on the last 6 years of historical data, including the most current data. We extrapolate the underlying trend and incorporate the impact of significant new connections and embedded generation. In sections 5.2 to 5.4 below, we explain the specific approach for distribution feeders, zone substations and transmission lines.

Independently, the Utilities Commission of the Northern Territory (Utilities Commission) engages the Australian Energy Market Operator (AEMO) to prepare annual regional demand forecasts for Darwin-Katherine, Alice Springs and Tennant Creek.[17] We discuss trends at a system level in section 5.1.

5.1 Trends in demand forecasts – Regional outlook

The regional actual and forecast demand for the Darwin–Katherine, Alice Springs and Tennant Creek for minimum and maximum demand days are set out in **Figures 13, 14** and **15.**

The forecasts are based on the Utilities Commission's NT Electricity Outlook Report 2018-19. The forecasts were prepared for the Utilities Commission by AEMO, with feeder and zone substation forecasts and other relevant data supplied by Power and Water at the time of the report. Due to the timing of the 2020 TDAPR, we have not been able to incorporate the Utilities Commission's updated report for 2019-20.

At a high level we have seen a decline in maximum demand in 2019-20 across all three networks compared to what was forecast by AEMO for the Utilities Commission in 2018-19. While we have not undertaken an in-depth examination, we consider this has been a result of greater penetration of solar behind the meter and less business activity. The lower than forecast maximum demand in 2019-20 is reflected in our demand forecasts for distribution feeders, zone substations and transmission lines.

As noted in the overview, an emerging issue on our network is falling minimum demand. Actual data for 2019-20 shows a significant decline in minimum demand for Darwin-Katherine and Alice Springs compared to AEMO's forecast. This is explained by growing solar installations on the network and lower than normal activity due to COVID-19. Next year we will seek to undertake minimum demand forecasts at a local level to identify where there are particular issues on our network.

[17] Utilities Commission of the Northern Territory, "Northern Territory Electricity Outlook Report - 2018-19" can be accessed at: https://utilicom.nt.gov.au/__data/assets/pdf_file/0010/895357/2018-19-NT-Electricity-Outlook-Report.pdf

On this note, we have prepared the demand forecasts in very uncertain times. The long-term impacts of the COVID-19 pandemic on the development of our network cannot be reliably forecast at this stage. Our initial analysis suggests that there was a material decline in energy consumption during the most recent dry season.

While our forecasts incorporate recent data such as committed connections, we have not expressly modelled the impacts of COVID-19 on existing business activity.

We expect tourism and hospitality industries may be subdued in the short term due to lower international travellers, but this may be balanced by increased domestic tourism. We also cannot reliably forecast how a slowdown in global growth may impact exports and demand for our local products. We would expect that our 2021 TDAPR would be able to use actual data to understand the impacts from COVID-19.

Figure 13: Darwin-Katherine Maximum Demand – Actuals and Forecasts (MW)

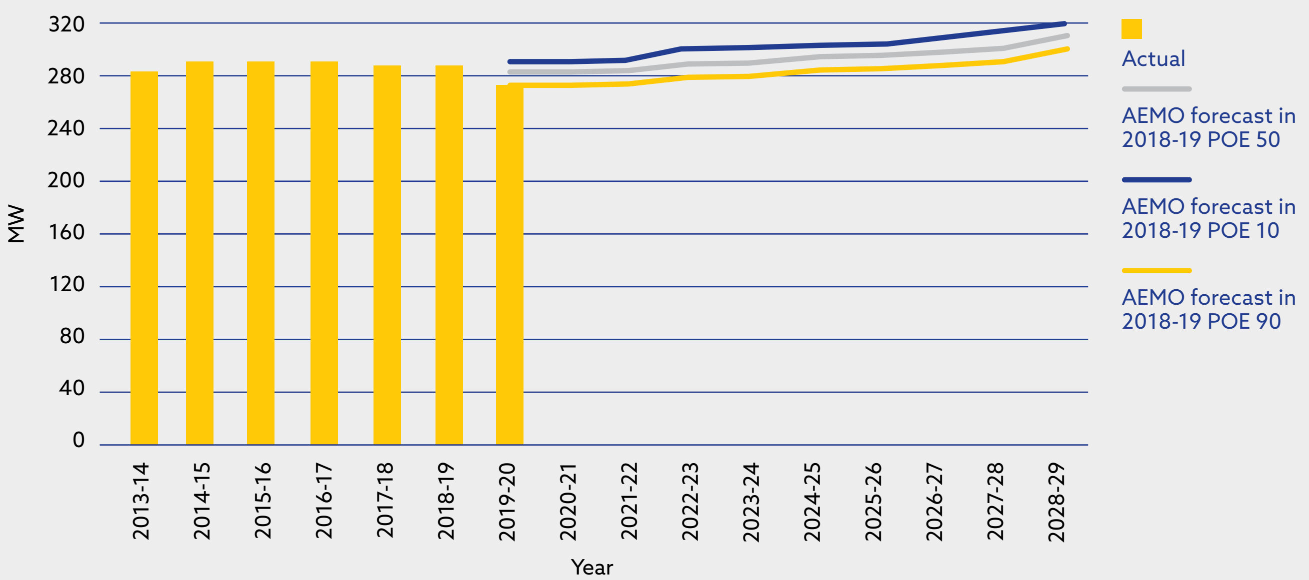


Figure 13: Darwin-Katherine Minimum Demand – Actuals and Forecasts (MW)

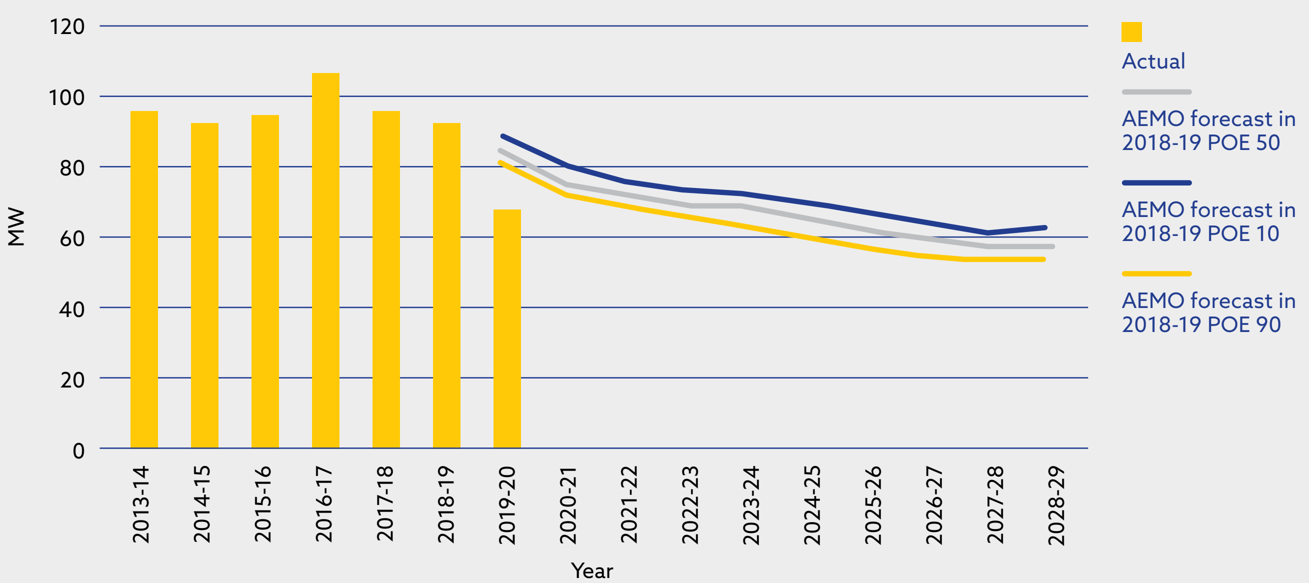


Figure 14: Alice Springs Maximum Demand – Actuals and Forecasts (MW)

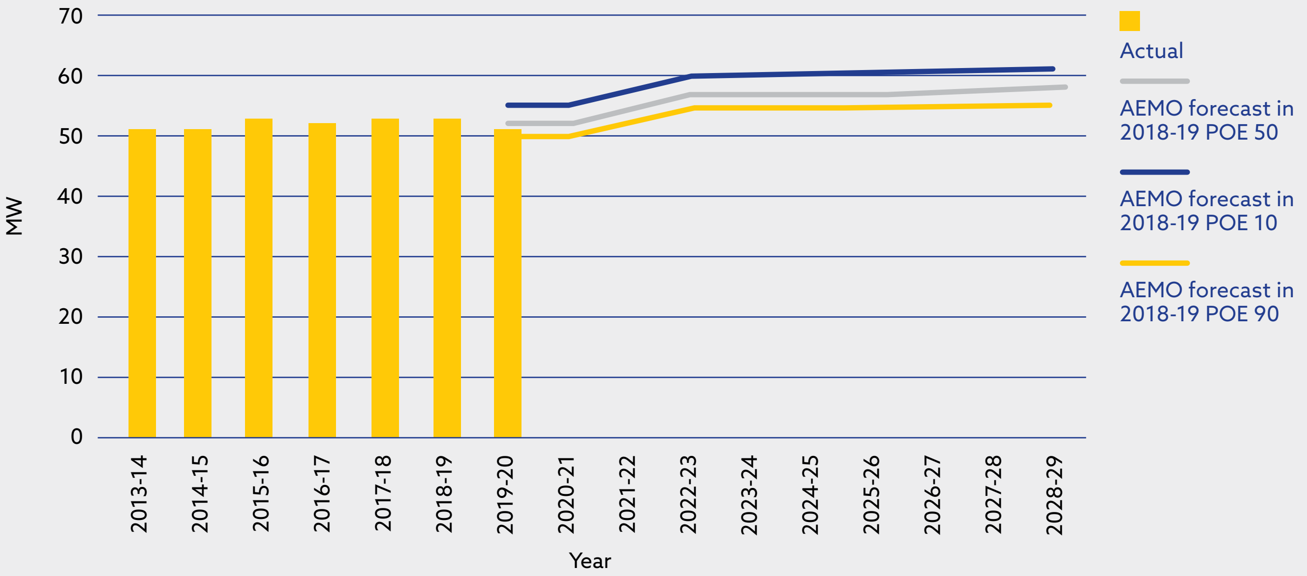


Figure 14: Alice Springs Minimum Demand – Actuals and Forecasts (MW)

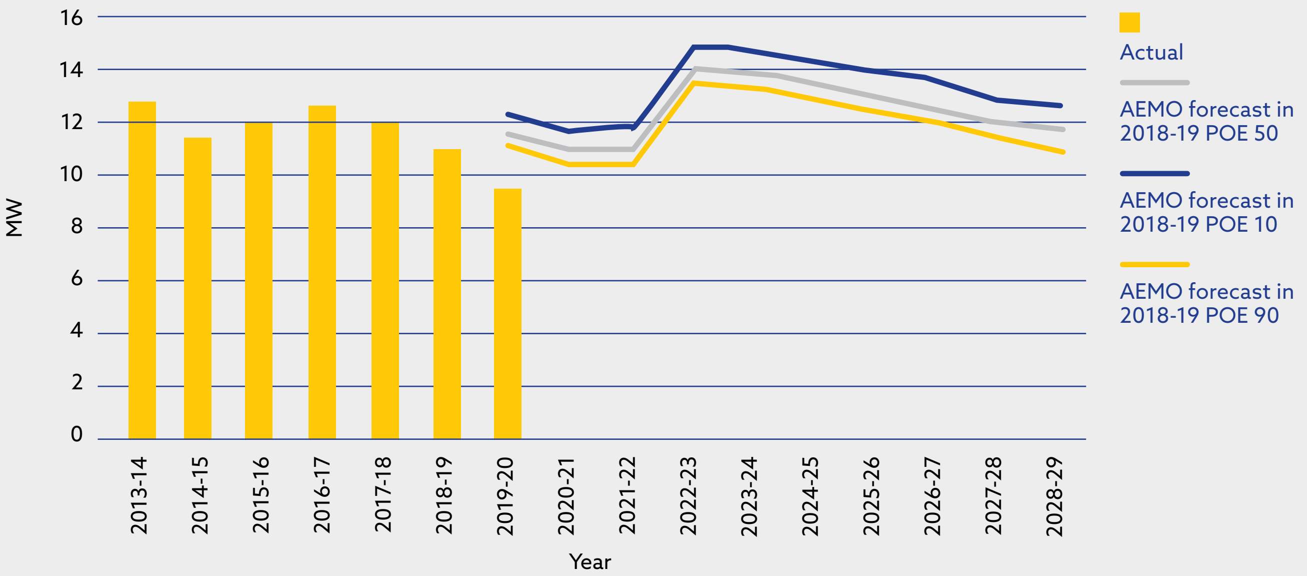


Figure 15: Tennant Creek Maximum Demand – Actuals and Forecasts (MW)

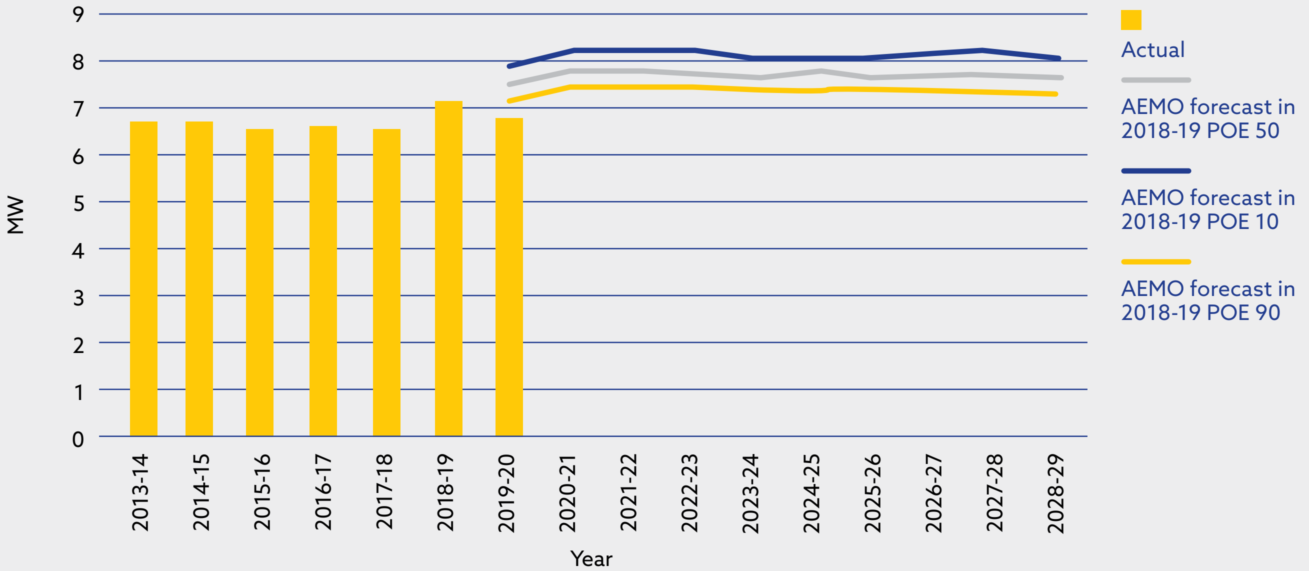
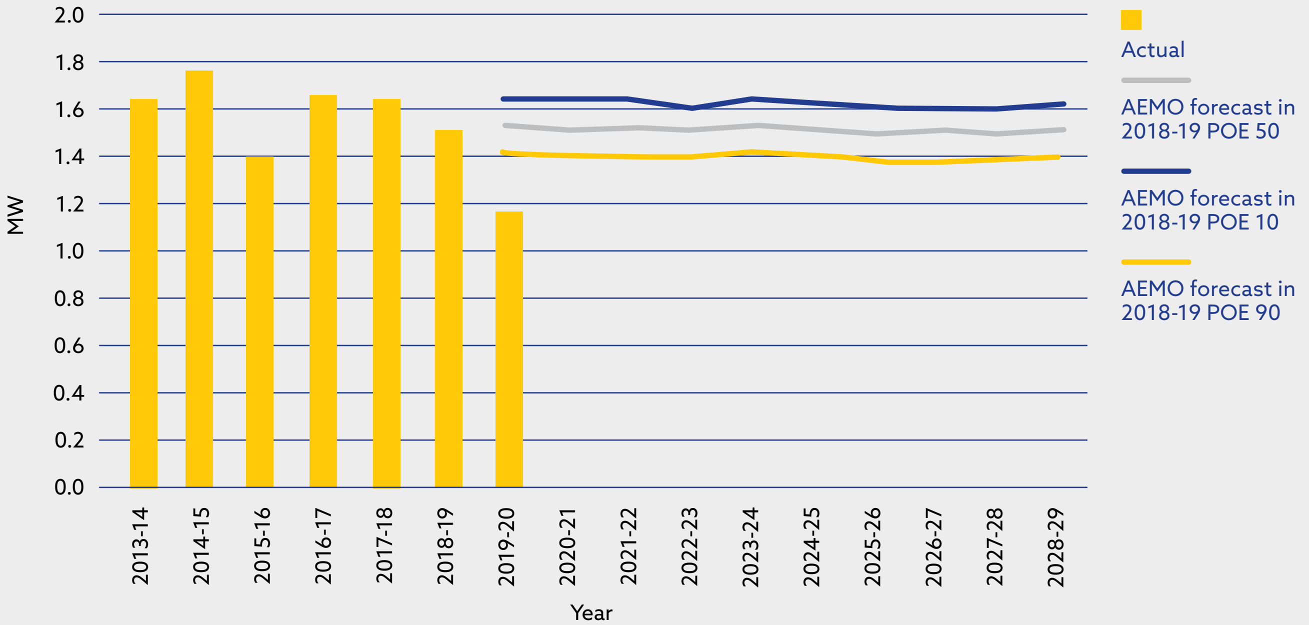


Figure 15: Tennant Creek Minimum Demand – Actuals and Forecasts (MW)



Berrimah zone substation.

5.2 Distribution feeders

We forecast maximum demand on each distribution feeder on our network. The starting process is to identify the underlying trend in maximum demand growth on the feeder. We examine 6 years of maximum data including the current year to determine the linear trend in maximum demand, excluding the impact of new connections, embedded generation and temporary transfers. For 2019-20, the 'base value' relied on 30-minute interval SCADA data[18], which is then adjusted to remove temporary transfers and the impact of new connections and embedded generation.

Our next step is to adjust the 'base value' in 2019-20 to incorporate the impact of permanent new connections, embedded generation, and permanent transfers that occurred in that year. The underlying trend is then extrapolated from 2019-20 to develop a forecast trend for each feeder. 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.

Due to the large volume of feeders on our network, we have not provided the forecasts in this report. However, at a high level we expect a reduction in maximum demand compared to 2019-20 actuals for most feeders, reflecting the underlying trend we have seen at a system level over the last 6 years. The forecasts are lower than what we prepared for the 2019 TDAPR.

Only three feeders will experience a capacity issue in the 2019-20 to 2023-24 period based on recent forecasts, and these are located on the Darwin urban network.
The driver for higher demand relates to new major housing or commercial developments on the feeder. As discussed in Chapter 6, the limitations will be addressed through load transfers from adjacent feeders with spare capacity.

5.3 Zone substations

Power and Water has 26 zone substations 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 ten years, with this year's TDAPR providing a forecast of maximum demand for 2020-21 to 2029-30.

We forecast maximum demand for zone substations using the general approach described for distribution feeders as set out in section 5.2. However, a key difference is that we weather correct the recorded maximum demand to normalise the impact of varying temperature across years.

The first step in our weather correction process is to record the maximum ambient temperature of the day when maximum demand occurred. This establishes a correlation between maximum demand and temperature. Weather-corrected maximum demand is based on the difference between the maximum daily temperature for each region and the assumed 50% probability of exceedance (PoE) and 10% PoE temperatures for the regional reference weather station.

We identify the linear underlying trend for each zone substation's 10% PoE and 50% PoE weather-corrected maximum demand for the preceding six years[19] (including the current year). We then include the impact of committed connections and embedded generation.

We also compare our zone substation forecasts with those prepared by AEMO for the Utilities Commission. Where there are material differences, we investigate the reason. In most cases, the reason is a timing mismatch where AEMO's review does not incorporate the previous summer or updated information on connections.

The 2019-20 maximum demand actuals, and the 10% and 50% POE forecasts for 2020-21 to 2029-30 for each zone substation are set out at Attachment J, together with information on existing capacity under different contingencies. The information identifies the zone substations where a system limitation has occurred under a 10% and 50% POE forecasts.

In general, the demand forecasts are lower than forecast in last year's TDAPR. However, our forecasts are still predicting growth in demand in some of our zone substations relating to new housing and commercial developments. System limitations emerging out of these demand forecasts are discussed in Chapter 6.

5.4 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 2020-21 to 2029-30.

Our forecast method relies on zone substation and generation connection point forecasts. Our approach is to use the 50% 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 connecting to the transmission network.

The demand forecasts for transmission lines are set out at Attachment H. System limitations emerging out of the transmission line demand forecasts are discussed in Chapter 6.

[18] If there are apparent errors with SCADA data, we may also use interval meter data from high voltage customer connections or substation data.

[19] 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.

6. Our plans to address network limitations

The system limitations identified in the 2020 TDAPR are largely consistent with last year. A key change from last year is the inclusion of a material capacity limitation at Wishart modular substation by 2024-25 due to forecast new large connections in the area. We are also forecasting capacity limitations at Katherine and Humpty Doo zone substations. The material asset condition limitations relate to the Berrimah and Humpty Doo zone substations where key assets are deteriorated. We also will be replacing our critical Energy Management System.

In this section we identify system limitations on our transmission and distribution networks based on our most recent planning review. The purpose is to raise awareness of emerging issues on the network with stakeholders, and to engage on solutions. In the sections below we discuss limitations on the Darwin-Katherine transmission network, Darwin urban distribution network, Darwin rural and Katherine distribution network, and Alice Springs transmission and distribution networks. We have not identified any limitations in Tennant Creek in this year's TDAPR.

Power and Water have no planned projects which require a regulatory investment test.[20] Further we have no completed or cancelled projects to report, and no projects over $2 million that address urgent or unforeseen network issues.

A key change in our 2020 TDAPR is that we are reporting all capacity system limitations for zone substations under a critical contingency under N-1 even if we can manage the need without an expenditure solution. We consider this provides stakeholders with more information on our planning decisions.

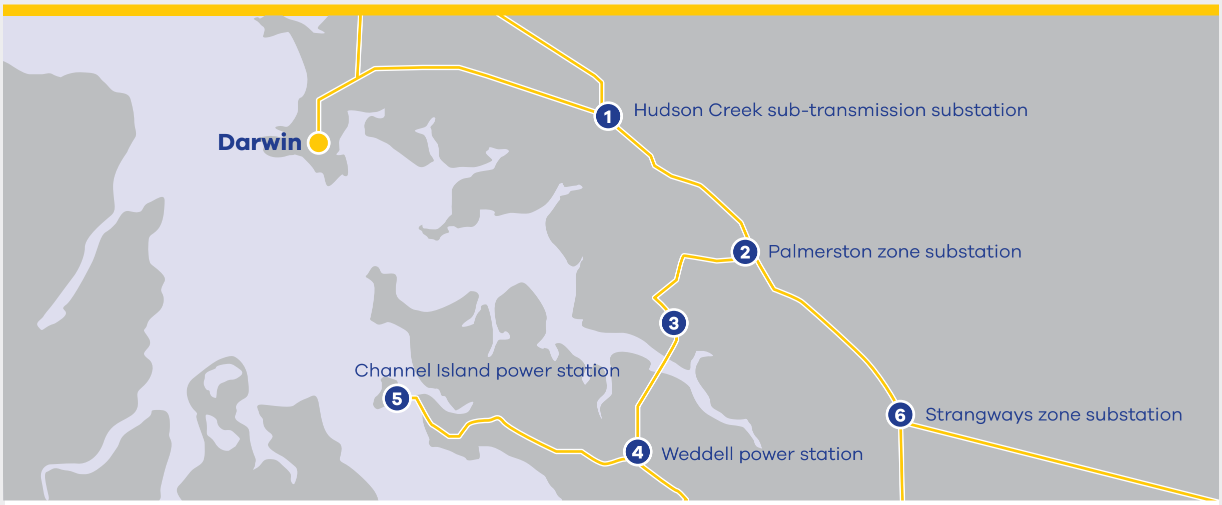
6.1 Darwin-Katherine transmission network

Our transmission network in Darwin-Katherine comprises subtransmission substations and 132kV and 66kV transmission lines that transport energy from power stations to our zone substations on the distribution network. Our planning horizon for identifying condition and capacity issues on the transmission network is 10 years.

At a high level, we note that the major limitations relate to asset condition including secondary systems and circuit breakers in zone substations, and corrosion on transmission towers and equipment on transmission lines. We have also identified capacity limitations under contingency conditions at Hudson Creek sub-transmission substation and on transmission lines from Hudson Creek. The identified limitations are consistent with our TDAPR report from last year. **Figure 16** provides a visual summary of identified limitations over the 10 year planning horizon.

[20] Under the NT NER, Power and Water is only required to undertake a RIT-D for a project that has not been approved by the AER in the 2019-24 determination.

Figure 16: Darwin-Katherine transmission network – identified system limitations



1 Asset condition limitation

Replace circuit breakers at Hudson Creek

Capacity limitation

Procure spare transformer for Hudson Creek

1 2 3 Capacity limitation

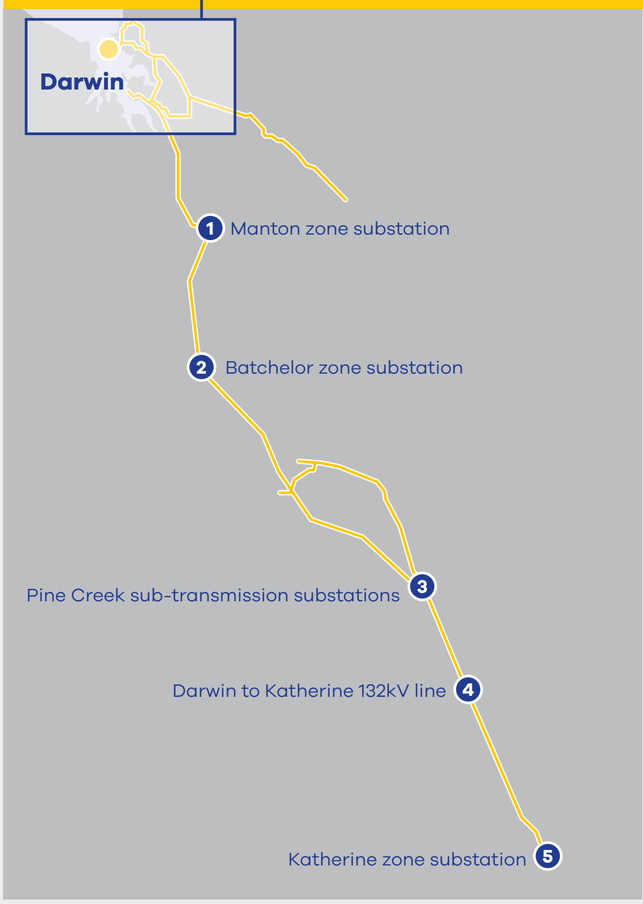
Uprate line or additional generation on Hudson Creek to Palmerston and Hudson Creek to Archer to meet transmission line under N-1

4 6 Asset condition limitation

Replace insulators and cross arms on transmission lines between Strangways and Weddell

1 5 Asset condition limitation

Replace insulators and cross arms on transmission lines between Channel Island and Hudson Creek



1 Asset condition limitation

Replace secondary system

2 Asset condition limitation

Replace secondary system

3 Asset condition limitation

Replace secondary system

4 Asset condition limitation

Replace earthing system on towers on Darwin-Katherine 132kV line

5 Asset condition limitation

Replace secondary system

Asset condition limitations

Transmission assets are integral to ensuring ongoing secure and reliable services to our customers. Asset failures on our transmission network can lead to large scale outages and security issues, and consequently we undertake rigorous monitoring of these assets.

The key condition issues with our transmission network in Darwin-Katherine are secondary systems and earthing systems on transmission towers. No issues have been identified in relation to the Alice Springs transmission network. A summary of key issues, together with the preferred solution and estimated timing are provided in **Table 5.**

Table 5: Forecast asset condition limitations on transmission network

Asset	Location	System Limitation and preferred solution	Project timing
Secondary systems on subtransmission substation and zone substations	Manton, Batchelor Creek, Pine Creek and Katherine	The Darwin-Katherine Transmission line is the main supply for the townships of Pine Creek and Katherine. The secondary systems in the subtransmission substation and zone 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.	2023
Earthing system on transmission towers	Darwin-Katherine 132KV Line	Earthing systems mitigate voltage issues when lighting hits a transmission line. Our investigations suggest that the earthing system is not performing due to physical damage and corrosion. Our preferred solution to address the issue is to refurbish the tower earthing components, including below ground earthing conductors and potential changes to insulator configuration.	2021 and onwards
Insulators and cross arms on transmission lines	Channel Island to Hudson Creek (132kV line) and Weddell to Strangways (66kV line)	This program seeks to address corrosion issues with insulators on the 132kV Channel Island to Hudson Creek line and crossarms on the 66kV Weddell to Strangways line. Corrosion increases the likelihood of asset failure, which presents a safety risk for our staff and to the public. Further, these assets are crucial for the security of the network. To address this risk we intend to replace ageing insulators and crossarms.	2021 and onwards
Circuit breakers	Hudson Creek subtransmission substation and Palmerston zone substation	The high voltage circuit breakers in these substations are reaching end of life, and have a history of moisture entering the active parts. This significantly increases the risk of the circuit breaker failing to operate when required to isolate a fault. The failure of the assets can also be explosive. Our options analysis indicates that we should replace all of the circuit breakers on a substation by substation basis, commencing with those in worst condition at Hudson Creek.	2021 and onwards

Capacity limitations on transmission network

As part of our annual review, we have sought to identify capacity constraints on transmission substations and transmission lines on the Darwin-Katherine network.

Consistent with last year's report we have found that the Hudson Creek sub-transmission substation is currently unable to supply connected zone substations in the Darwin urban area if two of the three 125MVA transformers fail simultaneously. **Table 6** identifies the extent of the overload of Hudson Creek if two critical contingencies occur. Even with additional generation from Weddell Power Station, the overloads are materially significant. Our preferred solution is to purchase a spare power 132/66kV power transformer, which will be used to replace a failed transformer.

Table 6: Forecast capacity limitations – Sub-transmission substations in Darwin-Katherine (MVA)

Sub-transmission substation	Criteria	Rating (MVA)	Overload (MVA)									
			FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	F30
Hudson Creek	N-2	127.5	13.62	33.62	52.58	58.69	75.92	75.24	77.24	72.78	75.75	72.46

We have also undertaken contingency analysis of our transmission lines to identify if any lines would exceed capacity in the planning horizon. The system limitations for transmission lines are consistent with last year's TDAPR, but the expected overload on the identified lines has increased.

Under a critical contingency (N-1) on the line from Hudson Creek to Palmerston zone substation, the 66kV overhead line from Hudson Creek to Archer zone substation is expected to exceed capacity by 10 per cent by 2029-30. Similarly, under a critical contingency on the line from Hudson Creek to Archer zone substation, the 66kV overhead line from Hudson Creek to Palmerston zone substation is expected to exceed capacity by 8 per cent by 2029-30. We are currently exploring two options to address the overloads under N-1 including increasing generation at Weddell power station and uplifting the line rating from 64MVA to 90MVA for each of the lines. **Table 7** identifies the expected overload that occurs on Hudson Creek to Archer if the Hudson Creek to Palmerston line is out of service, and vice versa.

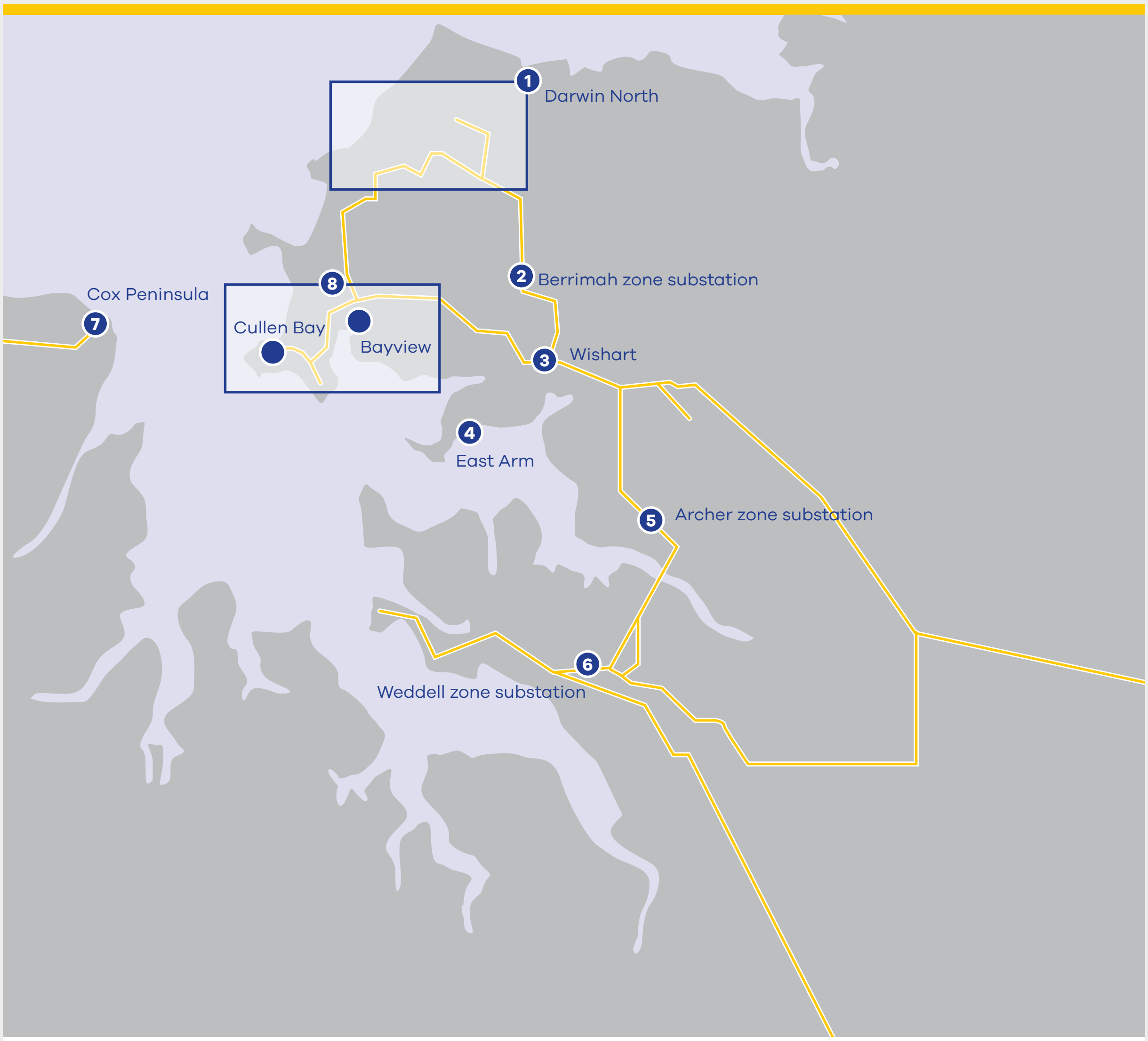
Table 7: Forecast capacity limitations – Transmission lines in Darwin-Katherine (MVA)

Transmission lines	Criteria	Rating (MVA)	Overload (MVA)									
			FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	F30
Hudson Creek to Archer	N-1	64	-	-	-	-	-	-	-	-	5.82	6.48
Hudson Creek to Palmerston	N-1	64	-	-	-	-	-	-	-	-	4.68	5.39

6.2 Darwin Urban – Distribution network

The Darwin urban distribution network extends to the Northern suburbs of Darwin to Strangways in the west, Weddell in the south, and Cox Peninsula (centre yard) in the east. A visual summary of identified system limitations is provided in **Figure 17**.

Figure 17: Darwin urban distribution network – identified system limitations



1 Asset condition limitation

Replace high voltage cable and refurbish distribution substations

2 Asset condition limitation

Replace zone substation

3 Capacity limitation

Use demand management, load transfers, and spare transformer to defer construction of new substation

4 Asset condition limitation

Replace high Voltage cable

5 Capacity limitation

Address through load transfer

6 Capacity limitation

Address through load transfer

7 Asset condition limitation

Consider non-network options, or alternatives to like for like replacement

8 Asset condition limitation

Replace low Voltage cable

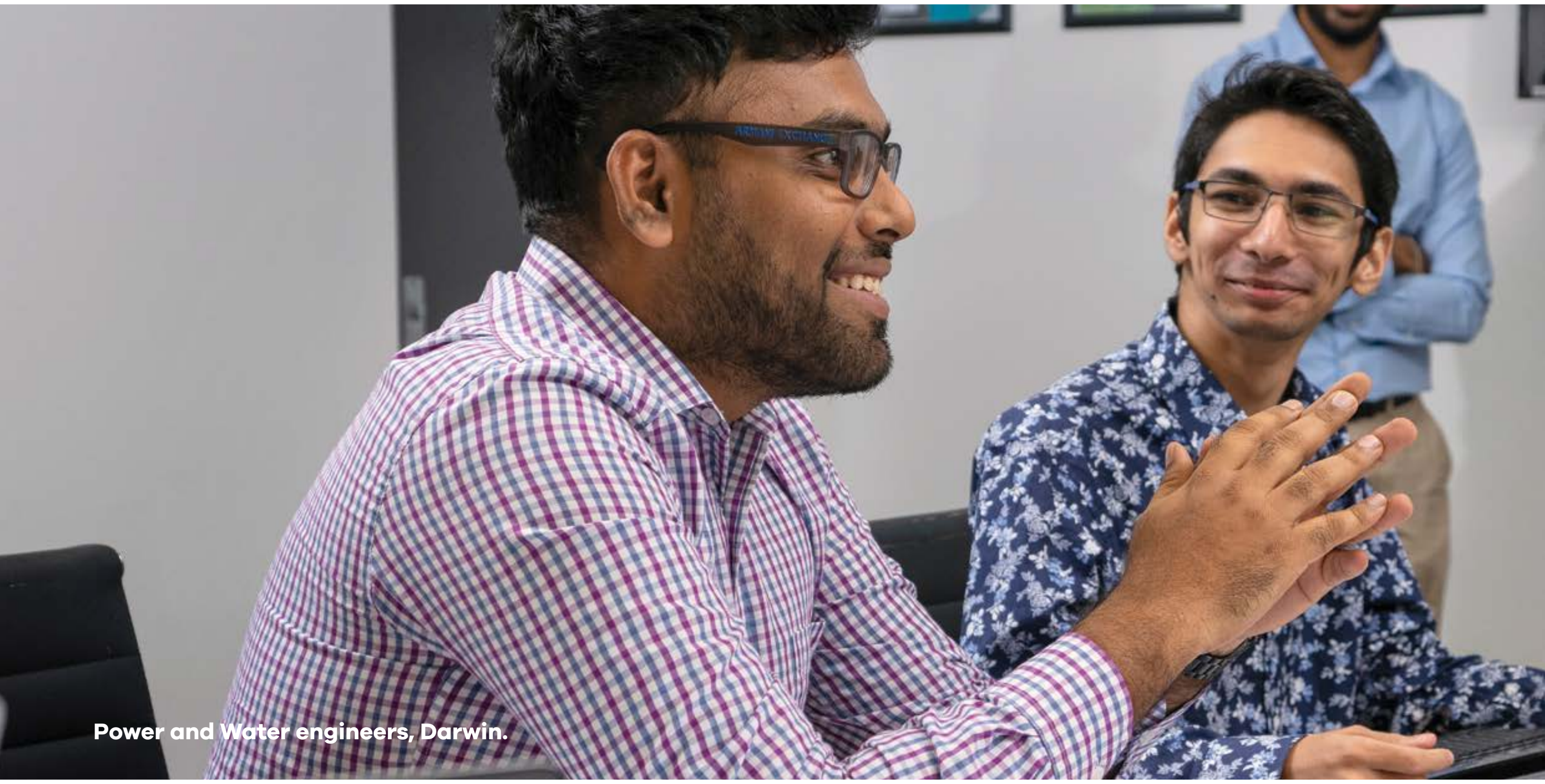
Asset condition limitations

Our asset management processes have identified key risks with zone substation equipment, underground lines and distribution substations in urban Darwin. Key issues and solutions are summarised in **Table 8.**

Table 8: Forecast asset condition limitations – Darwin urban distribution network

Asset	Location	System Limitation and preferred solution	Project timing
Zone substation	Berrimah	The assets in Berrimah zone substation are at the end of their serviceable life. The 66kV oil circuit breakers are in poor condition and can cause significant damage to adjacent equipment when they fail. Our workers have also encountered safety issues with the 11kV switchboard. Our options analysis indicates that building a new greenfield zone substation in an adjacent location is the least cost option to address the issues at Berrimah zone substation.	2024
High Voltage cable	East Arm	We will be replacing 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 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.	2023
High Voltage cable	Darwin North	Our asset investigations have shown that the sheath and insulation of some segments of cable are damaged from water ingress, resulting in water treeing. This exposes our workers to safety risks when using tools or cutting cable. We will be replacing about 37 kilometres of the 103 kilometre line until 2023-24. We have not identified any non-network solutions that can address the risk.	2021 and onwards
Underground distribution substations	Darwin North	We have a substantial number of underground distribution substations that are approaching end of life. The most common failure mode of these assets is corrosion at the bottom of the transformer tank, which can lead to asset failure. There are safety risks to the public from asset failure, particularly given that the assets are located in areas accessible to the public. Our options analysis indicated that a targeted replacement and refurbishment program minimised safety and reliability risks. The program will be ongoing until 2023-24.	2021 and onwards

Asset	Location	System Limitation and preferred solution	Project timing
Low Voltage cables	Cullen Bay and Bayview	The cables in this area have insulation issues from water ingress. The neutral conductor in Cullen Bay is also installed to an old standard which is no longer considered fit for purpose, and poses a safety risk to our workers and the community in the area. Further, the deterioration issues increase the risk of asset failure. Our options analysis identified that a targeted replacement of high-risk segments of cable was the solution that efficiently and prudently managed the risks.	2021 and onwards
Zone substation	Cox Peninsula	The Cox Peninsula area is currently serviced by an undersea cable from Mandorah in Darwin. The centre yard zone substation at Cox Peninusla transforms the voltage to 11kV. The circuit breakers at the zone substation are at risk of failure due to their age and are not supported. Further the insulation on the transformers is compromised with numerous oil leaks. Due to reduced capacity in the area, we are examining a range of potential options to address the retirement of the zone substation including the possibility of a microgrid, or a land cable from Berry Springs. Subject to our options assessment, we expect the asset to be retired by 2021.	2023
Energy Management System	Darwin	The system helps us to manage the electricity network from a centralised control room including switching, outage management, contingencies, performance and dispatch. The system is approaching end of life. We will upgrade the EMS software to the current revision levels allowing us to have a 'fully supported' status for both software and hardware. The project will be undertaken in 2021.	2024
SCADA and Communications	Darwin	We are also planning to replace SCADA and Communications assets that have reached the end of their serviceable life and which are now using obsolete technology no longer supported by the vendor. Vendor support is critical to having equipment repaired, resolving software and firmware bugs, updating security patches to guard against cyber threats, and general overall support in programming and maintaining this equipment. The project will be ongoing until 2023-24.	2021 and onwards



Power and Water engineers, Darwin.

Capacity limitations

We have identified capacity limitations for Wishart, Archer, Centre Yard and Weddell zone substations under a single contingency (N-1). **Table 9** identifies the expected overload with further information on the drivers and solutions set out below.

Archer Zone Substation currently consists of two transformers. Under a single contingency (N-1) the zone substation cannot meet the expected demand forecast from 2021-22 onwards, mainly due to new housing developments in the area. There are distribution feeder ties to Palmerston Zone Substation, with load transfer capacity of approximately 17.0MVA. The system limitation could be addressed through a load transfer to Palmerston without a network or non-network solution.

Weddell Zone Substation is located on Channel Island Road and supplies the Weddell area. It comprises three transformers, and has an N-1 rating of 15.6MVA. The forecast demand is expected to exceed the N-1 rating from 2020/21 onwards due to large commercial loads. The system limitation could be addressed through a load transfer to Strangways zone substation without a network or non-network solution.

The forecast demand at Wishart modular substation reflects our expectations of significant load locating in the East Arm area in 2024-25. This would significantly exceed the normal operating capacity of the modular substation. Currently we can provide support if the exiting modular substation fails by using a spare transformer. We are also investigating opportunities to transfer load to Berrimah zone substation, and building new feeder interconnections into the East Arm area from Archer and Palmerston zone substations including installing capacitor banks in East Arm area. In the longer term we are looking at complementary non-network solutions such as diesel generators to meet the additional load in 2023-24 under normal operating conditions, so as to defer construction of a new zone substation as long as possible.

Centre Yard is located at Cox Peninsula which is serviced by an undersea cable from Mandorah in Darwin. We are forecasting that load will continue to increase in the area. Under N-1, the zone substation does not meet the forecast load. However, we already have a generator with 1MW capacity in place in case of a contingency event.

We have also identified three distribution feeders that we expect to have a system limitation over the planning horizon based on updated maximum demand forecasts as set out in **Table 10.**

The load on the 11BE19 (Hidden Valley) feeder can be transferred permanently to adjacent distribution feeders such as 11WN03 (Maranga), 11BE04 (McMillans) and 11BE13 (Kormilda) from 2024-25 onwards. For the Yarrawonga (11PA08) feeder in Palmerston, the cable replacement work is in progress and expected to be completed by end of December 2020. This will increase the capacity of the feeder consistent with last year's TDAPR. The load on the 11PA26 (Gateway) feeder can be transferred permanently to the uprated 11PA08 (Yarrawonga) feeder and 11PA23 (Georgina) feeder.

Table 9: Forecast capacity limitations – Zone substations in Darwin urban areas (MVA)

Zone substations	Criteria	Rating (MVA)	Overload (MVA) under N-1 excluding load transfer capacity				
			FY21	FY22	FY23	FY24	FY25
Archer	N-1	31.5	0.00	2.44	7.46	12.48	16.49
Centre Yard	N-1	0.5	0.07	0.10	0.14	0.17	0.20
Weddell	N-1	15.6	0.55	0.57	0.60	0.63	0.66
Wishart (Modular)	N-1	10.0	8.09	8.08	9.22	11.10	23.85

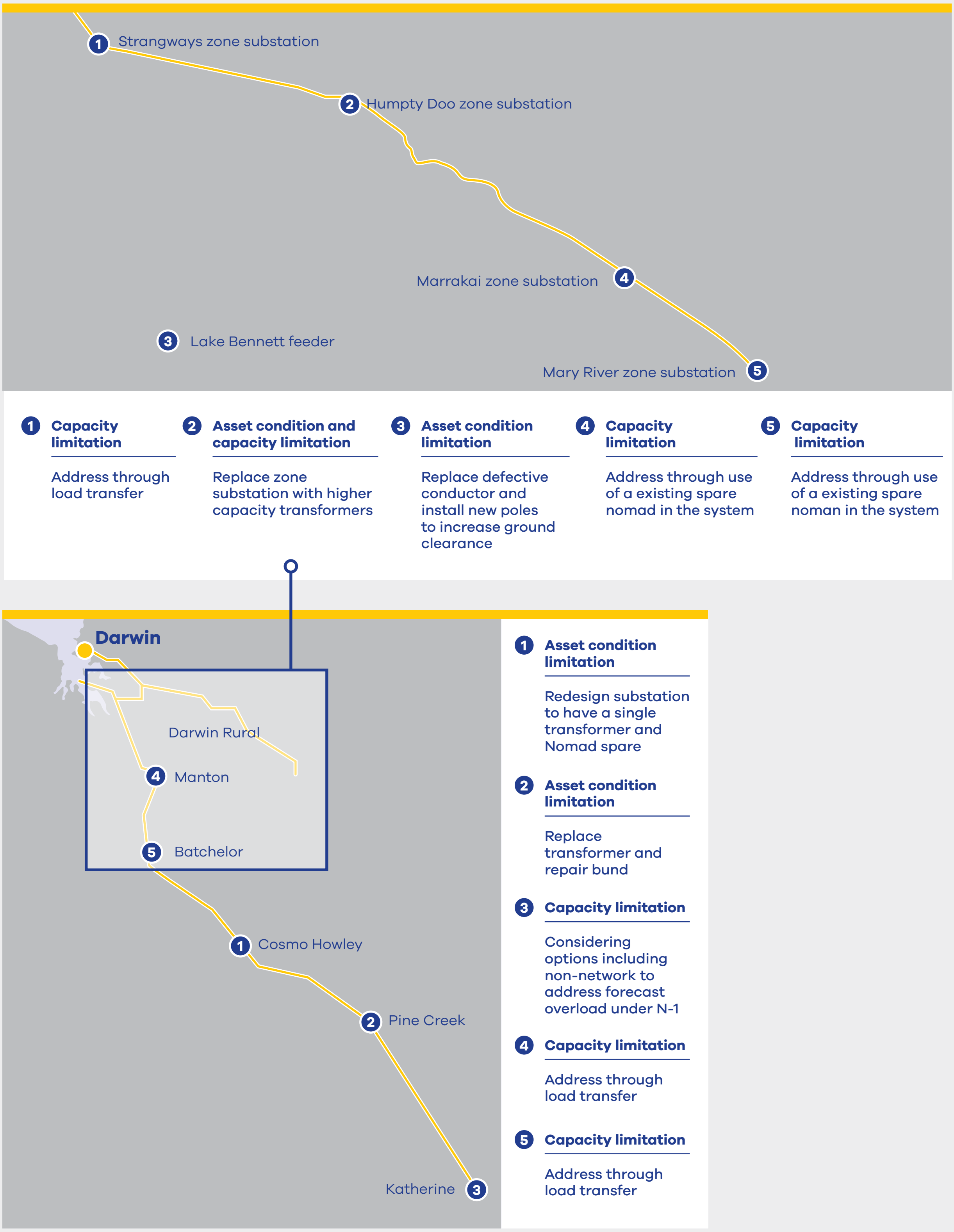
Table 10: Forecast capacity limitations – Distribution feeders in Darwin Urban distribution network (MVA)

Distribution feeders	Criteria	Rating (MVA)	Overload (MVA) under N-1 excluding load transfer capacity				
			FY21	FY22	FY23	FY24	FY25
Berrimah zone substation feeder 11BE19 (Hidden Valley)	N	6.3	-	-	-	-	0.2
Palmerston zone substation feeder 11PA08 (Yarrawonga)	N	5.2	-	0.1	0.4	0.6	0.5
Palmerston zone substation feeder 11PA26 (Gateway)	N	6.3	-	-	-	0.7	0.7

6.3 Darwin Rural and Katherine – Distribution Network

Power and Water supplies energy to regulated rural areas in Darwin such as Humpty Doo, Marrakai and Mary River. Our distribution network also supplies customers in locations between Darwin to Katherine such as Pine Creek, Batchelor and Manton. A visual summary of the identified system limitations for these areas is provided in **Figure 18.**

Figure 18: Darwin Rural and Katherine distribution network – identified system limitations



Asset condition

Table 11 below identifies key asset condition limitations in the Darwin rural and Katherine distribution network.

Table 11: Forecast asset condition limitations – Darwin rural and Katherine distribution networks

Asset	Location	System Limitation and preferred solution	Project timing
Zone substation	Humpty Doo	There are condition issues with the assets within the zone substation including the 66kV circuit breaker which has a history of failures associated with the operating arm, and the power transformers which have excessive level of moisture in the paper insulation, largely due to significant continuous oil leaks. There are also condition issues with the 22kV switchgear including gas leaks, and the secondary systems are obsolete and spares are difficult to source. We also note that there is a concurrent capacity driver as noted in the next section.	2023
Poles and Pole tops	Lake Bennett	The Lake Bennett feeder is located south of Darwin and extends for a length of more than 40 kilometres. The feeder does not comply with the ground clearance regulations particularly on road crossing spans. There is also a history of defects including burnt conductor, broken strands and conductor corrosion. Based on our options analysis, the preferred option is to install over 200 mid-span poles and replace about 250 pole tops together with replacing the remaining overhead conductor that has not been replaced previously.	2021 and onwards
Transformer in zone substation	Cosmo Howley	The substation is located about 200 kilometres south of Darwin and predominantly supplies a mine. The switchgear has previously been replaced, but the transformers are approaching 60 years and experiencing numerous oil leaks due to failing insulation. While we continue to undertake corrective measures through oil reconditioning, we expect that the transformer will fail due to inability to withstand transients at its age. Our options analysis has identified a lower cost option than a like for like replacement, by having a single transformer and a nomad connection in case the transformer fails.	2022
Transformer and repair bund in zone substation	Pine Creek	The existing transformer in the zone substation was a refurbished unit when installed in 2008. It has many condition issues including deterioration of internal paper insulation, evidence of internal arcing, and minor oil leaks. Internal arcing is a major concern as it can result in transformer failure and occasionally an oil fire. The function of a bund is to prevent oil leaks from contaminating the ground. However, the bund has cracks and is not connected to an oil separator tank. Our options assessment indicates that the economic solution is to replace the transformer with an existing asset held onsite, and to seal the bund and install an oil separator system.	2021

Capacity constraints

We have identified capacity limitations at 7 zone substations under a single contingency (N-1) in as set out in **Table 12**. We discuss each zone substation below. There are no identified limitations on distribution feeders over the planning period.

The Batchelor zone substation has significant capacity under normal operating conditions, but under N-1 cannot meet the relatively low load in the area. The load can be transferred to Manton Zone Substation. Similarly, Manton zone substation cannot meet load under N-1 but load can be transferred from Batchelor zone substation.

The Humpty Doo area is serviced by a zone substation on the Arnhem Highway. The zone substation has two 2.5 MVA transformers that are connected by a 66kV radial line from Strangways. The forecast load is expected to exceed the capacity of the zone substation in 2020-2021, mainly due to increased load requirements from connected customers in the area. Currently, the limitation cannot be addressed through a load transfer from an adjacent zone substation but there is a spare transformer that we can install in an emergency. We are currently assessing options on the optimal solution to concurrently address asset condition and capacity limitations. This includes examining whether the transformer capacity at the zone substation should be increased at the time of replacement.

The Marrakai and Mary River are single transformer zone substations at the far end of the Darwin rural network. Both substations have significant capacity to meet load under normal operating conditions, but the load could not be met under N-1. Under these emergency conditons, we could transport and connect a spare nomad transformer with 10 MVA capacity to restore load in the area. We note that the substations have relatively young transformers so the risk of a failure is less likely. We are currently undertaking probabilistic planning on this N-1 condition. Risk assessment has been undertaken and we are in the process of formlising the risk assessment.

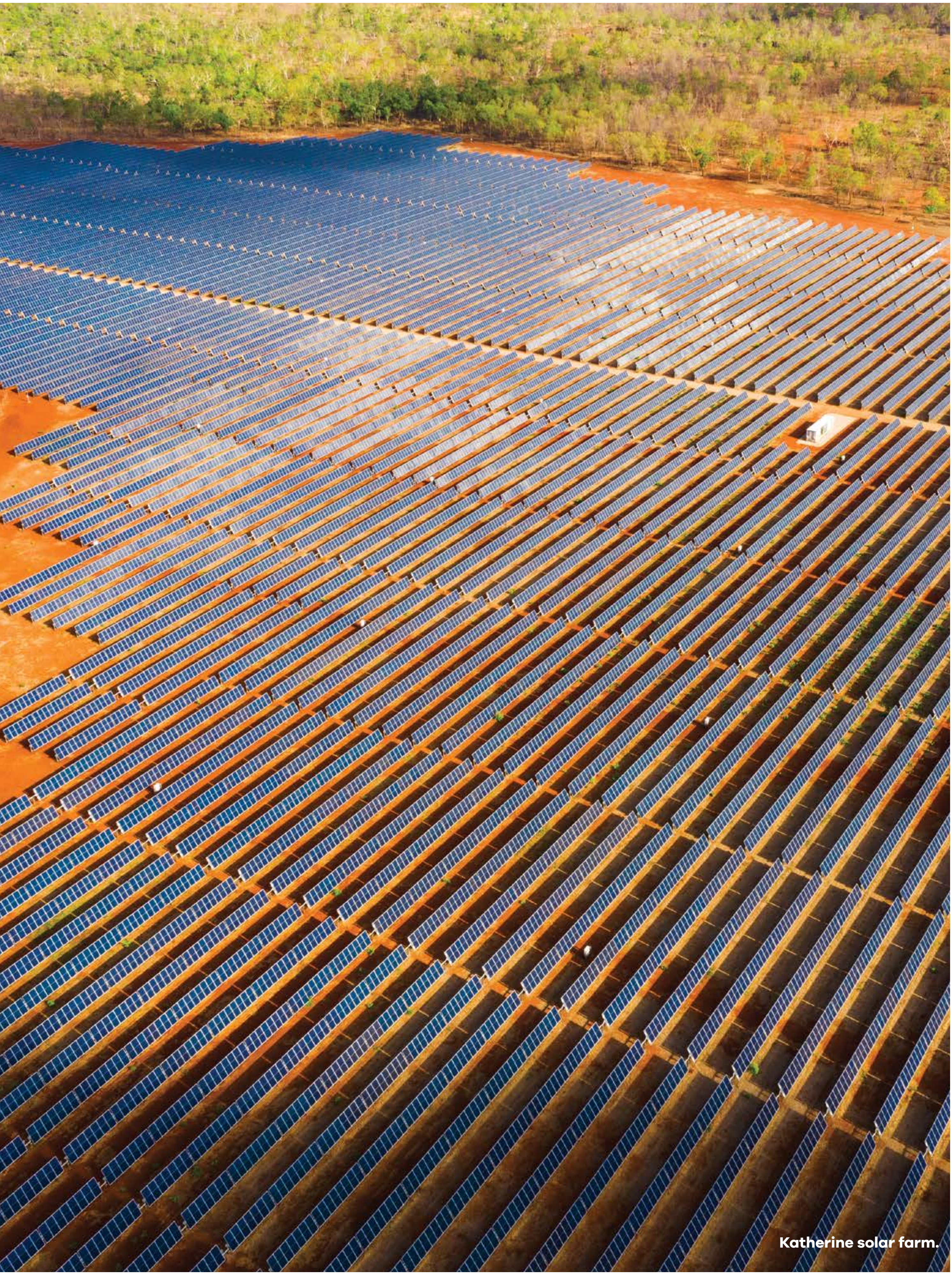
Strangways Zone Substation is located in Bees Creek and largely services the Darwin rural area. It is comprised of two 27MVA transformers and provides a 66kV radial line to Humpty Doo, Marrakai and Mary River zone substations. We are forecasting that the zone substation will be marginally overloaded in 2021-22 under a single critical contingency (N-1) However, we consider the limitation can be addressed by transferring load to Humpty Doo, Palmerston, Weddell and Manton zone Substations.

The Katherine zone substation supplies the township and surrounding area. It is connected to the 132kV transmission line from Darwin and comprises a 27MVA and 33MVA transformer. We are forecasting that the zone substation will be overloaded in 2020-21 under a single critical contingency (N-1), and that the overload will continue to increase over the planning period. This is due to large housing developments in Katherine East, and commercial loads (Katherine logistics and agribusiness hub) locating in the area over the next few years. We are currently undertaking a planning study to identify commercial opportunities to procure generation from new and existing generators that directly connect to the 22kV bus at Katherine zone substation. This would allow us to supply load for the short period where an overload may occur under N-1 conditions. We also consider there may be opportunities for batteries to support the load if one of the transformers fail.

We also note that we will be increasing capacity at a zone substation located in Tindal in the Katherine region and the 22kV distribution feeder that supplies the load. This is a dedicated substation for a large customer, and therefore the upgrade will be fully funded by that customer.
We expect the works will be completed in 2022.

Table 12: Forecast capacity limitations – Zone substations in Darwin rural and Katherine distribution network (MVA)

Zone substations	Criteria	Rating (MVA)	Overload (MVA) under N-1 excluding load transfer capacity				
			FY21	FY22	FY23	FY24	FY25
Batchelor	N-1	0.0	1.61	1.61	1.61	1.60	1.60
Humpty Doo	N-1	2.7	2.12	3.09	5.30	7.26	7.55
Manton	N-1	0.0	4.34	5.38	6.43	7.47	8.51
Marrakai	N-1	0.0	0.99	1.01	1.03	1.05	1.06
Mary River	N-1	0.0	2.65	2.64	2.63	2.62	2.61
Strangways	N-1	30.3	0.00	0.39	1.13	1.87	2.61
Katherine	N-1	28.8	6.53	10.25	11.65	13.05	14.45



Katherine solar farm.

6.4 Alice Springs transmission and distribution Networks

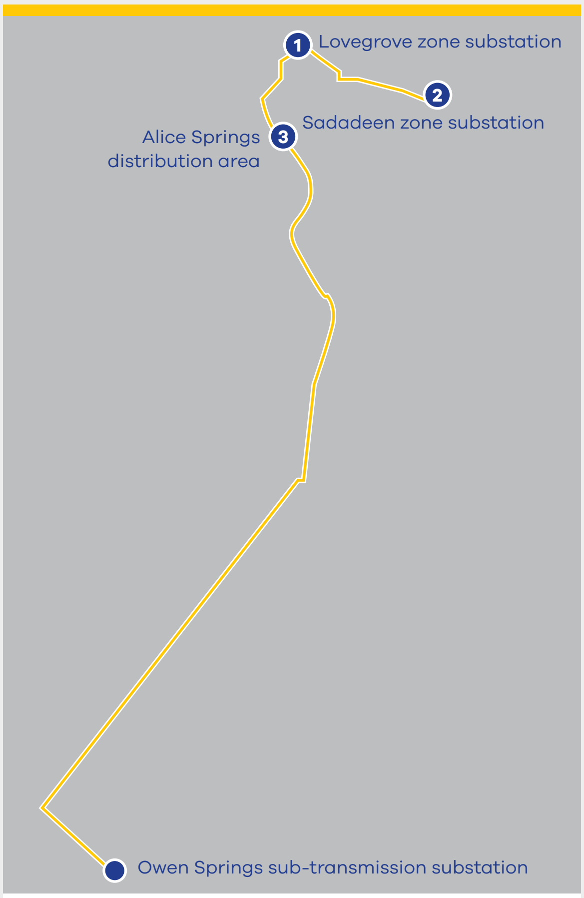
The Alice Springs network is significantly smaller than the Darwin-Katherine network. **Figure 19** shows that there are only two system limitations on the Alice Springs network.

The transmission network in Alice Springs is relatively small comprising a sub-transmission substation and 2 transmission lines. We have not identified any limitations on the transmission network.

The only asset condition limitation we have identified on the distribution network relates to poles. The poles exhibit corrosion from high salinity and moisture levels in the soil. A high proportion of poles affected are between the ages of 30 and 50 years when corrosion issues start to impact the integrity of the pole. The integrity issues pose significant safety risks to the public and our field crews from failing poles. We will be targeting replacement and refurbishment of the poles that are in worst condition and pose highest risk to the community. The project will be ongoing until 2023-24.

There are two capacity limitations for zone substations under a critical contingency (N-1) in Alice Springs as set out in **Table 13**. There are no distribution feeders forecast to be overloaded over the 5 year period.

Figure 19: Alice Springs – Identified system limitations



1 **Capacity limitation**

Address through load transfer

2 **Capacity limitation**

Address through load transfer

3 **Asset condition limitation**

Replace corroded poles that pose highest safety risk to the community

Table 13: Forecast capacity limitations – Zone substations in Alice Springs (MVA)

Zone substations	Criteria	Rating (MVA)	Overload (MVA) under N-1 excluding load transfer capacity				
			FY21	FY22	FY23	FY24	FY25
Lovegrove (22kV load)	N-1	0.0	0.98	0.97	0.96	0.96	0.95
Sadadeen (Ron Goodin 11kV load)	N-1	15.7	0.94	0.94	0.94	0.94	0.94

We are forecasting that the 11kV load connected to Sadadeen zone substation will be overloaded in 2020-21 under a single critical contingency (N-1), and that overload will persist going forward. The limitation can be addressed by transferring load from Lovegrove zone substation, once new feeder cables are installed at Lovegrove Zone Substation in March 2021. The new feeder cables will increase the transfer capacity by 4.7 MVA and increase the flexibility in the network.

We also note that the 22kV load connected at Lovegrove substation cannot be met if the feeder is out of service. We can use a spare 1 MW generator in Alice Springs to supply the load under emergency conditions. We are currently undertaking probabilistic planning on this N-1 condition. Risk assessment has been undertaken and we are in the process of formalising the risk assessment.

Pine Creek.

Appendices

Appendix A: Progress on ICT

Our Information and Communications Technology (ICT) strategy is directed at supporting key improvements to our business including:

- 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 the higher standards and expectations in the NT NER, and to meet new compliance obligations such as for metering and connections.

In our revised proposal for the 2019-24 period, we recognised that our planned program required streamlining, sequencing, and prioritising to ensure efficient delivery. At a high level we are on track with delivering our planned program for the 2019-24 period.

A key focus of our investment is modernising our suite of core systems including upgrades to our asset management system (Maximo), retail management system, and financial systems. We are also implementing a new meter data management, customer relationship management (CRM) and outage management system (OMS). We will be shortly carrying out an expression of interest and request for price to identify the investments that maximise value on these projects, with the exception of OMS and CRM which are sequenced for later in the 2019-24 regulatory period.

We have already undertaken Phase 1 of our upgrade of the geographic information system (GIS). The GIS system termed "ESRI" has been decoupled from Maximo and replaced with an off the shelf integration layer that allows flexibility and reduced customisation. This process will lessen the integration requirements of future projects such as the Maximo upgrade.

In terms of our hardware replacement programs we have shifted and virtualised corporate systems, and at the same time successfully transitioned Power and Water to the new Government Data Centre. We are also delivering on our proposed software update process by buying new licences for our asset management system (Maximo) and enterprise system for SCADA.

We had also proposed a mix of programs specifically aimed at improving the efficiency of our operations and planning of electricity network services. In the 2019-20 year, we have sought to prioritise urgent activities such as automating the data we provide to the AER in our Regulatory Information Notices, as part of our broader data and reporting project. We have also delivered aspects of our Fleet ICT project including navigation software.

We are at the early stages of planning on other projects we proposed to implement in the 2019-24 regulatory period including system planning tools, investment planning and forecasting, scheduling and mobility. We will undertake more detailed planning on these projects once we have modernised our core systems to ensure we extract maximum value.

Appendix B: Asset types and quantities

Table 14 identifies the count of network assets as reported in our 2019-20 Category Analysis Regulatory Information Notice.

Table 14: Asset count for Power and Water regulated network

Asset group	Asset category	Quantity
Poles	> 22 kV & < = 66 kV; Concrete	70
	< = 1 kV; Steel	13350
	> 1 kV & < = 11 kV; Steel	6681
	> 11 kV & < = 22 kV; Steel	21662
	> 22 kV & < = 66 kV; Steel	2262
	> 66 kV & < = 132 kV; Steel	951
Overhead conductors	< = 1 kV	1185
	> 1 kV & < = 11 kV	353
	> 11 kV & < = 22 kV ; SWER	9
	> 11 kV & < = 22 kV ; Multiple-Phase	3113
	> 22 kV & < = 66 kV	376
	> 66 kV & < = 132 kV	354
Underground cables	< = 1 kV	695
	> 1 kV & < = 11 kV	771
	> 11 kV & < = 22 kV ;	97
	> 33 kV & < = 66 kV	39
Service lines	< = 11 kV ; Residential ; Simple Type	46834
	< = 11 kV ; Commercial & Industrial ; Simple Type	9474
Transformers	Pole Mounted ; < = 22kV ; < = 60 kVA ; Single Phase	104
	Pole Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Single Phase	1
	Pole Mounted ; < = 22kV ; < = 60 kVA ; Multiple Phase	660
	Pole Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Multiple Phase	2123
	Pole Mounted ; < = 22kV ; > 600 kVA ; Multiple Phase	3
	>Kiosk Mounted ; < = 22kV ; < = 60 kVA ; Single Phase	291
	>Kiosk Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Single Phase	33
	>Kiosk Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Multiple Phase	1047
	>Kiosk Mounted ; < = 22kV ; > 600 kVA ; Multiple Phase	240
	Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 60 kVA and < = 600 kVA ; Multiple Phase	76
	Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 600 kVA ; Multiple Phase	210
	Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; < = 15 MVA	66
	Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; > 15 MVA and < = 40 MVA	3
	Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; < = 15 MVA	14
	Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; > 15 MVA and < = 40 MVA	24
	Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; > 40 MVA	10
	Ground Outdoor / Indoor Chamber Mounted; > 66 kV & < = 132 kV ; < = 100 MVA	5
	Ground Outdoor / Indoor Chamber Mounted; > 66 kV & < = 132 kV ; > 100 MVA	3
	Other-Transformer	1

Table 14: Asset count for Power and Water regulated network (continued)

Asset group	Asset category	Quantity
Switchgear	< = 11kV; Switch	2952
	< = 11kV; Circuit Breaker	309
	> 11kV and < = 22kV; Switch	3208
	> 11kV and < = 22kV; Circuit Breaker	233
	> 33kV and < = 66kV; Switch	150
	> 33kV and < = 66kV; Circuit Breaker	103
	> 66kV and < = 132kV; Switch	131
	> 66kV and < = 132kV; Circuit Breaker	31
SCADA, Network Control and Protection Systems	Field Devices	1445
	Local Network Wiring Assets	643
	Communications Network Assets	547
	Master Station Assets	1
	Communications Site Infrastructure	384
	Communications Linear Assets	372404
Other	Buildings	36
	Instrument Transformers	307
	Metering Units	80
	Pillars	7578
	Substation Auxiliary Plant	86
	Voltage Regulators	12
	Civil and Grounds	36
	Fire Systems	33
	Capacitor Banks	32

Appendix C: Worst performing feeders

Table 15 identifies the worst performing feeders by segment for 2019 -20 including information on the dominant cause of outages and impact on performance. We also identify if these were the same feeders as reported in last year's TDAPR.

Table 15: Worst performing feeders in 2019-20

Category	Feeder Name	SAIDI	Cause and impact on reported minutes	Same as 2018 19?
CBD	11DA17 DA-ML	1.8	Nine outages, predominantly caused by vegetation (1.5 mins)	No
CBD	11DA14 STATE SQUARE	0.99	One outage caused by equipment failure (HV cable fault)	No
CBD	11MS02 SMITH	0.71	One outage caused by equipment failure (LV pillar fault)	No
CBD	11ML09 DALY	0.11	Two outages perdominantly caused by third party (0.1 mins)	No
CBD	11AK03 AUSTIN LANE	0.04	One outage caused by equipment failure (HV cable fault)	No
Urban	22KA22 KATHERINE	11.97	18 outages, predominantly caused by asset failure (4.5 mins) and unknown (4.4 mins)	Yes
Urban	11CA12 MARRARA	6.49	Eight outages, predominantly caused by animals (3.5 mins) and asset failure (2.0 mins)	Yes
Urban	11DA27 STUART PARK	5.32	11 outages, predominantly caused by vegetation (5.2 mins)	Yes
Urban	11DA19 GARDENS	4.5	Two outages, predominantly caused by third party (4.5 mins)	No
Urban	11CA16 NAKARA	3.29	14 outages, predominantly caused by asset failure (2.9 mins)	No
Rural Short	22SY03 VIRGINIA	32	49 outages, predominantly caused by vegetation (13.8 mins) and third party (6.2 mins)	Yes
Rural Short	22SY11 HERBERT	29	74 outages, predominantly caused by weather (13.1 mins) and animals (4.5 mins)	Yes
Rural Short	22PA202 HOWARD SPRINGS	19.42	51 outages, predominantly caused by vegetation (16.7 mins)	Yes
Rural Short	22SY02 MCMINNS	11.94	38 outages, predominantly caused by vegetation (4.2 mins), unknown (3.0 mins) and animals (2.5 mins)	No
Rural Short	11CA24 PARER	11.41	One outage caused by equipment failure (HV cable fault)	No
Rural Long	22SY04 DUNDEE	1,167.07	38 outages, predominantly caused by weather (674.1 mins), asset failure (371.0 mins) and unknown (118.0 mins)	Yes
Rural Long	22KA10 MATARANKA 1	388.26	88 outages, predominantly caused by asset failure (151.7 mins), third party (93.2 mins), unknown (65.4 mins) and animals (48.0 mins)	Yes
Rural Long	22TC01 ALI CURUNG	14.16	17 outages, predominantly caused by unknown (7.7 mins) and asset failure (5.2 mins)	Yes

Appendix D: Steady state voltage limits and range

Table 16 sets out our prescribed voltage limits and preferred operating range for single phase and three phase connections. Low Voltage is nominally supplied at 230V single phase or 400V three phase. The range of low voltage supply is specified in section 5 of AS61000.3.100.

Table 16: Voltage assessment performance

Nominal Voltage	Voltage Limits		Preferred operating range	
	V1% Minimum (-6% of Vnom)	V99% Maximum (+10% of Vnom)	Minimum (-2% of Vnom)	Maximum (+6% of Vnom)
Single phase 203V	216 V	253 V	225V	244V
Three phase 400V	376 V	440 V	392 V	424 V

Appendix E: Asset maintenance strategies

Table 17 summarises our maintenance strategies for zone substations. **Table 18** summarises our maintenance strategy for distribution assets. **Table 19** summarises our maintenance strategy for transmission assets. **Table 20** summarises our maintenance strategy for secondary systems.

Table 17: Maintenance strategy for distribution assets zone substation assets

Asset class	Maintenance strategy			
Zone substation	Visual: monthly			
	Detailed: three-monthly			
	Thermographic and partial discharge survey: annually			
HV Circuit breakers - outdoor		Oil CB	Vacuum CB	Gas CB
	Functional:	two-yearly	three-yearly	six-yearly
	Diagnostic:	four-yearly	12-yearly	12-yearly
	Intrusive:	eight-yearly	NA	NA
HV Circuit Breakers - indoor		Oil CB	Vacuum CB	Gas CB
	Functional:	two-yearly	three-yearly	six-yearly
	Diagnostic:	four-yearly	12-yearly	12-yearly
	Intrusive:	eight-yearly	NA	NA
Indoor switchboards	Functional: once-yearly			
	Diagnostic: five-yearly			
	Intrusive: five-yearly			
Outdoor disconnectors and busbars	Functional (open/close exercise): two-yearly			
	Diagnostic: six-yearly			
Capacitor banks	Functional: six-monthly			
	Intrusive: five-yearly			
Power transformers	Functional: once-yearly (DGA)			
	Diagnostic: six-yearly (>20yrs old) and 12-yearly < 20yrs old			
Transformer On Load Tap Changers (OLTC)	Diagnostic (DGA): once-yearly			
	Intrusive: OEM Recommendations			
Transformer bushings (66 kV and above)	Diagnostic: three-yearly			
Instrument transformers	Diagnostic: six-yearly, four-yearly, four-yearly for ages <20 years, ages >=20years and CVT respectively			
Earth grids	Functional: five-yearly			
	Diagnostic: 10-yearly			
Batteries and chargers	Functional: yearly			
	Diagnostic: two years after installation then every two years for batteries >8 years of age OR when functional indicates investigation is required			
Auxiliary systems, buildings, grounds	Functional check of auxiliary systems operation: yearly			
	Inspection of structures: five to eight-yearly			
	Fire detection/suppression: Based on local regulations			

Table 18: Maintenance strategy for distribution assets

Asset class	Maintenance strategy
Distribution feeder - overhead	Ground-based inspection: three-yearly
Distribution feeder - underground	Ground-based inspection: three-yearly
Distribution pole	Ground-based inspection: three-yearly
	Diagnostic: Assessed based on current level of section loss
HV pole top structures	Ground-based inspection: three-yearly
	Post feeder outage patrol: Carried out on risk basis
LV pole top structures	Ground-based inspection: three-yearly
Conductors and connectors	Ground-based inspection: three-yearly
	Post feeder outage patrol: Carried out on risk basis
Air break switches	Ground-based inspection: three-yearly, with opportunistic inspection during switching operations
	Functional maintenance: five-yearly (backbone only)
Gas break switches	Ground-based inspection: three-yearly, with opportunistic inspection during switching operations
Gas circuit reclosers	Ground-based inspection: three-yearly
	Functional maintenance: two-yearly
Overhead network earthing systems	Ground-based inspection: three-yearly
	Diagnostic: five-yearly
Distribution substations – pole-top and ground	Ground-based inspection: three-yearly
Voltage regulators	Ground-based inspection: three-yearly
	Diagnostic: two-yearly (DGA)
Distribution capacitors	Ground-based inspection: three-yearly
Ring main units	Inspection: three-yearly
LV pillars	Inspection: 10-yearly, with opportunistic inspection during switching operations

Table 19: Maintenance Strategy for Transmission Lines

Asset class	Maintenance strategy
132kV transmission lines	Annual patrol of line using aircraft or ground based depending on location and accessibility. 15-year detailed inspection poles/towers, pole-top and line hardware. This is staggered with a selection of towers across the entire line route being inspected 3 yearly to develop asset condition trends and drive out of cycle inspections for specific failures or developing failures observed.
66kV transmission lines	Annual patrol of line using aircraft or ground based depending on location and accessibility. 25-year detailed inspection poles/towers, pole-top and line hardware. This is staggered with a selection of towers across the entire line route being inspected five-yearly to develop asset condition trends and drive out of cycle inspections for specific failures or developing failures observed.
66kV cables	Annual checks of oil systems for oil-filled cables (SCADA monitored). Annual inspection and partial discharge scans of cable terminations. Three-yearly detailed visual inspection of undersea cable route using remotely operated vehicle.

Table 20: Maintenance strategy for secondary systems

Asset class	Maintenance strategy
Protection	Dependent on relay type and circuit voltage. Functional checks at two, three or six-year intervals. IO/Trip checks at two or three-year intervals.
SCADA	Master station backup: three-monthly Server maintenance: two-monthly Firewall maintenance: six-monthly SCADA site inspection: three-yearly
Communications	Communications site inspection including tower and earthing: three-yearly Remote monitoring of fibre optic and microwave equipment: six-monthly

Appendix F: Further information

The following documents are available for further information on the asset management strategy and methodology:

- Strategic Asset Management Plan
- Asset Strategies and Objectives
- Various Asset Class Management Plans
- Statement of Corporate Intent.

The above documents can be requested by contacting:

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Appendices published separately to this report

Appendix F and Appendix G set out how the 2020 TDAPR has complied with the National Electricity Rules provisions. This can be accessed on our website under this year's TDAPR.

The following appendices are available as an Excel file which can be accessed on our website under this year's TDAPR.

Appendix I – Transmission Capacity Utilisation

Appendix J – Transmission contingency analysis

Appendix K – Zone substation forecasts and constraints

Appendix L – AER System limitation template

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