Transmission and Distribution Annual Planning Report 2019

PowerWater

Executive Summary

Power and Water Corporation is the licensed transmission and distribution network service provider for the Northern Territory's regulated electricity network[1]. We are also responsible for planning, building, operating and maintaining reliable electricity networks between generators and consumers.

Power and Water is required to produce a Distribution Annual Planning Report (DAPR) and a Transmission Annual Planning Report (TAPR) each year under the National Electricity Rules of the Northern Territory (NT NER). NT NER allows for both documents to be combined in a single Transmission and Distribution Annual Planning Report (TDAPR). The requirements of the TDAPR are set out in Schedules 5.8 and 5.12.2 of the NT NER, which came into effect in 2019.

The TDAPR covers a planning period of five years for the distribution network and 10 years for the transmission network. For these timeframes, the TDAPR outlines the results of the annual planning review and presents the most recent annual load forecasts, network constraints, network performance as well as the plans and committed investments by Power and Water to address any issues. Other information contained in the TDAPR includes regional development plans, demand management and our approach to asset management.

We manage our network across four regions, namely Darwin, Katherine, Tennant Creek and Alice Springs. The Darwin and Katherine regions are connected by a single 132kV transmission line while Tennant Creek and Alice Springs are both isolated networks. As such, a combined demand forecast was completed for Darwin and Katherine and separately for Tennant Creek and Alice Springs. The 10-year demand forecast for Darwin-Katherine is showing a predominantly flat profile with a slight increase after 2026. The forecasts for Tennant Creek show a slight decrease in demand over the same period. In Alice Springs, an increase in system demand in 2021 is expected before a slight decrease for the remainder of the period.

With relatively flat demand forecast, there is no significant driver for augmentation. However, a number of new transmission connection points are forecast to allow for connection of four solar farms and one gas thermal generator. Three of the solar farms and the thermal generator will be connected to the Darwin region, while one solar farm will be connected to the Katherine region. Territory Generation is currently investigating options on the future of Ron Goodin Power Station and recently commissioned a new 5MW battery system in the Alice Springs region. There are no major development plans for Tennant Creek.

The growing penetration of renewable energy in the Northern Territory, which is expected to increase significantly over coming years, is also reflected in the rooftop solar photovoltaic (PV) systems installed. Currently only 13% of our customers have solar PV, but the total capacity of solar PV systems has increased from 5MW in 2010/11 to more than 70MW in 2018/19. This has resulted in a shift of the average daily system peak demand from 2.30pm in 2013 to 5.00pm in 2018, and presents a challenge to ensure the effective integration of renewable energy technologies into the power system does not compromise system security and at the same time, meets our customers' expectations.

Distributed Energy Resources (DER) in the Northern Territory are also expected to increase in the future. This will put pressure on Power and Water to meet the demands of customers while delivering electricity in a more efficient manner, placing more emphasis on non-network solutions rather than increased spending on

[1] As defined in the *National Electricity (Northern Territory) (National Uniform Legislation) Act 2015*, that being the: Darwin electricity system, Katherine electricity system, Tennant Creek electricity system, Alice Springs electricity system and Darwin to Katherine 132kV power line.

network assets. In preparation for this outcome, Power and Water is in the process of developing its Demand Side Engagement Document (DSED) to promote efficient management of the network by using non-network options to manage demand constraints rather than building more infrastructure. As well as a DSED, we are also developing a Virtual Power Plant (VPP) program to investigate the feasibility of non-traditional options for various power system support services.

The annual planning review did not identify any constraints on the transmission network, however, capacity constraints were identified at seven zone substations under N-1 contingencies (loss of the largest transformer at the zone substation) resulting in overloading the zone substations:

- Archer Zone Substation, Katherine Zone Substation and Weddell Zone Substation are forecast to have increasing overload under N-1 contingency. Options are being investigated to resolve these issues.
- Lovegrove Zone Substation has a small overload forecast which will be managed via load transfers.
- Strangways Zone Substation will have a temporary overload constraint which will be resolved as the forecast demand decreases to below the N-1 capacity.
- Humpty Doo Zone Substation is a single transformer zone substation planned for replacement in 2023-24.

Power and Water reported good network reliability during the 2018-19 period, meeting seven out of the 10 System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) reliability targets. Of the three unmet targets, two were related to the central business district (CBD) feeder category where the underground topology of the network resulted in longer outages being required to repair faults. The third metric not met was the rural short feeder category for the number of interruptions (SAIFI) which was predominately due to adverse weather conditions. Plans to improve feeder reliability have been implemented, including a dedicated program focused on the top five poorly performing feeders from each feeder category.

In the final determination for the 2019-24 regulatory control period, the Australian Energy Regulator (AER) determined that the Service Target Performance Incentive Scheme (STPIS) will not apply to Power and Water for the 2019-24 period.

We are committed to prudently and efficiently managing the network, and to ensure it remains secure and reliable, by identifying emerging issues in a timely manner through our annual planning process and evaluating network and non-network options to minimise cost to customers.

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Abbreviations

Abbreviation	Definition/description
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMP	Asset Management Plan
AMS	Asset Management System
AS	Alice Springs network
AVR	Automatic Voltage Regulator
BC	Business Case
BESS	Battery Energy Storage System
BI	Business Intelligence
BNI	Business Needs Identification
BOM	Bureau of Meteorology
CBD	Central Business District
CIPS	Channel Island Power Station
DAPR	Distribution Annual Planning Report
DER	Distributed Energy Resources
DFA	Distribution Fault Anticipation
DGA	Dissolved Gas Analysis
DK	Darwin-Katherine network
DNSP	Distribution Network Service Provider
DSED	Demand Side Engagement Document
EIP	Electricity Industry Performance code
HV	High Voltage
IWG	Industry Working Group
kV	Kilo-volt
LV	Low Voltage
MD	Maximum Demand
MED	Major Event Day
N	System normal
N-1	Single contingency condition
NER	Neutral Earthing Resistor
NT NER	Northern Territory National Electricity Rules
NEX	Neutral Earthing Reactor
NSP	Network Service Provider
NT	Northern Territory
NTC	Network Technical Code
NTG	Northern Territory Government
OLTC	On Load Tap Changer
OMS	Outage Management System
PBC	Preliminary Business Case
PD	Partial Discharge
PIR	Post implementation Review
PoE	Probability of Exceedance
PQ	Power Quality
PV	Photovoltaic
QoS	Quality of Supply
ROCOF	Rate of Change of Frequency

Abbreviation	Definition/description
RIN	Regulatory Information Notice
RMU	Ring Main Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAMP	Strategic Asset Management Plan
SCADA	Supervisory Control and Data Acquisition
SCI	Statement of Corporate Intent
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
TAPR	Transmission Annual Planning Report
TC	Tennant Creek network
TDAPR	Transmission and Distribution Annual Planning Report
TNSP	Transmission Network Service Provider
UCNT	Utilities Commission of the Northern Territory
UFLS	Under Frequency Load Shedding
UG	Underground
UPS	Uninterruptable Power Supply
ZSS	Zone Substation

Glossary

Abbreviation	Definition/description
Connection Point	The agreed point of supply established between the Network Service Provider and another Generator or Customer.
Distribution Network	Any part of the electricity network which is not a transmission network as per Chapter 10 (Glossary) of the NT NER
Embedded Generation	A generating unit that is directly connected to the distribution network as opposed to the transmission network.
Network	Refers to Power and Water regulated network as defined in the *National Electricity (Northern Territory) (National Uniform Legislation) Act 2015*, that being the: Darwin electricity system, Katherine electricity system, Tennant Creek electricity system, Alice Springs electricity system and Darwin to Katherine 132kV power line.
Primary Distribution Feeder	A circuit from a zone substation to supply distribution substations.
Sub-transmission	Any part of the electricity network which operates to deliver electricity from the transmission system to the distribution network.
Total Capacity (N)	Total capacity under system normal conditions
Total Nameplate Capacity	Capacity as stated on nameplate
Transmission Network	Any part of the electricity network which operates at nominal voltages of 66kV and above as per Chapter 10 (Glossary) of the NT NER. It does not include the transformers in distribution zone substations.

1 Introduction

The introduction of the Northern Territory National Electricity Rules (NT NER) on 1 December 2019 mandated the requirement for the publication of annual planning reports that provide information on the regulated distribution and transmission electricity networks in the Northern Territory.

Clause 5.12.2 and 5.13.2 of chapter 5 of the NT NER require Power and Water to publish its combined Transmission Annual Planning Report (TAPR) and Distribution Annual Planning Report (DAPR) on the outcomes of its annual transmission and distribution planning reviews of the transmission network (over the 10-year period from 2019/20 to 2028/29) and of the distribution network (over the five-year period from 2019/20 to 2023/24).

This inaugural Transmission and Distribution Annual Planning Report (TDAPR) has been prepared by Power and Water in accordance with the information required by NT NER clauses 5.12.2 and 5.13.2, and schedule 5.8. It aims, in addition to satisfying the requirements of the NT NER, to inform market participants and stakeholders about system limitations and network and non-network developments on the regulated electricity network. This report also provides information on Power and Water's asset management approach including asset replacement programs and projects.

1.1 Structure of this report

This combined DAPR and TAPR is structured as follows:

- Chapter 2 provides an overview of Power and Water as an organisation, its electricity network, and its operating framework and constraints;
- Chapter 3 provides information on regional development plans
- Chapter 4 provides Power and Water's forecasts for the planning periods applicable to its electricity distribution and transmission networks;
- Chapter 5 provides information on network asset retirements and deratings;
- Chapter 6 provides details on system limitations for transmission and distribution systems;
- Chapter 7 provides information on frequency control schemes;
- Chapter 8 provides details on overloaded feeders;
- Chapter 9 provides information on network investments;
- Chapter 10 provides information on joint planning obligations;
- Chapter 11 provides information on network performance;
- Chapter 12 provides information on our asset management approach;
- Chapter 13 provides details on demand management; and
- Chapter 14 provides details on current and future information technology and communications investment.

2 Power and Water overview

2.1 Organisation overview

Power and Water is established under the *Power and Water Corporation Act 2002* (PWC Act) and is a NT government owned corporation under the *Government Owned Corporations Act 2001* (GOC Act). Our objectives under section 4 of the *GOC Act* are to:

- operate at least as efficiently as any comparable business; and
- maximise the sustainable return to the Northern Territory Government on our investment.

Power and Water is a multi-utility in that it:

- owns and operates the large dams and groundwater fields to deliver clean drinking water to households and businesses, and removes and treats wastewater before disposing of it in an environmentally responsible manner
- operates a retail water and wastewater business
- owns and operates the regulated electricity network and parts of the unregulated electricity network in our licenced areas
- provides electricity, water and sewerage services to remote Aboriginal communities and outstations, through its not-for-profit subsidiary, Indigenous Essential Services Pty Ltd (IES), under agreement with the Northern Territory Government
- ensures the electricity network is balanced and stable, safe and reliable through its System Control operations and operates the interim wholesale electricity market
- manages large scale gas purchase and transportation agreements and sells that gas to Territory Generation and other large businesses across the Northern Territory as well as interstate with the completion of the Northern Gas Pipeline
- retails electricity to a small number of mining towns, as a result of legacy contracts with the Government
- owns and operates five generation plants in regional areas and sells the electricity to Jacana Energy
- is one of the key responders after a natural disaster, helping restore essential services to the community.

Power and Water has more than 95,000 electricity and water customers (including regions and remote customers) and is structured along three main lines of business (power, water, and gas) supported by core operations and business services.

Power Services

Power Services plans, builds, operates and maintains safe, reliable and efficient electricity networks (including meters) to transmit electricity between generators and both regulated and non-regulated customers in the Northern Territory.

In addition, Power Services provides electricity to geographically isolated and dispersed Aboriginal communities and outstations across the Northern Territory on behalf of IES, as funded by the Department of Local Government, Housing and Community Development (DLGHCD). This includes the generation and retailing of electricity for many rural towns and remote communities from medium scale gas turbines, smaller scale diesel machines and integrated solar-diesel and battery storage arrangements.

Electricity is distributed to an estimated 244,300 people across an area of 1.3 million square kilometres. Electricity network services for the three regulated networks (Darwin to Katherine, Tennant Creek and Alice

Springs) are delivered pursuant to the 2019 Network Price Determination, administered by the Australian Energy Regulator (AER).

Water Services

Water Services plans, constructs, operates and maintains water and sewerage infrastructure assets for the long term to provide safe, reliable and efficient water and sewerage services to five major centres and five of the 15 minor centres, with the remaining minor centres provided with water services only.

In addition, Water Services provides water and sewerage services to geographically isolated and dispersed Aboriginal communities and outstations across the Northern Territory on behalf of IES, as funded by the DLGHCD. This includes 72 Aboriginal communities and 66 outstations, of which 15 communities are provided with water services only.

Core Operations

In line with Power and Water's new operating model, a new Core Operations unit has been established to lead system control, market operations, remote services, SCADA and communications and metering functions.

System Control

System Control has a statutory role in monitoring and controlling the operation of the regulated power systems in the Northern Territory and for overseeing their safe, secure and reliable operation. The System Control Licence, which is issued by the Utilities Commission, determines Power and Water's statutory obligations. Since May 2015, System Control has also been performing the trading/dispatch and market services functions of the Interim Northern Territory Electricity Market, along with other market operator functions. This will continue pending the final design and commencement of the Northern Territory Electricity Market (NTEM). Other non-regulated services are also provided both internally and to other market participants.

Remote Services (Indigenous Essential Services)

IES is a wholly owned not-for-profit subsidiary of Power and Water, operating under agreement with the DLGHCD. IES coordinates the delivery of electricity, water and sewerage services to 72 geographically isolated and dispersed Aboriginal communities and 66 outstations. Services in Aboriginal communities are delivered on behalf of IES through the Power Services and Water Services lines of business, in line with Power and Water's new operating model, to leverage the skills and expertise within the business. An Essential Service Operator (ESO) delivery model has been adopted to maximise opportunities for local and Aboriginal employment and training.

Gas Services

Gas Services manages long-term gas acquisition, sales and pipeline transmission arrangements to ensure gas is delivered to electricity generators and other major gas customers. It is also focused on seeking new gas market opportunities and maximising the use of existing gas supply entitlements and transmission capacity including the new NGP.

Business support services

Centralised services are provided across the corporation through the following business support areas – Transformation, People Culture and Customer, Information Technology and Systems, and the Office of the Chief Financial Officer.

As the remainder of this report relates to only the Power Services business, all references to Power and Water henceforth refers to the Power Services business only.

2.2 Our operating environment

Power and Water is subject to both the National Electricity Law (NEL) and the NT NER, both of which are enacted in the Northern Territory through the *National Electricity (Northern Territory) (National Uniform Legislation) Act 2015* and associated regulations.

Power and Water is regulated by the Australian Energy Regulator (AER). Power and Water's first regulatory proposal made under the NT NER came into effect on 1 July 2019 for the period 1 July 2019 – 30 June 2024. The AER final decision, released on 30 April 2019, sets Power and Water's network revenue, and the structures of our network tariffs and charges, for the five-year period.

In addition, Power and Water is supporting the Northern Territory Government's Roadmap to Renewables. This Roadmap to Renewables aims to transition to 50% renewable energy by 2030[2]. As part of this transition, the NT Government announced a $5m investment to install rooftop photovoltaic (PV) on 25 selected Northern Territory schools[3] which commenced in 2018/2019.

2.2.1 Network Technical Code and Network Planning Criteria

The Network Technical Code and Network Planning Criteria is a requirement specified in the *Northern Territory Electricity Networks (Third Party Access) Code*, which was repealed in July 2019 under section 17 of the *National Electricity (Northern Territory) (National Uniform Legislation) Act 2015*. Section 25 of the same Act provides for an existing technical code to become a Network Technical Code under the *Electricity Reform (Administration) Regulations 2000*, which in section 25 broadly duplicates the obligations and responsibilities that Power and Water previously held under the *Northern Territory Electricity Networks (Third Party Access) Code*.

As the network provider, it is Power and Water's obligation to publish the Network Technical Code. We may make amendments to the Network Technical Code, but must first consult the Utilities Commission of the Northern Territory, and make any alterations required by the Commission prior to publishing the amended Network Technical Code. If Power and Water wishes to make material amendments to the Network Technical Code, we must consult with and invite submissions from interested parties on the proposed amendments. Power and Water must consider the feedback from interested parties prior to finalising and publishing the amended Network Technical Code. The document describes:

- Network Technical Code: The technical requirements designed to ensure that the network and the customer installations and equipment connected to the network may be operated and maintained in a secure manner; and

[2] https://roadmaptorenewables.nt.gov.au/?a=460760
[3] http://newsroom.nt.gov.au/mediaRelease/28494

- Network Planning Criteria: Specifies the network requirements to ensure a safe, secure, and reliable supply for all network users.

The Network Technical Code covers requirements related to system security, testing, control and protection, and metering for customer installations. It is currently undergoing a review and public consultation process which will include updated Generator Performance Standards (GPS) to better cater for inverter based generation.

The Network Planning Criteria set out the supply contingency criteria used to plan Power and Water's network. Supply contingency criteria[4] relate to the ability of the supply system (network and generation) to be reconfigured after a fault, so that the supply to customers is restored.

The steady state criteria[5] define 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.

The stability criteria[6] ensure the power system can return to a steady-state or equilibrium operating condition following a disturbance.

The quality of supply criteria[7] regulate the voltage and current waveforms in the network and criteria are established for voltage fluctuations, system frequency, harmonic distortion, voltage unbalance and network reliability.

2.3 Electricity network

Power and Water is licenced[8] by the Utilities Commission of the Northern Territory to own and operate three separate regulated electricity networks within the Northern Territory as shown in Figure 1. These are:

- **Darwin–Katherine (DK)**, the largest system, supplies the city, suburbs and surrounding areas of Darwin and Palmerston, the township of Katherine and its surrounding rural areas. The Darwin–Katherine 132 kV transmission line links these two centres with intermediate 132kV substations at Manton and Pine Creek. There are power stations located at Channel Island, Weddell, Pine Creek and Katherine;
- **Tennant Creek (TC)** system supplies the township of Tennant Creek and surrounding rural areas from its centrally located power station; and
- **Alice Springs (AS)** 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. We service, by a considerable margin, the smallest customer base compared to other distribution utilities in Australia's National Electricity Market (NEM), but have the largest service area of any distribution network.

[4] Power and Water Corporation Network Technical Code and Planning Criteria, section 14
[5] Power and Water Corporation Network Technical Code and Planning Criteria, section 15
[6] Power and Water Corporation Network Technical Code and Planning Criteria, section 16
[7] Power and Water Corporation Network Technical Code and Planning Criteria, section 17
[8] Utilities Commission of the Northern Territory 2015, *Network Licence issued to Power and Water Corporation date of issue 31 March 2000 as varied on 3 April 2015*, UCNT, Darwin

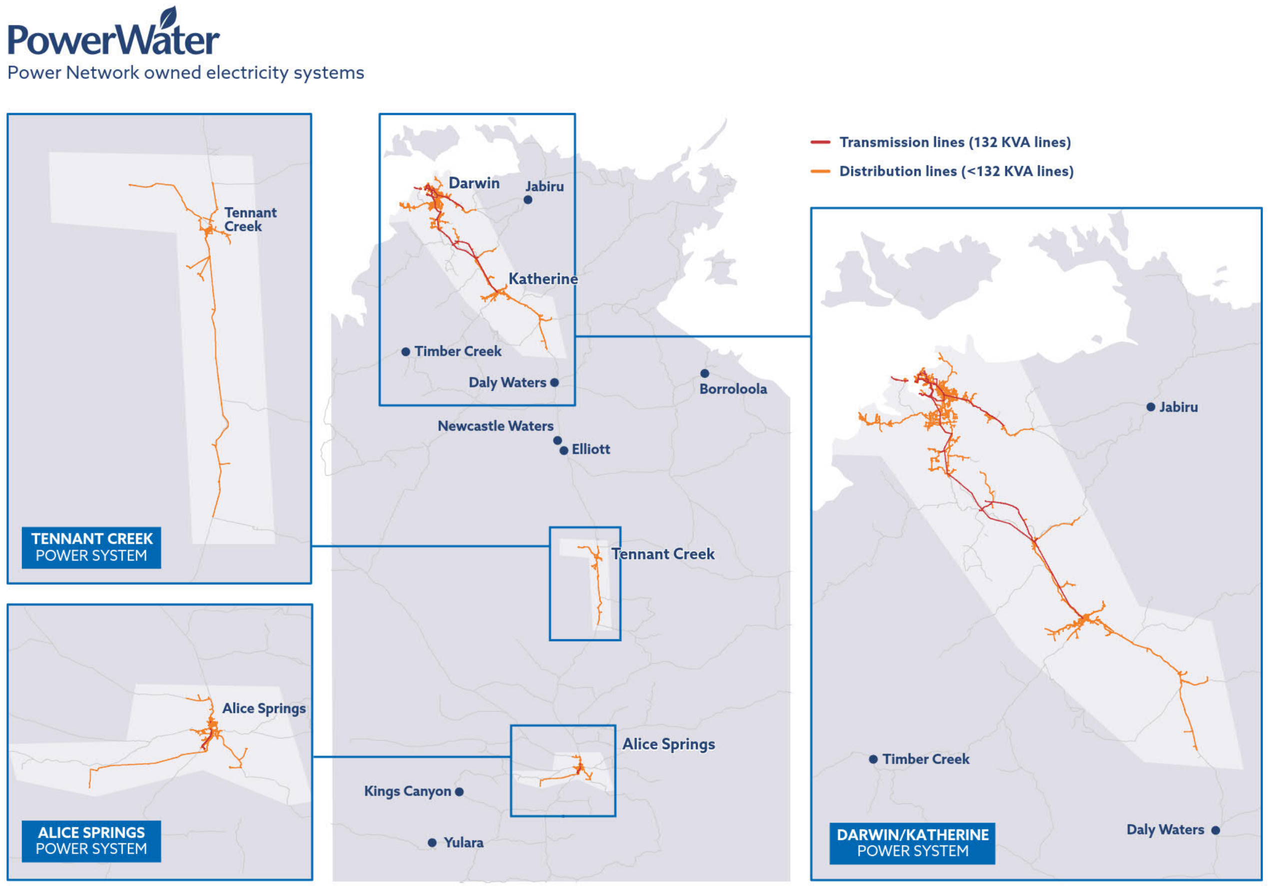

Figure 1 Our regulated electricity distribution service areas

Power and Water is responsible for planning, building, operating and maintaining a reliable electricity network between generators and customers for these three regulated networks. Figure 2 illustrates the Northern Territory electricity supply chain.

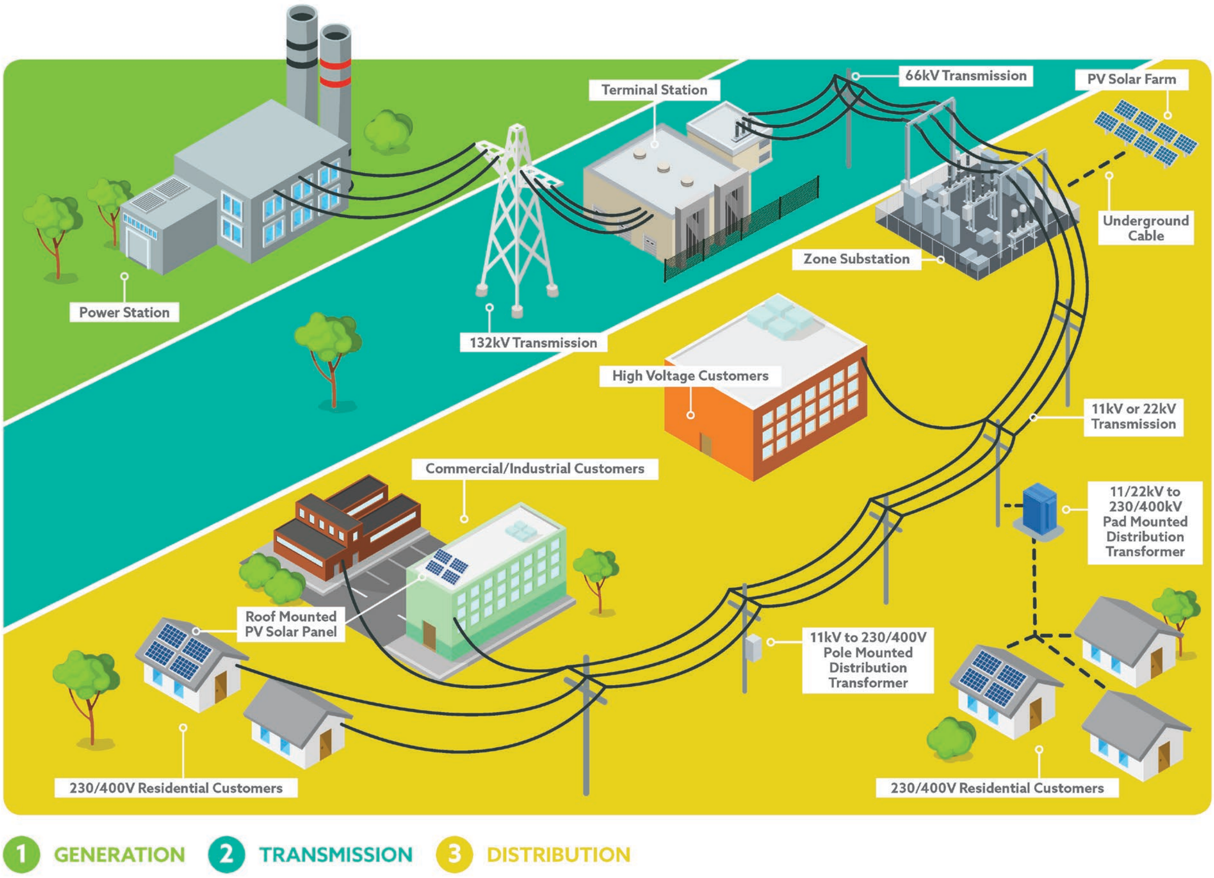

Figure 2 The Northern Territory electricity supply chain

2.4 Network assets

Power and Water power network includes transmission, sub-transmission and distribution assets as shown in **Table 1**. Power and Water's electricity networks operate at transmission voltages of 132kV and 66kV, high voltage distribution voltages of 22kV and 11kV, and at low voltage for local distribution. Most of our distribution network is a three-phase system, with some pockets of single-phase systems in the Darwin region.

Table 1 Classification of Power and Water network assets

Asset description	Network classification
132kV terminal stations and associated ancillary equipment 132kV transmission lines 66kV transmission lines	Transmission network assets

Asset description	Network classification
66kV zone substations and associated ancillary equipment Primary distribution feeders HV (<66kV) and LV distribution lines and cables Distribution substations Distribution switchgear	Distribution network assets

Power and Water operates in contrasting climatic conditions, ranging from the tropical monsoonal north with pronounced wet summer and dry winter conditions north of Katherine, to the arid desert climate south of Tennant Creek. Extremes of weather can range from powerful cyclones and tropical storms in the north, to dust storms and persistent drought in central Australia. Furthermore, termites are extremely active across the whole Territory, which dictates the use of steel and concrete rather than wooden power poles.

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. Low load density and wide geographical spread impact network topography, with Darwin, Manton, Pine Creek and Katherine connected by a 132kV radial transmission line. The rest of the transmission and distribution network typically consists of a mesh network.

2.4.1 Transmission network

132kV transmission lines

The 132kV transmission network comprises almost 354 km of overhead 132kV transmission line made up by two 132kV lines from Channel Island Power Station (CIPS) to Hudson Creek Terminal Station, and a single 132kV line from CIPS to Katherine zone substation via Manton, Batchelor and Pine Creek terminal stations.

66kV transmission lines

The NT NER include 66kV transmission lines in the transmission network classification. There are approximately 416km of 66kV circuits in the network, of which 39km is underground and 377km is overhead. Most of the 66 kV circuits are within the Darwin-Katherine system, while a small section exists in Alice Springs, connecting Owen Springs substation to Lovegrove Zone Substation.

132kV and 66kV substations

The transmission network also includes terminal stations that interconnect 132kV and 66kV transmission lines, which are different to zone substations that connect the 66kV network to the 22kV and 11kV distribution network. In Darwin Katherine, this includes Channel Island, Hudson Creek, Manton, Pine Creek and Katherine Terminal Stations, while in Alice Springs, it includes Owen Springs Terminal Station.

2.4.2 Distribution network

Power and Water's distribution network is supplied by 24 zone substations and typically operates at 11kV in urban areas and 22kV in rural locations. The low voltage distribution network is mostly a three phase system operating at 400/230V.

Zone substations

Our zone substations are usually supplied from two or more 66kV transmission lines although some rural zone substations are supplied from a single source. The zone substation steps the voltage down to be distributed through primary distribution feeders. Most power transformers in the zone substations have on-load tap changers (OLTC) and automatic voltage regulators (AVR) that regulate the voltage level to maintain nominal voltage in response to changes in loading levels.

Primary distribution feeders

Power and Water's primary distribution feeders are largely three-phase radial feeders that provide supply to distribution substations. They may be overhead or underground. Most primary distribution feeders are 11kV in urban areas and 22kV in rural areas.

Single phase system

While most of Power and Water's distribution network is three-phase, small pockets of single-phase systems exist in the Darwin urban areas.

In the Darwin urban area, some parts of Leanyer, Malak and Karama are supplied from 6.3kV single-phase distribution substations.

Distribution substations

Power and Water owns and maintains approximately 4,830 distribution substations in the Darwin-Katherine, Tennant Creek and Alice Springs regions. Our standard distribution substations can be pole-mounted, kiosk mounted or ground mounted indoor/outdoor. Some kiosk mounted transformers are equipped with ring main units (RMU), and are also known as 'package subs'.

Newer package subs now include smart meters, enabling remote download of meter data. This allows the total energy usage of all customers supplied from a particular distribution substation to be downloaded remotely for more efficient network modelling and planning.

Low voltage network

Power and Water's LV network is supplied at nominal voltages of 400V three-phase and 230V single-phase.

2.4.3 Asset summary

Power and Water's network asset types and quantities are detailed in Appendix B.

2.5 Methodologies used in preparing DAPR and TAPR

Power and Water's augmentation and replacement capital expenditure projects are a direct consequence of the network planning process and asset management approach.

Our network planning process considers the forecasted load against the Network Technical Code and Network Planning Criteria. Power and Water's forecasting method is described in section 4.1. Network constraints are determined annually by comparing forecasted loads for feeders, zone substations, and transmission lines against equipment ratings. This information is fed into the TDAPR and a planning report completed for every identified constraint that focuses on feasible network and non-network options to address the issue.

Preventative maintenance provides Power and Water the opportunity to understand the condition of the asset. From this, we can determine an economic balance between the cost of maintenance, replacement or refurbishment, so as to achieve minimum asset life cycle cost. Power and Water's asset management approach and strategy are explained in greater detail in section 12.

Solutions to address constraints will be further developed through Power and Water's Project Investment and Delivery Framework. 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 logic, identifying the issue and the risk to the organisation.

Once the BNI has been approved for a project, it will be included in the five-year capital works budget that is reviewed annually and used as an input to the TDAPR. This information will also be used in the distribution determination proposal every five years.

After the BNI is approved, we develop a Preliminary Business Case (PBC), analysing 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 (BC) for the project, before the project is implemented in order to demonstrate sufficient project analysis and development prior to seeking approval to proceed. A BC would include more detailed project information than a PBC, including management plans, procurement and delivery strategies, detailed cost estimates and schedules.

After the completion of the project, we will 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.

Figure 3 shows the planning process as well as the internal project development and approval process to address the identified constraint.

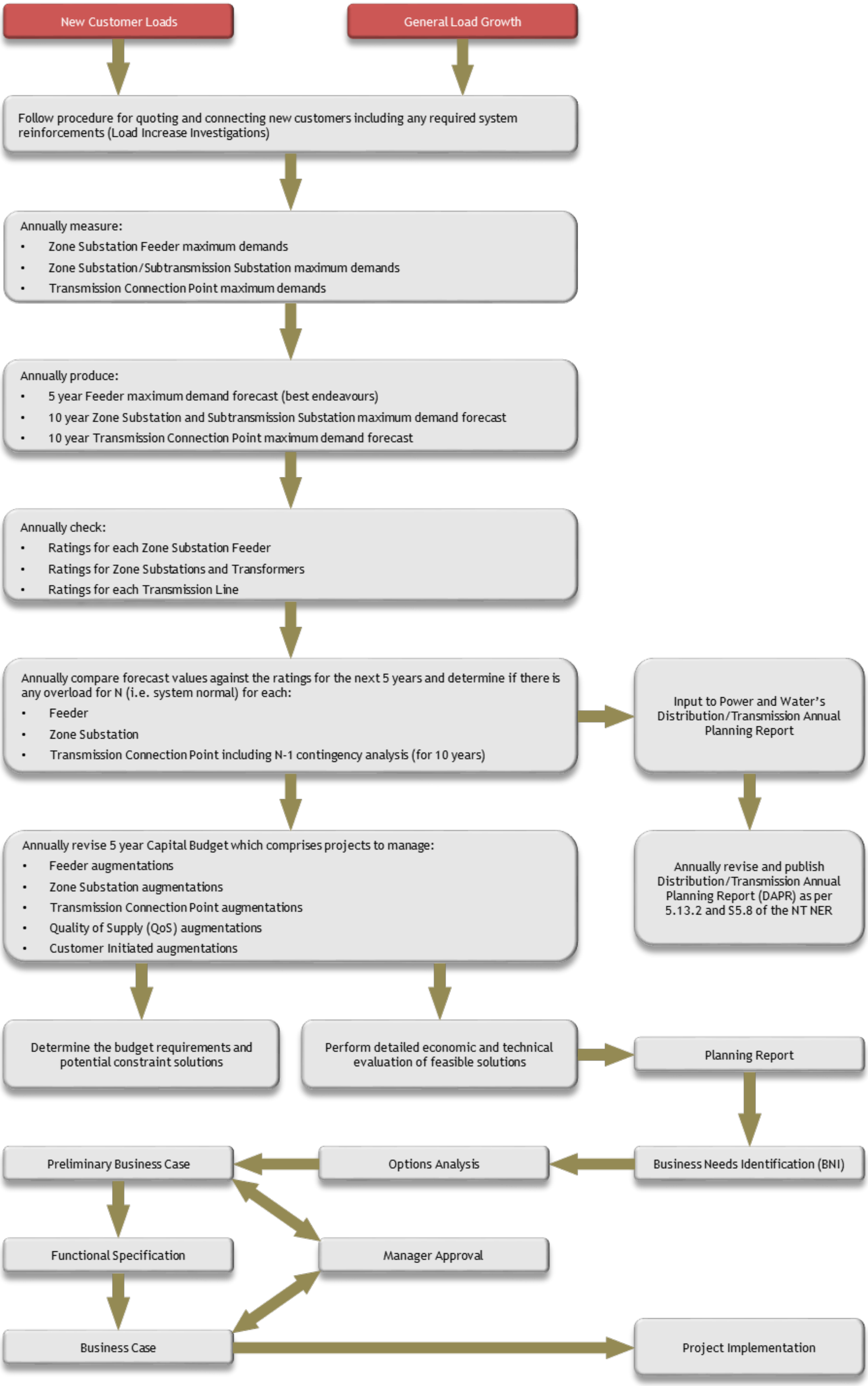

Figure 3 Overview of Power and Water's capacity planning process

3 Regional development plans

This section includes maps of Power and Water network, identifying sub-transmission lines, transmission substation, zone substations and transmission-distribution connection points, and any system limitations occurring in the forward planning period from 2018/19 to 2023/24. Power stations are also shown for completeness.

Power and Water's customers are supplied primarily from 11kV or 22kV distribution feeders. Feeders are augmented to facilitate customer connection requests, meet increases in customer demand and satisfy requirements as set out in the Network Planning Criteria (in particular regarding Quality of Supply). Occasionally, new feeders/lines, zone substation upgrades and transmission line upgrades are required due to increasing demand or new customers. These projects generally require months or years of planning and studies. As such, Power and Water should be notified of any proposed development in the very early stages to facilitate connection of new load and generation.

Power and Water has developed regional development plans for each of the regulated regions including Darwin urban, Darwin rural, Katherine, Tennant Creek and Alice Springs. These are presented in the following sections.

3.1 Darwin regional development plan

The Darwin network consists of urban and rural areas. The Darwin urban area includes the CBD and surrounding suburbs, the northern suburbs and the Palmerston area. Hudson Creek Terminal Station is the only transmission-distribution connection point in this area. Within this area, there are two main generating sites, namely Channel Island and Weddell Power Stations.

The majority of the zone substations in this area operate at 66/11kV with the exception of Weddell (66/22kV), Strangways (66/22kV) and Hudson Creek (132/66kV).

Developments include a new thermal power station (connecting to 66kV switchyard at Hudson Creek Terminal Station, which is expected to be commissioned in 2020).

System limitations exist for Hudson Creek Terminal Station, Archer Zone Substation and Strangways Zone Substation – refer to section 6.1.1. Feeder limitations exist at Casuarina Zone Substation – refer to section 8.1.

Table 2 below lists the terminal and zone substations. These are shown graphically on Figure 4.

Table 2 Darwin urban substations

Terminal substations	Zone substations		
Hudson Creek	Archer	Darwin	Palmerston
	Berrimah	Frances Bay	Strangways
	Casuarina	Hudson Creek	Weddell
	Centre Yard	Leanyer	Woolner

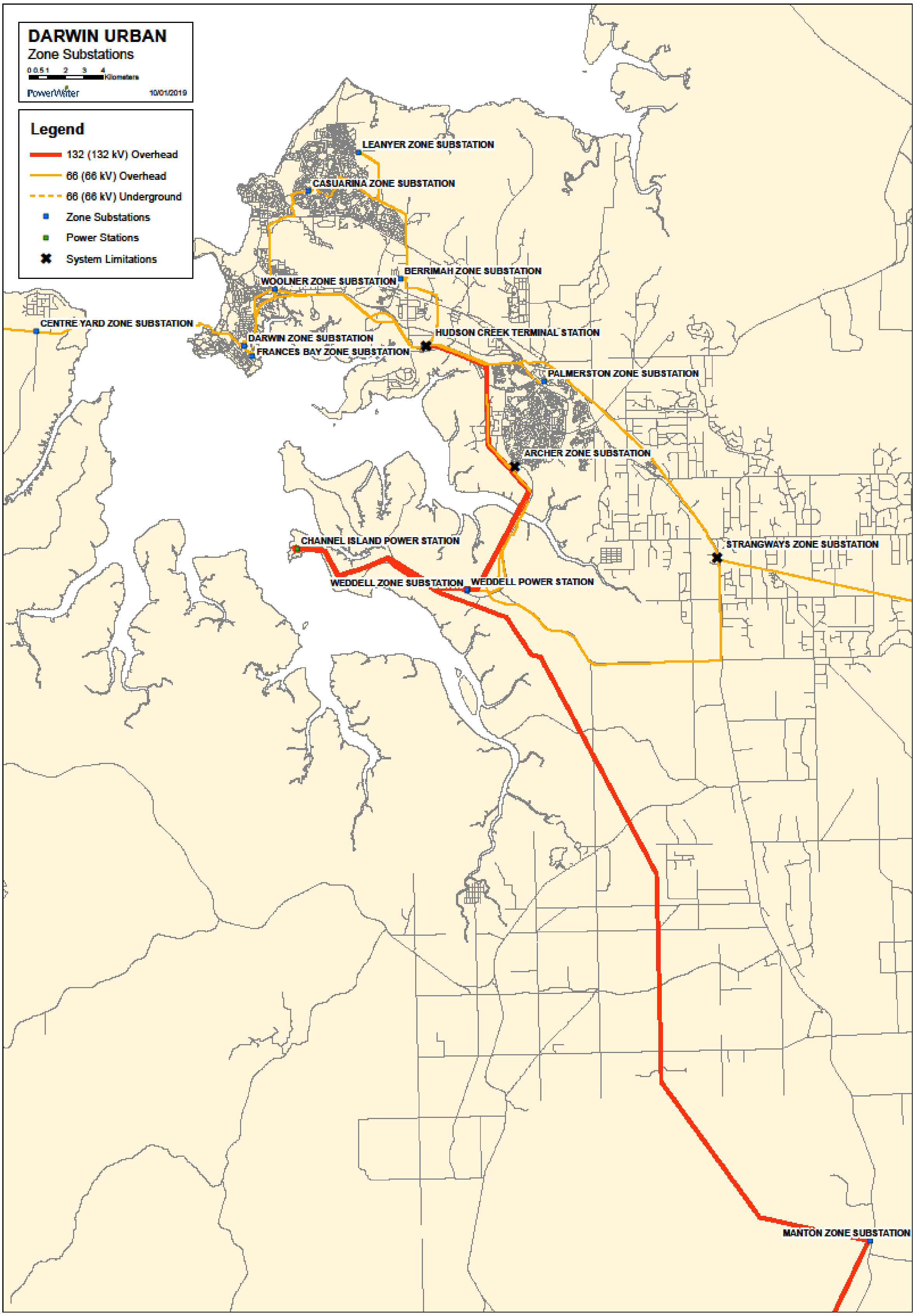

Figure 4 Darwin urban regional map

The Darwin rural area includes areas from Strangways to Batchelor in the south, extending east out to Mary River. There is no generation in this area.

Humpty Doo, Marrakai and Mary River operate at 66/22kV while Manton and Batchelor both operate at 132/22kV.

Developments include two Batchelor Solar Farms (connecting to 22kV switchboard at Batchelor Zone Substation, which is expected to be commissioned in 2020) and Manton Solar Farm (connecting to 22kV switchboard at Manton Zone Substation, which is expected to be commissioned in 2020).

No system or feeder limitations exist for this area.

Table 3 below lists the lists the terminal and zone substations. These are shown graphically on Figure 5.

Table 3 Darwin rural substations

Terminal substations	Zone substations
Batchelor	Batchelor
Manton	Humpty Doo
	Manton
	Marrakai
	Mary River

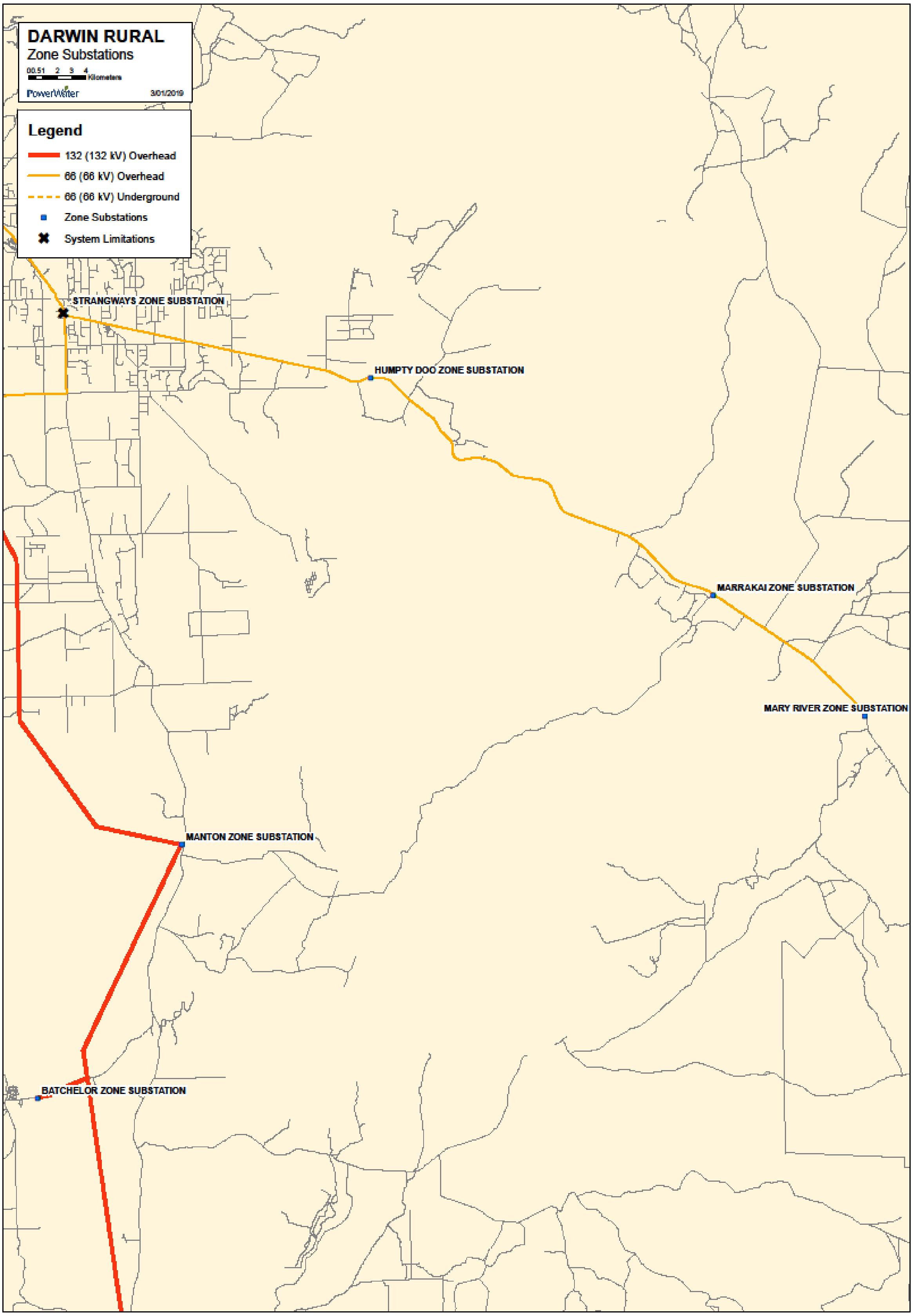

Figure 5 Darwin rural regional map

3.2 Katherine regional development plan

The Katherine region includes the townships of Katherine and Pine Creek in the north. There is generation at both these sites.

Pine Creek operates at 132/66kV while Katherine operates at 132/22kV.

The Katherine Solar Farm, anticipated to be commissioned in early 2020, will be connected to the 22kV switchboard at Katherine Zone Substation.

System limitations exists for Katherine Zone Substation – refer to section 6.2. Also, the substation can experience high voltages on the 132kV during periods of low load due to the Ferranti effect on the DKTL.

Table 4 below lists the terminal and zone substations. These are shown graphically on Figure 6.

Table 4 Katherine substations

Terminal substations	Zone substations
Katherine	Katherine
Pine Creek	Pine Creek

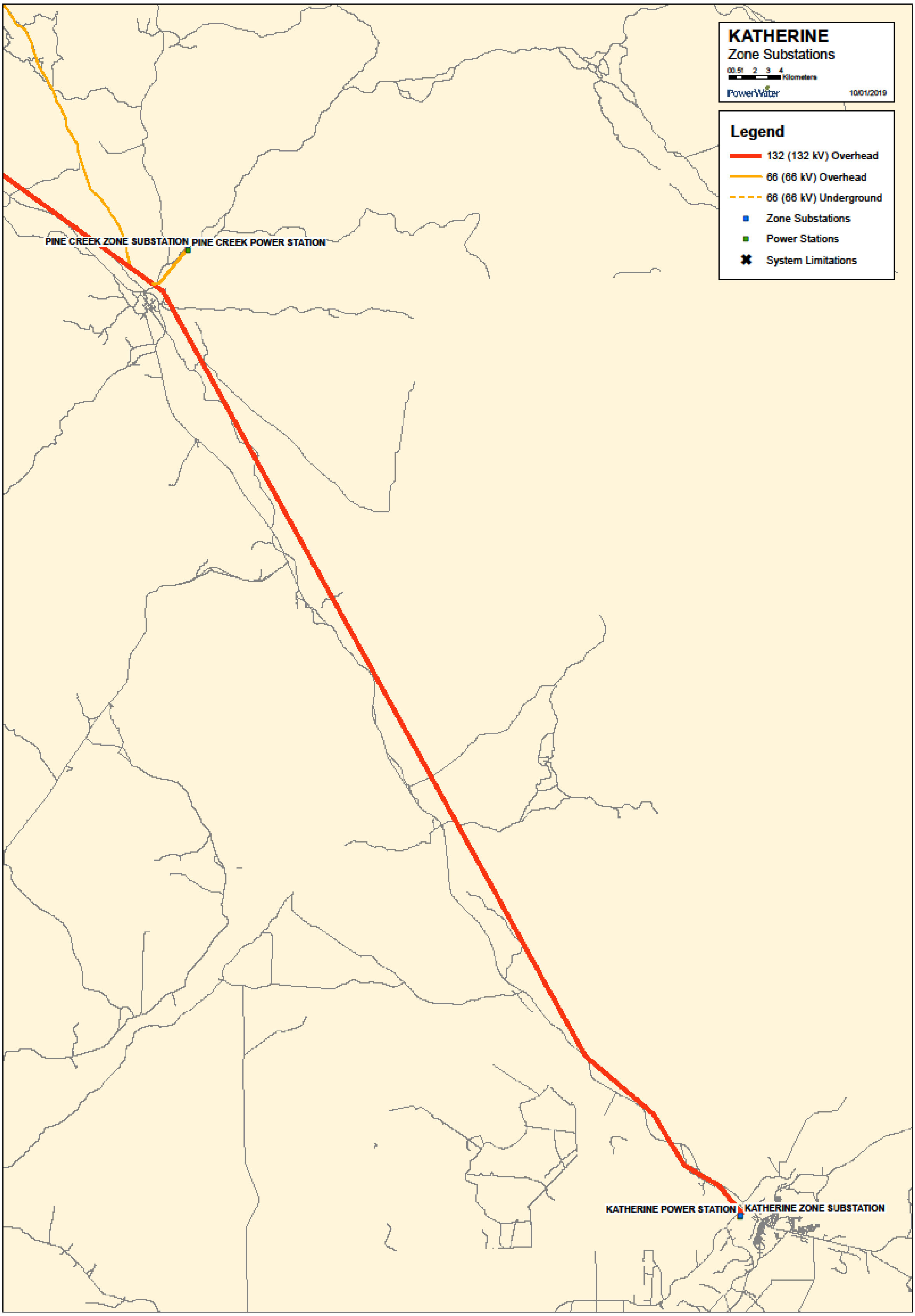

Figure 6 Katherine regional map

3.3 Tennant Creek regional development plan

The Tennant Creek area comprises of a single power station, with an adjacent zone substation. Power is generated at 11 kV and stepped up to 22 kV at the zone substation. Customers are supplied from the 22 kV primary distribution feeders.

Table 5 below lists the terminal and zone substations. Figure 7 shows the extent of the Tennant Creek area.

Table 5 Tennant Creek substations

Terminal substations	Zone substations
	Tennant Creek

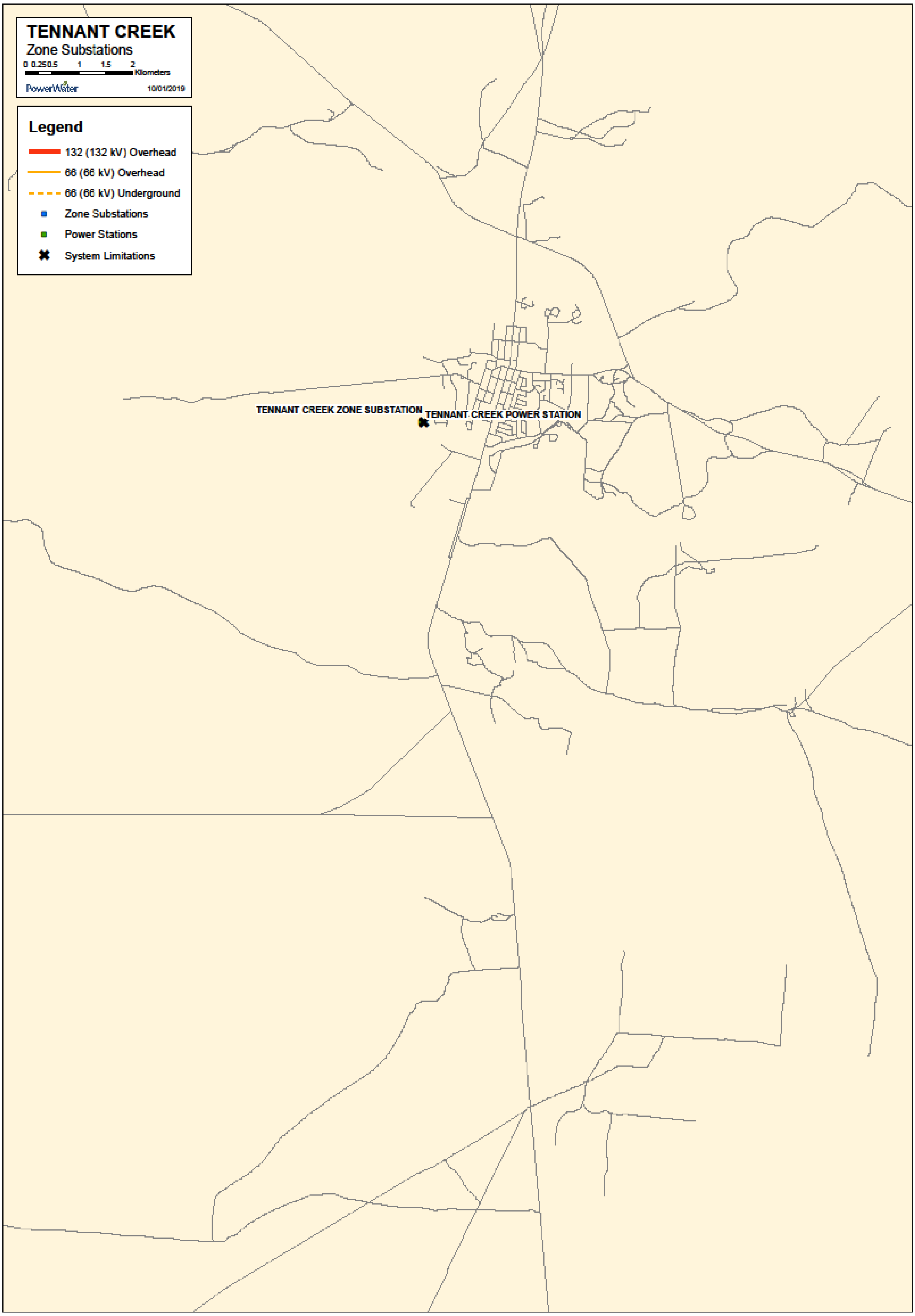

Figure 7 Tennant Creek regional map

3.4 Alice Springs regional development plan

The Alice Springs area includes Lovegrove in the north, Ron Goodin and Sadadeen in the east and Owen Springs in the south. Currently, there is generation at Ron Goodin and Owen Springs though Territory Generation have confirmed their plans to decommission Ron Goodin Power Station sometime in the near future. Other developments that have occurred in 2019 include the commissioning of a 5MW Battery Energy Storage System (BESS) at Ron Goodin.

Lovegrove operates at 66/22kV and 22/11kV, Ron Goodin at 22/11kV, Sadadeen at 22kV and Owen Springs at 66/11kV.

System limitations exists for Lovegrove Zone Substation – refer to section 6.2.

Table 6 below lists the terminal and zone substations. These are shown graphically on Figure 8.

Table 6 Alice Springs substations

Terminal substations	Zone substations
Owen Springs	Ron Goodin
	Sadadeen
	Lovegrove

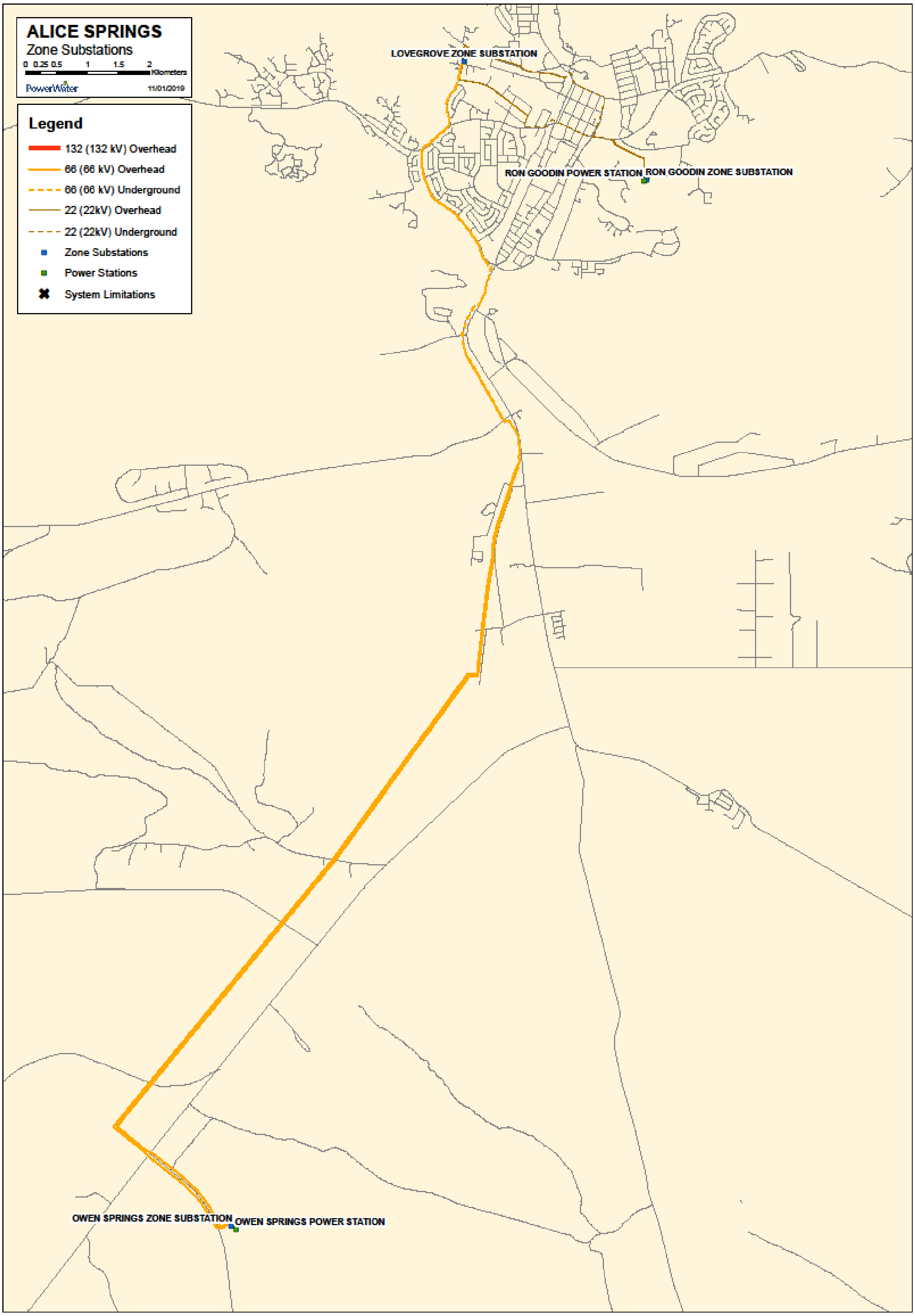

Figure 8 Alice Springs Regional map

4 Forecasts for the forward planning period

4.1 Forecasting methodology

Power and Water's demand forecasts are calculated for the 12-month period from 1 April to 31 March to coincide with the timing of the Northern Territory's wet and dry seasons. Forecasts for feeders and zone substations are prepared each year. Distribution feeder and zone substations maximum demand forecasts are determined taking into account historical maximum demand, completed or committed block loads and embedded generation sources and recent or expected changes to the network.

Power and Water's forecasting process comprises the steps shown in Figure 9. The rest of this section details each of these steps.

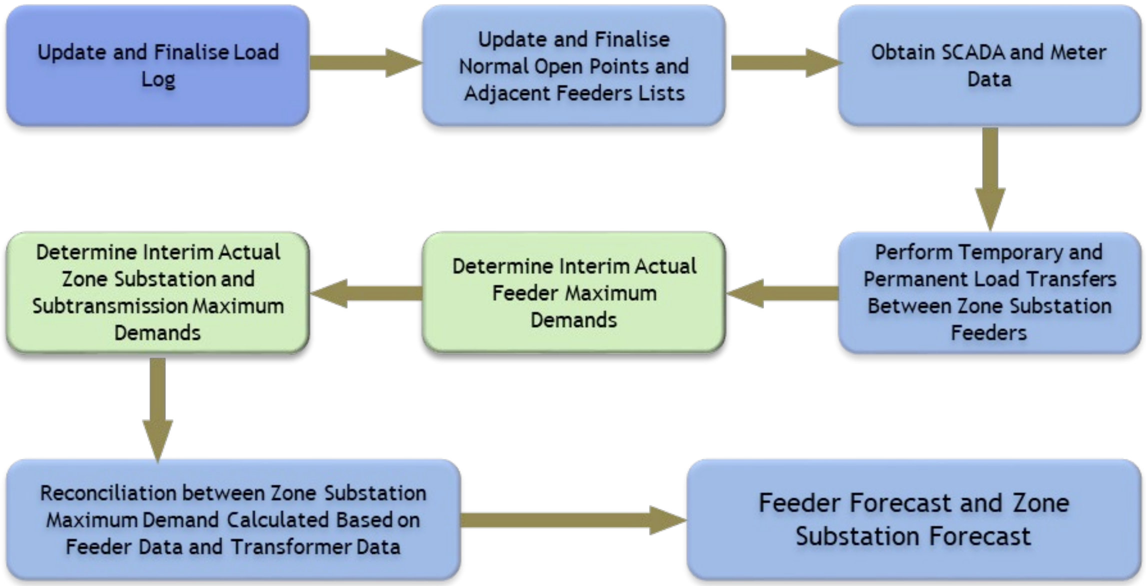

Figure 9 Power and Water forecasting process

4.2 Historical trend analysis

4.2.1 Update and finalise the load log

The status of all loads in the load log that are yet to be connected to the network must be verified. All loads that have been connected during the previous year or are future committed block loads must be recorded in the load log.

Any load transfers between feeders that were considered when planning the new connections must also be recorded. These future committed block loads and transfers will form part of the feeders and zone substation forecasts.

4.2.2 Update and finalise the normal open points and adjacent feeders list

The normal open points of the network must be verified against other information sources (GIS and SLDs) to ensure consistency. The normal open points can then be used to generate an adjacent feeders list. This is also a useful tool in determining the potential sources of temporary/permanent load transfers.

4.2.3 Obtain SCADA and meter data

Operational SCADA data from zone substations is obtained in 30-minute intervals for the period from 1 April to 31 March each year. This information is obtained by the Network Planning team through an online portal and detailed SCADA data is downloaded for each substation over the complete preceding planning years. EMS reports are used to retrieve the SCADA data on the Transmission Substation/Zone Substation/Modular Substation basis to download all the data points in a single file.

Two further sources of metering data are available from the Metering team: interval metering records installed at major high voltage customers' premises (>1MVA), and meter data from meters installed at Transmission/Zone Substation/Modular Substation.

SCADA data is used to determine the actual feeder maximum demands and Transmission/Zone Substation/Modular Substation maximum demands. If the SCADA data is corrupted or unavailable, then the meter data can be used.

4.2.4 Perform temporary and permanent load transfers between zone substation feeders

To obtain the interim actual maximum demand of each feeder, we analyse the data and correct for all temporary and permanent load transfers. We then cleanse data errors in order to obtain the normal underlying load profile for each feeder.

SCADA data errors can include anomalous large spikes in load flow, absences of data, and periods of no fluctuation in demand. Temporary and permanent load transfers result from normal network operational actions taken, for example, to manage load flows during planned or unplanned outages.

4.2.5 Determine interim actual feeder maximum demands

After all errors and load transfers occurring on a feeder have been corrected, we determine interim actual feeder maximum demands in two ways: based on summation of feeder demand, and/or based on transformer loading. Incoming transmission feeder maximum demands are only based on transformer data.

4.2.6 Reconciliation between zone substation maximum demand calculated based on feeder data and transformer data

If the difference between maximum demand based on summation of feeders and that based on summation of transformers is less than 10%, we base the zone substation maximum demand on the summation of transformer loading. If the variance is more than 10%, we review the maximum demand calculations in more detail to identify the reason for the variance. If the transformer data is corrupted for whatever reason, we base the ZSS maximum demand on the summation of feeder demands.

Once the values are considered to be satisfactory from the reconciliation process then the actual feeder maximum demands, actual zone substation, and transmission feeder maximum demands are finalised.

4.3 Spatial forecast process

Power and Water undertakes spatial demand forecasts at two separate but aligned levels of the network:

- Feeder forecast
- Zone substation forecast.

4.3.1 Feeder forecast

We forecast maximum demand on each 22kV and 11kV distribution feeder as follows:

Determine actual feeder maximum demand:

We identify the actual maximum demand on each zone substation feeder after the consideration of any temporary/permanent load transfers and embedded generation. We also record the date and time of occurrence of maximum demand.

Determine temporary changes:

We identify any transfers between adjacent feeders. These changes are applied after the actual maximum demands are calculated in order to correct any imbalance in load between feeders. These transfers apply for the entire forecasting year. As such, they are not taken into account during the feeder maximum demand correction in the SCADA and meter data sheets as they are only temporary transfers.

Determine Permanent Changes:

We identify the addition and/or removal of any permanent loads on each feeder, including any future committed block loads.

Determine Base Values:

This value is the corrected load on the feeder after taking into account any temporary or permanent changes.

Determine load forecast:

We identify the linear trend for each feeder's base maximum demand for the preceding six years (including the current year), and forecast forward for a five-year period, including the effect of any future-committed block loads. 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.

4.3.2 Zone substation forecast

We forecast maximum demand on each zone substation as follows:

Determine actual maximum demand

We identify the actual maximum demand on each zone substation after the consideration of any temporary/permanent load transfers and embedded generation. We also record the date and time of occurrence of maximum demand.

Determine temporary changes

Temporary changes would have been analysed at the feeder forecast level. We would only apply the same changes at the zone substation level if the transfer being considered is not from same zone substation.

Determine permanent changes

We identify the addition and/or removal of any permanent loads on each zone substation, including any future committed block loads. Although these changes would already have been applied at the feeder forecast level, they need to be replicated in the zone substation forecast.

Determine load-corrected maximum demand values

This value is the load corrected maximum demand on the feeder after taking into account any temporary or permanent changes.

Determine maximum temperature of the day when maximum demand occurred

We record the maximum ambient temperature of the day when maximum demand occurred in order to correlate maximum demand with temperature.

Determine 50% PoE and 10% PoE load and weather-corrected maximum demand

Weather-corrected maximum demand is based on the difference between the maximum daily temperature for the region/system and the assumed 50% probability of exceedance (PoE) and 10% PoE temperatures for the regional/system reference weather station. This value is calculated taking into account load corrected maximum demand, correction factors and maximum temperature of the data when maximum demand occurred.

Determine 50% PoE and 10% PoE weather-corrected maximum demand forecast

We identify the linear trend for each zone substation's 10% PoE and 50% PoE weather-corrected maximum demand for the preceding six years (including the current year), and in each case forecast for a ten-year period, including the effect of any future-committed block loads, which we assume will be 100% utilised. 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.

4.4 Transmission-distribution connection points

4.4.1 2019 zone substation forecast

Forecasts for zone substation are contained in Attachment A2 (10% and 50% PoE), which is provided separately to this report. Due to the scale of Power and Water's network, Power and Water's distribution system zone substations connect directly to the transmission network.

For 2018/19, Power and Water obtained maximum demand forecasts at the zone substation and regional level from Utilities Commission of the Northern Territory's (UCNT's) Electricity Outlook Report 2017/18 that was developed with the assistance of the Australian Energy Market Operator (AEMO). In consultation with UCNT and AEMO, Power and Water supplied the SCADA data and feeder forecasts from which zone substation and system forecasts were developed.

The AEMO zone substation forecast values were compared against Power and Water forecast values for each zone substation for a forward period of 10 years. The forecast adopted for each zone substation was based on an analysis of both forecasts. Appendix C lists the forecasting methodology adopted for each zone substation.

4.5 Transmission lines forecast

Forecasts for the transmission lines are contained in Attachment A1, which is provided separately to this report.

Transmission line forecasts are based on coincident wet season 50% PoE load forecasts at the zone substations.

The transmission system forecast is used for the consideration of normal and contingency flows on the transmission network lines and underpins proposals to develop that network. It comprises a forecast of the zone substation load and generation at each of the existing and new connection points to the transmission network looking forward for a 10-year period.

The process used to determine the transmission system forecast is as follows:

- Existing and future generation developments
- Known step changes in demand, such as those arising from the connection of new transmission customers or changes in demand for existing customers, are determined;
- The forecast of zone substation demands described in section 4.4.1 is used as the basis to determine the demand at each connection point to the transmission network with an appropriate allowance for load diversity.

4.6 System demand

4.6.1 Historic system demand

Energy consumption has been fairly consistent from day-to-day, but typically shows a long afternoon peak and increasingly a growing evening peak. Table 7 provides the system peak demand for 2018/19 and Figure 10 provides the hourly demand curves for the Darwin-Katherine system in the 2018/19 wet season (October to March).

Table 7 System peak demand 2018/19

Power System	System Peak Demand (MW) 2018/19 actual
Darwin–Katherine	287
Alice Springs	52.9
Tennant Creek	7.2

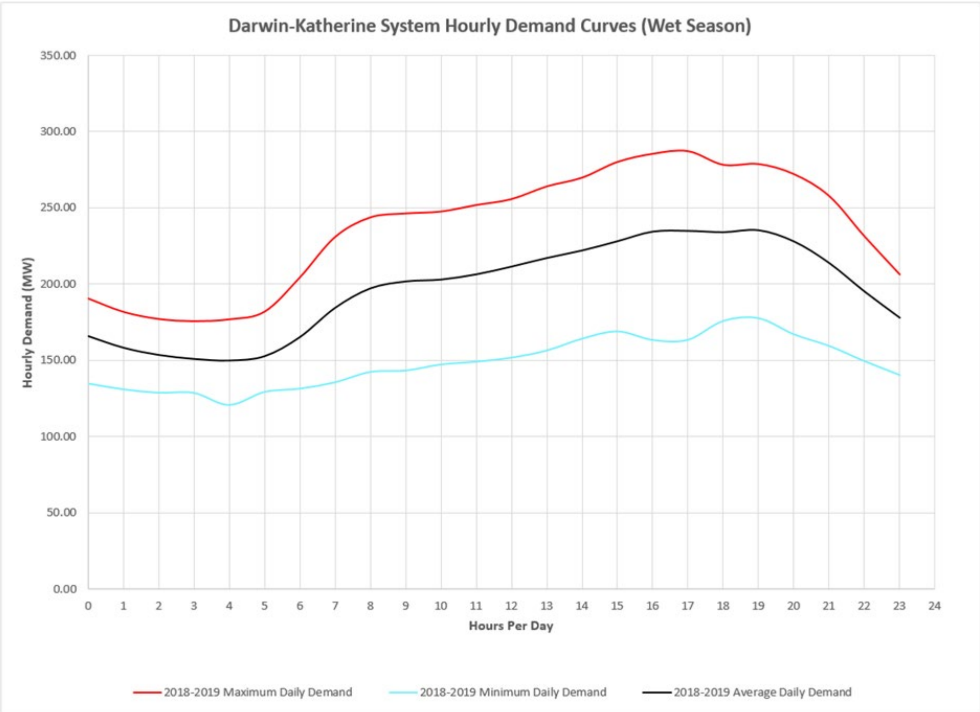

Figure 10 2018/19 Darwin-Katherine system hourly demand curves, wet season

Our 200 large users account for approximately 35% of total energy delivered, and include some major isolated loads for mine and government sites.

Air conditioning load is a major driver of increasing energy demand, with the majority of households in the Northern Territory installing and using air conditioning. Although ownership of air conditioners has increased steadily for the past 50 years, air conditioning systems have become increasingly efficient, which results in a dampened effect on increasing energy demand.

4.6.2 System forecast

The system forecasts for the Darwin–Katherine, Alice Springs and Tennant Creek are based on UCNT's *NT Electricity Outlook Report 2017-18.* The forecasts were completed by AEMO with feeder and zone substation forecasts and other relevant data supplied by Power and Water. Draft forecasts were provided to Power and Water for review before publishing.

4.6.2.1 System demand forecast – Darwin–Katherine

The system maximum and minimum demand for the Darwin–Katherine system is shown in Figure 11. The maximum demand occurs during the wet season and is expect to grow slowly after the initial drop due to the completion of the Inpex gas plant construction.

The forecast minimum demand typically occurs during the dry season where the humidity drops and the air conditioning usage decreases. It is forecasted to steady decline over the forecast period.

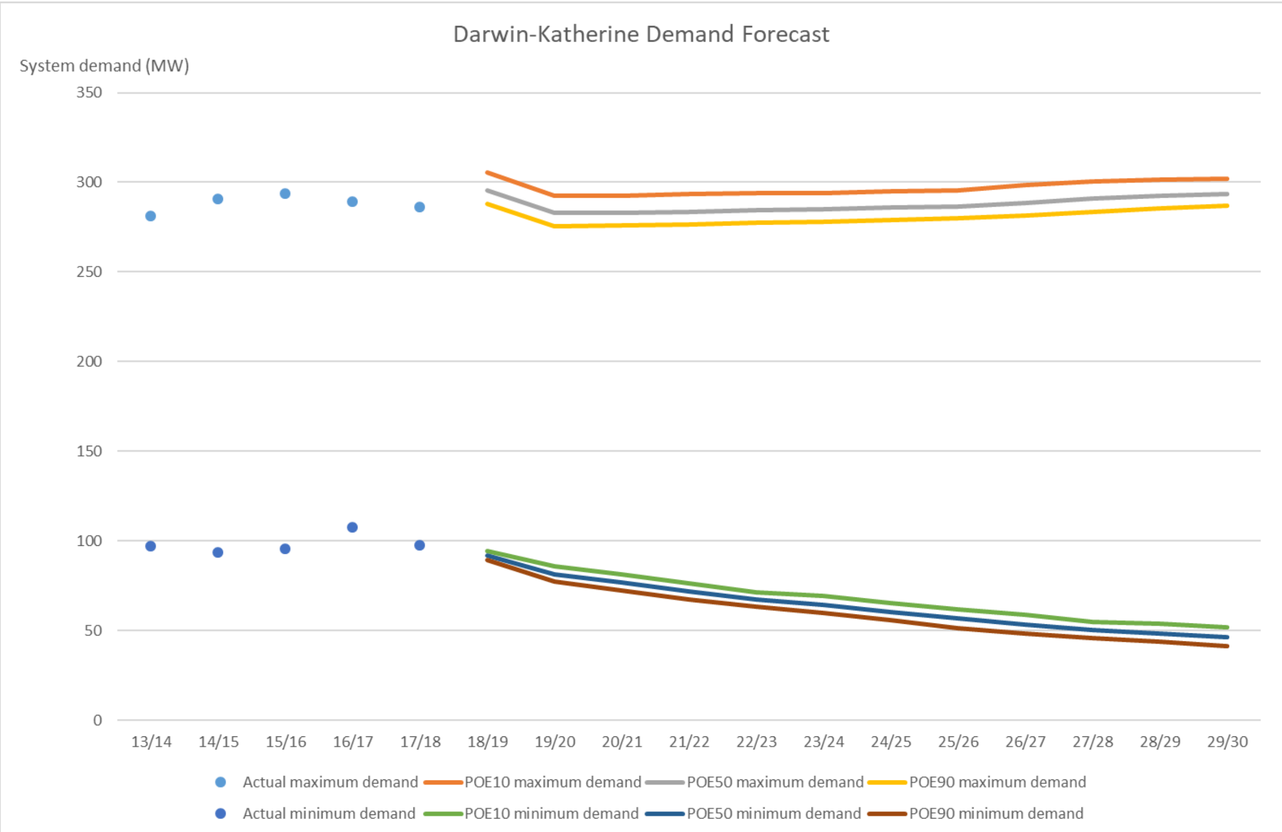

Figure 11 Darwin-Katherine system demand forecast[9]

[9] UCNT *NT electricity outlook report 2017-18*

4.6.2.2 System demand forecast – Alice Springs

The system maximum and minimum demand for Alice Springs is shown in Figure 12. The maximum demand typically occurs during the summer months. A large customer is expected to be connected in 2020-21 but the demand is expected to decline steady over the forecast period due to the continual uptake of solar PV systems.

The minimum demand usually occurs during the shoulder season and is also expected to steadily decline.

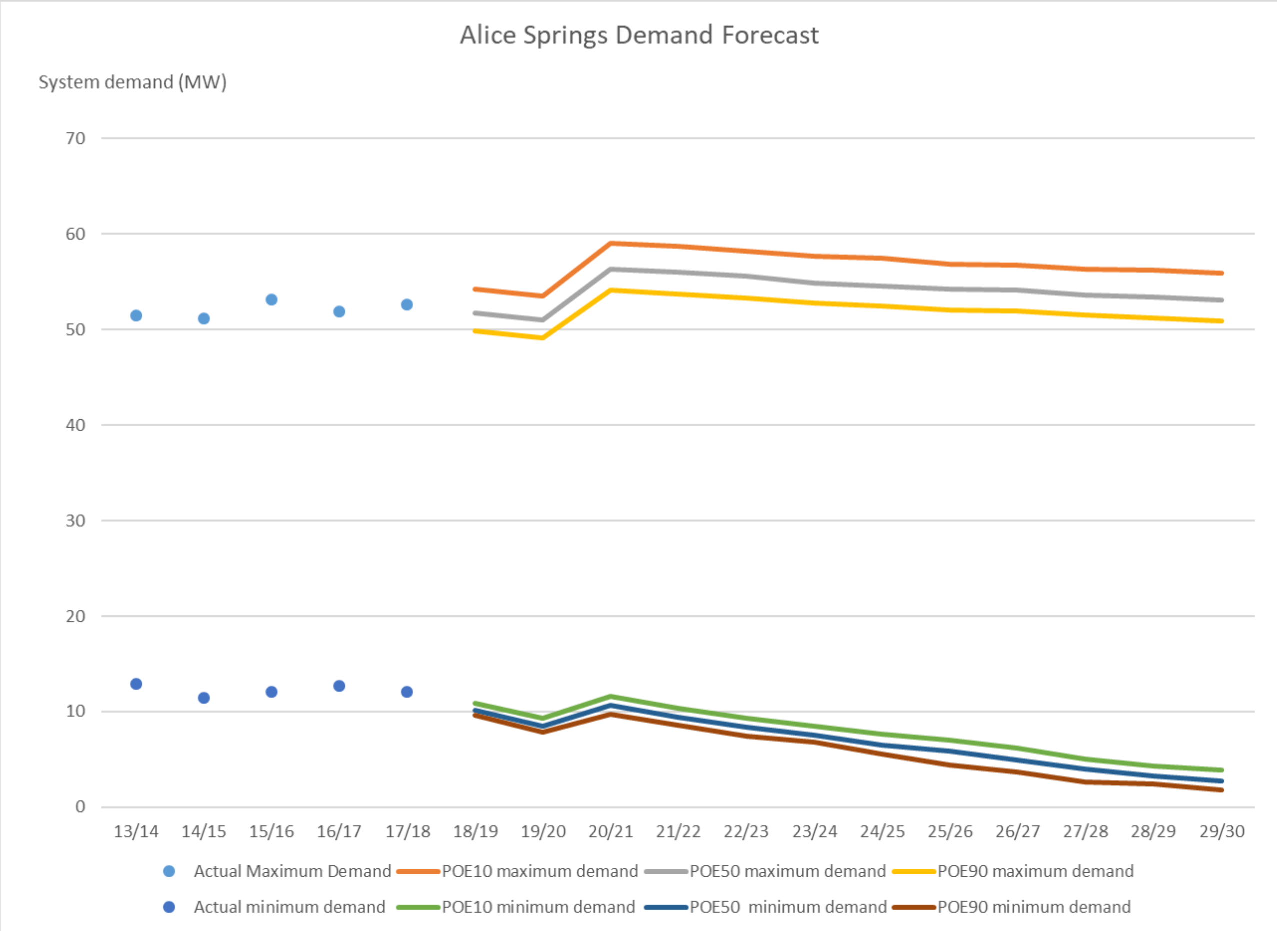

Figure 12 Alice Springs system demand forecast[10]

[10] UCNT *NT electricity outlook report 2017-18*

4.6.2.3 System demand forecast – Tennant Creek

The maximum and minimum system demand for Tennant Creek is shown in Figure 13. The maximum demand is expected to occur in the summer and it is projected to stay relatively flat. It is forecasted to increase in 2019 due to loads supporting the Northern Gas Pipeline (NGP). NGP has advised that pipeline operations will use its own generation normally and the grid as backup supply to compress gas.

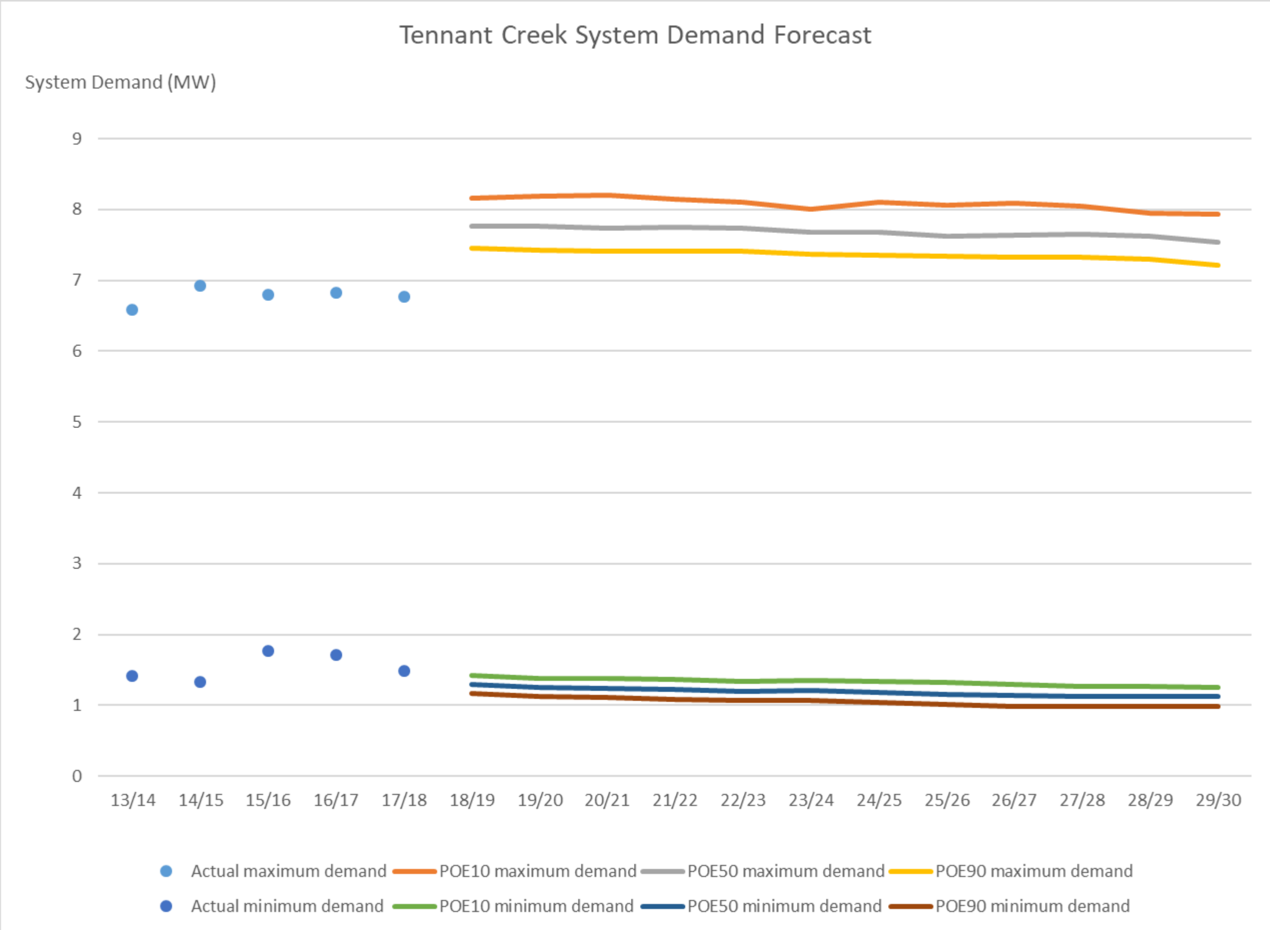

Figure 13 Tennant Creek system demand forecast

4.7 Future transmission and distribution connection points and zone substations

4.7.1 Future transmission connection points

A number of new generators are forecasted to be connected to the transmission network in the forward planning period. These are detailed below:

1. Katherine solar farm: A new 25MW solar PV farm is planned to be commissioned by 2019. It will be connected to Katherine zone substation on the 22kV switchboard.
2. Batchelor solar farm: A new 10MW solar PV farm is planned to be built in 2020. It will be connected to Batchelor zone substation on the 22kV switchboard.
3. Batchelor solar farm: A second 10MW solar PV farm is also planned to be built in 2020. It will also be connected to the 22kV switchboard at Batchelor.

4. Manton solar farm: A new 10MW solar PV farm is planned to be construction in 2020 and will connect to the Manton 22kV switchboard.
5. Hudson Creek thermal power station: A 12MW gas thermal power station will be built at Hudson Creek next to the existing terminal substation. It will be connected via a 66kV cable from the existing switchyard.

4.7.2 Future transmission - distribution connection points

Power and Water has not identified a requirement for future transmission - distribution connection points in the forward planning period.

4.7.3 Future transmission connection points

There is a forecast transmission line located in the area of Wishart, connecting a new power station to Hudson Creek Terminal Station. This sub-transmission line is forecast to be loaded to 12MW, with estimated commissioning in 2021.

4.7.4 Future zone substations

Power and Water has not identified a requirement for future zone substations in the forward planning period. The existing Berrimah Zone Substation will be replaced and will be renamed Trevor Horman Zone Substation.

4.8 Reliability performance forecast

Schedule 5.8(b)4 of the NER requires the Distribution Network Service Provider to provide performance forecast against reliability targets in the Service Target Performance Incentive Scheme (STPIS). The requirements related to STPIS are not applicable to Power and Water at this time.

4.9 Factors that impact the network

4.9.1 Fault levels

For safety reasons, equipment connected to Power and Water's network must be rated to at least the prescribed fault level rating in of the network at any time and for any normal network configuration, as stated in the Network Technical Code and Network Planning Criteria. Our minimum equipment fault levels[11] for the network are outlined below:

Table 8 Network equipment fault level ratings

Network voltage level	Fault level rupturing capacity
415V	31.5kA – supplied from one transformer 63kA – supplied from two transformers in parallel
11kV	25kA in metropolitan areas 20kA in rural areas
22kV	15kA
66kV	31kA
132kV	31kA

[11] Power and Water Corporation Network Technical Code and Planning Criteria, table 16

As the system configuration is changed, fault levels may increase over time. This is particularly true with the addition of more generators, embedded generation, power transformers and large motors. In general, the prospective fault currents in the distribution network are within the above prescribed limits. Where neutral/ground fault currents are likely to exceed the prescribed limits, Power and Water assess the requirement for fault limiting devices, such as Neutral Earthing Resistors (NER) or Neutral Earthing Reactors (NEX).

In some areas where secondary distribution switchgear is installed, like the Central Business District (CBD), the zone substation fault levels increases above the equipment fault levels. This resulted in the zone substation switchboard operating in a split bus configuration to maintain the system fault level below the equipment fault rating.

At Palmerston Zone Substation, the 11kV fault level at the primary switchboard is approaching the equipment fault level of 25kA due to the installation of a third transformer and a new 66kV sub-transmission line. Investigations are in progress to determine the risk and identify potential solutions.

4.9.2 Voltage levels and quality of supply

Power and Water are responsible for providing customers with a voltage supply within quality limits defined by Technical Code specifications and Australia Standards. Voltage levels and Quality of Supply (QoS) can be affected by a number real time factors including:

- Transmission and generation disturbances due to transient events;
- Switching of network equipment such as reactive plant;
- Installation and switching of customer loads; and
- Installation and switching of embedded generation.

Power and Water’s distribution network was initially designed for 240 V +/- 6% based on traditional network topology with power flowing downstream, resulting in voltage drop. However, this has changed in recent times. The cumulative effect of increasing PV systems, uninterruptible power supply (UPS), power factor correction and electronic switching devices being connected to the system is greatly affecting QoS. Larger voltage fluctuations are present, with power flow in either direction and complex interactions between network equipment and customer connected components. Voltage quality on the 415V network is discussed in sections 11.2 and 11.3.

There is evidence that the voltage of the 132kV transmission line is approaching the upper limits at Katherine during low load periods. This is due to the Ferranti effect from capacitance of a long, radial and lightly loaded line. Solutions being considered includes installation of shunt reactors or establishing an agreement with a generator for reactive VAR control.

4.9.3 Other power system security requirements

To maintain power system security the System Control Technical Code obligates the Power System Controller to maintain the power system in a secure operating state. A power system is in a secure operating state, if in the reasonable opinion of the System Operator:

- the relevant power system is in a satisfactory operating state; and
- the relevant power system will promptly return to a satisfactory operating state following the occurrence of any credible contingency event in accordance with the Secure System Guidelines.

The most notable issue affecting power system security recently has been Under Frequency Load Shedding (UFLS). UFLS is the interruption of certain loads in order to keep system frequency within acceptable boundaries. Following a number of specific contingency events, relay upgrades and protection setting changes were carried out as part of a new UFLS system. The new UFLS system allows for an increased number of UFLS stages or blocks as well as a Rate of Change of Frequency (ROCOF) function. The new system enables faster and more targeted operation of UFLS leading to fewer feeders being isolated during loss of Generation events.

There are no other significant power system security requirements that may have a material impact on Power and Water's distribution network.

4.9.4 Aging assets

Asset age and condition information is analysed using our asset management system. While asset age provides some indication of asset health, asset condition and risk are the main factors that drive the requirement for replacement.

Events such as the creation of NTEC, Cyclone Tracy and the Casuarina Zone Substation event of 2008, drove high volumes of replacement activity. These events had an impact that is unique in Australia and resulted in asset age profiles that may differ from other electricity network owners and operators.

In particular, a significant volume of distribution assets was installed after Cyclone Tracy in 1974, both due to the replacement of existing overhead assets in the immediate aftermath, and the establishment of new underground suburbs in subsequent years. These assets are now between 35 and 45 years old and many are approaching their expected service life. An increasing number will exceed expected service life in the next regulatory period. The majority of distribution assets are replace-on-failure; that is, they are only replaced due to in-service failure or assessed as having an unacceptable safety or environmental risk (under our condition and failure based replacement program). The exception is particular condition or type issues identified where earlier intervention is economically justified by extending the assets life, such as corrosion protection of ground mounted enclosures and pole footings.

The Casuarina event initiated a step change in zone substation replacement activity over the 2009-2016 period. Aging zone substations housing oil-filled switchgear in poor condition were targeted for replacement due to operator and public safety concerns. As a result of this period of activity, zone substation assets are generally in good condition and we forecast a lower level of replacement expenditure in the near term.

The most significant upcoming works driven by asset condition and risk are:

- Condition and failure based asset replacement program
- Darwin northern suburbs cable replacements
- Alice Springs pole replacements
- Berrimah Zone Substation replacement.

5 Network asset retirements and de-ratings

Power and Water has proposed a series of planned asset retirements and replacements of network assets as outlined in the Asset Management Plans for our various asset classes. It should be noted that the Asset Management Plans outline in more detail the quantities of assets and the reasons for their planned retirement.

No asset de-ratings which result in a system limitation have been identified in the forward planning period.

The asset retirements are summarised below in Table 9.

Table 9 Asset retirements

Asset	Location	Reason for Retirement	Proposed Retirement Date	Change to Retirement Date
132kV terminal substation secondary systems	Channel Island, Manton, Batchelor, Pine Creek and Katherine	Asset condition	2020-21	N/A
High voltage cables	Darwin northern suburbs	Asset condition	2020-2024	N/A
High voltage cables	Port feeder	Asset condition	2020-2021	N/A
Distribution poles	Alice Springs	Asset condition	2020-2024	N/A
Berrimah Zone Substation	Berrimah	Asset condition	2020-2021	N/A
Humpty Doo Zone Substation	Humpty Doo	Asset condition	2022-2023	N/A
Centre Yard Zone Substation	Cox Peninsula	Asset condition	2022	N/A
Power transformers	Cosmo Howley	Asset condition	2021	N/A
Power transformers	Pine Creek	Asset condition	2020	N/A
High voltage conductor	Adelaide River	Asset condition	2020-2024	N/A
Pole tops	Darwin coastal areas	Asset condition	2020-2024	N/A
Single phase substations	Darwin northern suburbs	Asset condition	2020-2024	N/A
Low voltage cables	Cullen Bay and Bayview	Asset condition	2020-2024	N/A
HV circuit breakers	Hudson Creek and Palmerston	Asset condition	2020-2024	N/A

6 System limitations for transmission and distribution systems

Attachment B 2019 system limitation template details the system limitations study and timings set out in this section. This attachment is provided separately to this report.

6.1 System limitations for transmission system

Transmission contingency analysis was completed for the 10 years from 2019/20 to 2029/30 for the Darwin-Katherine transmission network. No system limitations were identified from the study.

However, it was discovered that due to the planned generator retirements published in the Utilities Commission's *Northern Territory Electricity Outlook Report 2017/18*, there will be inadequate generation in the Darwin – Katherine network to meet the system demand from 2027/28. New sources of generation will need to be established and operating by 2027/28. Hence, the last two years of the transmission forecast and contingency analysis was unable to be completed.

6.1.1 Hudson Creek 132/66kV transmission substation

Hudson Creek transmission substation is a major distribution hub in Darwin, linking Channel Island Power Station to the majority of zone substations in the Darwin area. It consists of three 125MVA (nameplate rating) transformers. Area demand currently exceeds N-2 substation rating (loss of two transformers). There is no ability to transfer load away from Hudson Creek. The preferred solution is to purchase a spare 132/66kV transformer, which will be used to replace a failed transformer.

The system limitation is summarised below in Table 10, with further details available in Attachment B.

Table 10 Hudson Creek sub-transmission substation system limitation summary

Zone substation	Reliability criterion	Rating MVA	Overload MVA				
			2019/20	2020/21	2021/22	2022/23	2023/24
Hudson Creek	N-2	131.5	71.47	71.08	69.39	65.22	62.70
	N-1	263	-60.03	-60.42	-62.11	-66.28	-68.80

6.1.2 Weddell transmission loop

In the Darwin-Katherine 66kV transmission network, there is a group of zone substations (Hudson Creek, Palmerston, Archer, Weddell and Strangways) that is connected in a ring configuration. Sources for this transmission loop are the Hudson Creek Terminal Station and Weddell Power Station.

Under N-1 operation of the 66kV Hudson Creek to Palmerston transmission line, the 66kV transmission line from Hudson Creek to Archer Zone Substation would be loaded to around 99% by 2026-27, i.e. 63.4MVA against 64MVA thermal capacity. This limitation can be managed by increasing Weddell Power Station generation into the transmission loop.

Similarly, under N-1 operation of the transmission line from Hudson Creek to Archer Zone Substation, the Hudson Creek to Palmerston transmission line would be loaded to 96% by 2026-27, i.e. 61.5MVA versus its 64MVA thermal rating. Likewise, increasing generation at Weddell Power Station can be used limit the loading on the Hudson Creek to Palmerston transmission line.

6.2 System limitations for distribution system

6.2.1 Archer 66/11kV Zone Substation

Archer Zone Substation currently consists of two 27MVA (nameplate rating) 66/11kV transformers. There are feeder ties to Palmerston Zone Substation, with load transfer capacity of approximately 13.7MVA.

Under N-1 (single contingency) conditions, the 50% PoE forecasted load from 2018/19 onwards will exceed the zone substation capacity. Potential solutions include load transfer to Palmerston, and construction of a new concrete footing allowing for the connection of the Nomad mobile substation in the event of the loss of a single transformer.

The forecasted overload is outlined below in Table 11.

Table 11 Archer Zone Substation system limitation summary

Zone substation	Reliability criterion	Rating MVA	Overload MVA				
			2019/20	2020/21	2021/22	2022/23	2023/24
Archer	N-1	31.5	4.64	5.76	5.87	5.80	6.47

6.2.2 Strangways 66/22kV zone substation

Strangways Zone Substation, located in Bees Creek, services the Darwin rural area. It is comprised of two 27MVA 66/22kV transformers and provides a 66kV radial line to Humpty Doo, Marrakai and Mary River zone substations. N-1 substation rating is forecasted to be exceeded in 2018/2019 and 2019/20. The loads from 2020/21 onwards are forecasted to decrease, resolving the overload issue. A potential solution is to transfer load to adjacent zone substations via feeder ties in the event of the loss of a single transformer.

Table 12 Strangways Zone Substation system limitation summary

Zone substation	Reliability criterion	Rating MVA	Overload MVA				
			2019/20	2020/21	2021/22	2022/23	2023/24
Strangways	N-1	30.3	1.09	1.15	1.20	1.25	1.30

6.2.3 Humpty Doo 66/22kV Zone Substation

The Humpty Doo area is serviced by a 66/22kV zone substation on the Arnhem Highway. It consists of a single 5MVA transformer supplied via a single 66kV transmission line connected to Strangways Zone Substation. The forecasted load is expected to surpass the rating of the zone substation in 2020/2021. The zone substation is also due for replacement in 2023/24.

Table 13 Humpty Doo Zone Substation system limitation summary

Zone substation	Reliability criterion	Rating MVA	Overload MVA				
			2019/20	2020/21	2021/22	2022/23	2023/24
Humpty Doo	N	5.0	-	0.14	2.11	3.81	4.10

6.2.4 Katherine 132/22kV zone substation

Katherine Zone Substation supplies the Katherine Township and the surrounding area. It is connected to the 132kV transmission line from Darwin and comprises two 132/22kV, 29MVA transformers. Katherine Power Station, owned by Territory Generation is connected to the 22kV switchboard. The N-1 rating is forecasted to be exceeded from 2019/20. Potential solutions, including non-network options, will be explored.

Table 14 Katherine Zone Substation system limitation summary

Zone substation	Reliability criterion	Rating MVA	Overload MVA				
			2019/20	2020/21	2021/22	2022/23	2023/24
Katherine	N-1	28.8	1.88	7.11	9.14	11.17	13.20

6.2.5 Weddell 66/22kV zone substation

Weddell Zone Substation is located on Channel Island Road and supplies the Weddell area. It comprises three 66/22kV transformers with an N-1 rating of 15.6MVA. The forecast demand is expected to exceed the N-1 rating from 2020/21. It is most likely that an increase in firm capacity will be required.

Table 15 Weddell Zone Substation system limitation summary

Zone substation	Reliability criterion	Rating MVA	Overload MVA				
			2019/20	2020/21	2021/22	2022/23	2023/24
Weddell	N-1	15.4	-	-	1.63	1.63	1.63

6.2.6 Lovegrove 66/22/11kV Zone Substation

Lovegrove Zone Substation is located in Alice Springs, north-west of the CBD, and receives power via two 66kV transmission lines from Owen Springs Power Station, stepping the voltage down to 22kV and 11kV for the distribution network. The 11kV demand is forecasted to cause the N-1 rating to be exceeded from 2019/20. It is expected that the increase in demand will be managed using the significant load transfer capacity between Lovegrove and Ron Goodin zone substations.

Table 16 Lovegrove Zone Substation system limitation summary

Zone substation	Reliability criterion	Rating MVA	Overload MVA				
			2019/20	2020/21	2021/22	2022/23	2023/24
Lovegrove 22kV	N-1	22.4	0.48	0.63	0.77	0.92	1.06
Lovegrove 66kV	N-1	57.2	0.27	-	-	-	-

7 Frequency control schemes

There are automatic under frequency load shedding (UFLS) schemes implemented for the Darwin-Katherine, Tennant Creek and Alice Springs networks.

7.1 Darwin-Katherine network

The UFLS scheme operating in the Darwin-Katherine network are based on a combination of defined frequency settings and rate of change of frequency. The scheme is implemented via feeder management relays located in the zone substation distribution switchboards. Each feeder is assigned to a block that is defined by frequency and rate of change settings. The system is designed so that under contingency events feeder blocks are progressively disconnected to ensure the system frequency remains above 47Hz.

7.2 Tennant Creek network

The UFLS scheme in Tennant Creek is based on defined frequency settings only. The scheme is implemented via feeder management relays with each feeder assigned to one of six blocks. The system is designed so that under contingency events feeder blocks are progressively disconnected to ensure the system frequency remains above 47Hz.

7.3 Alice Springs network

The UFLS scheme in Alice Springs is based on defined frequency settings only. The scheme is implemented via feeder management relays with each feeder assigned to one of six blocks. The system is designed so that under contingency events feeder blocks are progressively disconnected to ensure the system frequency remains above 47Hz.

Territory Generation also has a BESS installed. It is designed to provide frequency control ancillary services (FCAS) via a frequency droop curve to smooth frequency variations.

8 Overloaded primary distribution feeders

Only two primary distribution feeders are forecasted to be overloaded within the next two years as defined in Schedule 5.8(d). For planning purposes, all feeders are derated upon exiting the zone substation. The derating factor is purposely chosen to cover factors such as cable installation configuration (e.g. laid flat or trefoil), proximity to other feeders/circuits in the zone substation and air flow for cooling (i.e. in conduit, cable tray).

8.1 11CA15 (Hospital) feeder

The feeder 11CA15 originates from 66/11kV Casuarina Zone Substation and currently services the Royal Darwin Hospital. Maximum demand has been at or above the feeder rating since 2010 with a positive projected growth rate.

The most preferred solution is to transfer load to adjacent feeders, given that the overload is less than 1 MVA over next five years.

Potential solutions for the future include an additional feeder to supply the Royal Darwin Hospital area. There is currently a circuit breaker at Leanyer Zone Substation allocated to Royal Darwin Hospital, though the feeder has not been constructed. The requirement for this additional feeder will be closely monitored in the coming years.

The overload on 11CA15 is detailed in Table 17 below.

Table 17 11CA15 feeder load exceedance

Feeder Name	Location	Feeder Rating (MVA)	2019/20 Load Exceedance (MVA)	2020/21 Load Exceedance (MVA)	2021/22 Load Exceedance (MVA)	2022/23 Load Exceedance (MVA)	2023/24 Load Exceedance (MVA)
11CA15 (Hospital)	Casuarina Zone Substation	5.18	0.61	0.67	0.70	0.76	0.82

8.2 11PA08 (Yarrawonga) feeder

The feeder 11PA08 originates from 66/11kV Palmerston Zone Substation and currently services industrial loads in Yarrawonga area. Maximum demand is exceeded from 2020/21 onwards due to the connection of block loads with a negative projected growth rate.

The most preferred solution is to transfer load to adjacent feeders, given that the overload is less than 1MVA over next five years. Network Augmentation may be required if the load transfers are not possible in some scenarios.

The overload on 11PA08 is detailed in

Table 18.

Table 18 PA08 feeder load exceedance

Feeder Name	Location	Feeder Rating (MVA)	2019/20 Load Exceedance (MVA)	2020/21 Load Exceedance (MVA)	2021/22 Load Exceedance (MVA)	2022/23 Load Exceedance (MVA)	2023/24 Load Exceedance (MVA)
11PA08 (Yarrawonga)	Palmerston Zone Substation	5.18	0	0.40	0.61	0.80	0.67

9 Network investments

9.1 Regulatory investment tests

Transitional rules in NT NER chapter 11A, clause 11A.1(5) exempts Power and Water from the requirement to undertake regulatory investment tests in relation to projects that satisfy the following criteria:

- assessed by the AER for the purposes of its distribution determination for the period of five years commencing on 1 July 2019, or
- projects where an assessment equivalent to a regulatory investment test has been commenced by Power and Water before 1 July 2019.

Regulatory investment tests are required for projects that:

- do not satisfy the above criteria, such as projects identified after 1 July 2019, and
- meet the NER criteria for a regulatory investment test.

However, there are no projects planned that require regulatory investment tests at the date of this report.

9.2 Completed or cancelled investments

Power and Water has no completed or cancelled investments to report.

9.3 Committed investments

9.3.1 Distribution investments over $5 million

Distribution projects with a budget exceeding $5 million assessed by the AER for the purposes of its distribution determination for the period of five years commencing on 1 July 2019, notwithstanding that they are not subject to a regulatory investment test, are listed below:

Table 19 Distribution projects above $5 million for the 2019-24 period

Project Details	Project Driver	Date Commissioned
11 kV Sadadeen Switchboard	Asset Condition	Jun 2020 (Forecast)
Berrimah Zone Substation Replacement	Asset Condition	Jun 2021 (Forecast)
Alice Springs corroded poles replacement	Asset Condition	Jun 2024 (Forecast)
Energy Management System replacement	Asset Condition	Feb 2023 (Forecast)
Humpty Doo Zone Substation replacement	Asset Condition	Jun 2023 (Forecast)
Wishart Zone Substation construction	Load Growth	Jun 2024 (Forecast)

9.3.2 Transmission investments over $5 million

Notwithstanding that they are not subject to a regulatory investment test, transmission projects with a budget exceeding $5 million are listed below:

Table 20 Transmission projects above $5 million for the 2019-24 period

Project Details	Project Driver	Date Commissioned
Pine Creek 66kV Switchyard	Asset Condition	Jun 2020 (Forecast)

9.4 Investments to address an urgent or unforeseen network issue

Power and Water does not have any committed investments in the forward planning period over $2 million to address urgent or unforeseen network issues.

10 Joint planning

Power and Water operates standalone networks without interconnections to any other network service provider. Power and Water has no requirement to plan its network jointly with any other regulated entity.

11 Network Performance

11.1 Reliability obligations

11.1.1 Reliability measures and targets

Power and Water's objective is to maintain network reliability performance and comply with the regulatory requirements established by the Northern Territory Electricity Industry Performance (EIP) Code (the Code) and the National Electricity Rules as in force in the Northern Territory (NT NER) at minimum cost to customers and within the regulatory allowances.

The Code, which was published on 25 October 2017, requires Power and Water to report on distribution network reliability statistics on a yearly basis using System Average Interruption Duration Index (SAIDI) which represents the average minutes off supply per customer, and System Average Interruption Frequency Index (SAIFI) which represents the average number of interruptions experienced per customer.

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.

The NT NER came into effect from 1 December 2019 and requires Power and Water to maintain reliability and security of the distribution system and of the supply of standard control services. The NT NER also require the AER to make a determination regarding the applicability of the Service Target Performance Incentive Scheme which is discussed in section 11.1.2 below.

The metrics to be reported only apply to unplanned outages and are adjusted to exclude any interruption that is initiated due to the following causes (defined in clause 7.2.3 of the Code):

- failure of equipment that is not owned or controlled by Power and Water where the likely cause is within the customer's installation
- generation likely caused by generator failure or failure of a system supporting generation
- manual load shedding event caused by generation shortfall
- planned interruption where customers were given at least two days' notice before the interruption
- public safety, including house fire and events where police or fire department directly request isolations to access to perform rescues, etc
- any interruption that occurred on a major event day (MED) that has been approved by Utilities Commission NT. The MEDs are identified by using the 2.5 Beta Method described in IEEE Standard 1366 and are only account for in the analysis after approval by the Utilities Commission NT. In the 2018-19 regulatory period, there were no MEDs.

The SAIDI and SAIFI metrics for 2019-24 are required for each of the four regions in NT (Darwin, Katherine, Tennant Creek and Alice Springs) and for each of the feeder categories in both adjusted and unadjusted forms. However, performance targets are only provided for adjusted SAIDI and SAIFI by feeder category in Table 21. In addition to reporting the SAIDI and SAIFI measures, Power and Water is required to use the SAIDI performance of each feeder to identify the top five poorly performing feeders in each feeder category. For each poorly performing feeder, Power and Water must identify the cause of the poor performance and the remedial actions.

11.1.2 Service Target Performance Incentive Scheme (STPIS)

In accordance with clause 6.12.1(9) of the NT NER, in each distribution determination the AER must make a decision on which incentive schemes will apply to Power and Water for that regulatory control period.

In the final determination for the 2019-24 regulatory control period, the AER determined that the STPIS will not apply to Power and Water for the 2019-24 period.

11.1.3 Our reliability performance

This section reports the SAIDI and SAIFI performance by feeder category against the targets set by the Code. The 2018-19 actual performance of each feeder category, as measured by adjusted SAIDI and SAIFI, is provided in Table 21 compared to the target.

Table 21 Distribution network reliability performance for 2018-19

Feeder Category	Adjusted SAIDI [minutes]			Adjusted SAIFI [interruptions]		
	Performance Target[1]	Actual Performance	Result	Performance Target[1]	Actual Performance	Result
CBD	4.0	14.20	Target not met	0.1	0.20	Target not met
Urban	140.0	70.44	Target met	2.0	1.66	Target met
Rural short	190.0	172.10	Target met	3.0	3.04	Target not met
Rural long	1500.0	1447.27	Target met	19.0	15.68	Target met
Whole of network	175.8	132.08	Target met	2.6	2.40	Target met

Note 1: The performance targets apply for the period 2019-24

The CBD feeder category did not meet both the SAIDI and SAIFI performance targets in 2018-19. There were four interruptions affecting underground CBD feeders that contributed 99% of SAIDI and SAIFI to this category. Two of the outages were caused by equipment failure and two were caused by operator error.

Actions taken to address these outages were replacement of the failed assets and ongoing monitoring of the condition of the CBD cables to identify those with an elevated risk of failure. Operating and maintenance procedures will be reviewed and improved to avoid future inadvertent interruptions to customers.

Rural short feeders met the SAIDI performance targets in 2018-19 but did not meet the SAIFI targets. Adverse weather (30% contribution) and vegetation (20% contribution) were two key drivers of the poor SAIFI performance. The following actions are being undertaken to improve the performance of the rural short feeder category and to maintain the performance of the urban and rural long feeder categories:

- condition-based replacement of conductor sections where repeat failures have occurred.
- targeted pole top hardware upgrades (based on historical failure locations) including replacement of old porcelain insulators, installing animal guards, replacing connection hardware.
- distribution pole inspection, refurbishment and replacement program in Alice Springs based on observed corrosion and known soil conditions.
- continuation of the 11kV cable replacement program in Darwin's northern suburbs.
- targeted vegetation removals including overhanging tress, hazard trees and fast growing species.
- utilisation of Distribution Fault Anticipation (DFA) technology to assist in the faster location of faults for rapid restoration, prediction of asset failures and identification of repeat transient fault locations.

- increased automation of the network by installing remotely operated switches, automatic reclosers and fused sectionalisers, allowing system operators to isolate faults faster and improve restoration time.

Review of the historical reliability performance shows that there has been significant improvement following the 2008 Casuarina failure due to improvement initiatives implemented based on the Davies Enquiry[12]. Since 2014 network SAIDI is demonstrating a flat trend in most feeder categories which indicates that prudent investment and effective asset maintenance practices have resulted in maintenance of network performance.

Improvements in SAIFI are not as significant compared to SAIDI due to transient faults in the northern region from intense lightning and storm activity in the wet season, as well as animal related transient faults in the dry season. Reducing the frequency of these transient events is challenging and Power and Water is implementing the initiatives listed above to help address this issue.

11.1.4 Top-5 poorly performing feeders based on SAIDI performance

The top five poorly performing feeders in each feeder category together with their actual SAIDI and dominant cause are provided in Table 22.

Table 22 Poorly performing feeders by feeder category

Category	Feeder Name	SAIDI	Cause
CBD	11WB03 BENNETT	5.80	one outage caused by human error
CBD	11MS04 PEEL	4.38	one outage caused by equipment failure
CBD	11MS10 SHADFORTH	2.14	two outages caused by equipment failure
CBD	11DA26 DA-AK	1.81	one outage caused by human error
CBD	11AK01 HARRY CHAN	0.05	one forced outage
Urban	22KA22 KATHERINE	14.03	14 outages, predominantly caused by weather (12.5 min) and animals (1.4 min)
Urban	11RG02 GOLF	10.35	13 outages caused by equipment failure (5.6 min) and safety requirements (4.7 min)
Urban	11DA27 STUART PARK	10.33	eight outages predominately caused by weather (8.5 min)
Urban	11WN02 FANNIE BAY	5.69	10 outages predominately caused by equipment failure (2 min), animals (1.7 min) and vegetation (1.9 min)
Urban	11CA12 MARRARA	4.44	five outages caused by asset failure
Rural short	22SY11 HERBERT	22.87	45 outages caused by third party impacts (8.7 min), and weather (8.2) and vegetation (2.6 min)
Rural short	22SY03 VIRGINIA	22.62	29 outages caused by weather (14.8 min) and asset defects or failures (7 min)
Rural short	11CA23 MOIL	13.62	11 outages caused by third party impacts (12.3 min) and animals (1.1 min)
Rural short	22PA202 HOWARD SPRINGS	12.83	41 outages caused by weather () and vegetation (9.5 min) and vegetation (3 min)
Rural short	22SY15 DARWIN RIVER	10.74	35 outages caused by weather (6.4 min), asset defects (1.7 min) and third party impacts (1.3 min)

[12] Mervyn Davies, February 2009, Independent Enquiry into Casuarina Substation Events and Substation Maintenance Across Darwin: Final Report

Rural long	22SY04 DUNDEE	1284.78	40 outages caused by Equipment failure or defects (486 min), weather (423 min) and animals (269 min) there were also a range of other minor contributors.
Rural long	22KA10 MATARANKA 1	84.14	48 outages predominately caused by weather (41 min), animals (15.4 min), vegetation (16 min) and third party impacts (9 min)
Rural long	22TC01 ALI CURUNG	78.36	25 outages caused predominantly by weather (60 min) and vegetation (15.7 min)

Improvement program by feeder category

Power and Water has an annual feeder improvement program intended to remediate identified poorly-performing feeders. The performance information is analysed to identify the root causes and develop improvements that will reduce the frequency and/or duration of interruptions.

Where a feeder's performance has been affected by a one-off type interruption or has no prior history of poor performance, action may not be prudent. In these cases, the feeder may be monitored and the next worst performing feeder may be targeted.

The following sections set out the actions identified to address each of the five poor-performing feeders per feeder category.

CBD Feeder Category

There are no feeder improvement tasks planned on the poorly-performing CBD feeders identified in 2019-20. Assessment of the outage causes found that the equipment failures and instances of operator error do not indicate there is a systemic or recurrent issue that needs to be addressed outside of normal inspection and maintenance tasks.

Urban Feeder Category

The feeder improvement tasks set out in Table 23 are planned for implementation in 2019-20 on the top five poorly performing urban feeders.

Table 23 Urban Feeder Category - Top Five Worst Performing Feeders

Feeder Name	SAIDI	Brief Description of the Task
22KA22 KATHERINE	14.03	Investigations into improvement opportunities to be carried out in 2019-20. Most unplanned outages during 2018-19 were associated with severe thunderstorms or upstream loss of supply (132kV transmission line outages).
11RG02 GOLF	10.35	No task planned – The feeder has not performed poorly in two consecutive years.
11DA27 STUART PARK	10.33	No task planned – The feeder has not performed poorly in two consecutive years.
11WN02 FANNIE BAY	5.69	Relocate a recloser to a location that will improve its effectiveness. Other operational performance issues have also been taken into account when identifying improvement on this feeder.
11CA12 MARRARA	4.44	No task planned – The feeder has not performed poorly in two consecutive years.

Rural Short Feeder Category

The feeder improvement tasks set out in Table 24 are planned for implementation in 2019-20 on the top five poorly performing rural short feeders.

Table 24 Rural Short Feeder Category - Top Five Worst Performing Feeders

Feeder Name	SAIDI	Brief Description of the Task
22SY11 HERBERT	22.87	Replacement of conductor and associated hardware in locations where repeat failures have occurred. Installation of animal protection.
22SY03 VIRGINIA	22.62	Replacement of conductor and associated hardware in locations where repeat failures have occurred.
11CA23 MOIL	13.62	Significant one-off event contributed 90% of SAIDI. No remedial action planned.
22PA202 HOWARD SPRINGS	12.83	Replacement of conductor and associated hardware in locations where repeat failures have occurred. Installation of animal protection.
22SY15 DARWIN RIVER	10.74	Reconfiguration and addition of automated network switchgear to improve restoration times (synergies with 22SY04 Dundee improvement program).

Rural Long Feeder Category

The feeder improvement tasks set out in Table 25 are planned for implementation in 2019-20 on the top five poorly performing rural long feeders.

Table 25 Rural Long Feeder Category - Top Five Worst Performing Feeders

Feeder Name	SAIDI	Brief Description of the Task
22SY04 DUNDEE	1284.78	A variety of outage causes and locations contributed to this feeder's performance, predominately associated with intense storm activity. The DFA system data is being analysed to identify areas for remediation to ensure efficient expenditure. Currently, the focus is on improving resilience to lightning damage and additional animal protection.
22KA10 MATARANKA 1	84.14	No task planned – The feeder has not performed poorly in two consecutive years.
22TC01 ALI CURUNG	78.36	Upgrade of reclosers to improve functionality and remote monitoring.

11.1.5 Compliance with reliability measures and standards

The data that is relied on to measure reliability performance of the network is obtained from the various sources, such as customer calls and SCADA, and is recorded in Maximo, our works management system.

There is a service level agreement between Power and Water and the System Operator that ensures complete data is collected, recorded and made available in Maximo in a timely manner. Compliance with the service level agreement is also monitored monthly by Power and Water.

The quality of data used to ensure compliance with the target standards is improved by cleansing the data regularly. The data is also reviewed by the System Controller daily followed by a monthly joint review of the data by System Operator and Power and Water personnel.

The data recorded in Maximo is analysed monthly and network performance indicators (notably, SAIDI and SAIFI) are monitored, tracked and reported on a monthly basis in business reports. As part of data analysis and reporting, the SAIDI and SAIFI analysis is used to determine the monthly trends and causes of the major events for that particular month. Monthly analysis is also used to explain certain feeder category trends that become evident from the analysis.

Power and Water has a yearly feeder upgrade program that is intended to maintain the reliability of the network based on reliability targets. The SAIDI and SAIFI performance of each feeder is used to identify feeders that should be included in the annual feeder improvement program, taking into account the annual budget allocated. Actions that provide the most significant benefit at lowest cost are then identified and scheduled in the annual capital or maintenance works program.

Since the customer connection and/or reconnection requests also affect the performance of the network, Power and Water ensures that customer requests are handled and resolved in a timely manner.

11.2 Quality of Supply (QoS) obligations

Quality of Supply (QOS) refers to the electrical specification of supply, and includes measures such as voltage levels and fluctuations, harmonic distortion, and voltage unbalance. Currently, Power and Water's Network Technical Code and Network Planning Criteria set out the standards for the QoS customers can expect. The standards are discussed in the following sections.

Power and Water is currently in a transition period and is exempt from some sections of the NT NER. Once Power and Water has fully transitioned, Chapter 5 of the NT NER will specify the QoS standards.

11.2.1 Steady state voltage

Power and Water supply voltage to customers at both low voltage (LV) and high voltage (HV). For steady state voltage levels, Power and Water adhere to Australian Standards AS60038 and AS61000.3.100.

Low voltage network

LV is nominally supplied at 230V single phase or 400V three phase. The range of LV supply is specified in AS61000.3.100 Section 5. An extract is reproduced below in Table 26.

Table 26 LV Voltage limits

Nominal voltage Vnom	Voltage limits		Preferred operating range	
	$V_{1\%}$ Minimum (-6% of V_{nom})	$V_{99\%}$ Maximum (+10% of V_{nom})	Minimum (-2% of V_{nom})	Maximum (+6% of V_{nom})
Single phase 230V	216V	253V	225V	244V
Three phase 400V	376V	440V	392V	424V

High voltage network

Power and Water's high voltage customers are supplied at 11kV, 22kV or 66kV. Prospective customers requiring HV supply should seek advice from Power and Water on the available supply voltages at their location early in the project planning phase.

11.2.2 Voltage fluctuations, harmonics and unbalance

A voltage fluctuation (flicker) occurs when the shape of the voltage waveform is maintained but the magnitude varies and may fall outside the steady state supply voltage range. The magnitude may change 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). Voltage fluctuations may be repetitive, irregular or regular. Short duration voltage disturbances generally occur due to faults on the network and may not be economically eliminated. Voltage fluctuations are generally categorised as temporary over-voltages caused by a (credible) contingency event, and step-changes in voltage level due to switching.

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. The distorted waveforms can be analysed so that they can be characterised as the superposition of additional higher harmonic frequency waveforms of different magnitudes upon the fundamental waveform. Each harmonic frequency will be an integer multiple of the fundamental frequency, and the magnitude of each harmonic voltage or current will lead to a measure of the waveforms' total harmonic distortion, expressed as a percentage of the fundamental voltage or current. The impact is potential mal-operation of devices, flickering of lights, and possibly overheating of equipment.

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.

The standards applied to voltage fluctuations, harmonics and unbalance are set out in the Power and Water's Network Technical Code and Network Planning Criteria.

11.3 Quality of Supply (QoS) performance

11.3.1 QoS complaints

Power and Water analyses the network to ensure satisfactory performance, in accordance with the quality of supply criteria, whenever a new customer is connected or a complaint from an existing customer is received.

The aspects of quality of supply that are monitored and analysed are steady state voltage and voltage fluctuation, as well as network frequency on isolated regional networks. Harmonic voltage and voltage unbalance are only measured following a complaint or, depending on the nature of the load, when a new user is connected.

Power and Water is required to report to the AER on the number of quality of supply complaints as part of the annual Regulatory Information Notice (RIN). In 2018-19, there were 47 complaints received related to QoS. The number of complaints received by category were:

- nine due to voltage spikes
- five related to solar power
- four due to a voltage swell, and
- four due to low supply voltage
- 25 were identified to be in the 'Other' category.

The causes of these complaints were investigated and number of complaints by cause were:

- 14 caused by faulty network equipment
- eight caused by a problem on the customer premises
- four due to environmental impacts
- three had no problem identified, and
- one was the result of a network constraint
- 17 were identified to be in the 'Other' category.

11.3.2 Low voltage quality

Power and Water conducts audits of low voltage quality, using a random sample of customers. Power quality assessment was performed in 2019 on the data obtained from meters installed at customers' connection points.

The meters installed measure and record voltage information for a period of 80 days, with measurements averaged over 10-minute intervals. In each of the three regions, the following samples were assessed:

- Darwin: seven residential and five commercial sites.
- Katherine: two residential and 10 commercial sites.
- Alice Springs: seven residential and six commercial.

The outcome of the assessment is shown in Table 27 below.

Table 27 Steady state voltage performance

Voltage zone	Darwin	Katherine	Alice Springs
Below limits	0.00%	0.02%	0.26%
Lower operating zone	7.00%	1.60%	0.00%
Preferred operating zone	91.00%	44.00%	56.74%
Upper operating zone	2.00%	52.00%	42.71%
Above limits	0.00%	2.38%	0.29%

The table shows that 100% of measured voltages in Darwin were within the acceptable zone, and 91% were within the preferred operating zone.

From initial investigations, the high voltages experienced by some customers in Katherine is partly due to high transmission voltages on the 132kV Darwin-Katherine transmission line during low load periods. Voltage regulation on the 132/66kV transformers is restricted due to a limited number of buck taps. Power and Water will undertake further investigation to address this issue. Possible solutions include installation of shunt reactors and engaging a third party for reactive power control during low load periods.

Close to 99% of the voltages at Alice Springs are within the upper and lower limits. It is expected that with the proposed decommissioning of Ron Goodin Power Station, the voltages on the low voltage network will improve. The generators at Ron Goodin Power Station are currently connected to the same switchboard as the 11kV feeders at Sadadeen, limiting control on the voltage set point on the distribution network. The voltage regulation set point will be lowered once the power station is decommissioned.

11.3.3 Quality of supply corrective actions

Power and Water is actively managing QoS through various methods which include both proactive and reactive activities.

Power and Water monitors the voltage levels at zone substations using permanently installed monitoring equipment in all zone substations and using portable equipment to undertake cyclic monitoring of distribution substations across the network. We use Power Quality (PQ) and GIS data to assist in the development of electrical models of LV circuits to better predict power quality issues. Solar PV installation parameters are reviewed regularly and new technology solutions are assessed, such as 'volt response' in solar PV inverters, to ensure efficient solutions to PQ issues can be implemented.

Power and Water also undertakes reactive actions to resolve any identified QoS issues, including:

- Distribution transformer tap adjustments;
- Installation of an additional distribution transformers and dividing the local LV network between these transformers;
- Upgrading a distribution transformers with a higher capacity transformers;
- Upgrading LV and/or HV conductors with a higher capacity conductors; and
- Phase balancing.

11.3.4 Compliance with QoS measures and standards

Power and Water developed a process to improve management of voltage levels on their network. A longer-term approach has been implemented to review equipment and equipment standards from customer level to transmission interconnection. The objective is to ensure there is sufficient flexibility within the network to provide greater voltage control as customer devices change and the penetration of solar PV increases.

12 Asset management approach

12.1 Asset management framework

Power and Water manages a broad range of assets to supply power across three regions in Northern Territory. We apply a whole-of-lifecycle asset management approach and are continually improving our asset management knowledge and practices to ensure safe, reliable and efficient delivery of services to our customers.

An overview of Power and Water's asset management process is shown in Figure 14. It shows how the corporate drivers inform the power network drivers which in turn drive asset management strategies and plans. The measurements of success and targets provide a feedback loop to enable continuous improvement.

This process provides the linkage and 'line of sight' from the Power and Water Board's Strategic Direction, Statement of Corporate Intent (SCI) and Business Plan to the delivery of services.

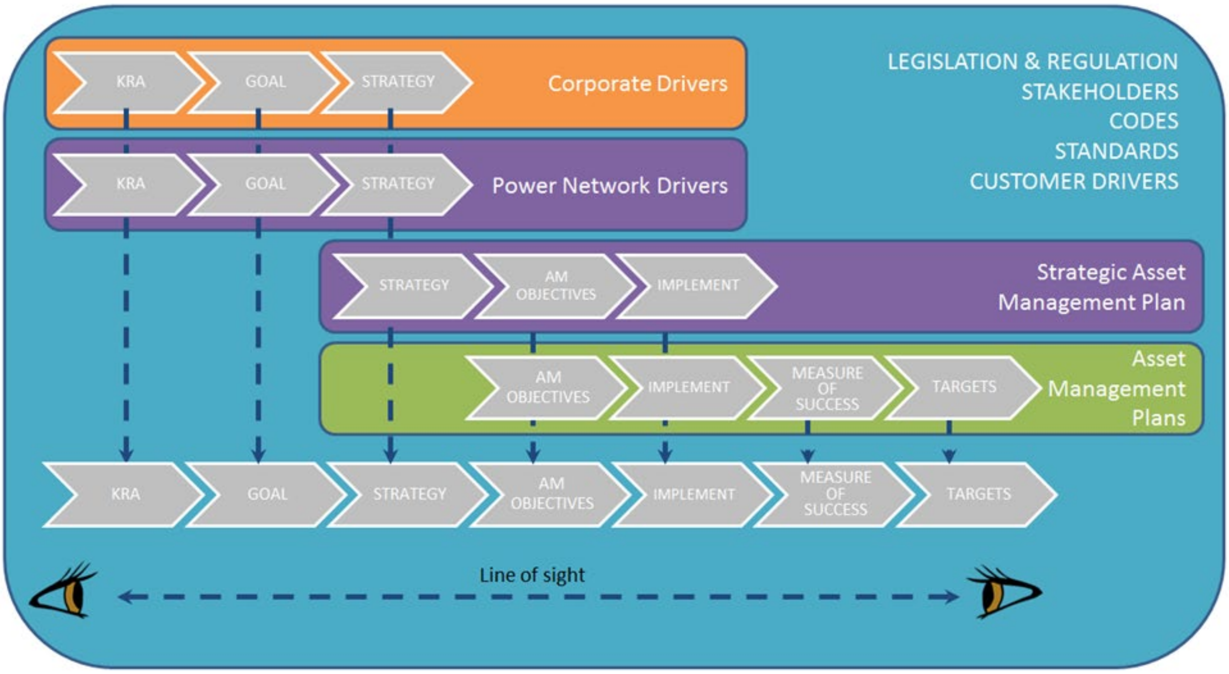

Figure 14 Asset management line of sight diagram

12.2 Asset management strategies

The Strategic Asset Management Plan (SAMP) is developed based on the corporate and power networks strategies, policies (including the Asset Management Policy) and corporate risk frameworks to ensure strategic alignment with the requirements of corporate stakeholders is maintained. The SAMP defines the asset management objectives for each asset class.

Asset management objectives are then analysed and asset class specific strategies and plans, such as Asset Management Plans or Strategic Action Plans, are developed that describe the project or programmes that will be implemented to achieve the asset management objectives.

Implementation of the approved plans is monitored through measures of success which provide a feedback loop to assess how well the strategies and plans are achieving the objectives and enable opportunities to refine these strategies and plans.

Power and Water develops its strategies and plans in accordance with Good Electricity Industry Practice as defined in the National Electricity Rules. The following sections provide an overview of the main focus of the asset strategies.

1.1.1 Network growth

Power and Water has a robust demand forecasting process as described in Section 4 that is used for the basis of network growth planning. The Technical Code and Planning Criteria sets out supply contingencies that describe the required time to restore supply in different network categories, the forecast demand scenario to use (50% probability of exceedance) and the cyclic rating of assets.

Forecast demand is compared to the asset or substation capacity to identify when the capacity is expected to be exceeded and when the required supply contingencies can no longer be achieved. Appropriate mitigation options are developed and analysed to identify the most economical solution to resolve the network constraint.

12.2.1 Asset maintenance

Power and Water applies a whole of lifecycle approach to managing its network assets. To achieve this, assets are inspected and maintained in a planned manner to ensure defects can be systematically identified and schedule for remediation.

The recent roll-out of mobile field devices for maintenance work enables asset information to be captured and entered directly into the asset management system. This initiative have been critical to the improvement of our capacity in understanding the network condition and analysing reliability performance data, have resulted in significant reduction in maintenance expenditure, particularly on Preventative Maintenance.

Power and Water is currently reviewing and developing of 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. The four types of maintenance that is currently undertaken are:

- Visual inspections of overhead and ground mounted equipment.
- Functional checks to ensure asset performance is adequate to maintain reliability. This may include oil sampling for dissolved gas analysis (DGA) and oil quality, greasing and lubrication, cleaning, thermographic and partial discharge scans.
- Diagnostic maintenance to determine characteristics such as insulation integrity. This may include partial discharge (PD) tests, other electrical tests, DGA and oil sampling.
- Intrusive maintenance to assess assets with a known wear-out failure mode that is preventable through maintenance. This type of maintenance generally requires the asset to be offline and out of service and may include any of the types of tests listed above, as well as internal inspection, cleaning and general maintenance.

The frequency of inspections and maintenance for each asset class is dependent on several factors, including:

- The operating environment e.g. areas of high corrosion, and location of asset;
- The performance and demand profile that the asset is exposed to;
- The condition of the asset, assessed based on defect history, age and measurements where available and economically justifiable based on the consequences of failure;
- Known defects/deficiencies with particular manufacturers/models. Industry working group (IWG) allows benchmarking with other Australian utilities.

Table 28 through to Table 31 summarise our maintenance strategies for each asset class.

Table 28 Zone substation maintenance strategy

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

** Some models have increased frequency due to known anomalies

Table 29 Distribution maintenance strategy

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 30 Transmission lines maintenance strategy

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 31 Secondary systems maintenance strategy

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

12.2.2 Asset replacement

Power and Water apply a whole-of-lifecycle cost assessment to determine the optimal time for asset replacement based on operational costs (i.e. maintenance), risk to network reliability and safety, asset condition and the capital cost of the asset.

The costs associated with each phase of an asset’s life changes depending on the asset type, age and condition of the asset. Most asset classes are managed through routine inspection with identified defects categorised by severity. The severity classification has defined timescales for defect rectification to maintain the expected life of the assets and meet the safety and reliability outcomes required. The cost of asset maintenance typically increases as assets reach their expected end-of-life and wear out. As the condition deteriorates, the expected failure rate increases the expected cost to customers of reduced service levels such as safety and network reliability also increases. Eventually it becomes more economic to replace the asset than to continue maintaining it.

However, not all assets have the same impact on safety and network reliability. To manage the network as efficiently as possible, different strategies are applied to each asset class. The strategies applied include run-to-failure, condition-based replacement, planned replacement, demand driven and customer driven replacement. The strategies applied to each asset depends on the asset risk profile, capital value and criticality to reliable and safe operation of the network.

The replacement strategies and asset classes they are applied is described in Table 32 and Table 33 below.

Table 32 Asset risk profile suitability by replacement strategy

Replacement Strategy	Asset risk profile suitability
Replace-on-failure (Functional failure)	Asset has low criticality, low consequence Asset condition information is difficult to gather
Condition-based (Conditional failure)	Asset is critical and cost of risk exceeds replacement cost Asset condition is measurable
Planned (Proactive replacement)	Other risks result in action (e.g. network need is changing, emerging safety or environmental risks, change in technology, legislative and compliance changes) 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	Planning process identifies that the existing installed capacity is insufficient to supply the forecast demand
Customer-driven	Individual customer requests new/increased capacity

Table 33 Asset class replacement strategies

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	✓		✓		✓

12.3 Distribution losses

Distribution losses represent the difference in total energy that is received from the transmission-distribution connection points and the amount received by customers. Typical losses in the distribution network in urban areas are 3-4% of the energy consumed at the customers' end, but may be larger in rural networks where the distribution feeders are longer.

Distribution losses result in two noticeable inefficiencies, namely customers paying more for energy as retailers include the losses in the energy price and greenhouse gas emissions are created when generating lost energy. It should be noted that losses occur in all parts of the electricity network, including sub-transmission lines, power transformers, distribution lines, distribution transformers, and service lines to the customer.

Power and Water recognises the adverse effects of distribution losses to the customer and the environment, and endeavours to minimise the losses in the network by several methods:

- Voltage regulation installed at strategic points on the distribution network
- Installation of distribution zone substations close to the load.
- Adequate sizing of cables and conductors, to minimise overloading and reduce loading on feeders. This may involve re-conductoring some parts of highly loaded overhead feeders with larger conductors.
- Using higher voltages for feeders that are expected to be longer.

12.4 Issues identified through asset management

No issues have been identified through asset management that may impact on the system limitations in this report.

12.5 Other 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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13 Demand management

While the concept of demand management is not new, it is currently Power and Water's preferred option when assessing options to address system limitations. In the past, system limitations were generally resolved through the construction of new poles, wires and zone substations. The approach that Power and Water is moving towards is one where demand management (and/or investment deferral) is the preferred option, leading to prudent and efficient spending when required.

13.1 Non-network options

In assessing potential solutions to network issues, Power and Water has considered a number of non-network options in the past year. These are detailed in the sections below.

13.1.1 Wishart Zone Substation

A temporary NOMAD mobile substation was installed at Wishart in 2015 to improve the voltage profile in the 11kV network at East Arm. We determined a temporary solution was the prudent and efficient solution given the load uncertainty at the time. Wishart Zone Substation also reduced the transformer loadings at Berrimah Zone Substation, which are approaching end of life.

Demand in the East Arm and Wishart areas are expected to continue growing in the 2019-24 regulatory period and exceed the 10MVA capacity of the NOMAD substation. To address this increase in demand, non-network solutions will be explored to further defer the network solutions at Wishart Zone Substation.

Non-networks solutions to be explored include:

Load curtailment/demand side response

Load curtailment/demand side response involves an agreement between us and our customers whereby the customers agrees to reduce their load at our request.

This option provides a controlled way of reducing load during peak demand periods but is highly dependent on the number and type of customers willing to participate.

Distributed solar PV

This option involves incentivising customers to invest in solar PV and battery energy storage systems. It relies on distributed rooftop solar PV to provide security of supply during a single transformer contingency scenario. For the option to be an effective and reliable source of power supply, a significant step increase in customer uptake of solar PV in the Wishart supply area is required, as well as sustained ideal weather conditions during an extended contingency restoration period.

Micro-grid

This option involves taking a section of the integrated network to operate in an islanded mode. It will require network augmentation to establish a supply substation, generator connection, special protection schemes, and the establishing of non-standard operational practices to operate within a mesh environment.

Back-up generation

Back-up generation involves installing diesel generators at the zone substations to provide extra capacity when required. While the cost of operation is high due to the price of diesel fuel, it could be a viable and cost effective solution to support the load at risk while deferring the need for greater investment in the construction of a permanent zone substation. This will depend on the expected period of operation and duty cycle.

13.1.2 Sadadeen Zone Substation

Sadadeen Zone Substation is a 22/11kV substation located in Alice Springs. It connects to Lovegrove Zone Substation via two 22kV express tie cables with a firm capacity of 19MVA each. Currently, there are two 19MVA 22/11kV transformers connecting the 22kV switchboard to the 11kV switchboard at Ron Goodin Power Station. The 11kV switchboard connects both generators from the power station as well as feeders on the 11kV network.

Ron Goodin Power Station is due to be decommissioned in the near future, following which all power for Alice Springs will be generated from Owen Springs Power Station and transmitted to Sadadeen Zone Substation via Lovegrove Zone Substation through the two 22kV express ties. The 11kV load at Ron Goodin and 22kV load at Sadadeen are forecast to exceed the firm rating of the 22kV express ties.

In 2017, Territory Generation decided to construct a BESS in Alice Springs with the primary objective to reduce their spinning reserve requirements due to the high volume of solar PV entering the network. Power and Water had discussions with Territory Generation and agreed to build the BESS at Sadadeen Zone Substation to provide additional voltage support and peak lopping functions once the generators at Ron Goodin Power Station are decommissioned for a limited period. This deferred the need to build additional network elements to support the load at Sadadeen.

13.2 Key issues due to applications to connect embedded generating units

Power and Water has received significant interest in connection of embedded generating units in recent years. Approximately 13% of our customers have rooftop solar PV systems installed[13], nearly all of which have been installed in the last 10 years. Increasing penetration of solar PV systems from approximately 5MW total capacity in 2010/11 to 24.7MW in 2015/16, and to more than 70MW in 2018/19 has resulted in a steady reduction in daytime network energy demand. Figure 15 shows the increasing rate of solar PV installation, driven by various factors such as Northern Territory Government incentives, and reduction in cost of PV systems due to decreasing costs of equipment, increased competition and supply in the market.

[13] Power and Water Corporation customer PV application database

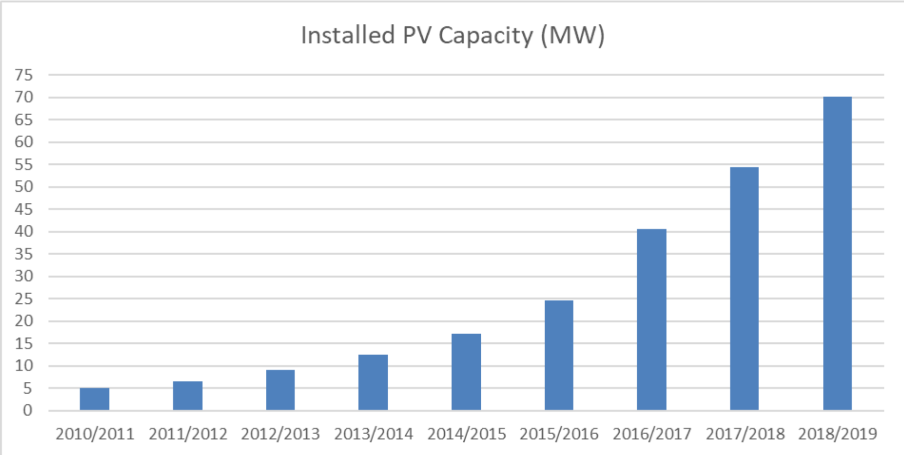

Figure 15 Installed PV capacity in the Northern Territory (MW)

One pronounced effect on the network of solar PV is the shift in the timing of daily system peak demand. Figure 16 compares the half-hourly average system load on the Darwin-Katherine network in December 2013 and December 2018, the months in which system peak demand occurred. The chart illustrates the significant shift of the average daily system peak demand from 2.30pm in 2013 to 5.00pm in 2018.

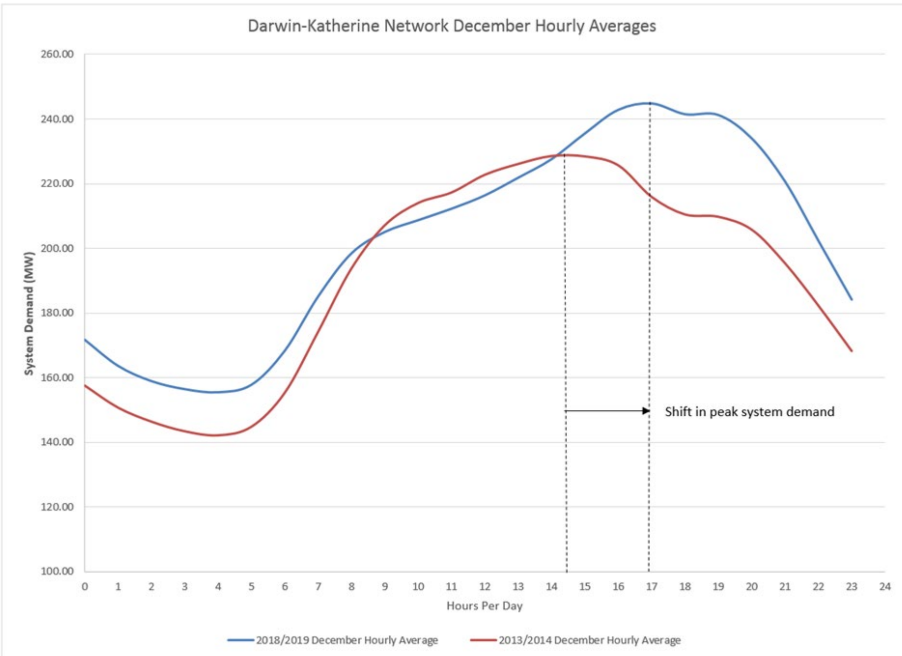

Figure 16 Darwin-Katherine network December hourly averages (MW)

To date, uptake of energy storage systems in domestic installations has been limited, likely due to the comparatively high cost of energy storage systems at present, the generous 1:1 feed-in tariff incentives by energy retailers, and the transient nature of much of the Northern Territory population. However, this may change significantly if the costs of energy storage systems fall, and particularly if the feed-in tariff regime changes such that the payments customers could receive for the export of excess energy to the network fall significantly in comparison with the savings that could be made by storing the excess electricity and using it later to offset the cost of energy during the evening peak.

As PV uptake increases, the network may begin to experience periods of export from pockets of the distribution network to the upstream sub-transmission system. While Power and Water has not yet identified any feeders exhibiting reverse power flow during low demand/high solar PV generation periods, we continue to monitor the situation carefully as most of our zone substations are not designed to accommodate reverse power flows.

More immediate challenges posed by increasing uptake of solar PV systems are related to managing the wide range of voltage levels that result from large and rapid swings between peak demand and peak generation export (due to intermittent variability of solar PV system outputs caused, for example, by variable cloud coverage), and power system stability issues, particularly in smaller networks such as in Alice Springs.

Several embedded generators are proposing to connect to the Darwin-Katherine 132kV transmission line (DKTL). The DKTL is a radial line from Channel Island to Katherine, connecting to Manton, Batchelor and Pine Creek Zone Substations along the way. There is existing generation located at Katherine and Pine Creek and new generation proposed at Katherine, Manton and Batchelor. The combination of comparatively low load on the line and significantly increased generation capacity would result in significant power transfer north to Channel Island. This means the DKTL may pose as a potential contingency risk as unplanned outages may result in a significant loss of generation in the Darwin-Katherine system, increasing the likelihood of under frequency load sheds.

13.3 Actions taken to promote non-network proposals

Power and Water is in the process of developing its Demand Side Engagement Document (DSED). Once developed, this document will provide a framework for our demand side engagement process. It will include a description of how we will investigate, develop, assess and report on potential non-network options to address network constraints caused by new connections. The DSED will be made available on our website.

During the early stages of an access application to connect to the network, the proponent of the connection will commence discussions with us regarding network capacity and location. The location of a proposed network connection is driven by the availability of land and the ease of connection to the network. At this stage, we will establish whether any system limitations exist, and if so, determine whether the system limitation can be alleviated by the new network connection (which is typically generation) or if a system constraint is created by the connection of a new load.

13.4 Future plans for demand management and embedded generation

Non-network options, such as demand management and embedded generation are becoming more important, especially in regulated networks where emphasis is placed on finding the least cost solution.

We appreciate the importance of non-network options and is committed to finding the best solution for customers in terms of cost and benefit. In developing options for network deficiencies, some of the non-network alternatives that Power and Water has previously and will continue to consider, include:

- Demand side response, where the customer is encouraged to use less energy during peak hours, or shift energy usage to off-peak hours.
- Encouraging energy efficiency, especially in appliances.
- Use of DER, where generation is decentralised, located close to the load, and can comprise of multiple generation and energy storage devices. DER are typically generated from renewable resources and in the Northern Territory this is likely to be in the form of solar PV panels. DER can also consist of energy storage which are typically comprise of BESS.

We are developing a Virtual Power Plant (VPP) program to investigate the feasibility of non-traditional options for various power system support services, not only focusing on arbitrage opportunities. This program aims to develop skills, knowledge and systems in Power and Water and assist in the effective and commercially efficient orchestration of DER. The area of VPP is becoming increasingly viable as the economics of distributed battery systems become more compelling for customer installations into the future.

The maturing of network technology and trends will bring about more opportunities to implement non-network solutions, which we are keen to realise in the future. We encourage the use of non-network solutions as a means of addressing network deficiencies, especially where the perceived benefits and the investment costs are much less than traditional networked solutions.

13.5 Connection enquiries and applications received

Power and Water is transitioning to the NT NER Chapter 5 during 2019-20 and will be required to follow the processes set out in Chapter 5 of the NT NER from 1 July 2019.

Connection applications for 2018/19 were completed under Chapter 2 of the Electricity Networks (Third Party Access) Code (the Code). The Code does not define a process that is equivalent to a Connection Enquiry in the NT NER and only defines a process that is equivalent to a Connection Application, which is referred to as an access application.

For the purpose of reporting in this section, we have reported connection enquiries as a written request or notification of an interest to connect under Chapter 2 of the Code, but without submitting an access application as defined under Chapter 2 of the Code.

Table 34 below provides a summary of connection enquiries and applications received in 2018/19.

Table 34 Connections enquiries and applications 2018/19

Connection enquiries and applications 2018/19	Quantity	unit
Connection enquiries received	11	
Connection applications received	12	
Average time taken to complete applications to connect	NA[14]	days

[14] Application of the National Electricity Rules (Northern Territory) commenced July 2019

14 Investment in information communications and technology systems

Power and Water's investments in information communications and technology (ICT) that occurred in 2018-19 are provided in Table 35.

Planned investments in ICT related to management of network assets in the forward planning period are provided in Table 36.

Table 35 Current ICT investments

Current ICT investments
RINs
• Implemented a business intelligence (BI) tool to enable Power and Water to collect and collate network business data for RINs reporting to the AER, as a regulatory compliance requirement. • The project was completed in August 2019.
ESRI (Dekho) Upgrade
• Upgraded a core asset management system to remain within vendor support parameters in line with industry practices and efficiently support core network asset management functions. • This replaced the previous Dekho GIS system. The project was completed in September 2019.
ESRI Maximo Decoupling project
• Upgraded a core asset management system to remain within vendor support parameters in line with industry practices and efficiently support core network asset management functions. • The project was completed in August 2019.
Data and Reporting Program
• Implemented a set of business intelligence data and reporting tools to improve the reliability of enterprise data and reporting function capabilities for the distribution network business. • The business case has been endorsed and implementation is in progress. The project is scheduled for completion in July 2021.

Table 36 Planned ICT investments

Planned ICT investments
Maximo Upgrade
• Upgrade the existing asset management system to a current version to reduce maintenance costs, leverage enhanced business capability and reduce operational risks for key areas in operations.
Meter Data Management System

• Implement systems and processes required to:
  • comply with the NT NER requirements (Chapter 7a).
  • provide customer benefits available from improved metering data.

EMS SCADA Replacement
• Replace the existing Energy Management System that is approaching its end-of-life.
FMS Realignment
• Upgrade of core Financial Management System to support efficient financial management functions.

Appendix A - Power and Water contacts

The purpose of this document is to provide information on Power and Water's network, including forecasted load and system limitations occurring in the forward planning period, and committed projects to address system limitations. This document is not intended to be used for other purposes.

For any queries relating to information published in this TDAPR please contact:

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Appendix B – Asset types and quantities

Table 37 Asset types and quantities

ASSET GROUP	ASSET CATEGORY	QUANTITY
POLES BY: HIGHEST OPERATING VOLTAGE; MATERIAL TYPE	> 22kV and < = 66kV; Concrete	70
	< = 1kV; Steel	13,244
	> 1kV and < = 11kV; Steel	6,771
	> 11kV and < = 22kV; Steel	21,928
	> 22kV and < = 66kV; Steel	2,248
	> 66kV and < = 132kV; Steel	964
OVERHEAD CONDUCTORS BY: HIGHEST OPERATING VOLTAGE; NUMBER OF PHASES (AT HV)	< = 1kV	1,194
	> 1kV and < = 11kV	370
	> 11kV and < = 22kV; SWER	9
	> 11kV and < = 22kV; Multiple-Phase	3,157
	> 22kV and < = 66kV	377
	> 66kV and < = 132kV	354
UNDERGROUND CABLES BY: HIGHEST OPERATING VOLTAGE	< = 1kV	735
	> 1kV and < = 11kV	775
	> 11kV and < = 22kV	95
	> 33kV and < = 66kV	39
SERVICE LINES BY: CONNECTION VOLTAGE; CUSTOMER TYPE; CONNECTION COMPLEXITY	< = 11kV; Residential; Simple Type	46,806
	< = 11kV; Commercial and Industrial; Simple Type	9,405
TRANSFORMERS BY: MOUNTING TYPE; HIGHEST OPERATING VOLTAGE; AMPERE RATING;	Pole Mounted; < = 22kV; < = 60kVA; Single Phase	111
	Pole Mounted; < = 22kV; > 60kVA and < = 600kVA; Single Phase	1
	Pole Mounted; < = 22kV; < = 60kVA; Multiple Phase	668

ASSET GROUP	ASSET CATEGORY	QUANTITY
NUMBER OF PHASES (AT LV)	Pole Mounted; < = 22kV; > 60kVA and < = 600kVA; Multiple Phase	2,100
	Pole Mounted; < = 22kV; > 600kVA; Multiple Phase	3
	Kiosk Mounted; < = 22kV; < = 60kVA; Single Phase	301
	Kiosk Mounted; < = 22kV; > 60kVA and < = 600kVA; Single Phase	15
	Kiosk Mounted; < = 22kV; > 60kVA and < = 600kVA; Multiple Phase	1,056
	Kiosk Mounted; < = 22kV; > 600kVA; Multiple Phase	231
	Ground Outdoor / Indoor Chamber Mounted; < 22kV; > 60kVA AND < = 600kVA; Multiple Phase	77
	Ground Outdoor / Indoor Chamber Mounted; < 22kV; > 600kVA; Multiple Phase	212
	Ground Outdoor / Indoor Chamber Mounted; > = 22kV and < = 33kV; < = 15MVA	65
	Ground Outdoor / Indoor Chamber Mounted; > = 22kV and < = 33kV; > 15MVA and < = 40MVA	3
	Ground Outdoor / Indoor Chamber Mounted; > 33kV and < = 66kV; < = 15MVA	13
	Ground Outdoor / Indoor Chamber Mounted; > 33kV and < = 66kV; > 15MVA and < = 40MVA	24
	Ground Outdoor / Indoor Chamber Mounted; > 33kV and < = 66kV; > 40MVA	9
	Ground Outdoor / Indoor Chamber Mounted; > 66kV and < = 132kV; < = 100MVA	5
	Ground Outdoor / Indoor Chamber Mounted; > 66kV and < = 132kV; > 100MVA	3
	Other-Transformer	2
SWITCHGEAR BY: HIGHEST OPERATING VOLTAGE	< = 11kV; Switch	3,045
	< = 11kV; Circuit Breaker	336

ASSET GROUP	ASSET CATEGORY	QUANTITY
SWITCH FUNCTION	> 11kV and < = 22kV; Switch	3,300
	> 11kV and < = 22kV; Circuit Breaker	231
	> 33kV and < = 66kV; Switch	130
	> 33kV and < = 66kV; Circuit Breaker	103
	> 66kV and < = 132kV; Switch	131
	> 66kV and < = 132kV; Circuit Breaker	31
SCADA, NETWORK CONTROL AND PROTECTION SYSTEMS BY: FUNCTION	Field Devices	1,417
	Local Network Wiring Assets	643
	Communications Network Assets	519
	Master Station Assets	1
	Communications Site Infrastructure	351
	Communications Linear Assets	362,084
OTHER BY: DNSP DEFINED	Buildings	36
	Instrument Transformers	319
	Metering Units	82
	Pillars	7,505
	Substation Auxiliary Plant	81
	Voltage Regulators	13
	Civil and Grounds	36
	Fire Systems	33
	Capacitor Banks	31
	Power Transformer Refurbishment	9
	Pole Refurbishment	144

Appendix C – Zone substation forecasting methodology selection

Table 38 Zone substation forecast methodology

Zone Substation	Forecast Methodology Adopted	Comments
Archer	AEMO	AEMO forecast values were used as their forecast values are higher than Power and Water and more conservative.
Brewer and Sadadeen (22kV loads)	AEMO	AEMO forecast values were used as their forecast values are higher than Power and Water and more conservative.
Batchelor	AEMO	AEMO forecast values were used as their forecast values are slightly higher than Power and Water and more conservative.
Berrimah	AEMO	AEMO forecast values were used as the Power and Water linear regression of slope had a high negative growth which was conflicting with the AEMO forecast values. AEMO forecast values are more conservative.
Casuarina	AEMO	AEMO forecast values were used as the Power and Water linear regression of slope had a high negative growth which was conflicting with the AEMO forecast values. AEMO forecast values are more conservative.
Centre Yard	AEMO	AEMO forecast values were used as their forecast values are slightly higher than Power and Water. The differences between Power and Water and AEMO forecast values were quite negligible.
Cosmo Howley	Power and Water	Power and Water forecast values were used as AEMO forecast values does not consider the recently committed block loads. In this case, Power and Water forecast values are more conservative.
Darwin	AEMO	AEMO forecast values were used as the Power and Water linear regression of slope had a high negative growth which was conflicting with the AEMO forecast values. AEMO forecast values are more conservative.

Zone Substation	Forecast Methodology Adopted	Comments
Frances Bay	AEMO	AEMO forecast values were used as the Power and Water linear regression of slope had a high negative growth which was conflicting with the AEMO forecast values. AEMO forecast values are more conservative.
Humpty Doo	Power and Water	Power and Water forecast values were used as AEMO forecast values does not consider the recently committed block loads. In this case, Power and Water forecast values are more conservative.
Katherine	Power and Water	Power and Water forecast values were used as AEMO forecast values does not consider the recently committed block loads. In this case, Power and Water forecast values are more conservative.
Leanyer	Power and Water	Power and Water forecast values were used though the differences between Power and Water and AEMO forecast values were quite negligible. Only exception is in 2018/2019, the forecasted AEMO maximum demand was higher than Power and Water calculated maximum demand.
Lovegrove (22-11 kV load)	Power and Water	Power and Water forecast values were used as they are higher than AEMO and more conservative.
Lovegrove (22 kV load)	Power and Water	Power and Water forecast values were used as AEMO values are not available.
Lovegrove (66-22 kV load)	AEMO	AEMO forecast values were used as the Power and Water linear regression of slope had a high negative growth which was conflicting with the AEMO forecast values. AEMO forecast values are more conservative.
Manton	Power and Water	Power and Water forecast values were used as they are higher than AEMO and more conservative. Manton Zone Substation had existing large loads that were not at full utilisation (utilisation levels were obtained with zone substation meter data) and the remaining load was forecasted to occur in the next few years.

Zone Substation	Forecast Methodology Adopted	Comments
Marrakai	Power and Water	Power and Water forecast values were used as they are slightly higher than AEMO forecast values.
Mary River	AEMO	AEMO forecast values were used as their forecast values are slightly higher than Power and Water. The differences between Power and Water and AEMO forecast values were quite negligible.
Palmerston	Power and Water	Power and Water forecast values were used as they are higher than AEMO and more conservative. AEMO forecast values also did not consider the recently committed block loads. Some of the existing large loads were not at full utilisation (utilisation levels were obtained with zone substation meter data) and the remaining load was forecasted to occur in the next few years.
Pine Creek	Power and Water	Power and Water forecast values were used as AEMO values are not available.
Sadadeen (Ron Goodin 11 kV load)	AEMO	AEMO forecast values were used as the Power and Water linear regression of slope had a high negative growth which was conflicting with the AEMO forecast values. AEMO forecast values are more conservative.
Strangways	Power and Water	Power and Water forecast values were used as they are higher than AEMO and more conservative.
Tennant Creek	Power and Water	Power and Water forecast values were used though the differences between Power and Water and AEMO forecast values were quite negligible.
Union Reef	Power and Water	Power and Water forecast values were used as AEMO values are not available.
Weddell	Power and Water	Power and Water forecast values were used as they are higher than AEMO and more conservative. AEMO forecast values also does not consider the recently committed block loads.
Wishart	Power and Water	Power and Water forecast values were used as they are higher than AEMO and more conservative. AEMO forecast values also does not consider the recently committed block loads.

Zone Substation	Forecast Methodology Adopted	Comments
Woolner	AEMO	AEMO forecast values were used as the Power and Water linear regression of slope had a high negative growth which was conflicting with the AEMO forecast values. AEMO forecast values are more conservative.

Appendix D - NT NER and DAPR cross reference

Table 39 NT NER cross reference with DAPR

NT NER Schedule 5.8		Report section
(a)	**information regarding the Distribution Network Service Provider and its network, including:**	
(1)	a description of its network;	Section 2.3
(2)	a description of its operating environment;	Section 2.2
(3)	the number and types of its distribution assets;	Section 2.4 Appendix (b)
(4)	methodologies used in preparing the DAPR, including methodologies used to identify system limitations and any assumptions applied; and	Section 2.5
(5)	analysis and explanation of any aspects of forecasts and information provided in the DAPR that have changed significantly from previous forecasts and information provided in the preceding year;	Not applicable
(b)	**forecasts for the forward planning period, including at least:**	
(1)	a description of the forecasting methodology used, sources of input information, and the assumptions applied;	Sections 4.1, 4.2 and 4.3
(2)	load forecasts: (i) at the transmission-distribution connection points; (ii) for sub-transmission lines; and (iii) for zone substations, (iv) including, where applicable, for each item specified above: (v) total capacity; (vi) firm delivery capacity for summer periods and winter periods; (vii) peak load (summer or winter and an estimate of the number of hours per year that 95% of peak load is expected to be reached); (viii) power factor at time of peak load; (ix) load transfer capacities; and (x) generation capacity of known *embedded generating units*;	Sections 4.4 and 4.5 attachment A1, attachment A2
(3)	forecasts of future transmission-distribution connection points (and any associated connection assets), sub-transmission lines and zone substations, including for each future transmission-distribution connection point and zone substation: (i) location; (ii) future loading level; and (iii) proposed commissioning time (estimate of month and year).	Section 4.7
(4)	forecasts of the Distribution Network Service Provider's performance against any reliability targets in a service target performance incentive scheme; and	Section 4.8

NT NER Schedule 5.8	Report section
(5) a description of any factors that may have a material impact on its network, including factors affecting; (i) fault levels; (ii) voltage levels; (iii) other power system security requirements; (iv) the quality of supply to other Network Users (where relevant); and (v) ageing and potentially unreliable assets.	Section 4.9
(b1) for all network asset retirements, and for all network asset de-ratings that would result in a system limitation, that are planned over the forward planning period, the following information in sufficient detail relative to the size or significance of the asset:	
(1) a description of the network asset, including location; (2) the reasons, including methodologies and assumptions used by the Distribution Network Service Provider, for deciding that it is necessary or prudent for the network asset to be retired or de-rated, taking into account factors such as the condition of the network asset; (3) the date from which the Distribution Network Service Provider proposes that the network asset will be retired or de-rated; and (4) if the date to retire or de-rate the network asset has changed since the previous Distribution Annual Planning Report, an explanation of why this has occurred.	Section 5
(b2) for the purposes of subparagraph (b1), where two or more network assets are: **(1) of the same type;** **(2) to be retired or de-rated across more than one location;** **(3) to be retired or de-rated in the same calendar year; and** **(4) each expected to have a replacement cost less than $200,000 (as varied by a cost threshold determination)** **those assets can be reported together by setting out in the Distribution Annual Planning Report:**	
(5) a description of the network assets, including a summarised description of their locations; (6) the reasons, including methodologies and assumptions used by the Distribution Network Service Provider, for deciding that it is necessary or prudent for the network assets to be retired or de-rated, taking into account factors such as the condition of the network assets; (7) the date from which the Distribution Network Service Provider proposes that the network assets will be retired or de-rated; and (8) if the calendar year to retire or de-rate the network assets has changed since the previous Distribution Annual Planning Report, an explanation of why this has occurred.	Section 5
(c) information on system limitations for sub-transmission lines and zone substations, including at least:	
(1) estimates of the location and timing (month(s) and year) of the system limitation;	Section 6.2

NT NER Schedule 5.8		Report section
(2)	analysis of any potential for load transfer capacity between supply points that may decrease the impact of the system limitation or defer the requirement for investment;	Section 6.2
(3)	impact of the system limitation, if any, on the capacity at transmission-distribution connection points;	Section 6.2
(4)	a brief discussion of the types of potential solutions that may address the system limitation in the forward planning period, if a solution is required; and	Section 6.2
(5)	where an estimated reduction in forecast load would defer a forecast system limitation for a period of at least 12 months, include: (i) an estimate of the month and year in which a system limitation is forecast to occur as required under subparagraph (1); (ii) the relevant connection points at which the estimated reduction in forecast load may occur; and (iii) the estimated reduction in forecast load in MW or improvements in power factor needed to defer the forecast system limitation;	Section 6.2
(d)	**for any primary distribution feeders for which a Distribution Network Service Provider has prepared forecasts of maximum demands under clause 5.13.1(d)(1)(iii) and which are currently experiencing an overload, or are forecast to experience an overload in the next two years the Distribution Network Service Provider must set out:**	
(1)	the location of the primary distribution feeder;	Section 6.2
(2)	the extent to which load exceeds, or is forecast to exceed, 100% (or lower utilisation factor, as appropriate) of the normal cyclic rating under normal conditions (in summer periods or winter periods);	Section 6.2
(3)	the types of potential solutions that may address the overload or forecast overload; and	Section 6.2
(4)	where an estimated reduction in forecast load would defer a forecast overload for a period of 12 months, include: (i) estimate of the month and year in which the overload is forecast to occur; (ii) a summary of the location of relevant connection points at which the estimated reduction in forecast load would defer the overload; (iii) the estimated reduction in forecast load in MW needed to defer the forecast system limitation.	Section 6.2
(e)	**a high-level summary of each RIT-D project for which the regulatory investment test for distribution has been completed in the preceding year or is in progress, including:**	
(1)	if the regulatory investment test for distribution is in progress, the current stage in the process;	Section 9.1
(2)	a brief description of the identified need;	Section 9.1
(3)	a list of the credible options assessed or being assessed (to the extent reasonably practicable);	Section 9.1

NT NER Schedule 5.8	Report section
(4) if the regulatory investment test for distribution has been completed a brief description of the conclusion, including: (i) the net economic benefit of each credible option; (ii) the estimated capital cost of the preferred option; and (iii) the estimated construction timetable and commissioning date (where relevant) of the preferred option; and	Section 9.1
(5) any impacts on Network Users, including any potential material impacts on connection charges and distribution use of system charges that have been estimated;	Section 9.1
(f) for each identified system limitation which a Distribution Network Service Provider has determined will require a relevant regulatory investment test, provide an estimate of the month and year when the test is expected to commence;	Section 9.1
(g) a summary of all committed investments to be carried out within the forward planning period with an estimated capital cost of $2 million or more (as varied by a cost threshold determination) that are to address an urgent and unforeseen network issue as described in clause 5.17.3(a)(1), including:	
(1) a brief description of the investment, including its purpose, its location, the estimated capital cost of the investment and an estimate of the date (month and year) the investment is expected to become operational;	Section 9.4
(2) a brief description of the alternative options considered by the Distribution Network Service Provider in deciding on the preferred investment, including an explanation of the ranking of these options to the committed project. Alternative options could include, but are not limited to, generation options, demand side options, and options involving other distribution or transmission networks;	Section 9.4
(h) the results of any joint planning undertaken with a Transmission Network Service Provider in the preceding year, including:	
(1) a summary of the process and methodology used by the Distribution Network Service Provider and relevant Transmission Network Service Providers to undertake joint planning;	Section 10
(2) a brief description of any investments that have been planned through this process, including the estimated capital costs of the investment and an estimate of the timing (month and year) of the investment; and	Section 10
(3) where additional information on the investments may be obtained;	Section 10
(i) the results of any joint planning undertaken with other Distribution Network Service Providers in the preceding year, including:	
(1) a summary of the process and methodology used by the Distribution Network Service Providers to undertake joint planning	Section 10
(2) a brief description of any investments that have been planned through this process, including the estimated capital cost of the investment and an estimate of the timing (month and year) of the investment; and	Section 10
(3) where additional information on the investments may be obtained;	Section 10

NT NER Schedule 5.8		Report section
(j)	**information on the performance of the Distribution Network Service Provider's network, including:**	
(1)	a summary description of reliability measures and standards in applicable regulatory instruments;	Section 11.1.1
(2)	a summary description of the quality of supply standards that apply, including the relevant codes, standards and guidelines;	Section 11.2
(3)	a summary description of the performance of the distribution network against the measures and standards described under subparagraphs (1) and (2) for the preceding year;	Sections 11.1.2, 11.3
(4)	where the measures and standards described under subparagraphs (1) and (2) were not met in the preceding year, information on the corrective action taken or planned;	Sections 11.1.3, 11.1.4, 11.3.3
(5)	a summary description of the Distribution Network Service Provider's processes to ensure compliance with the measures and standards described under subparagraphs (1) and (2); and	Sections 11.1.5, 11.3.4
(6)	an outline of the information contained in the Distribution Network Service Provider's most recent submission to the AER under the service target performance incentive scheme;	Section 11.1.2
(k)	**information on the Distribution Network Service Provider's asset management approach, including:**	
(1)	a summary of any asset management strategy employed by the Distribution Network Service Provider;	Sections 12.1, 12.2
(1A)	an explanation of how the Distribution Network Service Provider takes into account the cost of distribution losses when developing and implementing its asset management and investment strategy;	Section 12.3
(2)	a summary of any issues that may impact on the system limitations identified in the Distribution Annual Planning Report that has been identified through carrying out asset management; and	Section 12.4
(3)	information about where further information on the asset management strategy and methodology adopted by the Distribution Network Service Provider may be obtained;	Section 12.5
(l)	**information on the Distribution Network Service Provider's demand management activities, including:**	
(1)	a qualitative summary of: (i) non-network options that have been considered in the past year, including generation from embedded generating units; (ii) key issues arising from applications to connect embedded generating units received in the past year; (iii) actions taken to promote non-network proposals in the preceding year, including generation from embedded generating units; and (iv) the Distribution Network Service Provider's plans for demand management and generation from embedded generating units over the forward planning period;	Section 13

NT NER Schedule 5.8	Report section
(2) a quantitative summary of: (i) connection enquiries received under clause 5.3A.5; (ii) applications to connect received under clause 5.3A.9; and (iii) the average time taken to complete applications to connect;	Section 13.5
(m) information on the Distribution Network Service Provider's investments in information technology and communication systems which occurred in the preceding year, and planned investments in information technology and communication systems related to management of network assets in the forward planning period; and	Section 14
(n) a regional development plan consisting of a map of the Distribution Network Service Provider's network as a whole, or maps by regions, in accordance with the Distribution Network Service Provider's planning methodology or as required under any regulatory obligation or requirement, identifying:	
(1) sub-transmission lines, zone substations and transmission-distribution connection points; and	Section 3
(2) any system limitations that have been forecast to occur in the forward planning period, including, where they have been identified, overloaded primary distribution feeders.	Section 3

Appendix E - NT NER and TAPR cross reference

Table 40 NT NER cross reference with TAPR

NT NER Section 5.12.2(C) The Transmission Annual Planning Report must be consistent with the TAPR Guidelines and set out:		Report section
1 the forecast loads submitted by a Distribution Network Service Provider in accordance with clause 5.11.1 or as modified in accordance with clause 5.11.1(d), including at least:		
(i)	a description of the forecasting methodology, sources of input information, and the assumptions applied in respect of the forecast loads;	Sections 4.1, 4.2, 4.3
(ii)	a description of high, most likely and low growth scenarios in respect of the forecast loads;	Section 4.6. Attachment A2, Attachment A3
(iii)	an analysis and explanation of any aspects of forecast loads provided in the Transmission Annual Planning Report that have changed significantly from forecasts provided in the Transmission Annual Planning Report from the previous year; and	Not applicable
(iv)	an analysis and explanation of any aspects of forecast loads provided in the Transmission Annual Planning Report from the previous year which are significantly different from the actual outcome;	Not applicable
1A) for all network asset retirements, and for all network asset de-ratings that would result in a network constraint, that are planned over the minimum planning period specified in clause 5.12.1(c), the following information in sufficient detail relative to the size or significance of the asset:		
(i) (ii) (iii) (iv) (v)	a description of the network asset, including location; the reasons, including methodologies and assumptions used by the Transmission Network Service Provider for deciding that it is necessary or prudent for the network asset to be retired or de-rated, taking into account factors such as the condition of the network asset; the reasons, including methodologies and assumptions used by the Transmission Network Service Provider for deciding that it is necessary or prudent for the network asset to be retired or de-rated, taking into account factors such as the condition of the network asset; the date from which the Transmission Network Service Provider proposes that the network asset will be retired or de-rated; and if the date to retire or de-rate the network asset has changed since the previous Transmission Annual Planning Report, an explanation of why this has occurred;	Section 5
1B) for the purposes of subparagraph (1A), where two or more network assets are:		

NT NER Section 5.12.2(C) The Transmission Annual Planning Report must be consistent with the TAPR Guidelines and set out:		Report section
(i)	of the same type;	Section 5
(ii)	to be retired or de-rated across more than one location;	
(iii)	to be retired or de-rated in the same calendar year; and	
(iv)	each expected to have a replacement cost less than $200,000 (as varied by a cost threshold determination),	
(v)	those assets can be reported together by setting out in the Transmission Annual Planning Report: a description of the network assets, including a summarised description of their locations;	
(vi)	the reasons, including methodologies and assumptions used by the Transmission Network Service Provider, for deciding that it is necessary or prudent for the network assets to be retired or de- rated, taking into account factors such as the condition of the network assets;	
(vii)	the date from which the Transmission Network Service Provider proposes that the network assets will be retired or de-rated; and	
(viii)	if the calendar year to retire or de-rate the network assets has changed since the previous Transmission Annual Planning Report, an explanation of why this has occurred;	
2) planning proposals for future connection points		**Section 4.7**
3) a forecast of constraints and inability to meet the network performance requirements set out in schedule 5.1 or relevant legislation or regulations of a participating jurisdiction over 1, 3 and 5 years, including at least:		
(i)	a description of the constraints and their causes;	Section 6.1
(ii)	the timing and likelihood of the constraints;	Attachment A1
(iii)	a brief discussion of the types of planned future projects that may address the constraints over the next five years, if such projects are required; and	
(iv)	sufficient information to enable an understanding of the constraints and how such forecasts were developed;	
4) in respect of information required by subparagraph (3), where an estimated reduction in forecast load would defer a forecast constraint for a period of 12 months, including:		

NT NER Section 5.12.2(C) The Transmission Annual Planning Report must be consistent with the TAPR Guidelines and set out:		Report section
(i)	the date from which the Transmission Network Service Provider proposes that the network assets will be retired or de-rated; and	Section 6.1 Attachment A1
(ii)	if the calendar year to retire or de-rate the network assets has changed since the previous Transmission Annual Planning Report, an explanation of why this has occurred;	
(iii)	the estimated reduction in forecast load in MW needed; and	
(iv)	a statement of whether the Transmission Network Service Provider plans to issue a request for proposals for augmentation, replacement of network assets, or a non-network option identified by the annual planning review conducted under clause 5.12.1(b) and if so, the expected date the request will be issued;	
5) for all proposed augmentations to the network and proposed replacements of network assets the following information, in sufficient detail relative to the size or significance of the project and the proposed operational date of the project:		
(i)	project/asset name and the month and year in which it is proposed that the asset will become operational;	Section 9.3.2
(ii)	the reason for the actual or potential constraint, if any, or inability, if any, to meet the network performance requirements set out in schedule 5.1 or relevant legislation or regulations of a participating jurisdiction, including load forecasts and all assumptions used;	
(iii)	the proposed solution to the constraint or inability to meet the network performance requirements identified in subparagraph (ii), if any;	
(iv)	total cost of the proposed solution;	
(v)	whether the proposed solution will have a material inter-network impact. In assessing whether an augmentation to the network will have a material inter-network impact a Transmission Network Service Provider must have regard to the objective set of criteria published by AEMO in accordance with clause 5.21 (if any such criteria have been published by AEMO); and	
(vi)	other reasonable network options and non-network options considered to address the actual or potential constraint or inability to meet the network performance requirements identified in subparagraph (ii), if any. Other reasonable network and non- network options include, but are not limited to, interconnectors, generation options, demand side options, market network service options and options involving other transmission and distribution networks;	
6)	**the manner in which the proposed augmentations and proposed replacements of network assets relate to the most recent NTNDP and the development strategies for current or potential national transmission flow paths that are specified in that NTNDP;**	**Not applicable**
6A)	**for proposed new or modified emergency frequency control schemes, the manner in which the project relates to the most recent power system frequency risk review;**	**Not applicable**
7) information on the Transmission Network Service Provider's asset management approach, including:		

NT NER Section 5.12.2(C) The Transmission Annual Planning Report must be consistent with the TAPR Guidelines and set out:		Report section
(i)	a summary of any asset management strategy employed by the Transmission Network Service Provider;	Sections 12.1, 12.2
(ii)	a summary of any issues that may impact on the system constraints identified in the Transmission Annual Planning Report that has been identified through carrying out asset management; and	Section 12.4
(iii)	information about where further information on the asset management strategy and methodology adopted by the Transmission Network Service Provider may be obtained.	Section 12.5
8) any information required to be included in a Transmission Annual Planning Report under:		
(i)	clause 5.16.3(c) in relation to a network investment which is determined to be required to address an urgent and unforeseen network issue; or	Section 9.4
(ii)	clauses 5.20B.4(h) and (i) and clauses 5.20C.3(f) and (g) in relation to network investment and other activities to provide inertia network services, inertia support activities or system strength services.	Not applicable
9)	**emergency controls in place under jurisdictional electricity legislation, including the Network Service Provider's assessment of the need for new or altered emergency controls under that clause;**	**Section 7**
10)	**facilities in place under jurisdictional electricity legislation;**	**Section 7**
11)	**an analysis and explanation of any other aspects of the Transmission Annual Planning Report that have changed significantly from the preceding year's Transmission Annual Planning Report, including the reasons why the changes have occurred; and**	**Not applicable**
12)	**the results of joint planning (if any) undertaken with a Transmission Network Service Provider under clause 5.14.3 in the preceding year, including a summary of the process and methodology used by the Transmission Network Service Providers to undertake joint planning and the outcomes of that joint planning.**	**Not applicable**

DARWIN/KATHERINE SYSTEM TRANSMISSION CAPACITY UTILISATION 2019 - 2029																
Transmission Line					Maximum Demand - (MVA)											
From	To	Voltage (kV)	Circuit Number	Item	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	Comment
CIPS 132	HC 132	132	A	Maximum Demand	82.8	90.4	89.4	91.5	91.9	92.3	98.2	98.7	99.3	0.0	0.0	
				Normal Rating	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	
				Contingency Rating	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	
				Utilisation	31%	34%	34%	34%	35%	35%	37%	37%	37%	0%	0%	
CIPS 132	HC 132	132	B	Maximum Demand	83.7	91.3	90.4	92.5	92.9	93.3	99.2	99.7	100.4	0.0	0.0	
				Normal Rating	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	
				Contingency Rating	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	266.0	
				Utilisation	31%	34%	34%	35%	35%	35%	37%	37%	38%	0%	0%	
CIPS 132	Manton 132	132	1	Maximum Demand	14.5	15.9	19.8	20.9	23.1	25.0	16.9	17.7	19.9	0.0	0.0	
				Normal Rating	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	
				Contingency Rating	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	
				Utilisation	10%	11%	14%	14%	16%	17%	12%	12%	14%	0%	0%	
Manton 132	Batchelor 132	132	1	Maximum Demand	10.9	12.7	16.0	16.5	18.3	19.7	11.4	12.7	14.6	0.0	0.0	
				Normal Rating	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	
				Contingency Rating	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	
				Utilisation	10%	12%	15%	15%	17%	18%	11%	12%	14%	0%	0%	
Batchelor 132	Pine Creek 132	132	1	Maximum Demand	8.3	11.1	15.0	15.7	17.6	19.1	10.0	11.3	13.3	0.0	0.0	
				Normal Rating	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	
				Contingency Rating	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	
				Utilisation	8%	10%	14%	15%	16%	18%	13%	11%	12%	0%	0%	
Pine Creek 132	Katherine 132	132	1	Maximum Demand	22.3	14.5	18.5	20.0	21.9	24.1	14.9	15.9	18.0	0.0	0.0	
				Normal Rating	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	
				Contingency Rating	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	
				Utilisation	7%	14%	17%	19%	21%	22%	14%	15%	17%	0%	0%	
Pine Ck ZSS 66	Pine Ck Power Station 66	66	1	Maximum Demand	14.2	5.0	4.2	4.5	4.2	5.0	8.5	7.6	7.5	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Utilisation	22%	8%	7%	7%	7%	8%	13%	12%	12%	0%	0%	
Pine Ck Power Station 66	Union Reef Tee 66	66	1	Maximum Demand	4.5	16.3	16.5	16.7	16.8	17.0	17.1	17.3	17.4	0.0	0.0	
				Normal Rating	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	
				Contingency Rating	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	
				Utilisation	14%	49%	50%	50%	51%	52%	52%	52%	53%	0%	0%	
Union Reef Tee 66	Brocks Ck Tee 66	66	1	Maximum Demand	4.4	7.5	7.7	7.8	8.0	8.2	8.3	8.4	8.6	0.0	0.0	
				Normal Rating	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	
				Contingency Rating	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	
				Utilisation	13%	23%	23%	24%	24%	25%	25%	26%	26%	0%	0%	
Brocks Ck Tee 66	Cosmo Howley 66	66	1	Maximum Demand	4.7	7.7	7.9	8.0	8.1	8.3	8.4	8.5	8.7	0.0	0.0	
				Normal Rating	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	
				Contingency Rating	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	
				Utilisation	14%	23%	24%	24%	25%	25%	25%	26%	26%	0%	0%	
Hudson Creek 66	Berrimah 66	66	1	Maximum Demand	26.1	26.7	26.2	27.0	26.4	26.3	27.0	27.0	27.1	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	
				Utilisation	41%	42%	41%	42%	41%	41%	42%	42%	42%	0%	0%	
Hudson Creek 66	Berrimah 66	66	2	Maximum Demand	26.1	26.7	26.2	27.0	26.4	26.3	27.0	27.0	27.1	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	
				Utilisation	41%	42%	41%	42%	41%	41%	42%	42%	42%	0%	0%	
Hudson Creek 66	Woolner 66	66	1	Maximum Demand	36.5	36.4	35.4	35.0	34.2	34.0	33.7	33.7	33.9	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Utilisation	57%	57%	55%	55%	53%	53%	53%	53%	53%	0%	0%	
Hudson Creek 66	Woolner 66	66	2	Maximum Demand	38.8	38.7	37.6	37.2	36.3	36.1	35.8	35.8	36.0	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Utilisation	0.6	0.6	59%	58.1%	56.7%	56.3%	56.0%	56.0%	56.2%	0.0%	0.0%	
Hudson Creek 66	Darwin 66	66	1	Maximum Demand	30.5	30.6	29.9	29.7	29.1	28.9	28.7	28.7	28.9	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Utilisation	48%	48%	47%	46%	45%	45%	45%	45%	45%	0%	0%	

Transmission Line					Maximum Demand - (MVA)											
From	**To**	**Voltage (kV)**	**Circuit Number**	**Item**	**2018-2019**	**2019-2020**	**2020-2021**	**2021-2022**	**2022-2023**	**2023-2024**	**2024-2025**	**2025-2026**	**2026-2027**	**2027-2028**	**2028-2029**	**Comment**
Hudson Creek 66	Palmerston 66	66	1	Maximum Demand	18.7	24.1	27.5	29.6	31.7	32.6	37.5	38.0	38.4	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Utilisation	29%	38%	43%	46%	50%	51%	59%	59%	60%	0%	0%	
Hudson Creek 66	Archer 66	66	1	Maximum Demand	17.6	18.9	18.1	19.3	20.3	20.8	25.0	25.3	25.6	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Utilisation	28%	29%	28%	30%	32%	32%	39%	40%	40%	0%	0%	
Archer 66	Palmerston 66	66	1	Maximum Demand	25.8	25.4	23.8	24.9	25.9	26.1	22.8	22.9	23.0	0.0	0.0	
				Normal Rating	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	
				Contingency Rating	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	
				Utilisation	29%	28%	26%	28%	29%	29%	25%	25%	26%	0%	0%	
Archer 66	Wishart 66	66	1	Maximum Demand	2.9	3.8	6.7	6.7	7.0	8.0	18.9	19.5	20.2	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Utilisation	0.0	0.1	10%	10.5%	11.0%	12.6%	29.5%	30.5%	31.6%	0.0%	0.0%	
Archer 66	Weddell 66	66	1	Maximum Demand	28.0	26.7	24.7	24.8	24.7	25.2	26.9	27.3	27.9	0.0	0.0	
				Normal Rating	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	
				Contingency Rating	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	
				Utilisation	31%	30%	27%	28%	27%	28%	30%	30%	31%	0%	0%	
Archer 66	Weddell 66	66	2	Maximum Demand	35.2	33.6	31.1	31.2	31.0	31.7	33.8	34.3	35.1	0.0	0.0	
				Normal Rating	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	
				Contingency Rating	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	
				Utilisation	39%	37%	35%	35%	34%	35%	38%	38%	39%	0%	0%	
Weddell 66	Strangways 66	66	1	Maximum Demand	22.7	23.3	22.8	23.7	24.4	24.7	24.7	25.0	25.3	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Utilisation	35%	36%	36%	37%	38%	39%	39%	39%	40%	0%	0%	
Strangways 66	Humpty Doo 66	66	1	Maximum Demand	5.7	7.0	7.7	9.4	10.9	11.2	11.5	11.7	12.0	0.0	0.0	
				Normal Rating	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	
				Contingency Rating	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	
				Utilisation	23%	28%	31%	38%	44%	45%	46%	47%	48%	0%	0%	
Humpty Doo 66	Marrakai 66	66	1	Maximum Demand	3.4	3.4	3.4	3.4	3.4	3.4	3.5	3.5	3.5	0.0	0.0	
				Normal Rating	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	
				Contingency Rating	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	
				Utilisation	13%	14%	14%	14%	14%	14%	14%	14%	14%	0%	0%	
Marrakai 66	Mary River	66	1	Maximum Demand	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	0.0	0.0	
				Normal Rating	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	
				Contingency Rating	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	
				Utilisation	0.1	0.1	11%	10.9%	10.9%	10.9%	10.9%	10.9%	10.9%	0.0%	0.0%	
Palmerston 66	Strangways 66	66	1	Maximum Demand	7.9	10.0	10.9	11.8	12.6	12.7	13.2	13.4	13.4	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Utilisation	12%	16%	17%	18%	20%	20%	21%	21%	21%	0%	0%	
Berrimah 66	Leanyer 66	66	1	Maximum Demand	29.7	29.5	29.2	28.5	28.1	28.1	27.9	28.0	28.3	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Utilisation	46%	46%	46%	45%	44%	44%	44%	44%	44%	0%	0%	
Leanyer 66	Casuarina 66	66	1	Maximum Demand	18.7	18.2	17.6	16.7	16.0	15.8	15.3	15.1	15.1	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Utilisation	29%	28%	27%	26%	25%	25%	24%	24%	24%	0%	0%	
Casuarina 66	Woolner 66	66	1	Maximum Demand	22.6	22.5	22.4	22.0	21.5	21.5	21.7	21.7	21.7	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Utilisation	35%	35%	35%	34%	34%	34%	34%	34%	34%	0%	0%	
Woolner 66	Darwin 66	66	1	Maximum Demand	10.7	11.4	11.3	11.6	11.6	11.5	11.4	11.6	11.7	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Utilisation	17%	18%	18%	18%	18%	18%	18%	18%	18%	0%	0%	
Woolner 66	Frances Bay 66	66	1	Maximum Demand	11.2	11.7	11.6	11.9	11.8	11.7	11.6	11.8	11.9	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Utilisation	17%	18%	18%	19%	18%	18%	18%	18%	19%	0%	0%	

Transmission Line					Maximum Demand - (MVA)											
From	To	Voltage (kV)	Circuit Number	Item	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	Comment
Darwin 66	Frances Bay 66	66	1	Maximum Demand	11.6	10.7	10.4	9.5	9.3	9.3	9.2	9.2	9.3	0.0	0.0	
				Normal Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Contingency Rating	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	
				Utilisation	18%	17%	16%	15%	15%	14%	14%	14%	15%	0%	0%	
Darwin 66	Centre Yard 66	66	1	Maximum Demand	1.8	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9	0.0	0.0	
				Normal Rating	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	
				Contingency Rating	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	
				Utilisation	7%	7%	7%	7%	7%	7%	7%	7%	7%	0%	0%	

GENERAL COMMENTS

1 80% diversity is considered for Zone substation loads

2 The peak load in the Darwin Kathrine system occurs around 1700 hours. Hence, the solar generator dispatch is considered as 10% of Installed capacity assuming intermittent cloud cover in Wet season.

3 The renewable generation in the Darwin Kathrine system is expected to grow and hence there might be changes in the power flows.

4 In the year 2027-28, 2028-29, the total Darwin Katherine system demand is expected to be 363MW and 368MW respectively. The generation in these periods available would be 264.02MW and hence generation short fall of 125MW (assuming current spinning reserve policy applies in the future) is anticipated due to retirement of the generators & Increase of block load expected in the Darwin Katherine system.

NOTE

1 The line rating are updated according to the following documents.
132_66kV_DIAG_ 2_7-2019.pdf
132_66kV_DIAG_1_12-2018.pdf
Dwn_22kV_Diags 11_4-2019.pdf
Dwn_22kV_Diags 12_10-2019.pdf

DARWIN/KATHERINE SYSTEM TRANSMISSION CONTINGENCY ANALYSIS 2019 TO 2029

HUDSON CREEK - PALMERSTON - STRANGWAYS - WEDDELL - ARCHER

	TRANSMISSION LINE DETAILS						CONTINGENCY LOADING (MVA)											Comment
	From	To	Voltage (kV)	Circuit No.	Status	Item	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	
CONTINGENCY SCENARIO 1	Hudson Creek 66	Palmerston 66	66	1	Out of Service	Load Before Outage	18.70	24.09	27.51	29.61	31.72	32.62	37.52	38.02	38.43	0.00	0.00	
						Load After Outage	0.0	0.0	0	0	0	0	0	0	0	0	0	
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64	
						Utilisation Before Outage	29%	38%	43%	46%	50%	51%	59%	59%	60%	0%	0%	
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
	Hudson Creek 66	Archer 66	66	1	In Service	Load Before Outage	17.64	18.87	18.11	19.26	20.34	20.79	25.02	25.35	25.59	0.00	0.00	During (N-1) operation of 66kV line from Hudson creek to Palmerston, the 66kV Overhead line from Hudson Creek to Archer line would be loaded to around 99% i.e. 63.4MVA against 64MVA thermal rating by 2026-27. The Weddell generation can be increased to limit this loading to 64MVA.
						Load After Outage	27.8	36.3	42.3	46.1	49.9	51.5	61.7	62.7	63.4	0.0	0.0	
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64	
						Utilisation Before Outage	28%	29%	28%	30%	32%	32%	39%	40%	40%	0%	0%	
						Utilisation During Outage	43%	57%	66%	72%	78%	80%	96%	98%	99%	0%	0%	
	Weddell 66	Strangways 66	66	1	In Service	Load Before Outage	22.66	23.27	22.82	23.70	24.43	24.72	24.74	25.00	25.30	0.00	0.00	
						Load After Outage	23.6	25.0	25.3	26.5	27.5	27.9	28.5	28.8	29.2	0.0	0.0	
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64	
						Utilisation Before Outage	35%	36%	36%	37%	38%	39%	39%	39%	40%	0%	0%	
						Utilisation During Outage	37%	39%	40%	41%	43%	44%	44%	45%	46%	0%	0%	
	Palmerston 66	Strangways 66	66	1	In Service	Load Before Outage	7.90	9.98	10.87	11.78	12.61	12.68	13.25	13.35	13.40	0.00	0.00	
						Load After Outage	6.3	7.7	8.0	8.7	9.3	9.2	9.2	9.2	9.2	0.0	0.0	
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64	
						Utilisation Before Outage	12%	16%	17%	18%	20%	20%	21%	21%	21%	0%	0%	
						Utilisation During Outage	10%	12%	13%	14%	14%	14%	14%	14%	14%	0%	0%	
	Archer 66	Palmerston 66	66	1	In Service	Load Before Outage	25.85	25.44	23.81	24.94	25.91	26.10	22.85	22.89	22.97	0.00	0.00	
						Load After Outage	35.8	41.5	45.6	48.7	51.7	52.8	54.1	54.6	55.1	0.0	0.0	
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90	
						Utilisation Before Outage	29%	28%	26%	28%	29%	29%	25%	25%	26%	0%	0%	
						Utilisation During Outage	40%	46%	51%	54%	57%	59%	60%	61%	61%	0%	0%	
	Archer 66	Weddell 66	66	1	In Service	Load Before Outage	27.98	26.73	24.73	24.79	24.68	25.17	26.86	27.30	27.90	0.00	0.00	
						Load After Outage	26.8	25.3	23.3	23.3	23.3	23.7	25.5	25.9	26.5	0.0	0.0	
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90	
						Utilisation Before Outage	31%	30%	27%	28%	27%	28%	30%	30%	31%	0%	0%	
						Utilisation During Outage	30%	28%	26%	26%	26%	26%	28%	29%	29%	0%	0%	
	Archer 66	Weddell 66	66	2	In Service	Load Before Outage	35.18	33.61	31.10	31.18	31.04	31.66	33.79	34.34	35.09	0.00	0.00	
						Load After Outage	33.7	31.8	29.3	29.4	29.2	29.9	32.0	32.6	33.4	0.0	0.0	
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90	
						Utilisation Before Outage	39%	37%	35%	35%	34%	35%	38%	38%	39%	0%	0%	
						Utilisation During Outage	37%	35%	33%	33%	32%	33%	36%	36%	37%	0%	0%	
CONTINGENCY SCENARIO 2	Hudson Creek 66	Archer 66	66	1	Out of Service	Load Before Outage	17.64	18.87	18.11	19.26	20.34	20.79	25.02	25.35	25.59	0.00	0.00	
						Load After Outage	0.0	0.0	0	0	0	0	0	0	0	0	0	
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64	
						Utilisation Before Outage	28%	29%	28%	30%	32%	32%	39%	40%	40%	0%	0%	
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
	Weddell 66	Strangways 66	66	1	In Service	Load Before Outage	22.66	23.27	22.82	23.70	24.43	24.72	24.74	25.00	25.30	0.00	0.00	
						Load After Outage	22.7	22.7	21.6	22.4	22.9	23.1	22.6	22.9	23.1	0.0	0.0	
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64	
						Utilisation Before Outage	35%	36%	36%	37%	38%	39%	39%	39%	40%	0%	0%	
						Utilisation During Outage	35%	35%	34%	35%	36%	36%	35%	36%	36%	0%	0%	
	Palmerston 66	Strangways 66	66	1	In Service	Load Before Outage	7.90	9.98	10.87	11.78	12.61	12.68	13.25	13.35	13.40	0.00	0.00	
						Load After Outage	7.9	10.7	12.1	13.2	14.2	14.4	15.6	15.8	15.8	0.0	0.0	
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64	
						Utilisation Before Outage	12%	16%	17%	18%	20%	20%	21%	21%	21%	0%	0%	
						Utilisation During Outage	12%	17%	19%	21%	22%	22%	24%	25%	25%	0%	0%	
	Archer 66	Palmerston 66	66	1	In Service	Load Before Outage	25.85	25.44	23.81	24.94	25.91	26.10	22.85	22.89	22.97	0.00	0.00	
						Load After Outage	30.6	26.2	19.7	20.2	20.4	20.2	17.1	17.1	17.1	0.0	0.0	
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90	
						Utilisation Before Outage	29%	28%	26.5%	27.7%	28.8%	29%	25%	25%	26%	0%	0%	
						Utilisation During Outage	34%	29%	22%	22%	23%	22%	19%	19%	19%	0%	0%	
	Archer 66	Weddell 66	66	1	In Service	Load Before Outage	27.98	26.73	24.73	24.79	24.68	25.17	26.86	27.30	27.90	0.00	0.00	
						Load After Outage	26.6	25.4	24.1	24.2	24.2	24.7	26.7	27.1	27.8	0.0	0.0	
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90	
						Utilisation Before Outage	31%	30%	27%	28%	27%	28%	30%	30%	31%	0%	0%	
						Utilisation During Outage	30%	28%	27%	27%	27%	27%	30%	30%	31%	0%	0%	
	Archer 66	Weddell 66	66	2	In Service	Load Before Outage	35.18	33.61	31.10	31.18	31.04	31.66	33.79	34.34	35.09	0.00	0.00	
						Load After Outage	33.4	32.0	30.3	30.4	30.4	31.1	33.5	34.1	34.9	0.0	0.0	
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90	
						Utilisation Before Outage	39%	37%	35%	35%	34%	35%	38%	38%	39%	0%	0%	
						Utilisation During Outage	37%	36%	34%	34%	34%	35%	37%	38%	39%	0%	0%	
	Hudson Creek 66	Palmerston 66	66	1	In Service	Load Before Outage	18.70	24.09	27.51	29.61	31.72	32.62	37.52	38.02	38.43	0.00	0.00	During (N-1) operation of 66kV line from Hudson creek to Archer, the 66kV Overhead line from Hudson Creek to Palmerstone line would be loaded to 96% i.e. 61.5MVA against its thermal rating of 64MVA by 2026-27. The Weddell generation can be increased to limit this loading to 64MVA.
						Load After Outage	24.7	33.8	40.3	43.9	47.6	49.2	59.8	60.8	61.5	0.0	0.0	
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64	
						Utilisation Before Outage	29%	38%	43%	46%	50%	51%	59%	59%	60%	0%	0%	
						Utilisation During Outage	39%	53%	63%	69%	74%	77%	94%	95%	96%	0%	0%	
CONTINGENCY SCENARIO 3	Weddell 66	Strangways 66	66	1	Out of Service	Load Before Outage	22.66	23.27	22.82	23.70	24.43	24.72	24.74	25.00	25.30	0.00	0.00	
						Load After Outage	0.0	0.0	0	0	0	0	0	0	0	0	0	
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64	
						Utilisation Before Outage	35%	36%	36%	37%	38%	39%	39%	39%	40%	0%	0%	
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
	Palmerston 66	Strangways 66	66	1	In Service	Load Before Outage	7.90	9.98	10.87	11.78	12.61	12.68	13.25	13.35	13.40	0.00	0.00	
						Load After Outage	30.0	32.7	33.4	35.3	36.9	37.2	37.6	38.0	38.3	0.0	0.0	
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64	
						Utilisation Before Outage	12%	16%	17%	18%	20%	20%	21%	21%	21%	0%	0%	
						Utilisation During Outage	47%	51%	52%	55%	58%	58%	59%	59%	60%	0%	0%	
	Archer 66	Palmerston 66	66	1	In Service	Load Before Outage	25.85	25.44	23.81	24.94	25.91	26.10	22.85	22.89	22.97	0.00	0.00	
						Load After Outage	43.8	43.7	41.7	43.5	45.1	45.5	42.2	42.5	42.8	0.0	0.0	
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90	
						Utilisation Before Outage	29%	28%	26.5%	27.7%	28.8%	29%	25%	25%	26%	0%	0%	
						Utilisation During Outage	49%	49%	46%	48%	50%	51%	47%	47%	48%	0%	0%	
	Archer 66	Weddell 66	66	1	In Service	Load Before Outage	27.98	26.73	24.73	24.79	24.68	25.17	26.86	27.30	27.90	0.00	0.00	
						Load After Outage	37.5	36.1	33.9	34.2	34.4	35.0	36.4	37.0	37.7	0.0	0.0	
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90	
						Utilisation Before Outage	31%	30%	27%	28%	27%	28%	30%	30%	31%	0%	0%	
						Utilisation During Outage	42%	40%	38%	38%	38%	39%	40%	41%	42%	0%	0%	
	Archer 66	Weddell 66	66	2	In Service	Load Before Outage	35.18	33.61	31.10	31.18	31.04	31.66	33.79	34.34	35.09	0.00	0.00	
						Load After Outage	47.0	45.3	42.5	42.9	43.1	43.9	45.7	46.4	47.3	0.0	0.0	
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90	
						Utilisation Before Outage	39%	37%	35%	35%	34%	35%	38%	38%	39%	0%	0%	
						Utilisation During Outage	52%	50%	47%	48%	48%	49%	51%	52%	53%	0%	0%	
	Hudson Creek 66	Palmerston 66	66	1	In Service	Load Before Outage	18.70	24.09	27.51	29.61	31.72	32.62	37.52	38.02	38.43	0.00	0.00	
						Load After Outage	18.7	25.5	30.1	32.5	34.9	35.9	40.8	41.4	41.8	0.0	0.0	
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64	
						Utilisation Before Outage	29%	38%	43%	46%	50%	51%	59%	59%	60%	0%	0%	
						Utilisation During Outage	29%	40%	47%	51%	55%	56%	64%	65%	65%	0%	0%	
	Hudson Creek 66	Archer 66	66	1	In Service	Load Before Outage	17.64	18.87	18.11	19.26	20.34	20.79	25.02	25.35	25.59	0.00	0.00	
						Load After Outage	17.9	17.6	15.3	16.2	16.9	17.3	21.1	21.3	21.5	0.0	0.0	
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64	
						Utilisation Before Outage	28%	29%	28%	30%	32%	32%	39%	40%	40%	0%	0%	
						Utilisation During Outage	28%	27%	24%	25%	26%	27%	33%	33%	34%	0%	0%	

CONTINGENCY SCENARIO 4	Palmerston 66	Strangways 66	66	1	Out of Service	Load Before Outage	7.90	9.98	10.87	11.78	12.61	12.68	13.25	13.35	13.40	0.00	0.00
						Load After Outage	0.0	0.0	0	0	0	0	0	0	0	0	0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	12%	16%	17%	18%	20%	20%	21%	21%	21%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Archer 66	Palmerston 66	66	1	In Service	Load Before Outage	25.85	25.44	23.81	24.94	25.91	26.10	22.85	22.89	22.97	0.00	0.00
						Load After Outage	20.4	18.7	16.0	16.5	16.9	17.0	13.9	13.9	13.9	0.0	0.0
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90
						Utilisation Before Outage	29%	28%	26.5%	27.7%	28.8%	29%	25%	25%	26%	0%	0%
						Utilisation During Outage	23%	21%	18%	18%	19%	19%	15%	15%	15%	0%	0%
	Archer 66	Weddell 66	66	1	In Service	Load Before Outage	27.98	26.73	24.73	24.79	24.68	25.17	26.86	27.30	27.90	0.00	0.00
						Load After Outage	25.2	23.5	21.0	20.8	20.5	20.9	22.9	23.4	23.9	0.0	0.0
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90
						Utilisation Before Outage	31%	30%	27%	28%	27%	28%	30%	30%	31%	0%	0%
						Utilisation During Outage	28%	26%	23%	23%	23%	23%	25%	26%	27%	0%	0%
	Archer 66	Weddell 66	66	2	In Service	Load Before Outage	35.18	33.61	31.10	31.18	31.04	31.66	33.79	34.34	35.09	0.00	0.00
						Load After Outage	31.7	29.5	26.4	26.2	25.8	26.4	28.9	29.4	30.1	0.0	0.0
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90
						Utilisation Before Outage	39%	37%	35%	35%	34%	35%	38%	38%	39%	0%	0%
						Utilisation During Outage	35%	33%	29%	29%	29%	29%	32%	33%	33%	0%	0%
	Hudson Creek 66	Palmerston 66	66	1	In Service	Load Before Outage	18.70	24.09	27.51	29.61	31.72	32.62	37.52	38.02	38.43	0.00	0.00
						Load After Outage	18.0	23.0	26.0	27.9	29.9	30.8	35.4	35.9	36.3	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	29%	38%	43%	46%	50%	51%	59%	59%	60%	0%	0%
						Utilisation During Outage	28%	36%	41%	44%	47%	48%	55%	56%	57%	0%	0%
	Hudson Creek 66	Archer 66	66	1	In Service	Load Before Outage	17.64	18.87	18.11	19.26	20.34	20.79	25.02	25.35	25.59	0.00	0.00
						Load After Outage	17.8	19.8	19.8	21.2	22.5	23.0	27.6	28.0	28.2	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	28%	29%	28%	30%	32%	32%	39%	40%	40%	0%	0%
						Utilisation During Outage	28%	31%	31%	33%	35%	36%	43%	44%	44%	0%	0%
	Weddell 66	Strangways 66	66	1	In Service	Load Before Outage	22.66	23.27	22.82	23.70	24.43	24.72	24.74	25.00	25.30	0.00	0.00
						Load After Outage	30.2	32.9	33.6	35.5	37.2	37.5	37.9	38.2	38.6	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	35%	36%	36%	37%	38%	39%	39%	39%	40%	0%	0%
						Utilisation During Outage	47%	51%	53%	55%	58%	59%	59%	60%	60%	0%	0%

CONTINGENCY SCENARIO 5	Archer 66	Palmerston 66	66	1	Out of Service	Load Before Outage	25.85	25.44	23.81	24.94	25.91	26.10	22.85	22.89	22.97	0.00	0.00
						Load After Outage	0.0	0.0	0	0	0	0	0	0	0	0	0
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90
						Utilisation Before Outage	29%	28%	26.5%	27.7%	28.8%	29%	25%	25%	26%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Archer 66	Weddell 66	66	1	In Service	Load Before Outage	27.98	26.73	24.73	24.79	24.68	25.17	26.86	27.30	27.90	0.00	0.00
						Load After Outage	24.0	22.6	20.9	20.7	20.4	20.9	23.0	23.4	24.0	0.0	0.0
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90
						Utilisation Before Outage	31%	30%	27%	28%	27%	28%	30%	30%	31%	0%	0%
						Utilisation During Outage	27%	25%	23%	23%	23%	23%	26%	26%	27%	0%	0%
	Archer 66	Weddell 66	66	2	In Service	Load Before Outage	35.18	33.61	31.10	31.18	31.04	31.66	33.79	34.34	35.09	0.00	0.00
						Load After Outage	30.1	28.4	26.3	26.0	25.7	26.2	28.9	29.5	30.2	0.0	0.0
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90
						Utilisation Before Outage	39%	37%	35%	35%	34%	35%	38%	38%	39%	0%	0%
						Utilisation During Outage	33%	32%	29%	29%	29%	29%	32%	33%	34%	0%	0%
	Hudson Creek 66	Palmerston 66	66	1	In Service	Load Before Outage	18.70	24.09	27.51	29.61	31.72	32.62	37.52	38.02	38.43	0.00	0.00
						Load After Outage	30.0	37.0	41.5	44.4	47.3	48.4	51.1	51.7	52.2	0.0	0.0
						Contingency Rating MVA	90	90	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	21%	27%	43%	46%	50%	51%	59%	59%	60%	0%	0%
						Utilisation During Outage	33%	41%	65%	69%	74%	76%	80%	81%	82%	0%	0%
	Hudson Creek 66	Archer 66	66	1	In Service	Load Before Outage	17.64	18.87	18.11	19.26	20.34	20.79	25.02	25.35	25.59	0.00	0.00
						Load After Outage	26.8	22.9	16.5	16.7	16.7	16.5	17.1	17.2	17.3	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	28%	29%	28%	30%	32%	32%	39%	40%	40%	0%	0%
						Utilisation During Outage	42%	36%	26%	26%	26%	26%	27%	27%	27%	0%	0%
	Weddell 66	Strangways 66	66	1	In Service	Load Before Outage	22.66	23.27	22.82	23.70	24.43	24.72	24.74	25.00	25.30	0.00	0.00
						Load After Outage	31.1	31.4	30.5	31.7	32.8	33.1	32.1	32.4	32.7	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	35%	36%	36%	37%	38%	39%	39%	39%	40%	0%	0%
						Utilisation During Outage	49%	49%	48%	50%	51%	52%	50%	51%	51%	0%	0%
	Palmerston 66	Strangways 66	66	1	In Service	Load Before Outage	22.66	23.27	10.87	11.78	12.61	12.68	13.25	13.35	13.40	0.00	0.00
						Load After Outage	2.3	2.7	3.5	4.0	4.5	4.5	6.3	6.4	6.4	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	35%	36%	17%	18%	20%	20%	21%	21%	21%	0%	0%
						Utilisation During Outage	4%	4%	5%	6%	7%	7%	10%	10%	10%	0%	0%

CONTINGENCY SCENARIO 6	Archer 66	Weddell 66	66	1	Out of Service	Load Before Outage	27.98	26.73	24.73	24.79	24.68	25.17	26.86	27.30	27.90	0.00	0.00
						Load After Outage	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90
						Utilisation Before Outage	31%	30%	27%	28%	27%	28%	30%	30%	31%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Archer 66	Weddell 66	66	2	In Service	Load Before Outage	35.18	33.61	31.10	31.18	31.04	31.66	33.79	34.34	35.09	0.00	0.00
						Load After Outage	57.4	54.1	49.9	49.9	49.5	50.5	53.4	54.3	55.5	0.0	0.0
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90
						Utilisation Before Outage	39%	37%	35%	35%	34%	35%	38%	38%	39%	0%	0%
						Utilisation During Outage	64%	60%	55%	55%	55%	56%	59%	60%	62%	0%	0%
	Hudson Creek 66	Palmerston 66	66	1	In Service	Load Before Outage	18.70	24.09	27.51	29.61	31.72	32.62	37.52	38.02	38.43	0.00	0.00
						Load After Outage	16.4	22.4	26.1	28.3	30.5	31.4	36.3	36.8	37.1	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	29%	38%	43%	46%	50%	51%	59%	59%	60%	0%	0%
						Utilisation During Outage	26%	35%	41%	44%	48%	49%	57%	57%	58%	0%	0%
	Hudson Creek 66	Archer 66	66	1	In Service	Load Before Outage	17.64	18.87	18.11	19.26	20.34	20.79	25.02	25.35	25.59	0.00	0.00
						Load After Outage	14.0	15.4	15.6	16.8	18.0	18.5	23.0	23.3	23.6	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	28%	29%	28%	30%	32%	32%	39%	40%	40%	0%	0%
						Utilisation During Outage	22%	24%	24%	26%	28%	29%	36%	36%	37%	0%	0%
	Weddell 66	Strangways 66	66	1	In Service	Load Before Outage	22.66	23.27	22.82	23.70	24.43	24.72	24.74	25.00	25.30	0.00	0.00
						Load After Outage	26.9	27.2	26.4	27.3	28.0	28.4	28.5	28.8	29.2	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	35%	36%	36%	37%	38%	39%	39%	39%	40%	0%	0%
						Utilisation During Outage	42%	42%	41%	43%	44%	44%	45%	45%	46%	0%	0%
	Palmerston 66	Strangways 66	66	1	In Service	Load Before Outage	7.90	9.98	10.87	11.78	12.61	12.68	13.25	13.35	13.40	0.00	0.00
						Load After Outage	4.3	6.4	7.4	8.4	9.2	9.2	9.8	9.9	9.8	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	12%	16%	17%	18%	20%	20%	21%	21%	21%	0%	0%
						Utilisation During Outage	7%	10%	12%	13%	14%	14%	15%	15%	15%	0%	0%
	Archer 66	Palmerston 66	66	1	In Service	Load Before Outage	25.85	25.44	23.81	24.94	25.91	26.10	22.85	22.89	22.97	0.00	0.00
						Load After Outage	22.2	21.8	20.5	21.6	22.6	22.7	19.2	19.2	19.2	0.0	0.0
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90
						Utilisation Before Outage	29%	28%	26.5%	27.7%	28.8%	29%	25%	25%	26%	0%	0%
						Utilisation During Outage	25%	24%	23%	24%	25%	25%	21%	21%	21%	0%	0%

CONTINGENCY SCENARIO 7	Archer 66	Weddell 66	66	2	Out of Service	Load Before Outage	35.18	33.61	31.10	31.18	31.04	31.66	33.79	34.34	35.09	0.00	0.00
						Load After Outage	0.0	0.0	0	0	0	0	0	0	0	0	0
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90
						Utilisation Before Outage	39%	37%	35%	35%	34%	35%	38%	38%	39%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Hudson Creek 66	Palmerston 66	66	1	In Service	Load Before Outage	18.70	24.09	27.51	29.61	31.72	32.62	37.52	38.02	38.43	0.00	0.00
						Load After Outage	15.4	21.6	25.5	27.7	29.9	30.8	35.7	36.2	36.5	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	29%	38%	43%	46%	50%	51%	59%	59%	60%	0%	0%
						Utilisation During Outage	24%	34%	40%	43%	47%	48%	56%	57%	57%	0%	0%
	Hudson Creek 66	Archer 66	66	1	In Service	Load Before Outage	17.64	18.87	18.11	19.26	20.34	20.79	25.02	25.35	25.59	0.00	0.00
						Load After Outage	12.4	14.1	14.7	16.0	17.3	17.9	22.5	22.8	23.1	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	28%	29%	28%	30%	32%	32%	39%	40%	40%	0%	0%
						Utilisation During Outage	19%	22%	23%	25%	27%	28%	35%	36%	36%	0%	0%
	Weddell 66	Strangways 66	66	1	In Service	Load Before Outage	22.66	23.27	22.82	23.70	24.43	24.72	24.74	25.00	25.30	0.00	0.00
						Load After Outage	29.0	29.2	28.3	29.1	29.8	30.2	30.4	30.8	31.2	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	35%	36%	36%	37%	38%	39%	39%	39%	40%	0%	0%
						Utilisation During Outage	45%	46%	44%	46%	47%	47%	48%	48%	49%	0%	0%
	Palmerston 66	Strangways 66	66	1	In Service	Load Before Outage	7.90	9.98	10.87	11.78	12.61	12.68	13.25	13.35	13.40	0.00	0.00
						Load After Outage	2.8	4.7	5.7	6.6	7.5	7.4	8.0	8.1	8.0	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	12%	16%	17%	18%	20%	20%	21%	21%	21%	0%	0%
						Utilisation During Outage	4%	7%	9%	10%	12%	12%	13%	13%	13%	0%	0%
	Archer 66	Palmerston 66	66	1	In Service	Load Before Outage	25.85	25.44	23.81	24.94	25.91	26.10	22.85	22.89	22.97	0.00	0.00
						Load After Outage	20.3	20.1	19.0	20.0	21.0	21.1	17.5	17.5	17.5	0.0	0.0
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90
						Utilisation Before Outage	29%	28%	26.5%	27.7%	28.8%	29%	25%	25%	26%	0%	0%
						Utilisation During Outage	23%	22%	21%	22%	23%	23%	19%	19%	19%	0%	0%
	Archer 66	Weddell 66	66	1	In Service	Load Before Outage	27.98	26.73	24.73	24.79	24.68	25.17	26.86	27.30	27.90	0.00	0.00
						Load After Outage	54.8	51.5	47.5	47.4	47.1	48.0	50.5	51.4	52.5	0.0	0.0
						Contingency Rating MVA	90	90	90	90	90	90	90	90	90	90	90
						Utilisation Before Outage	31%	30%	27%	28%	27%	28%	30%	30%	31%	0%	0%
						Utilisation During Outage	61%	57%	53%	53%	52%	53%	56%	57%	58%	0%	0%

HUDSON CREEK - BERRIMAH - LEANYER - CASUARINA - WOOLNER

CONTINGENCY SCENARIO 8	Hudson Creek 66	Berrimah 66	66	1 OR 2	Out of Service	Load Before Outage	26.06	26.68	26.20	26.98	26.43	26.28	27.02	27.00	27.10	0.00	0.00
						Load After Outage	0.0	0.0	0	0	0	0	0	0	0	0	0
						Contingency Rating MVA	60	60	60	60	60	60	60	60	60	60	60
						Utilisation Before Outage	43%	44%	44%	45%	44%	44%	45%	45%	45%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Hudson Creek 66	Berrimah 66	66	2 OR 1	In Service	Load Before Outage	26.06	26.68	26.20	26.98	26.43	26.28	27.02	27.00	27.10	0.00	0.00
						Load After Outage	47.8	48.9	48.0	49.4	48.4	48.1	49.5	49.5	49.6	0.0	0.0
						Contingency Rating MVA	60	60	60	60	60	60	60	60	60	60	60
						Utilisation Before Outage	43%	44%	44%	45%	0%	44%	45%	45%	45%	0%	0%
						Utilisation During Outage	80%	81%	80%	82%	81%	80%	83%	82%	83%	0%	0%
	Berrimah 66	Leanyer 66	66	1	In Service	Load Before Outage	29.75	29.51	29.15	28.51	28.08	28.11	27.88	28.03	28.26	0.00	0.00
						Load After Outage	25.2	24.9	24.7	23.9	23.5	23.6	23.2	23.4	23.6	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	46%	46%	46%	45%	44%	44%	44%	44%	44%	0%	0%
						Utilisation During Outage	39%	39%	39%	37%	37%	37%	36%	37%	37%	0%	0%
	Leanyer 66	Casuarina 66	66	1	In Service	Load Before Outage	18.69	18.19	17.57	16.68	16.00	15.75	15.26	15.12	15.06	0.00	0.00
						Load After Outage	14.2	13.6	13.1	12.1	11.5	11.3	10.6	10.5	10.4	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	29%	28%	27%	26%	25%	25%	24%	24%	24%	0%	0%
						Utilisation During Outage	22%	21%	20%	19%	18%	18%	17%	16%	16%	0%	0%
	Casuarina 66	Woolner 66	66	1	In Service	Load Before Outage	22.59	22.55	22.38	22.01	21.54	21.52	21.67	21.68	21.75	0.00	0.00
						Load After Outage	27.3	27.4	27.1	26.9	26.3	26.3	26.5	26.5	26.6	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	35%	35%	35%	34%	34%	34%	34%	34%	34%	0%	0%
						Utilisation During Outage	43%	43%	42%	42%	41%	41%	41%	41%	42%	0%	0%
	Hudson Creek 66	Woolner 66	66	1	In Service	Load Before Outage	36.55	36.41	35.45	35.00	34.19	33.97	33.73	33.74	33.91	0.00	0.00
						Load After Outage	38.3	38.2	37.2	36.8	35.9	35.7	35.5	35.5	35.7	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	57%	57%	55%	55%	53%	53%	53%	53%	53%	0%	0%
						Utilisation During Outage	60%	60%	58%	57%	56%	56%	56%	56%	56%	0%	0%
	Hudson Creek 66	Woolner 66	66	2	In Service	Load Before Outage	38.80	38.65	37.63	37.16	36.30	36.06	35.81	35.82	36.00	0.00	0.00
						Load After Outage	40.6	40.5	39.5	39.1	38.2	37.9	37.7	37.7	37.9	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	61%	60%	59%	58%	57%	56%	56%	56%	56%	0%	0%
						Utilisation During Outage	64%	63%	62%	61%	60%	59%	59%	59%	59%	0%	0%

CONTINGENCY SCENARIO 9	Berrimah 66	Leanyer 66	66	1	Out of Service	Load Before Outage	29.75	29.51	29.15	28.51	28.08	28.11	27.88	28.03	28.26	0.00	0.00
						Load After Outage	0.0	0.0	0	0	0	0	0	0	0	0	0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	46%	46%	46%	45%	44%	44%	44%	44%	44%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Leanyer 66	Casuarina 66	66	1	In Service	Load Before Outage	18.69	18.19	17.57	16.68	16.00	15.75	15.26	15.12	15.06	0.00	0.00
						Load After Outage	11.3	11.6	11.9	12.2	12.5	12.8	13.1	13.4	13.7	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	29%	28%	27%	26%	0%	25%	24%	24%	24%	0%	0%
						Utilisation During Outage	18%	18%	19%	19%	20%	20%	20%	21%	21%	0%	0%
	Casuarina 66	Woolner 66	66	1	In Service	Load Before Outage	22.59	22.55	22.38	22.01	21.54	21.52	21.67	21.68	21.75	0.00	0.00
						Load After Outage	53.3	53.0	52.4	51.4	50.4	50.4	50.4	50.5	50.9	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	35%	35%	35%	34%	34%	34%	34%	34%	34%	0%	0%
						Utilisation During Outage	83%	83%	82%	80%	79%	79%	79%	79%	79%	0%	0%
	Hudson Creek 66	Woolner 66	66	1	In Service	Load Before Outage	36.55	36.41	35.45	35.00	34.19	33.97	33.73	33.74	33.91	0.00	0.00
						Load After Outage	48.2	47.9	46.8	46.1	45.1	44.8	44.5	44.6	44.8	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	57%	57%	55%	55%	53%	53%	53%	53%	53%	0%	0%
						Utilisation During Outage	75%	75%	73%	72%	70%	70%	70%	70%	70%	0%	0%
	Hudson Creek 66	Woolner 66	66	2	In Service	Load Before Outage	38.80	38.65	37.63	37.16	36.30	36.06	35.81	35.82	36.00	0.00	0.00
						Load After Outage	51.2	50.9	49.6	48.9	47.8	47.6	47.3	47.3	47.6	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	61%	60%	59%	58%	57%	56%	56%	56%	56%	0%	0%
						Utilisation During Outage	80%	80%	78%	76%	75%	74%	74%	74%	74%	0%	0%
	Hudson Creek 66	Berrimah 66	66	1	In Service	Load Before Outage	26.06	26.68	26.20	26.98	26.43	26.28	27.02	27.00	27.10	0.00	0.00
						Load After Outage	11.3	12.0	11.7	12.8	12.4	12.3	13.1	13.0	13.0	0.0	0.0
						Contingency Rating MVA	60	60	60	60	60	60	60	60	60	60	60
						Utilisation Before Outage	43%	44%	44%	45%	44%	44%	45%	45%	45%	0%	0%
						Utilisation During Outage	19%	20%	19%	21%	21%	20%	22%	22%	22%	0%	0%
	Hudson Creek 66	Berrimah 66	66	2	In Service	Load Before Outage	26.06	26.68	26.20	26.98	26.43	26.28	27.02	27.00	27.10	0.00	0.00
						Load After Outage	11.3	12.0	11.7	12.8	12.4	12.3	13.1	13.0	13.0	0.0	0.0
						Contingency Rating MVA	60	60	60	60	60	60	60	60	60	60	60
						Utilisation Before Outage	43%	44%	44%	45%	44%	44%	45%	45%	45%	0%	0%
						Utilisation During Outage	19%	20%	19%	21%	21%	20%	22%	22%	22%	0%	0%

CONTINGENCY SCENARIO 10	Leanyer 66	Casuarina 66	66	1	Out of Service	Load Before Outage	18.69	18.19	17.57	16.68	16.00	15.75	15.26	15.12	15.06	0.00	0.00
						Load After Outage	0.0	0.0	0	0	0	0	0	0	0	0	0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	29%	28%	27%	26%	25%	25%	24%	24%	24%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Casuarina 66	Woolner 66	66	1	In Service	Load Before Outage	22.59	22.55	22.38	22.01	21.54	21.52	21.67	21.68	21.75	0.00	0.00
						Load After Outage	41.9	41.4	40.5	39.2	38.0	37.8	37.4	37.2	37.3	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	35%	35%	35%	34%	0%	34%	34%	34%	34%	0%	0%
						Utilisation During Outage	66%	65%	63%	61%	59%	59%	58%	58%	58%	0%	0%
	Hudson Creek 66	Woolner 66	66	1	In Service	Load Before Outage	36.55	36.41	35.45	35.00	34.19	33.97	33.73	33.74	33.91	0.00	0.00
						Load After Outage	43.9	43.5	42.3	41.5	40.4	40.1	39.7	39.6	39.8	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	57%	57%	55%	55%	53%	53%	53%	53%	53%	0%	0%
						Utilisation During Outage	69%	68%	66%	65%	63%	63%	62%	62%	62%	0%	0%
	Hudson Creek 66	Woolner 66	66	2	In Service	Load Before Outage	38.80	38.65	37.63	37.16	36.30	36.06	35.81	35.82	36.00	0.00	0.00
						Load After Outage	46.6	46.2	44.9	44.1	42.9	42.6	42.1	42.1	42.2	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	61%	60%	59%	58%	57%	56%	56%	56%	56%	0%	0%
						Utilisation During Outage	73%	72%	70%	69%	67%	67%	66%	66%	66%	0%	0%
	Hudson Creek 66	Berrimah 66	66	1	In Service	Load Before Outage	26.06	26.68	26.20	26.98	26.43	26.28	27.02	27.00	27.10	0.00	0.00
						Load After Outage	16.5	17.4	17.3	18.5	18.3	18.3	19.3	19.4	19.5	0.0	0.0
						Contingency Rating MVA	60	60	60	60	60	60	60	60	60	60	60
						Utilisation Before Outage	43%	44%	44%	45%	44%	44%	45%	45%	45%	0%	0%
						Utilisation During Outage	28%	29%	29%	31%	31%	31%	32%	32%	32%	0%	0%
	Hudson Creek 66	Berrimah 66	66	2	In Service	Load Before Outage	26.06	26.68	26.20	26.98	26.43	26.28	27.02	27.00	27.10	0.00	0.00
						Load After Outage	16.5	17.4	17.3	18.5	18.3	18.3	19.3	19.4	19.5	0.0	0.0
						Contingency Rating MVA	60	60	60	60	60	60	60	60	60	60	60
						Utilisation Before Outage	43%	44%	44%	45%	44%	44%	45%	45%	45%	0%	0%
						Utilisation During Outage	28%	29%	29%	31%	31%	31%	32%	32%	32%	0%	0%
	Berrimah 66	Leanyer 66	66	1	In Service	Load Before Outage	29.75	29.51	29.15	28.51	28.08	28.11	27.88	28.03	28.26	0.00	0.00
						Load After Outage	11.2	11.6	11.8	12.2	12.5	12.8	13.1	13.4	13.7	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	46%	46%	46%	45%	44%	44%	44%	44%	44%	0%	0%
						Utilisation During Outage	18%	18%	19%	19%	19%	20%	20%	21%	21%	0%	0%

CONTINGENCY SCENARIO 11	Casuarina 66	Woolner 66	66	1	Out of Service	Load Before Outage	22.59	22.55	22.38	22.01	21.54	21.52	21.67	21.68	21.75	0.00	0.00
						Load After Outage	0.0	0.0	0	0	0	0	0	0	0	0	0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	35%	35%	35%	34%	34%	34%	34%	34%	34%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Hudson Creek 66	Woolner 66	66	1	In Service	Load Before Outage	36.55	36.41	35.45	35.00	34.19	33.97	33.73	33.74	33.91	0.00	0.00
						Load After Outage	27.9	27.8	26.9	26.6	26.0	25.7	25.4	25.5	25.6	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	57%	57%	55%	55%	0%	53%	53%	53%	53%	0%	0%
						Utilisation During Outage	44%	43%	42%	42%	41%	40%	40%	40%	40%	0%	0%
	Hudson Creek 66	Woolner 66	66	2	In Service	Load Before Outage	38.80	38.65	37.63	37.16	36.30	36.06	35.81	35.82	36.00	0.00	0.00
						Load After Outage	29.6	29.5	28.5	28.2	27.5	27.3	27.0	27.0	27.2	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	61%	60%	59%	58%	57%	56%	56%	56%	56%	0%	0%
						Utilisation During Outage	46%	46%	45%	44%	43%	43%	42%	42%	42%	0%	0%
	Hudson Creek 66	Berrimah 66	66	1	In Service	Load Before Outage	26.06	26.68	26.20	26.98	26.43	26.28	27.02	27.00	27.10	0.00	0.00
						Load After Outage	38.0	38.6	38.0	38.6	37.8	37.6	38.4	38.4	38.5	0.0	0.0
						Contingency Rating MVA	60	60	60	60	60	60	60	60	60	60	60
						Utilisation Before Outage	43%	44%	44%	45%	44%	44%	45%	45%	45%	0%	0%
						Utilisation During Outage	63%	64%	63%	64%	63%	63%	64%	64%	64%	0%	0%
	Hudson Creek 66	Berrimah 66	66	2	In Service	Load Before Outage	26.06	26.68	26.20	26.98	26.43	26.28	27.02	27.00	27.10	0.00	0.00
						Load After Outage	38.0	38.6	38.0	38.6	37.8	37.6	38.4	38.4	38.5	0.0	0.0
						Contingency Rating MVA	60	60	60	60	60	60	60	60	60	60	60
						Utilisation Before Outage	43%	44%	44%	45%	44%	44%	45%	45%	45%	0%	0%
						Utilisation During Outage	63%	64%	63%	64%	63%	63%	64%	64%	64%	0%	0%
	Berrimah 66	Leanyer 66	66	1	In Service	Load Before Outage	29.75	29.51	29.15	28.51	28.08	28.11	27.88	28.03	28.26	0.00	0.00
						Load After Outage	53.4	53.1	52.5	51.5	50.5	50.5	50.4	50.6	50.9	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	46%	46%	46%	45%	44%	44%	44%	44%	44%	0%	0%
						Utilisation During Outage	83%	83%	82%	80%	79%	79%	79%	79%	80%	0%	0%
	Leanyer 66	Casuarina 66	66	1	In Service	Load Before Outage	18.69	18.19	17.57	16.68	16.00	15.75	15.26	15.12	15.06	0.00	0.00
						Load After Outage	41.6	41.1	40.3	39.0	37.8	37.5	37.2	37.0	37.0	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	29%	28%	27%	26%	25%	25%	24%	24%	24%	0%	0%
						Utilisation During Outage	65%	64%	63%	61%	59%	59%	58%	58%	58%	0%	0%

CONTINGENCY SCENARIO 12	Hudson Creek 66	Woolner 66	66	1	Out of Service	Load Before Outage	36.55	36.41	35.45	35.00	34.19	33.97	33.73	33.74	33.91	0.00	0.00
						Load After Outage	0.0	0.0	0	0	0	0	0	0	0	0	0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	57%	57%	55%	55%	53%	53%	53%	53%	53%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Hudson Creek 66	Woolner 66	66	2	In Service	Load Before Outage	38.80	38.65	37.63	37.16	36.30	36.06	35.81	35.82	36.00	0.00	0.00
						Load After Outage	58.1	57.8	56.3	55.6	54.3	53.9	53.5	53.6	53.8	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	61%	60%	59%	58%	0%	56%	56%	56%	56%	0%	0%
						Utilisation During Outage	91%	90%	88%	87%	85%	84%	84%	84%	84%	0%	0%
	Hudson Creek 66	Berrimah 66	66	1	In Service	Load Before Outage	26.06	26.68	26.20	26.98	26.43	26.28	27.02	27.00	27.10	0.00	0.00
						Load After Outage	29.3	29.9	29.3	30.0	29.4	29.2	30.0	29.9	30.0	0.0	0.0
						Contingency Rating MVA	60	60	60	60	60	60	60	60	60	60	60
						Utilisation Before Outage	43%	44%	44%	45%	44%	44%	45%	45%	45%	0%	0%
						Utilisation During Outage	49%	50%	49%	50%	49%	49%	50%	50%	50%	0%	0%
	Hudson Creek 66	Berrimah 66	66	2	In Service	Load Before Outage	26.06	26.68	26.20	26.98	26.43	26.28	27.02	27.00	27.10	0.00	0.00
						Load After Outage	29.3	29.9	29.3	30.0	29.4	29.2	30.0	29.9	30.0	0.0	0.0
						Contingency Rating MVA	60	60	60	60	60	60	60	60	60	60	60
						Utilisation Before Outage	43%	44%	44%	45%	44%	44%	45%	45%	45%	0%	0%
						Utilisation During Outage	49%	50%	49%	50%	49%	49%	50%	50%	50%	0%	0%
	Berrimah 66	Leanyer 66	66	1	In Service	Load Before Outage	29.75	29.51	29.15	28.51	28.08	28.11	27.88	28.03	28.26	0.00	0.00
						Load After Outage	36.0	35.7	35.2	34.5	33.9	33.9	33.6	33.8	34.0	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	46%	46%	46%	45%	44%	44%	44%	44%	44%	0%	0%
						Utilisation During Outage	56%	56%	55%	54%	53%	53%	53%	53%	53%	0%	0%
	Leanyer 66	Casuarina 66	66	1	In Service	Load Before Outage	18.69	18.19	17.57	16.68	16.00	15.75	15.26	15.12	15.06	0.00	0.00
						Load After Outage	25.0	24.5	23.7	22.7	21.9	21.6	21.1	20.9	20.9	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	29%	28%	27%	26%	25%	25%	24%	24%	24%	0%	0%
						Utilisation During Outage	39%	38%	37%	35%	34%	34%	33%	33%	33%	0%	0%
	Casuarina 66	Woolner 66	66	1	In Service	Load Before Outage	22.59	22.55	22.38	22.01	21.54	21.52	21.67	21.68	21.75	0.00	0.00
						Load After Outage	16.5	16.5	16.5	16.2	15.9	15.9	16.1	16.1	16.1	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	35%	35%	35%	34%	34%	34%	34%	34%	34%	0%	0%
						Utilisation During Outage	26%	26%	26%	25%	25%	25%	25%	25%	25%	0%	0%

CONTINGENCY SCENARIO 13	Hudson Creek 66	Woolner 66	66	2	Out of Service	Load Before Outage	38.80	38.65	37.63	37.16	36.30	36.06	35.81	35.82	36.00	0.00	0.00
						Load After Outage	0.0	0.0	0	0	0	0	0	0	0	0	0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	61%	60%	59%	58%	57%	56%	56%	56%	56%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Hudson Creek 66	Berrimah 66	66	1	In Service	Load Before Outage	26.06	26.68	26.20	26.98	26.43	26.28	27.02	27.00	27.10	0.00	0.00
						Load After Outage	29.7	30.3	29.7	30.4	29.8	29.6	30.3	30.3	30.4	0.0	0.0
						Contingency Rating MVA	60	60	60	60	60	60	60	60	60	60	60
						Utilisation Before Outage	43%	44%	44%	45%	0%	44%	45%	45%	45%	0%	0%
						Utilisation During Outage	49%	50%	49%	51%	50%	49%	51%	51%	51%	0%	0%
	Hudson Creek 66	Berrimah 66	66	2	In Service	Load Before Outage	26.06	26.68	26.20	26.98	26.43	26.28	27.02	27.00	27.10	0.00	0.00
						Load After Outage	29.7	30.3	29.7	30.4	29.8	29.6	30.3	30.3	30.4	0.0	0.0
						Contingency Rating MVA	60	60	60	60	60	60	60	60	60	60	60
						Utilisation Before Outage	43%	44%	44%	45%	44%	44%	45%	45%	45%	0%	0%
						Utilisation During Outage	49%	50%	49%	51%	50%	49%	51%	51%	51%	0%	0%
	Berrimah 66	Leanyer 66	66	1	In Service	Load Before Outage	29.75	29.51	29.15	28.51	28.08	28.11	27.88	28.03	28.26	0.00	0.00
						Load After Outage	37.0	36.7	36.1	35.3	34.7	34.7	34.4	34.6	34.8	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	46%	46%	46%	45%	44%	44%	44%	44%	44%	0%	0%
						Utilisation During Outage	58%	57%	56%	55%	54%	54%	54%	54%	54%	0%	0%
	Leanyer 66	Casuarina 66	66	1	In Service	Load Before Outage	18.69	18.19	17.57	16.68	16.00	15.75	15.26	15.12	15.06	0.00	0.00
						Load After Outage	25.6	25.1	24.3	23.3	22.5	22.2	21.6	21.5	21.4	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	29%	28%	27%	26%	25%	25%	24%	24%	24%	0%	0%
						Utilisation During Outage	40%	39%	38%	36%	35%	35%	34%	34%	34%	0%	0%
	Casuarina 66	Woolner 66	66	1	In Service	Load Before Outage	22.59	22.55	22.38	22.01	21.54	21.52	21.67	21.68	21.75	0.00	0.00
						Load After Outage	15.8	15.8	15.8	15.5	15.2	15.2	15.4	15.4	15.5	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	35%	35%	35%	34%	34%	34%	34%	34%	34%	0%	0%
						Utilisation During Outage	25%	25%	25%	24%	24%	24%	24%	24%	24%	0%	0%
	Hudson Creek 66	Woolner 66	66	1	In Service	Load Before Outage	36.55	36.41	35.45	35.00	34.19	33.97	33.73	33.74	33.91	0.00	0.00
						Load After Outage	56.4	56.2	54.6	53.9	52.7	52.3	51.9	52.0	52.2	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	57%	57%	55%	55%	53%	53%	53%	53%	53%	0%	0%
						Utilisation During Outage	88%	88%	85%	84%	82%	82%	81%	81%	82%	0%	0%

HUDSON CREEK - WOOLNER - FRANCES BAY - DARWIN

CONTINGENCY SCENARIO 14	Hudson Creek 66	Woolner 66	66	1	Out of Service	Load Before Outage	36.55	36.41	35.45	35.00	34.19	33.97	33.73	33.74	33.91	0.00	0.00
						Load After Outage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
						Contingency Rating MVA	80	80	80	80	80	80	80	80	80	80	80
						Utilisation Before Outage	46%	46%	44%	44%	43%	42%	42%	42%	42%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Hudson Creek 66	Woolner 66	66	2	In Service	Load Before Outage	38.80	38.65	37.63	37.16	36.30	36.06	35.81	35.82	36.00	0.00	0.00
						Load After Outage	58.1	57.8	56.3	55.6	54.3	53.9	53.5	53.6	53.8	0.0	0.0
						Contingency Rating MVA	80	80	80	80	80	80	80	80	80	80	80
						Utilisation Before Outage	49%	48%	47%	46%	45%	45%	45%	45%	45%	0%	0%
						Utilisation During Outage	73%	72%	70%	69%	68%	67%	67%	67%	67%	0%	0%
	Hudson Creek 66	Darwin 66	66	1	In Service	Load Before Outage	30.51	30.59	29.91	29.68	29.06	28.89	28.67	28.73	28.88	0.00	0.00
						Load After Outage	41.8	41.8	40.8	40.4	39.6	39.3	39.0	39.1	39.3	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	48%	48%	47%	46%	45%	45%	45%	45%	45%	0%	0%
						Utilisation During Outage	65%	65%	64%	63%	62%	61%	61%	61%	61%	0%	0%
	Darwin 66	Frances Bay 66	66	1	In Service	Load Before Outage	11.59	10.70	10.42	9.52	9.29	9.26	9.22	9.25	9.31	0.00	0.00
						Load After Outage	16.6	15.7	15.3	14.3	14.0	13.9	13.8	13.9	14.0	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	18%	17%	16%	15%	15%	14%	14%	14%	15%	0%	0%
						Utilisation During Outage	26%	25%	24%	22%	22%	22%	22%	22%	22%	0%	0%
	Woolner 66	Frances Bay 66	66	1	In Service	Load Before Outage	11.19	11.69	11.65	11.87	11.78	11.75	11.64	11.77	11.87	0.00	0.00
						Load After Outage	6.5	7.1	7.1	7.4	7.4	7.4	7.3	7.4	7.5	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	17%	18%	18%	19%	18%	18%	18%	18%	19%	0%	0%
						Utilisation During Outage	10%	11%	11%	12%	12%	12%	11%	12%	12%	0%	0%
	Woolner 66	Darwin 66	66	1	In Service	Load Before Outage	10.75	11.36	11.33	11.65	11.57	11.54	11.44	11.56	11.67	0.00	0.00
						Load After Outage	5.4	6.0	6.1	6.5	6.5	6.5	6.4	6.6	6.7	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	17%	18%	18%	18%	18%	18%	18%	18%	18%	0%	0%
						Utilisation During Outage	8%	9%	10%	10%	10%	10%	10%	10%	10%	0%	0%

CONTINGENCY SCENARIO 15	Hudson Creek 66	Woolner 66	66	2	Out of Service	Load Before Outage	38.80	38.65	37.63	37.16	36.30	36.06	35.81	35.82	36.00	0.00	0.00
						Load After Outage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	61%	60%	59%	58%	57%	56%	56%	56%	56%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Hudson Creek 66	Darwin 66	66	1	In Service	Load Before Outage	30.51	30.59	29.91	29.68	29.06	28.89	28.67	28.73	28.88	0.00	0.00
						Load After Outage	43.0	43.0	41.9	41.5	40.6	40.4	40.1	40.1	40.4	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	48%	48%	47%	46%	45%	45%	45%	45%	45%	0%	0%
						Utilisation During Outage	67%	67%	66%	65%	63%	63%	63%	63%	63%	0%	0%
	Darwin 66	Frances Bay 66	66	1	In Service	Load Before Outage	11.59	10.70	10.42	9.52	9.29	9.26	9.22	9.25	9.31	0.00	0.00
						Load After Outage	17.4	16.5	16.0	15.0	14.7	14.6	14.6	14.6	14.7	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	18%	17%	16%	15%	15%	14%	14%	14%	15%	0%	0%
						Utilisation During Outage	27%	26%	25%	24%	23%	23%	23%	23%	23%	0%	0%
	Woolner 66	Frances Bay 66	66	1	In Service	Load Before Outage	11.19	11.69	11.65	11.87	11.78	11.75	11.64	11.77	11.87	0.00	0.00
						Load After Outage	5.6	6.2	6.3	6.6	6.6	6.6	6.6	6.7	6.8	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	17%	18%	18%	19%	18%	18%	18%	18%	19%	0%	0%
						Utilisation During Outage	9%	10%	10%	10%	10%	10%	10%	10%	11%	0%	0%
	Woolner 66	Darwin 66	66	1	In Service	Load Before Outage	10.75	11.36	11.33	11.65	11.57	11.54	11.44	11.56	11.67	0.00	0.00
						Load After Outage	4.3	5.0	5.1	5.5	5.6	5.6	5.5	5.7	5.8	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	17%	18%	18%	18%	18%	18%	18%	18%	18%	0%	0%
						Utilisation During Outage	3%	3%	3%	4%	4%	4%	4%	4%	4%	0%	0%
	Hudson Creek 66	Woolner 66	66	1	In Service	Load Before Outage	36.55	36.41	35.45	35.00	34.19	33.97	33.73	33.74	33.91	0.00	0.00
						Load After Outage	56.4	56.2	54.6	53.9	52.7	52.3	51.9	52.0	52.2	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	57%	57%	55%	55%	53%	53%	53%	53%	53%	0%	0%
						Utilisation During Outage	37%	37%	36%	35%	34%	34%	34%	34%	34%	0%	0%

CONTINGENCY SCENARIO 16	Hudson Creek 66	Darwin 66	66	1	Out of Service	Load Before Outage	30.51	30.59	29.91	29.68	29.06	28.89	28.67	28.73	28.88	0.00	0.00
						Load After Outage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	48%	48%	47%	46%	45%	45%	45%	45%	45%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Darwin 66	Frances Bay 66	66	1	In Service	Load Before Outage	11.59	10.70	10.42	9.52	9.29	9.26	9.22	9.25	9.31	0.00	0.00
						Load After Outage	4.9	5.2	5.3	5.7	5.7	5.6	5.6	5.6	5.6	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	18%	17%	16%	15%	15%	14%	14%	14%	15%	0%	0%
						Utilisation During Outage	8%	8%	8%	9%	9%	9%	9%	9%	9%	0%	0%
	Woolner 66	Frances Bay 66	66	1	In Service	Load Before Outage	11.19	11.69	11.65	11.87	11.78	11.75	11.64	11.77	11.87	0.00	0.00
						Load After Outage	25.3	25.9	25.5	25.6	25.3	25.1	24.9	25.1	25.3	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	17%	18%	18%	19%	18%	18%	18%	18%	19%	0%	0%
						Utilisation During Outage	40%	40%	40%	40%	39%	39%	39%	39%	39%	0%	0%
	Woolner 66	Darwin 66	66	1	In Service	Load Before Outage	10.75	11.36	11.33	11.65	11.57	11.54	11.44	11.56	11.67	0.00	0.00
						Load After Outage	26.9	27.5	27.1	27.3	26.9	26.8	26.6	26.8	26.9	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	17%	18%	18%	18%	18%	18%	18%	18%	18%	0%	0%
						Utilisation During Outage	42%	43%	42%	43%	42%	42%	42%	42%	42%	0%	0%
	Hudson Creek 66	Woolner 66	66	1	In Service	Load Before Outage	36.55	36.41	35.45	35.00	34.19	33.97	33.73	33.74	33.91	0.00	0.00
						Load After Outage	49.4	49.3	48.0	47.5	46.4	46.1	45.8	45.8	46.0	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	57%	57%	55%	55%	53%	53%	53%	53%	53%	0%	0%
						Utilisation During Outage	32%	32%	31%	31%	30%	30%	30%	30%	30%	0%	0%
	Hudson Creek 66	Woolner 66	66	2	In Service	Load Before Outage	38.80	38.65	37.63	37.16	36.30	36.06	35.81	35.82	36.00	0.00	0.00
						Load After Outage	52.5	52.4	51.0	50.4	49.3	49.0	48.6	48.6	48.9	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	61%	60%	59%	58%	57%	56%	56%	56%	56%	0%	0%
						Utilisation During Outage	34%	34%	33%	33%	32%	32%	32%	32%	32%	0%	0%

CONTINGENCY SCENARIO 17	Darwin 66	Frances Bay 66	66	1	Out of Service	Load Before Outage	11.59	10.70	10.42	9.52	9.29	9.26	9.22	9.25	9.31	0.00	0.00
						Load After Outage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	18%	17%	16%	15%	15%	14%	14%	14%	15%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Woolner 66	Frances Bay 66	66	1	In Service	Load Before Outage	11.19	11.69	11.65	11.87	11.78	11.75	11.64	11.77	11.87	0.00	0.00
						Load After Outage	23.1	22.7	22.3	21.6	21.3	21.2	21.1	21.3	21.4	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	17%	18%	18%	19%	18%	18%	18%	18%	19%	0%	0%
						Utilisation During Outage	36%	35%	35%	34%	33%	33%	33%	33%	33%	0%	0%
	Woolner 66	Darwin 66	66	1	In Service	Load Before Outage	10.75	11.36	11.33	11.65	11.57	11.54	11.44	11.56	11.67	0.00	0.00
						Load After Outage	2.3	3.1	3.5	4.4	4.5	4.5	4.4	4.5	4.6	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	17%	18%	18%	18%	18%	18%	18%	18%	18%	0%	0%
						Utilisation During Outage	4%	5%	5%	7%	7%	7%	7%	7%	7%	0%	0%
	Hudson Creek 66	Woolner 66	66	1	In Service	Load Before Outage	36.55	36.41	35.45	35.00	34.19	33.97	33.73	33.74	33.91	0.00	0.00
						Load After Outage	37.5	37.3	36.3	35.8	35.0	34.8	34.5	34.5	34.7	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	57%	57%	55%	55%	53%	53%	53%	53%	53%	0%	0%
						Utilisation During Outage	59%	58%	57%	56%	55%	54%	54%	54%	54%	0%	0%
	Hudson Creek 66	Woolner 66	66	2	In Service	Load Before Outage	38.80	38.65	37.63	37.16	36.30	36.06	35.81	35.82	36.00	0.00	0.00
						Load After Outage	39.9	39.6	38.6	38.0	37.1	36.9	36.6	36.7	36.8	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	61%	60%	59%	58%	57%	56%	56%	56%	56%	0%	0%
						Utilisation During Outage	26%	26%	25%	25%	24%	24%	24%	24%	24%	0%	0%
	Hudson Creek 66	Darwin 66	66	1	In Service	Load Before Outage	30.51	30.59	29.91	29.68	29.06	28.89	28.67	28.73	28.88	0.00	0.00
						Load After Outage	28.3	28.5	27.9	27.9	27.3	27.1	26.9	27.0	27.1	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	48%	48%	47%	46%	45%	45%	45%	45%	45%	0%	0%
						Utilisation During Outage	18%	19%	18%	18%	18%	18%	18%	18%	18%	0%	0%

CONTINGENCY SCENARIO 18	Woolner 66	Frances Bay 66	66	1	Out of Service	Load Before Outage	11.19	11.69	11.65	11.87	11.78	11.75	11.64	11.77	11.87	0.00	0.00
						Load After Outage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	17%	18%	18%	19%	18%	18%	18%	18%	19%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Woolner 66	Darwin 66	66	1	In Service	Load Before Outage	10.75	11.36	11.33	11.65	11.57	11.54	11.44	11.56	11.67	0.00	0.00
						Load After Outage	19.7	20.8	20.7	21.2	21.0	21.0	20.8	21.0	21.2	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	17%	18%	18%	18%	18%	18%	18%	18%	18%	0%	0%
						Utilisation During Outage	31%	32%	32%	33%	33%	33%	32%	33%	33%	0%	0%
	Hudson Creek 66	Woolner 66	66	1	In Service	Load Before Outage	36.55	36.41	35.45	35.00	34.19	33.97	33.73	33.74	33.91	0.00	0.00
						Load After Outage	35.6	35.4	34.5	34.0	33.2	33.0	32.8	32.8	32.9	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	57%	57%	55%	55%	53%	53%	53%	53%	53%	0%	0%
						Utilisation During Outage	56%	55%	54%	53%	52%	52%	51%	51%	51%	0%	0%
	Hudson Creek 66	Woolner 66	66	2	In Service	Load Before Outage	38.80	38.65	37.63	37.16	36.30	36.06	35.81	35.82	36.00	0.00	0.00
						Load After Outage	37.8	37.6	36.6	36.1	35.3	35.0	34.8	34.8	34.9	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	61%	60%	59%	58%	57%	56%	56%	56%	56%	0%	0%
						Utilisation During Outage	59%	59%	57%	56%	55%	55%	54%	54%	55%	0%	0%
	Hudson Creek 66	Darwin 66	66	1	In Service	Load Before Outage	30.51	30.59	29.91	29.68	29.06	28.89	28.67	28.73	28.88	0.00	0.00
						Load After Outage	32.8	33.0	32.3	32.2	31.5	31.3	31.1	31.2	31.4	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	48%	48%	47%	46%	45%	45%	45%	45%	45%	0%	0%
						Utilisation During Outage	21%	22%	21%	21%	21%	20%	20%	20%	20%	0%	0%
	Darwin 66	Frances Bay 66	66	1	In Service	Load Before Outage	11.59	10.70	10.42	9.52	9.29	9.26	9.22	9.25	9.31	0.00	0.00
						Load After Outage	23.1	22.7	22.3	21.6	21.3	21.2	21.1	21.3	21.4	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	18%	17%	16%	15%	15%	14%	14%	14%	15%	0%	0%
						Utilisation During Outage	15%	15%	15%	14%	14%	14%	14%	14%	14%	0%	0%

CONTINGENCY SCENARIO 19	Woolner 66	Darwin 66	66	1	Out of Service	Load Before Outage	10.75	11.36	11.33	11.65	11.57	11.54	11.44	11.56	11.67	0.00	0.00
						Load After Outage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	17%	18%	18%	18%	18%	18%	18%	18%	18%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Hudson Creek 66	Woolner 66	66	1	In Service	Load Before Outage	36.55	36.41	35.45	35.00	34.19	33.97	33.73	33.74	33.91	0.00	0.00
						Load After Outage	35.5	35.3	34.4	33.9	33.1	32.9	32.6	32.6	32.8	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	57%	57%	55%	55%	53%	53%	53%	53%	53%	0%	0%
						Utilisation During Outage	56%	55%	54%	53%	52%	51%	51%	51%	51%	0%	0%
	Hudson Creek 66	Woolner 66	66	2	In Service	Load Before Outage	38.80	38.65	37.63	37.16	36.30	36.06	35.81	35.82	36.00	0.00	0.00
						Load After Outage	37.7	37.5	36.5	36.0	35.1	34.9	34.7	34.7	34.8	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	61%	60%	59%	58%	57%	56%	56%	56%	56%	0%	0%
						Utilisation During Outage	59%	59%	57%	56%	55%	55%	54%	54%	54%	0%	0%
	Hudson Creek 66	Darwin 66	66	1	In Service	Load Before Outage	30.51	30.59	29.91	29.68	29.06	28.89	28.67	28.73	28.88	0.00	0.00
						Load After Outage	33.0	33.2	32.6	32.4	31.8	31.6	31.3	31.4	31.6	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	48%	48%	47%	46%	45%	45%	45%	45%	45%	0%	0%
						Utilisation During Outage	52%	52%	51%	51%	50%	49%	49%	49%	49%	0%	0%
	Darwin 66	Frances Bay 66	66	1	In Service	Load Before Outage	11.59	10.70	10.42	9.52	9.29	9.26	9.22	9.25	9.31	0.00	0.00
						Load After Outage	4.4	3.3	3.4	2.9	2.9	2.9	2.9	2.9	2.9	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	18%	17%	16%	15%	15%	14%	14%	14%	15%	0%	0%
						Utilisation During Outage	3%	2%	2%	2%	2%	2%	2%	2%	2%	0%	0%
	Woolner 66	Frances Bay 66	66	1	In Service	Load Before Outage	11.19	11.69	11.65	11.87	11.78	11.75	11.64	11.77	11.87	0.00	0.00
						Load After Outage	19.5	20.5	20.4	20.9	20.7	20.7	20.5	20.7	20.9	0.0	0.0
						Contingency Rating MVA	64	64	64	64	64	64	64	64	64	64	64
						Utilisation Before Outage	17%	18%	18%	19%	18%	18%	18%	18%	19%	0%	0%
						Utilisation During Outage	13%	13%	13%	14%	14%	14%	13%	14%	14%	0%	0%

CHANNEL ISLAND - HUDSON CREEK

CONTINGENCY SCENARIO 20	CIPS 132	Hudson Creek 132	132	A or B	Out of Service	Load Before Outage	82.81	90.35	89.43	91.48	91.90	92.28	98.18	98.66	99.31	0.00	0.00
						Load After Outage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
						Contingency Rating MVA	266	266	266	266	266	266	266	266	266	266	266
						Utilisation Before Outage	31%	34%	34%	34%	35%	35%	37%	37%	37%	0%	0%
						Utilisation During Outage	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	CIPS 132	Hudson Creek 132	132	B or A	In Service	Load Before Outage	83.70	91.32	90.39	92.46	92.88	93.27	99.23	99.72	100.37	0.00	0.00
						Load After Outage	167.7	183.1	181.4	185.6	186.5	187.3	199.4	200.4	201.7	0.0	0.0
						Contingency Rating MVA	266	266	266	266	266	266	266	266	266	266	266
						Utilisation Before Outage	31%	34%	34%	35%	35%	35%	37%	37%	38%	0%	0%
						Utilisation During Outage	63%	69%	68%	70%	70%	70%	75%	75%	76%	0%	0%

Substation		Substation rating MVA			2018/19 Peak				Hours > 95% of peak load	Load transfer capacity	Embedded generation	Non-coincident 10% PoE Forecast MVA					System limitation?	Non-coincident 50% PoE Forecast MVA					System limitation?
Voltage kV	Name	N	N-1	N-2	MVA	Power factor	Date	Wet/Dry	Hrs	MVA	MW	2019/20	2020/21	2021/22	2022/23	2023/24		2019/20	2020/21	2021/22	2022/23	2023/24	
11	Archer	63	31.5	-	26.44	0.953	03/12/18 18:30	Wet	12.5	13.70	-	37.76	38.91	39.04	38.91	39.56	YES	36.14	37.26	37.37	37.30	37.97	YES
22	Batchelor	33.6	-	-	1.60	0.986	31/10/18 16:00	Wet	1.5	1.80	-	3.14	3.12	3.09	3.06	3.04	NO	2.85	2.82	2.80	2.77	2.75	NO
11	Berrimah	76	38.1	-	26.11	0.982	22/02/19 15:00	Wet	4.5	11.20	-	30.74	29.91	32.62	31.77	31.39	YES	29.22	28.40	31.13	30.35	30.02	NO
11	Casuarina	83.7	55.8	27.9	42.85	0.990	10/12/18 17:30	Wet	25	16.85	-	50.96	50.02	48.49	47.07	46.74	NO	49.24	48.30	46.80	45.48	45.23	NO
11	Centre Yard	1	0.5	-	0.54	1.000	06/12/18 20:00	Wet	1.5	-	-	0.58	0.58	0.58	0.58	0.58	NO	0.55	0.55	0.55	0.55	0.55	NO
11	Darwin	114	76	38	29.50	0.859	07/12/18 16:30	Wet	12.5	26.35	-	38.56	38.15	39.34	38.80	38.58	NO	35.29	34.79	35.92	35.41	35.04	NO
11	Frances Bay	76	44.3	-	20.65	0.980	07/12/18 13:30	Wet	24	22.17	-	27.68	27.26	26.44	26.04	25.96	NO	25.07	24.70	24.04	23.47	23.44	NO
66	Hudson Creek	394.5	263	131.5	187.00	0.988	06/12/18 16:30	Wet	18	-	-	214.69	214.39	212.80	208.61	204.79	YES	202.97	202.58	200.89	196.72	194.20	YES
22	Humpty Doo	5	-	-	2.60	0.975	02/10/18 14:00	Wet	16	1.03	-	4.50	5.22	7.20	8.90	9.20	YES	4.43	5.14	7.11	8.81	9.10	YES
22	Katherine	64	28.8	-	28.25	0.922	12/11/18 16:00	Wet	30	-	-	31.42	36.67	38.72	40.77	42.81	YES	30.68	35.91	37.94	39.97	42.00	YES
11	Leanyer	54	27	-	12.85	0.921	06/12/18 19:30	Wet	19.5	9.43	-	14.08	14.44	14.80	15.16	15.52	NO	13.74	14.09	14.45	14.80	15.16	NO
22	Manton	27	-	-	3.81	0.979	09/10/18 17:00	Wet	3.5	3.40	-	4.80	5.59	6.37	7.16	7.95	NO	4.70	5.49	6.27	7.06	7.85	NO
22	Marrakai	2.5	-	-	0.92	0.957	17/09/18 0:00	Dry	5.5	-	-	0.97	0.99	1.00	1.02	1.04	NO	0.94	0.96	0.98	1.00	1.01	NO
22	Mary River	7.5	-	-	2.59	0.885	14/09/18 12:30	Dry	3.5	-	-	3.33	3.32	3.32	3.32	3.32	NO	3.10	3.10	3.09	3.09	3.09	NO
11	Palmerston	116.2	76.2	38.1	33.15	0.983	04/12/18 15:00	Wet	17	7.30	-	42.23	47.17	50.32	53.46	54.89	NO	41.36	46.28	49.41	52.53	53.94	NO
22	Palmerston	19	-	-	6.64	0.987	06/12/18 18:00	Wet	18.5	6.83	-	9.46	9.38	9.03	9.01	9.01	NO	9.08	9.00	8.59	8.64	8.64	NO
66	Pine Creek (PK)	30	-	-	23.82	1.000	30/09/18 6:30	Dry	24.5	-	-	27.99	27.99	27.99	27.99	27.99	NO	26.92	26.92	26.92	26.92	26.92	NO
66	Pine Creek (PC)	40	-	-	29.79	0.995	26/06/18 7:00	Dry	14	-	-	23.76	23.76	23.76	23.76	23.76	NO	23.76	23.76	23.76	23.76	23.76	NO
22	Pine Creek (PC)	1.8	-	-	0.74	0.922	09/10/18 19:00	Wet	9.5	-	-	0.77	0.77	0.77	0.77	0.77	NO	0.75	0.75	0.75	0.75	0.75	NO
22	Strangways	60.6	30.3	-	28.65	0.975	06/12/18 19:30	Wet	10	10.99	-	32.14	32.21	32.28	32.35	32.42	YES	31.39	31.45	31.50	31.55	31.60	YES
11	Tindal	12.9	8.6	4.3	4.93	0.919	21/03/19 14:00	Wet	25	-	-	4.52	4.52	4.52	4.52	4.52	NO	4.36	4.36	4.36	4.36	4.36	NO
22	Weddell	29.3	15.4	7.7	15.71	0.951	14/04/18 16:00	Dry	13.5	-	-	6.88	13.19	17.19	17.19	17.19	YES	6.72	13.03	17.03	17.03	17.03	YES
11	Wishart Modular	10	-	-	3.42	0.953	17/10/18 13:00	Wet	6	1.50	-	4.72	8.17	8.24	8.57	9.75	NO	4.64	8.08	8.15	8.49	9.67	NO
11	Woolner	92.7	61.8	30.9	34.15	0.989	01/11/18 15:30	Wet	5	21.05	-	36.18	35.17	33.84	32.60	32.14	NO	34.54	33.54	32.23	31.06	30.65	NO

Substation		Substation rating MVA			2018/19 Peak				Hours > 95% of peak load	Load transfer capacity	Embedded generation	Non-coincident 10% PoE Forecast MVA					System limitation?	Non-coincident 50% PoE Forecast MVA					System limitation?
Voltage kV	Name	N	N-1	N-2	MVA	Power factor	Date	Summer/ Winter	Hrs	MVA	MW	2019/20	2020/21	2021/22	2022/23	2023/24		2019/20	2020/21	2021/22	2022/23	2023/24	
22	Tennant Creek	16.8	8.4	-	7.13	0.980	31/01/19 15:00	Summer	13.5	-	-	8.33	8.18	8.03	7.88	7.73	No	7.96	7.81	7.65	7.50	7.34	No

Substation		Substation rating MVA			2018/19 Peak				Hours > 95% of peak load	Load transfer capacity	Embedded generation	Non-coincident 10% PoE Forecast MVA					System limitation?	Non-coincident 50% PoE Forecast MVA					System limitation?
Voltage kV	Name	N	N-1	N-2	MVA	Power factor	Date & Time	Summer/ Winter	Hrs	MVA	MW	2019/20	2020/21	2021/22	2022/23	2023/24		2019/20	2020/21	2021/22	2022/23	2023/24	
22	Brewer & Sadadeen loads 22				9.20	0.970	12/12/18 12:00	Summer	0.5	-	-	12.19	12.23	12.30	12.36	12.34		11.62	11.64	11.70	11.74	11.67	
22	Lovegrove loads 22				0.88	0.796	15/01/19 13:30	Summer	4.5	-	-	0.86	0.83	0.80	0.77	0.74		0.82	0.79	0.76	0.73	0.69	
11	Lovegrove 11	39.2	22.4	11.2	20.63	0.983	25/01/19 13:30	Summer	5.5	8.75	-	23.75	23.93	24.11	24.29	24.47	YES	22.88	23.03	23.17	23.32	23.46	YES
66	Lovegrove 66	114.4	57.2	-	31.35	0.827	11/03/19 17:00	Summer	1.5	-	-	60.48	59.60	59.21	58.67	58.00	YES	57.47	56.43	56.00	55.46	54.54	YES
66	Owen Springs	159.6	106.4	53.2	30.71	0.973	11/03/19 17:00	Summer	1.5	-	-	60.48	59.60	59.21	58.67	58.00	NO	57.47	56.43	56.00	55.46	54.54	NO
11	Ron Goodin	43.8	21.9	-	19.31	0.975	12/02/18 16:30	Summer	16.5	6.32	-	22.87	22.61	22.49	22.35	22.06	YES	21.29	20.99	20.85	20.68	20.30	NO

Field Name	Value	Units
Constraint primary driver	Capacity	
Location of constraint (start)	Lat: 12° 31.072' S Lon: 130° 58.445' E	
Location of constraint (end)	Lat: 12° 31.072' S Lon: 130° 58.445' E	
Maximo asset ID	MX870671	
Network element	Zone substation	
Residential customers affected	9575	
Residential customers affected	11.79	%
Asset rating 2019 - N	63	MVA
Asset rating 2020 - N	63	MVA
Asset rating 2021 - N	63	MVA
Asset rating 2022 - N	63	MVA
Asset rating 2023 - N	63	MVA
Asset rating 2019 - N	60	MW
Asset rating 2020 - N	60	MW
Asset rating 2021 - N	60	MW
Asset rating 2022 - N	60	MW
Asset rating 2023 - N	60	MW
Asset rating 2019 - N-1	31.5	MVA
Asset rating 2020 - N-1	31.5	MVA
Asset rating 2021 - N-1	31.5	MVA
Asset rating 2022 - N-1	31.5	MVA
Asset rating 2023 - N-1	31.5	MVA
Asset rating 2019 - N-1	30.0	MW
Asset rating 2020 - N-1	30.0	MW
Asset rating 2021 - N-1	30.0	MW
Asset rating 2022 - N-1	30.0	MW
Asset rating 2023 - N-1	30.0	MW
Forecast Demand 10% 2019	37.8	MVA
Forecast Demand 10% 2020	38.9	MVA
Forecast Demand 10% 2021	39.0	MVA
Forecast Demand 10% 2022	38.9	MVA
Forecast Demand 10% 2023	39.6	MVA
Forecast Demand 50% 2019	36.1	MVA
Forecast Demand 50% 2020	37.3	MVA
Forecast Demand 50% 2021	37.4	MVA
Forecast Demand 50% 2022	37.3	MVA
Forecast Demand 50% 2023	38.0	MVA
Forecast Demand 10% 2019	36.0	MW
Forecast Demand 10% 2020	37.1	MW
Forecast Demand 10% 2021	37.2	MW
Forecast Demand 10% 2022	37.1	MW
Forecast Demand 10% 2023	37.7	MW
Forecast Demand 50% 2019	34.4	MW
Forecast Demand 50% 2020	35.5	MW
Forecast Demand 50% 2021	35.6	MW
Forecast Demand 50% 2022	35.5	MW
Forecast Demand 50% 2023	36.2	MW

Voltage level	66.0	kV
Maximum load at risk 2019	4.4	MW
Maximum load at risk 2020	5.5	MW
Maximum load at risk 2021	5.6	MW
Maximum load at risk 2022	5.5	MW
Maximum load at risk 2023	6.2	MW
Energy at Risk 2019	3366.0	MWh
Energy at Risk 2020	5076.5	MWh
Energy at Risk 2021	5241.8	MWh
Energy at Risk 2022	5126.9	MWh
Energy at Risk 2023	6703.3	MWh
Preferred network investment	Load transfer to adjacent Palmerston Zone Substation and new footing for Nomad connection	
Preferred network investment capital cost	$ 1,100,000	$ (real)
Preferred annual network investment cost accuracy	$ 100,000	$ (real)
Preferred network investment cost upper bound	9%	+%
Preferred network investment cost upper bound	8%	-%
Proposed timing	1/06/2020	
Demand reduction required to defer investment by 1	4.6	MVA
Demand reduction required to defer investment by 1	4.4	MW
Annual deferral value	0	$ (real)
Load Transfer capability	13.7	MVA
Load Transfer capability	13.29	MW
Emergency Generation	0	MVA
Emergency Generation	0	MW

Field Name	Value	Units
Constraint primary driver	Capacity	
Location of constraint (start)	Lat: 12° 27.535' S Lon: 130° 55.915' E	
Location of constraint (end)	Lat: 12° 27.535' S Lon: 130° 55.915' E	
Maximo asset ID		
Network element	Zone substation	
Residential customers affected	55405	
Residential customers affected	68.22	%
Asset rating 2019 - N	394.5	MVA
Asset rating 2020 - N	394.5	MVA
Asset rating 2021 - N	394.5	MVA
Asset rating 2022 - N	394.5	MVA
Asset rating 2023 - N	394.5	MVA
Asset rating 2019 - N	382.7	MW
Asset rating 2020 - N	382.7	MW
Asset rating 2021 - N	382.7	MW
Asset rating 2022 - N	382.7	MW
Asset rating 2023 - N	382.7	MW
Asset rating 2019 - N-2	131.5	MVA
Asset rating 2020 - N-2	131.5	MVA
Asset rating 2021 - N-2	131.5	MVA
Asset rating 2022 - N-2	131.5	MVA
Asset rating 2023 - N-2	131.5	MVA
Asset rating 2019 - N-2	127.6	MW
Asset rating 2020 - N-2	127.6	MW
Asset rating 2021 - N-2	127.6	MW
Asset rating 2022 - N-2	127.6	MW
Asset rating 2023 - N-2	127.6	MW
Forecast Demand 10% 2019	214.69	MVA
Forecast Demand 10% 2020	214.39	MVA
Forecast Demand 10% 2021	212.80	MVA
Forecast Demand 10% 2022	208.61	MVA
Forecast Demand 10% 2023	204.79	MVA
Forecast Demand 50% 2019	202.97	MVA
Forecast Demand 50% 2020	202.58	MVA
Forecast Demand 50% 2021	200.89	MVA
Forecast Demand 50% 2022	196.72	MVA
Forecast Demand 50% 2023	194.20	MVA
Forecast Demand 10% 2019	212.11	MW
Forecast Demand 10% 2020	211.82	MW
Forecast Demand 10% 2021	210.25	MW
Forecast Demand 10% 2022	206.11	MW
Forecast Demand 10% 2023	202.34	MW
Forecast Demand 50% 2019	200.53	MW
Forecast Demand 50% 2020	200.15	MW
Forecast Demand 50% 2021	198.48	MW
Forecast Demand 50% 2022	194.36	MW
Forecast Demand 50% 2023	191.87	MW

Voltage level		132	kV
Maximum load at risk 2019		70.61	MW
Maximum load at risk 2020		70.23	MW
Maximum load at risk 2021		68.56	MW
Maximum load at risk 2022		64.44	MW
Maximum load at risk 2023		61.95	MW
Energy at Risk 2019		317748.22	MWh
Energy at Risk 2020		314589.19	MWh
Energy at Risk 2021		303582.61	MWh
Energy at Risk 2022		278285.20	MWh
Energy at Risk 2023		262361.59	MWh
Preferred network investment	Spare 132/66kV transformer		
Preferred network investment capital cost	$	1,850,000	$ (real)
Preferred annual network investment cost accuracy	$	555,000	$ (real)
Preferred network investment cost upper bound		30%	+%
Preferred network investment cost upper bound		30%	-%
Proposed timing		1/06/2023	
Demand reduction required to defer investment by 1		71.5	MVA
Demand reduction required to defer investment by 1		70.6	MW
Annual deferral value			$ (real)
Load Transfer capability		0	MVA
Load Transfer capability		0	MW
Emergency Generation		0	MVA
Emergency Generation		0	MW

Field Name	Value	Units
Constraint primary driver	Capacity	
Location of constraint (start)	Lat: 12° 33.850' S Lon: 131° 4.320' E	
Location of constraint (end)	Lat: 12° 33.850' S Lon: 131° 4.320' E	
Maximo asset ID	MX5189358	
Network element	Zone substation	
Residential customers affected	6752	
Residential customers affected	8.31	%
Asset rating 2019 - N	60.6	MVA
Asset rating 2020 - N	60.6	MVA
Asset rating 2021 - N	60.6	MVA
Asset rating 2022 - N	60.6	MVA
Asset rating 2023 - N	60.6	MVA
Asset rating 2019 - N	59.1	MW
Asset rating 2020 - N	59.1	MW
Asset rating 2021 - N	59.1	MW
Asset rating 2022 - N	59.1	MW
Asset rating 2023 - N	59.1	MW
Asset rating 2019 - N-1	30.3	MVA
Asset rating 2020 - N-1	30.3	MVA
Asset rating 2021 - N-1	30.3	MVA
Asset rating 2022 - N-1	30.3	MVA
Asset rating 2023 - N-1	30.3	MVA
Asset rating 2019 - N-1	29.5	MW
Asset rating 2020 - N-1	29.5	MW
Asset rating 2021 - N-1	29.5	MW
Asset rating 2022 - N-1	29.5	MW
Asset rating 2023 - N-1	29.5	MW
Forecast Demand 10% 2019	32.1	MVA
Forecast Demand 10% 2020	32.2	MVA
Forecast Demand 10% 2021	32.3	MVA
Forecast Demand 10% 2022	32.3	MVA
Forecast Demand 10% 2023	32.4	MVA
Forecast Demand 50% 2019	31.4	MVA
Forecast Demand 50% 2020	31.4	MVA
Forecast Demand 50% 2021	31.5	MVA
Forecast Demand 50% 2022	31.5	MVA
Forecast Demand 50% 2023	31.6	MVA
Forecast Demand 10% 2019	31.3	MW
Forecast Demand 10% 2020	31.4	MW
Forecast Demand 10% 2021	31.5	MW
Forecast Demand 10% 2022	31.5	MW
Forecast Demand 10% 2023	31.6	MW
Forecast Demand 50% 2019	30.6	MW
Forecast Demand 50% 2020	30.7	MW
Forecast Demand 50% 2021	30.7	MW
Forecast Demand 50% 2022	30.8	MW
Forecast Demand 50% 2023	30.8	MW

Voltage level	66.0	kV
Maximum load at risk 2019	1.1	MW
Maximum load at risk 2020	1.1	MW
Maximum load at risk 2021	1.2	MW
Maximum load at risk 2022	1.2	MW
Maximum load at risk 2023	1.3	MW
Energy at Risk 2019	210.5	MWh
Energy at Risk 2020	240.5	MWh
Energy at Risk 2021	255.6	MWh
Energy at Risk 2022	270.8	MWh
Energy at Risk 2023	315.5	MWh
Preferred network investment	Load transfer to adjacent zone susbtations under contingency conditions	
Preferred network investment capital cost	0	$ (real)
Preferred annual network investment cost accuracy	0	$ (real)
Preferred network investment cost upper bound	0%	+%
Preferred network investment cost upper bound	0%	-%
Proposed timing	1/01/2019	
Demand reduction required to defer investment by 1	1.2	MVA
Demand reduction required to defer investment by 1	1.1	MW
Annual deferral value	0	$ (real)
Load Transfer capability	11.0	MVA
Load Transfer capability	10.7	MW
Emergency Generation	0	MVA
Emergency Generation	0	MW

Field Name	Value	Units
Constraint primary driver	Capacity/ Asset Condition	
Location of constraint (start)	Lat: 12°36'31.3"S Lon: 131°15'56.3"E	
Location of constraint (end)	Lat: 12°36'31.3"S Lon: 131°15'56.3"E	
Maximo asset ID		
Network element	Zone substation	
Residential customers affected	122	
Residential customers affected	0.15	%
Asset rating 2019 - N	5.0	MVA
Asset rating 2020 - N	5.0	MVA
Asset rating 2021 - N	5.0	MVA
Asset rating 2022 - N	5.0	MVA
Asset rating 2023 - N	5.0	MVA
Asset rating 2019 - N	4.9	MW
Asset rating 2020 - N	4.9	MW
Asset rating 2021 - N	4.9	MW
Asset rating 2022 - N	4.9	MW
Asset rating 2023 - N	4.9	MW
Asset rating 2019 - N-1	0.0	MVA
Asset rating 2020 - N-1	0.0	MVA
Asset rating 2021 - N-1	0.0	MVA
Asset rating 2022 - N-1	0.0	MVA
Asset rating 2023 - N-1	0.0	MVA
Asset rating 2019 - N-1	0.0	MW
Asset rating 2020 - N-1	0.0	MW
Asset rating 2021 - N-1	0.0	MW
Asset rating 2022 - N-1	0.0	MW
Asset rating 2023 - N-1	0.0	MW
Forecast Demand 10% 2019	4.5	MVA
Forecast Demand 10% 2020	5.2	MVA
Forecast Demand 10% 2021	7.2	MVA
Forecast Demand 10% 2022	8.9	MVA
Forecast Demand 10% 2023	9.2	MVA
Forecast Demand 50% 2019	4.4	MVA
Forecast Demand 50% 2020	5.1	MVA
Forecast Demand 50% 2021	7.1	MVA
Forecast Demand 50% 2022	8.8	MVA
Forecast Demand 50% 2023	9.1	MVA
Forecast Demand 10% 2019	4.4	MW
Forecast Demand 10% 2020	5.1	MW
Forecast Demand 10% 2021	7.0	MW
Forecast Demand 10% 2022	8.7	MW
Forecast Demand 10% 2023	9.0	MW
Forecast Demand 50% 2019	4.3	MW
Forecast Demand 50% 2020	5.0	MW

Forecast Demand 50% 2021		6.9	MW
Forecast Demand 50% 2022		8.6	MW
Forecast Demand 50% 2023		8.9	MW
Voltage level		22.0	kV
Maximum load at risk 2019		0.0	MW
Maximum load at risk 2020		0.1	MW
Maximum load at risk 2021		2.1	MW
Maximum load at risk 2022		3.7	MW
Maximum load at risk 2023		4.0	MW
Energy at Risk 2019		0.0	MWh
Energy at Risk 2020		27.1	MWh
Energy at Risk 2021		8752.2	MWh
Energy at Risk 2022		34311.9	MWh
Energy at Risk 2023		40044.6	MWh
Preferred network investment	Rebuilt zone substation		
Preferred network investment capital cost	$	5,800,000	$ (real)
Preferred annual network investment cost accuracy	$	580,000	$ (real)
Preferred network investment cost upper bound		10%	+%
Preferred network investment cost upper bound		10%	-%
Proposed timing		1/07/2023	
Demand reduction required to defer investment by 1 year		4.05	MVA
Demand reduction required to defer investment by 1 year		4.00	MW
Annual deferral value		0	$ (real)
Load Transfer capability		0	MVA
Load Transfer capability		0	MW
Emergency Generation		0	MVA
Emergency Generation		0	MW

Field Name	Value	Units
Constraint primary driver	Capacity	
Location of constraint (start)	Lat: 14°27'29.7"S Lon: 132°14'44.0"E	
Location of constraint (end)	Lat: 14°27'29.7"S Lon: 132°14'44.0"E	
Maximo asset ID		
Network element	Zone substation	
Residential customers affected	3492	
Residential customers affected	4.30	%
Asset rating 2019 - N	64.0	MVA
Asset rating 2020 - N	64.0	MVA
Asset rating 2021 - N	64.0	MVA
Asset rating 2022 - N	64.0	MVA
Asset rating 2023 - N	64.0	MVA
Asset rating 2019 - N	59.0	MW
Asset rating 2020 - N	59.0	MW
Asset rating 2021 - N	59.0	MW
Asset rating 2022 - N	59.0	MW
Asset rating 2023 - N	59.0	MW
Asset rating 2019 - N-1	28.8	MVA
Asset rating 2020 - N-1	28.8	MVA
Asset rating 2021 - N-1	28.8	MVA
Asset rating 2022 - N-1	28.8	MVA
Asset rating 2023 - N-1	28.8	MVA
Asset rating 2019 - N-1	26.6	MW
Asset rating 2020 - N-1	26.6	MW
Asset rating 2021 - N-1	26.6	MW
Asset rating 2022 - N-1	26.6	MW
Asset rating 2023 - N-1	26.6	MW
Forecast Demand 10% 2019	31.4	MVA
Forecast Demand 10% 2020	36.7	MVA
Forecast Demand 10% 2021	38.7	MVA
Forecast Demand 10% 2022	40.8	MVA
Forecast Demand 10% 2023	42.8	MVA
Forecast Demand 50% 2019	30.7	MVA
Forecast Demand 50% 2020	35.9	MVA
Forecast Demand 50% 2021	37.9	MVA
Forecast Demand 50% 2022	40.0	MVA
Forecast Demand 50% 2023	42.0	MVA
Forecast Demand 10% 2019	29.0	MW
Forecast Demand 10% 2020	33.8	MW
Forecast Demand 10% 2021	35.7	MW
Forecast Demand 10% 2022	37.6	MW
Forecast Demand 10% 2023	39.5	MW

Forecast Demand 50% 2019		28.3	MW
Forecast Demand 50% 2020		33.1	MW
Forecast Demand 50% 2021		35.0	MW
Forecast Demand 50% 2022		36.9	MW
Forecast Demand 50% 2023		38.7	MW
Voltage level		22.0	kV
Maximum load at risk 2019		1.7	MW
Maximum load at risk 2020		6.6	MW
Maximum load at risk 2021		8.4	MW
Maximum load at risk 2022		10.3	MW
Maximum load at risk 2023		12.2	MW
Energy at Risk 2019		1195.5	MWh
Energy at Risk 2020		11942.7	MWh
Energy at Risk 2021		21588.2	MWh
Energy at Risk 2022		32757.3	MWh
Energy at Risk 2023		44304.4	MWh
Preferred network investment			
Preferred network investment capital cost	-		$ (real)
Preferred annual network investment cost accuracy	-		$ (real)
Preferred network investment cost upper bound			+%
Preferred network investment cost upper bound			-%
Proposed timing			
Demand reduction required to defer investment by 1 year		1.84	MVA
Demand reduction required to defer investment by 1 year		1.70	MW
Annual deferral value		0	$ (real)
Load Transfer capability		0	MVA
Load Transfer capability		0	MW
Emergency Generation		0	MVA
Emergency Generation		0	MW

Field Name	Value	Units
Constraint primary driver	Capacity	
Location of constraint (start)	Lat: 12°34'37.7"S Lon:130°56'57.1"E	
Location of constraint (end)	Lat: 12°34'37.7"S Lon:130°56'57.1"E	
Maximo asset ID		
Network element	Zone substation	
Residential customers affected	9	
Residential customers affected	0.01	%
Asset rating 2019 - N	29.3	MVA
Asset rating 2020 - N	29.3	MVA
Asset rating 2021 - N	29.3	MVA
Asset rating 2022 - N	29.3	MVA
Asset rating 2023 - N	29.3	MVA
Asset rating 2019 - N	27.6	MW
Asset rating 2020 - N	27.6	MW
Asset rating 2021 - N	27.6	MW
Asset rating 2022 - N	27.6	MW
Asset rating 2023 - N	27.6	MW
Asset rating 2019 - N-1	15.4	MVA
Asset rating 2020 - N-1	15.4	MVA
Asset rating 2021 - N-1	15.4	MVA
Asset rating 2022 - N-1	15.4	MVA
Asset rating 2023 - N-1	15.4	MVA
Asset rating 2019 - N-1	14.6	MW
Asset rating 2020 - N-1	14.6	MW
Asset rating 2021 - N-1	14.6	MW
Asset rating 2022 - N-1	14.6	MW
Asset rating 2023 - N-1	14.6	MW
Forecast Demand 10% 2019	6.9	MVA
Forecast Demand 10% 2020	13.2	MVA
Forecast Demand 10% 2021	17.2	MVA
Forecast Demand 10% 2022	17.2	MVA
Forecast Demand 10% 2023	17.2	MVA
Forecast Demand 50% 2019	6.7	MVA
Forecast Demand 50% 2020	13.0	MVA
Forecast Demand 50% 2021	17.0	MVA
Forecast Demand 50% 2022	17.0	MVA
Forecast Demand 50% 2023	17.0	MVA
Forecast Demand 10% 2019	6.5	MW
Forecast Demand 10% 2020	12.5	MW
Forecast Demand 10% 2021	16.4	MW
Forecast Demand 10% 2022	16.4	MW
Forecast Demand 10% 2023	16.4	MW
Forecast Demand 50% 2019	6.4	MW
Forecast Demand 50% 2020	12.4	MW

Forecast Demand 50% 2021	16.2	MW
Forecast Demand 50% 2022	16.2	MW
Forecast Demand 50% 2023	16.2	MW
Voltage level	22.0	kV
Maximum load at risk 2019	0.0	MW
Maximum load at risk 2020	0.0	MW
Maximum load at risk 2021	1.6	MW
Maximum load at risk 2022	1.6	MW
Maximum load at risk 2023	1.6	MW
Energy at Risk 2019	0.0	MWh
Energy at Risk 2020	0.0	MWh
Energy at Risk 2021	371.7	MWh
Energy at Risk 2022	371.7	MWh
Energy at Risk 2023	371.7	MWh
Preferred network investment		
Preferred network investment capital cost	-	$ (real)
Preferred annual network investment cost accuracy	-	$ (real)
Preferred network investment cost upper bound	-	+%
Preferred network investment cost upper bound	-	-%
Proposed timing	-	
Demand reduction required to defer investment by 1 year	1.64	MVA
Demand reduction required to defer investment by 1 year	1.60	MW
Annual deferral value	0	$ (real)
Load Transfer capability	0	MVA
Load Transfer capability	0	MW
Emergency Generation	0	MVA
Emergency Generation	0	MW

Field Name	Value	Units
Constraint primary driver	Capacity	
Location of constraint (start)	Lat: 23°41'29.7"S Lon:133°51'45.1"E	
Location of constraint (end)	Lat: 23°41'29.7"S Lon:133°51'45.1"E	
Maximo asset ID		
Network element	Zone substation	
Residential customers affected	6160	
Residential customers affected	7.58	%
Asset rating 2019 - N	39.2	MVA
Asset rating 2020 - N	39.2	MVA
Asset rating 2021 - N	39.2	MVA
Asset rating 2022 - N	39.2	MVA
Asset rating 2023 - N	39.2	MVA
Asset rating 2019 - N	38.5	MW
Asset rating 2020 - N	38.5	MW
Asset rating 2021 - N	38.5	MW
Asset rating 2022 - N	38.5	MW
Asset rating 2023 - N	38.5	MW
Asset rating 2019 - N-1	22.4	MVA
Asset rating 2020 - N-1	22.4	MVA
Asset rating 2021 - N-1	22.4	MVA
Asset rating 2022 - N-1	22.4	MVA
Asset rating 2023 - N-1	22.4	MVA
Asset rating 2019 - N-1	22.0	MW
Asset rating 2020 - N-1	22.0	MW
Asset rating 2021 - N-1	22.0	MW
Asset rating 2022 - N-1	22.0	MW
Asset rating 2023 - N-1	22.0	MW
Forecast Demand 10% 2019	23.7	MVA
Forecast Demand 10% 2020	23.9	MVA
Forecast Demand 10% 2021	24.1	MVA
Forecast Demand 10% 2022	24.3	MVA
Forecast Demand 10% 2023	24.5	MVA
Forecast Demand 50% 2019	22.9	MVA
Forecast Demand 50% 2020	23.0	MVA
Forecast Demand 50% 2021	23.2	MVA
Forecast Demand 50% 2022	23.3	MVA
Forecast Demand 50% 2023	23.5	MVA
Forecast Demand 10% 2019	23.3	MW
Forecast Demand 10% 2020	23.5	MW
Forecast Demand 10% 2021	23.7	MW
Forecast Demand 10% 2022	23.9	MW
Forecast Demand 10% 2023	24.1	MW
Forecast Demand 50% 2019	22.5	MW
Forecast Demand 50% 2020	22.6	MW

Forecast Demand 50% 2021	22.8	MW
Forecast Demand 50% 2022	22.9	MW
Forecast Demand 50% 2023	23.1	MW
Voltage level	11.0	kV
Maximum load at risk 2019	0.5	MW
Maximum load at risk 2020	0.6	MW
Maximum load at risk 2021	0.8	MW
Maximum load at risk 2022	0.9	MW
Maximum load at risk 2023	1.1	MW
Energy at Risk 2019	33.3	MWh
Energy at Risk 2020	33.5	MWh
Energy at Risk 2021	66.8	MWh
Energy at Risk 2022	67.1	MWh
Energy at Risk 2023	123.0	MWh
Preferred network investment	Load transfer and auto switching	
Preferred network investment capital cost	$ 100,000	$ (real)
Preferred annual network investment cost accuracy	$ 10,000	$ (real)
Preferred network investment cost upper bound	10%	+%
Preferred network investment cost upper bound	10%	-%
Proposed timing	1/07/2020	
Demand reduction required to defer investment by 1 year	0.51	MVA
Demand reduction required to defer investment by 1 year	0.50	MW
Annual deferral value	0	$ (real)
Load Transfer capability	8.75	MVA
Load Transfer capability	8.6	MW
Emergency Generation	0	MVA
Emergency Generation	0	MW

Field Name	Value	Units
Constraint primary driver	Capacity	
Location of constraint (start)	Lat: 23°41'29.7"S Lon:133°51'45.1"E	
Location of constraint (end)	Lat: 23°41'29.7"S Lon:133°51'45.1"E	
Maximo asset ID		
Network element	Zone substation	
Residential customers affected	10810	
Residential customers affected	13.30	%
Asset rating 2019 - N	114.4	MVA
Asset rating 2020 - N	114.4	MVA
Asset rating 2021 - N	114.4	MVA
Asset rating 2022 - N	114.4	MVA
Asset rating 2023 - N	114.4	MVA
Asset rating 2019 - N	94.6	MW
Asset rating 2020 - N	94.6	MW
Asset rating 2021 - N	94.6	MW
Asset rating 2022 - N	94.6	MW
Asset rating 2023 - N	94.6	MW
Asset rating 2019 - N-1	57.2	MVA
Asset rating 2020 - N-1	57.2	MVA
Asset rating 2021 - N-1	57.2	MVA
Asset rating 2022 - N-1	57.2	MVA
Asset rating 2023 - N-1	57.2	MVA
Asset rating 2019 - N-1	47.3	MW
Asset rating 2020 - N-1	47.3	MW
Asset rating 2021 - N-1	47.3	MW
Asset rating 2022 - N-1	47.3	MW
Asset rating 2023 - N-1	47.3	MW
Forecast Demand 10% 2019	60.5	MVA
Forecast Demand 10% 2020	59.6	MVA
Forecast Demand 10% 2021	59.2	MVA
Forecast Demand 10% 2022	58.7	MVA
Forecast Demand 10% 2023	58.0	MVA
Forecast Demand 50% 2019	57.5	MVA
Forecast Demand 50% 2020	56.4	MVA
Forecast Demand 50% 2021	56.0	MVA
Forecast Demand 50% 2022	55.5	MVA
Forecast Demand 50% 2023	54.5	MVA
Forecast Demand 10% 2019	50.0	MW
Forecast Demand 10% 2020	49.3	MW
Forecast Demand 10% 2021	49.0	MW
Forecast Demand 10% 2022	48.5	MW
Forecast Demand 10% 2023	48.0	MW
Forecast Demand 50% 2019	47.5	MW
Forecast Demand 50% 2020	46.7	MW

Forecast Demand 50% 2021	46.3	MW
Forecast Demand 50% 2022	45.9	MW
Forecast Demand 50% 2023	45.1	MW
Voltage level	66.0	kV
Maximum load at risk 2019	0.2	MW
Maximum load at risk 2020	0.0	MW
Maximum load at risk 2021	0.0	MW
Maximum load at risk 2022	0.0	MW
Maximum load at risk 2023	0.0	MW
Energy at Risk 2019	47.1	MWh
Energy at Risk 2020	0.0	MWh
Energy at Risk 2021	0.0	MWh
Energy at Risk 2022	0.0	MWh
Energy at Risk 2023	0.0	MWh
Preferred network investment	Emergency rating and load transfer	
Preferred network investment capital cost	$ -	$ (real)
Preferred annual network investment cost accuracy	$ -	$ (real)
Preferred network investment cost upper bound	10%	+%
Preferred network investment cost upper bound	10%	-%
Proposed timing	1/07/2020	
Demand reduction required to defer investment by 1 year	0.3	MVA
Demand reduction required to defer investment by 1 year	0.20	MW
Annual deferral value	0	$ (real)
Load Transfer capability	8	MVA
Load Transfer capability	6.6	MW
Emergency Generation	0	MVA
Emergency Generation	0	MW