Asset Management Plan – Transformers

Power and Water Corporation

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Approved By:	Prepared By:	Issue Date: Add date	Next Review: Add date	Status:
Add GM title	Add prepared by title	PWC Controlled Document No. Issued by Doc Control Officer		Version No:

Executive Summary

Power and Water Corporation (Power and Water) owns and operates the electricity transmission and distribution networks in the Northern Territory of Australia. Included in the networks are power transformers which perform a critical function in maintaining the business objectives of delivering a safe and reliable supply of electricity to Power and Water's customers.

Assets contribute a sizeable proportion to the total asset base *– only a small number of transformers are close to the end of their expected serviceable lives.*

Power transformers make up 5% of the total network value of the asset base. It is an aging asset fleet with an average age of 21 years and an average remaining life of 31 years, however, the average age is reduced by the large population of relatively young transformers. There are nine transformers that have less than 10 years expected life, six of these have less than five years life remaining.

Assets operate across a diverse environment *– temperature, humidity, rainfall, termite and soil types present a challenge to managing the assets.*

The Power and Water power network is subject to unique environmental and operational challenges ranging from the coastal tropical environments prone to cyclones, high temperatures and humidity and high annual rainfall, to desert environments subject to high ambient temperatures, occasional flooding, droughts, dust storms and surrounding factors including high termite infestation and aggressive soil conditions. This unique environment results in a more rapid rate of asset deterioration and lower worker productivity compared to peer distribution businesses.

The key impact of these climatic conditions is high moisture content in transformer oil, which results in an increased rate of internal deterioration.

There are two key challenges that require management *– internal condition and capacity constraints.*

Moisture ingress as a result of the climate (rain and humidity) and is further enabled by oil leaks and deterioration of seals and gaskets. The moisture causes the internal paper insulation to deteriorate which increases the risk of internal arcing and eventually a failure. The internal condition is measured through analysis of the gases dissolved in the oil. A number of transformers in poor condition are planned for replacement and permanent online oil filtering will be installed to manage oil moisture content.

Increasing demand in Darwin's three growth corridors of Archer, Palmerston and East Arm requires investment in additional capacity to service the customers. A new substation at Wishart will be established and a new transformer at Archer zone substation, along with load transfers, will meet the growing capacity while minimising capital expenditure (deferring the need for an additional transformer at Palmerston).

Due to the criticality of Hudson Creek for supplying the Darwin region, a strategic spare transformer will be purchased to manage the risk posed by the failure of one of the large 132kV/66kV 125 MVA transformers which have a long replacement time.

Maturing condition data associated with power transformers is a key asset management challenge. An increased focus on the collection of condition data and analysis are being put into effect. Focused routine inspections and targeted inspections and testing, prioritising high risk areas, are some of the proposed undertakings aimed at improving data collection and analysis during business as usual activities. Improved data will enable more advanced analysis and modelling to be undertaken to better support asset management decision making

<u>Investment programs are targeted to manage the key challenges</u> *– directed replacement.*

The following augmentation and asset renewal programs are proposed for the 2019-20 to 2023-24 regulatory period to address key asset challenges:

- establishing Wishart ZSS;
- a strategic spare 132kV/66kV 125 MVA transformer for Hudson Creek;
- installing fans on transformers at Tennant Creek to increase capacity;
- installing permanent online moisture management equipment; and
- replacement of transformers at Berrimah, Humpty Doo, Cosmo Howley, Centre Yard and Pine Creek zone substations.

The augmentation and renewal projects have been developed with the objective of managing the network risk. Modelling has identified that there is currently a very high amount of energy at risk that is concentrated in a few substations. This risk would grow overtime as local demand increases and transformers' condition deteriorates. The projects selected for the next regulatory period will mitigate the excessive risk and bring it to a level that is sustainable in the long term.

The power transformer programs are summarised as follows:

Investment category	2019-20 ($ million)	2020-21 ($ million)	2021-22 ($ million)	2022-23 ($ million)	2023-24 ($ million)	Total ($ million)
Augmentation	$2.10	$0.50	$9.00	$11.85	$8.78	**$32.23**
Renewal	$9.45	$9.68	$5.23	$2.33	$0.00	**$26.69**
Operational expenditure	$1.99	$1.99	$1.99	$1.99	$1.99	**$9.95**
Total	**$13.54**	**$12.17**	**$16.22**	**$16.17**	**$10.77**	**$68.87**

<u>Benefits from the investment program</u> *– network risk.*

The investments are not expected to impact the system performance directly; however, they will reduce the total risk on the network and reduce the operational expenditure required at these substations.

The reduction of risk on the network is shown through calculation of the expected energy at risk. This is a probabilistic approach to assigning a cost to the risk on the network based on the Value of Customer Reliability, the expected amount of energy to be unserved due to transformer failure and the cost to rectify any failures.

With investment over the next five year regulatory period the health and criticality profile for power transformers is expected to change to that shown in the second table below. The mitigated risk is demonstrated in the number of assets that transfer from the H3 health category.

For the transmission pole top assets, a reduced risk is reflected in the removal of all poor health assets in the H3 category.

Transformer health-criticality matrix (quantity) by 2023-24, with no investment

	H1	H2	H3
C1	38	21	5
C2	0	0	0
C3	3	0	0

Transformer health-criticality matrix (quantity) by 2023-24, with investment

	H1	H2	H3
C1	44	20	0
C2	0	0	0
C3	3	0	0

1 Purpose

The purpose of this asset management plan (AMP) is to define Power and Water's approach to managing power transformers. It frames the rationale and direction that underpins the management of these assets into the future:

- Short Term (0-2 years): Detailed maintenance and capital works plans for the upcoming financial year based on current asset condition.
- Medium Term (3-7 years) 2019-24 Regulatory Period: Strategies and plans based on trends in performance and health indicators.
- Long Term (8-12 years) 2024-29 Regulatory Period: Qualitative articulation of the expected long-term outcomes.

Power Transformer assets are managed to comply with the broad external requirements of legislation, codes and standards. This is achieved within an internal framework of policy, strategy and plans that are enabled through interrelated documents, systems and processes that establish the Power Networks asset management practices. The asset management system is summarised in Figure 1-1.

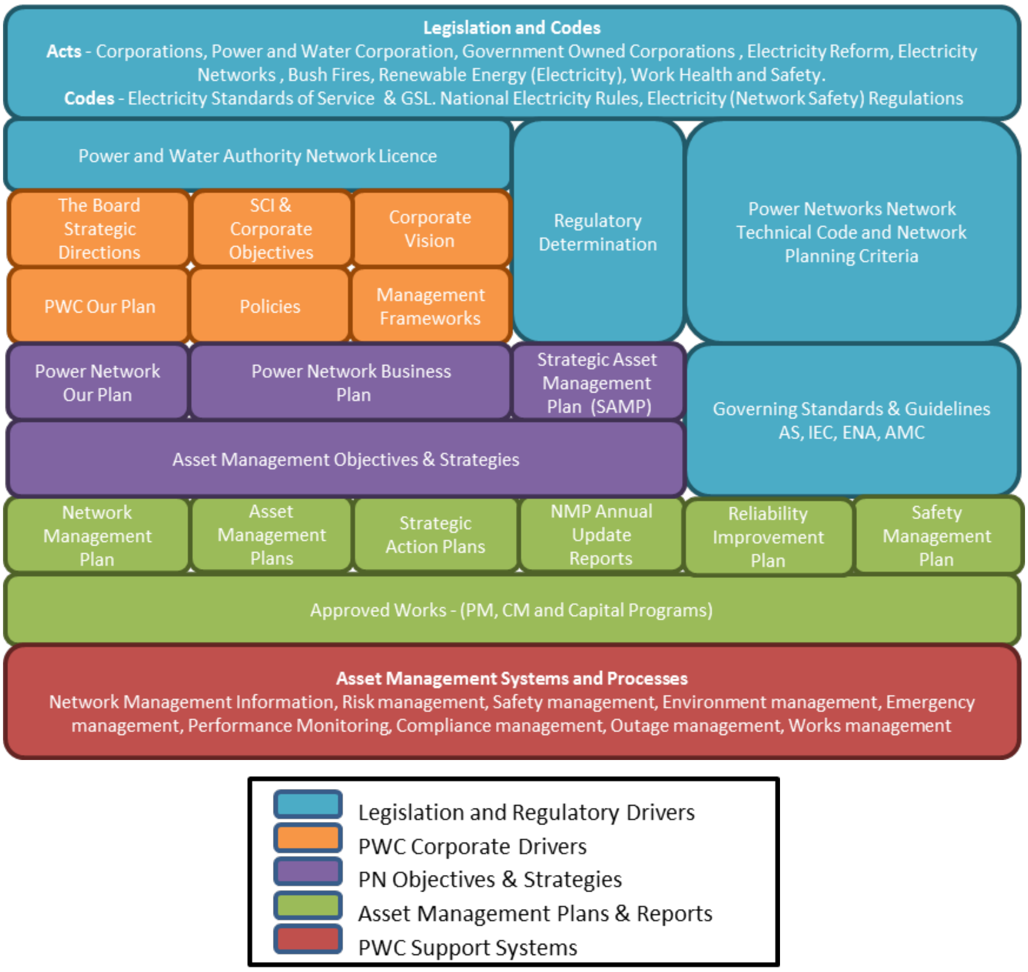


Figure 1-1: Asset Management System

2 Scope and Objectives

2.1 Asset class overview

This AMP covers all power transformers located in zone substations. Table 2.1: Overview of in-scope assets

Table 2.1 provides an overview of the asset fleet broken down by primary voltage and quantity. The scope does not include zone substation assets such as circuit breakers or protection.

Power and Water manages 76 power transformers (67 in service, two mobile units and seven spare) located in 31 separate zone substations. The transformers have primary voltages ranging from 132kV down to 11kV and capacities from 125 MVA down to 0.5MVA. Of the transformer fleet, 95% are part of the regulated asset base and 5% are not regulated.

Table 2.1: Overview of in-scope assets

Region	Primary voltage (kV)	Regulated	Non-Regulated	Spares	Mobile	Total
Darwin	132	5		4		9
	66	32	4	2	2	40
	22	1		1		2
Katherine	132	3				3
	66	4				4
	22	4				4
Alice Springs	66	5				5
	22	7				7
Tennant Creek	22	2				2
Total		**63**	**4**	**7**	**2**	**76**

Further information regarding the number, capacity and voltage of each transformer by substation and an overview of the manufacturer types is in Appendix B – Asset data.

The power transformer asset class accounts for 5% of Power and Water's assets by replacement cost and drives a number of inspection and maintenance activities. This is due to the criticality of the assets and the aggressive nature of the environment in which they are located.

2.2 Asset class function

Power transformers convert electricity from one voltage to another. In the context of electricity distribution, they are typically used to reduce the voltage down from transmission voltages (132kV) to distribution voltages (22kV or 11kV). They interface with other equipment such as surge arrestors, conductors and protection devices.

Power transformers are located in zone substations, and supply customers within a geographical area. They are high value assets that are essential to the functioning of the network and are therefore managed through inspection, testing and maintenance.

Power and Water has a unique network with a small customer base split across three separate networks of Darwin-Katherine, Alice Springs and Tennant Creek. As a result, there is a large variation between transformer capacities, ranging from 0.5 MVA at Centre Yard up to 125 MVA at Hudson Creek.

The function of power transformers within Power and Water's electricity network is illustrated by Figure 2-1.

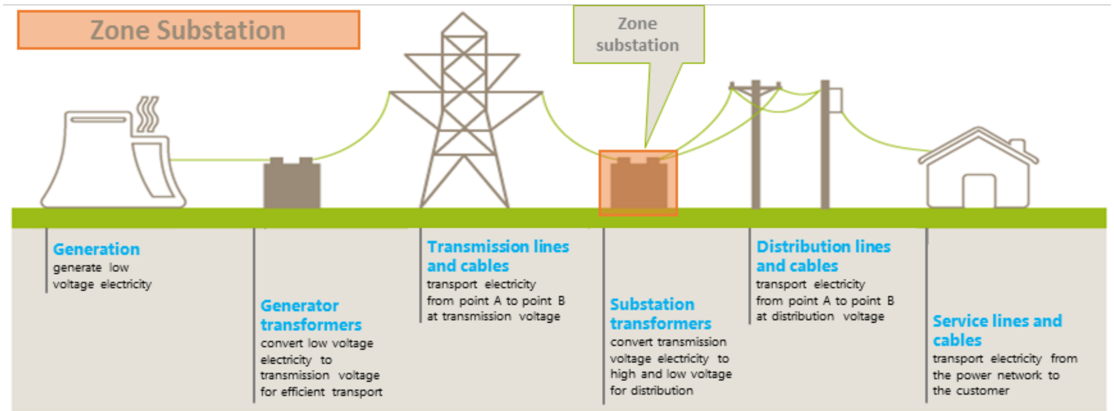


Figure 2-1 Diagram of in-scope assets

2.3 Asset objectives

The AMP provides a framework which steers the management of the asset class in a manner that supports the achievement of Power and Water's broader organisational goals. The Asset Management strategies are listed in the Strategic Asset Management Plan (SAMP) and are aligned to the Asset Management Objectives and implemented in through Asset Management Plans (specific to asset class) or Strategic Asset Plans as shown in Figure 2-2

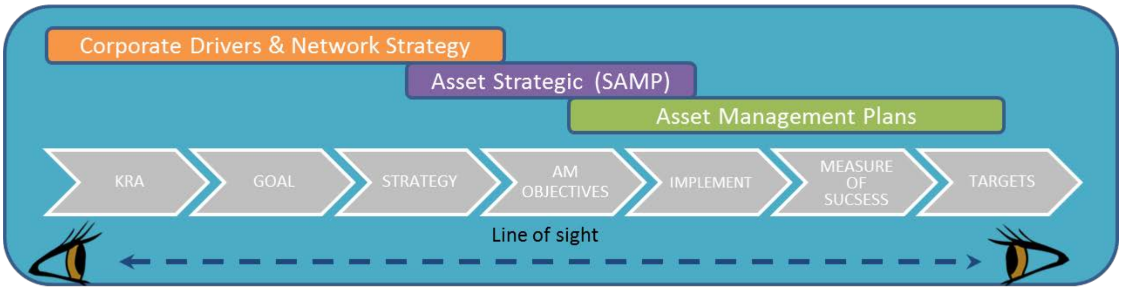


Figure 2-2 Asset Management Line of sight from Corporate and Network strategies through the Asset Management objective to the targets in the asset management plan.

Table 2.2provides the asset management objectives from the strategies that are relevant to this asset class along with the measures of success and the targets. This provides a 'line of sight' between the discrete asset targets and Power and Water corporate Key Result Areas.

Table 2.2: Asset Management Objectives, Measures of Success and Targets

Objectives	Measures	Targets
• Network related operation and maintenance tasks are quantified in terms of risk and used to inform investment decisions that affect Health and Safety outcomes for the organisation	• Total asset class specific safety incidents • Working at heights protection installed • Unauthorised access	• Total asset class specific safety incidents not exceeding TBA
• All environmental risks have been defined, mitigation controls implemented and responsibility for risk ownership has been assigned to appropriate leaders • Develop Environmental Improvement Plans for significant risks to reduce risk exposures and tracked through a governance framework • Develop performance indicators for intended environmental outcomes.	• Total asset class specific environmental incidents associated. • Non-compliant transformer bunding • Oil leaks greater than 100L	• Total asset class specific environmental incidents associated not exceeding TBA
• Ensure that the systems and processes provide sufficient and appropriate data and information to drive optimal asset and operating solutions.	• Asset class contribution to system SAIDI • Asset class contribution to system SAIFI • GSL contribution per year Guaranteed Service Levels	• SAIDI for this asset class TBA. • SAIFI for this asset class TBA. • GSL contribution per year TBA
• Proactively and systematically measure the network power quality	• Asset class related number of poor power quality incidents.	• TBA
• Ensure that the systems and processes provide sufficient and appropriate financial data • Understand the financial risks associated with asset management	• Variance to AMP forecast CAPEX • Variance to AMP forecast OPEX	• Variance to AMP forecast CAPEX +/-10% • Variance to AMP forecast OPEX +/-10%
• Develop systems and data that facilitate informed risk based decisions • Ensure that works programs optimise the balance between cost, risk and performance • Ensure the effective delivery of the capital investment program	• Network risk index quantified (Y/N) • Health and Criticality Parameters defined (Y/N)	• Achieved
• Identify, review and manage operational and strategic risks • Prioritise projects, programs and plans to achieve efficient and consistent risk mitigation. • Achieve an appropriate balance between cost, performance and risk consistent with regulatory and stakeholder expectations. • Define and communicate the level of risk associated with the investment program	• Critical spares analysis completed for asset class • Operator/Maintainer risk assessment completed for asset class and risk register updated	• Achieved
• Ensure that electricity network assets are maintained in a serviceable condition, fit for purpose and contributing positively to Power Networks business objectives.	• All staff are trained and hold appropriate qualifications for the tasks they undertake. • Peer benchmarking, i.e. a reasonableness test of underlying unit costs (capex, opex) • Asset class preventative maintenance completion	• Achieved

3 Context

3.1 Roles and responsibilities

Power and Water operates using an "Asset Owner / Asset Manager / Service Provider" business model. Although there is extensive collaboration and interfacing between the roles, generally speaking:

- the Asset Owner establishes the overall objectives for the assets;
- the Asset Manager develops the strategies and plans to achieve the objectives; and
- the Service Provider performs activities on the ground to deliver the plans.

3.2 RACI

Section 3.1 sets out the organisational roles and responsibilities. This section sets out the Responsibility, Accountability, Consulted, Informed (RACI) matrix for this asset class. This defines the roles and accountabilities for each task by allocating to specific roles/personnel in Power and Water.

Table 3.1: RACI matrix for power transformers

Process	Exec GM Power Networks	Group Manager Network Assets	Chief Engineer	Network Planning Manager	Major Project Delivery Manager	Southern Delivery Manager	Group Manager Service Delivery	Field Services Manager	Works Management Manager	Strategic Asset Engineering	Asset Quality & Systems
Establish condition limits		A	C	C		I	I	C/I	I	R	I
Performance and condition data analysis	I	A	I	I		I	I	I	I	R	I
Plan capital works (Options, costs, BNIs, BCs, etc.)	I	R	A		C/I	R	R	R	R	R	I
Execute maintenance plans	I	I	I			A	A	R	R	C/I	I
Deliver identified major projects and programs of work	I	C	A	C	R	R	R	C/I	C/I		
Manage asset data (data entry, verify data)		A	I	I						C/I	R
Monitor delivery of capital plans and maintenance	I	A	I	I	I	R	R	R	R	R	R

- *Accountable **(A)** means the allocated person has an obligation to ensure that the task is performed appropriately*
- *Responsible **(R)** means the allocated person must ensure the task is completed*
- *Consulted **(C)** means the allocated person must be included in the process for input but do not necessarily have specific tasks to do*
- *Informed **(I)** means this person must be kept up to date with progress as it may impact other parts of their responsibilities or accountabilities.*

3.3 Identification of needs

With respect to asset replacement, the identification of needs is guided by the risk profile for the asset. Table 3.2 below provides the guiding principles for the adoption of the most appropriate asset management strategy.

Table 3.2: Transformer asset management strategy overview

Asset Management Strategy	Asset risk profile suitability
Reactive (functional failure)	- Power transformers are high value assets and therefore are not intentionally run to failure. From time to time assets do fail in service, however, all reasonable and appropriate measures are undertaken to prevent this from occurring.
Condition based (Conditional failure)	- Power transformers are typically critical assets and functional failure is likely to result in loss of supply to customers or pose and environmental or safety risks. - Condition data is gathered regarding both internal and external components and used to forecast optimal timing for replacement of the transformer. - Asset condition modelling is done, based on actual data, to assist prioritisation of asset replacement. - Condition based replacement is forecast on a probabilistic/risk-based approach which involves a cost benefit analysis to ensure the proposed replacement option is optimal.
Demand driven	- The forecast demand at a substation, and growth/reduction over time, is forecast to identify when the existing installed capacity is insufficient for the demand and augmentation of the substation is planned.
Customer driven	- Large (HV) customers connecting to the network may require a dedicated transformer. These issues are managed through the connections process when they occur.

3.4 Selection of options and solutions

Once a transformer is identified as being in poor condition or having insufficient capacity to meet forecast load, a comprehensive set of options is considered to address the risk and ensure safe and reliable supply of power can be maintained. The suite of options should consider the solutions set out in Table 3.3 below, as relevant for the unique situation being assessed.

Table 3.3: Example options that should be considered

Asset Management Options	Asset risk profile suitability
Repair / life extension	- Applicable to condition based strategy only - Asset returned to “as good as old” condition (repair) or “better than old” (life extension) - Transformer (major) refurbishments are possible but not considered to provide significant life extension and therefore are not generally undertaken. Refurbishments are generally limited to the tank, bladder, tap changer replacement and oil replacement or filtering.
Like-for-like	- Replace the transformer with a modern equivalent of the same (or similar) capacity. This is generally the case when there is no load growth forecast or based on an economic analysis that considers demand, timing of replacement(s) and risk.
Alignment with other assets	- When transformers are replaced, other assets at the zone substation may

Asset Management Options	Asset risk profile suitability
	also require replacement. Economic analysis is undertaken to assess the most efficient option of aligning asset replacement or undertaking them as separate projects.
Network solution	- Temporary or permanent transfer of load to other substations to defer the need for augmentation or reduce energy at risk in case the failure of a poor condition transformer. This may be achieved through switching existing network or building new feeders.
Demand management/Non-network solutions	- Incentivizing customers to reduce their demand at peak times to defer the need to augment substation capacity - Generator support to meet peak demand

4 Asset base

4.1 Overview

Power and Water owns and maintains a portfolio of 67 power transformers in service and seven spares distributed across the four regions of Darwin, Katherine, Alice Springs and Tennant Creek, with the largest population in the Darwin Region. They operate at voltages of 132kV, 66kV, 22kV and 11kV.

Transformers consist of a main tank which contains insulating paper wrapped copper windings immersed in oil that act as both an insulation and cooling medium. Other main components of power transformers are:

- tap changer to regulate voltage;
- a radiator for cooling the oil, often with fans or pumps to improve the cooling efficiency;
- an oil reservoir to hold additional oil so the tank remains full;
- bushings to provide insulation and allow connection of the incoming conductor to the transformer; and
- bunding to contain oil leaks.

Different utilisation and climatic environments across the regions, particularly the heat and humidity during the wet season, present different challenges for managing transformers, with associated risk and expenditure implications.

4.2 Asset types

Table 4.1 shows the number of transformers by region, separated out by voltage level and whether they are regulated or unregulated assets. This table excludes two Nomad modular substations.

Table 4.1: Transformers on Power and Water network

Region	Primary voltage (kV)	Regulated	Non-Regulated	Spares	Mobile	Total
Darwin	132	5		4		9
	66	32	4	2	2	40
	22	1		1		2
Katherine	132	3				3

Region	Primary voltage (kV)	Regulated	Non-Regulated	Spares	Mobile	Total
	66	4				4
	22	4				4
Alice Springs	66	5				5
	22	7				7
Tennant Creek	22	2				2
Total		**63**	**4**	**7**	**2**	**76**

4.3 Breakdown of asset population

The range of transformers on Power and Water's network varies in capacity, primary voltage, manufacturer and cooling arrangements. This section provides an overview of the asset fleet under management by Power and Water.

4.3.1 Voltage and capacity

Transformers are sized to meet the forecast demand in the zone substations supply area. As a result of the geographical areas supplied by Power and Water, the transformers on the network range in size from 0.5 MVA through to 75/125 MVA and include primary voltages from 11kV to 132kV.

Table 4.2 provides an overview of the different transformer types, demonstrating that the predominant primary voltage is 66 kV and that there is a high proportion of small capacity transformers. The 7 spares and 2 Nomad units are shown in brackets.

Table 4.2: Transformers by capacity and primary voltage (spares and Nomads shown in brackets)

Capacity (MVA)	22 kV	66 kV	132 kV	Total
0-5	4 (1)	6	-	10
5-10	2	5	-	7
10-15	2	3 (3)	-	5
15-20	5	2	1	8
20-25	1	2	-	3
25-30	-	11 (1)	3 (1)	14
30-35	-	-	1	1
35-40	-	8	- (3)	8
40-45	-	3	-	3
45-50	-	5	-	5
120-125	-	-	3	3
Total	**14 (1)**	**45 (4)**	**8 (4)**	**67 (9)**

Typically, transformer failure modes include:

- deterioration of the internal paper insulation (due to ageing and high moisture content) resulting in internal arcing;
- winding damage due to through faults or surges;

- gasket deterioration leading to major leaks;
- severe external corrosion resulting in significant oil leaks which is an environmental hazard, can result in loss of internal insulation, enables moisture ingress and reduces cooling efficiency;
- gasket deterioration leading to major leaks; or
- high moisture content of oil which accelerates the deterioration of internal components.

Causes of the failures can generally be attributed to moisture accelerating deterioration of the assets and historical maintenance and monitoring practices. The inspection and maintenance activities are periodically reviewed, most recently in FY17, to ensure they reflect the modern practices and are in line with common industry practice.

4.3.2 Cooling

The capacity of transformers includes consideration of their temperatures while operating and any downstream limiting assets (such as cables or circuit breakers). Due to internal impedance, heat is generated while transformers are in service. When transformers heat up beyond their rated temperatures, the internal components start to degrade. Hence, better cooling allows more power to be transmitted without reaching temperatures that would cause damage. The types of cooling, in order of least to most effective, are:

- ONAN – Oil Natural Air Natural;
- ONAF – Oil Natural Air Forced, uses fans to improve cooling;
- ODAF – Oil Directional Air Forced, uses a combination of baffles in the transformer tank to direct the oil more efficiently and fans to improve cooling; and
- OFAF – Oil Forced Air Forced, uses a combination of pumps to move oil around the transformer tanks and external fans to improve cooling.

Measurement and monitoring of winding and oil temperature is an integral part of transformer cooling. Both traditional and modern (fibre optic) measurement of temperature is used across Power and Water's transformer fleet. The temperature monitoring starts cooling equipment (fans and/or pumps) whenever a transformer is overloaded and/or ambient conditions are extreme (high temperatures). This helps regulate transformer temperature.

More effective cooling means that more capacity is available from the transformer, however, additional components introduce additional assets to maintain. The majority of transformers on Power and Water's network are ONAF as shown in Table 4.3.

Table 4.3: Transformer cooling types

Cooling type	% of asset population
ONAN	30%
ONAF	47%
ODAF	12%
OFAF	3%
Unknown	8%

If the cooling equipment fails (predominantly fans or pumps) the impact is reducing the transformer rating to its ONAN rating, but otherwise the transformer can typically continue to operate normally.

The majority of issues experienced by Power and Water are failed fans. However, this is only an issue for emergency ratings. Due to normal load conditions, transformers are predominantly operated as ONAN as the operating temperatures are not hot enough to start the cooling controls.

The cooling pumps and fans can generally be repaired or replaced within a short timeframe and are considered to be low risk and low consequence assets.

4.3.3 Manufacturer

Table 4.4 shows there are transformers from 14 separate vendors with a variety of models and capacities which adds complexity to the maintenance of the assets. ABB, Westralian and Wilson have historically been the predominant manufacturers used by Power and Water, together accounting for 62% of the transformer fleet.

Table 4.4: Transformer manufacturers on the network (including spares and mobile transformers)

Make	Number
ABB	22
Wilson	19
Westralian	10
Tyree	8
English Electric	4
Alstom	3
Areva	2
Crompton	2
Pauwels	2
Lepper	1
Amp Control	1
Tyree Westinghouse	1
GEC	1
Total	**76**

Further detail of the asset fleet is provided in Appendix B – Asset data.

4.3.4 On-load tap changers (OLTC)

On-load tap changers (OLTC) enable the network operator to regulate the voltage output on the secondary side of the transformer. The operator can change settings on a transformer while it is in service to ensure the voltage output remains within tolerances set by the Technical Code. The mechanism changes (fine tunes) the ratio of the windings to increase or decrease the voltage. During this action, there is typically arcing which can produce gaseous by-products in the tap-changer oil. Tap changers can be controlled in three ways: remotely from the control room;

locally from the control room; and locally manually (rarely, if ever, done). Out of the 76 transformers, 54 (71%) have an OLTC. The majority of these are Reinhausen Type M, V and VV, as shown in Table 4.5.

Table 4.5: Transformer OLTC manufacturers and types

Make	Number
AEI	2
ATL	5
Crompton Parkinson	2
Reinhausen Type M	10
Reinhausen Type V	11
Reinhausen Type VV	24
Total	**54**

OLTCs enable Power and Water to regulate the network voltage by changing the winding ratio of power transformers. There are two main types of OLTC:

- Internal tap changers that are installed within the main transformer tank. To maintain these OLTCs, the transformer has to be removed from service, opened up and the OLTC removed. This increases the risk of damaging the windings or enabling ingress of moisture into the oil. These cannot be replaced independently of the transformer, and can result in full transformer replacement. These types of transformers/OLTCs are no longer purchased or installed by Power and Water, but are currently installed at Humpty Doo TF1 and 2 and Pine Creek 66kV TF1 and 2.
- Bolt on/integrated tap changers are attached to the external part of the tank or in a separate internal compartment, as with Reinhausen units typically used within Power Networks, and can be removed without risking damage to the windings or allowing water ingress. The time out of service is therefore reduced and increases the availability of the transformer. These can be replaced independently of the transformer if required.

Typical failure modes of OLTCs are:

- winding resistance issues;
- mechanical failure of drive mechanism, moving parts of selector and diverter switches can lead to internal arcing or failure between taps;
- leaks between main tank and OLTC tank; and
- wear of internal contacts leading to excessive arcing.

Typical consequences of OLTC failures are:

- arcing of selector/fixed contacts causing gassing, i.e. Pine Creek 132kV transformer;
- internal flashover due to contact or insulation failures can cause significant damage to the OLTC and to other components of the transformer;
- failures of drive mechanisms can lead to parallel transformers becoming “out-of-step”. This can lead to significant circulating currents and overloading of power transformers. In these circumstances, protection systems will operate to prevent damage to transformers which can impact customers;

- mechanical failures of the drive mechanism during a tap change can also cause internal arcing and potential catastrophic failure of OLTCs; and
- loss of OLTC function can cause significant operational challenges for control of network voltages. This may require the transformer to be taken out of service until repairs or replacement can be completed.

A full list of the number of OLTCs by age in each substation is provided in Appendix B – Asset data.

4.3.5 Bushings

Bushings provide insulation and allow connection from the incoming conductor to the internals of the transformer (passing through the grounded conductive external tank). These are essential components of transformers and can be replaced separately to the transformer.

Due to the safety risk of failure, Power and Water has historically tested bushings at a higher frequency than the main transformer windings, which is a common industry practice. However the most recent maintenance review in FY17 resolved that, going forward, bushings would be tested at the same frequency as the transformer. This is because many of the older bushings had been removed from the network and bushing condition was better understood as a result of ongoing condition assessment.

Failure modes of bushings include:

- loss of dielectric strength or partial discharge due to moisture ingress of insulation material which can lead to catastrophic failure and fire; and
- oil leaks due to seals and sight glass deterioration.

Consequences of bushing failure are:

- transformer must be removed from service and cannot operate until the bushing is replaced;
- depending on time of year the main tank oil can be exposed to water ingress, this is a concern during the wet season in the northern region;
- bushings can fail explosively, resulting in porcelain fragments being ejected at high velocity which can cause damage to adjacent bushings and other switchyard assets. This is a safety risk to personnel or the public that may be in the vicinity of the bushing. Porcelain fragments can travel 50-100metres; and
- potential for arcing from the incoming conductor to the transformer tank which can:
  - be a safety issue (step and touch potentials); and
  - cause catastrophic failure of the transformer, typically due to oil flowing out of the damaged bushing and simultaneous arcing which ignites the oil.

4.3.6 Bunding

Bunding is an oil containment area that captures any oil leaking from transformers. They are typically concrete construction and sized to contain a volume of liquid that is suitable for the rainfall expectations in the region.

Bunds are an important environmental control to prevent oil from contaminating the nearby land area and are normally connected to oil water separation devices.

Common failure modes include cracking of the bund walls. Other issues identified on the network include old bunds that were built with now outdated construction standards resulting in:

- unsealed bases;
- no oil water separation facilities; and
- bund height not sufficient to capture spill/splash angles required by the current Australian standards.

4.4 Asset profiles

4.4.1 Weighted average age

The age profiles and average age provides an indication of asset remaining life. Table 4.6 provides a summary of remaining life for each voltage level and region based on average replacement life of 50 years.

Table 4.6: Average age and remaining life by voltage

Primary voltage	Weighted Average Age (years)	Weighted Average Remaining Life (years)	% of asset population
22 kV	23.3	28.7	20%
66 kV	19.2	32.8	64%
132 kV	24.8	27.2	16%
Total fleet	20.9	31.1	100%

Table 4.7: Average age and remaining life by region

Primary voltage	Weighted Average Age (years)	Weighted Average Remaining Life (years)	% of asset population
ASP	19	33.0	16%
DRW	17.8	34.2	67%
KTH	38.1	13.9	14%
TCK	18	34.0	3%
Total fleet	20.9	31.1	100%

Table 4.6 indicates that there is no particular voltage level that appears to be at higher risk based on average age; however, Table 4.7 indicates that Katherine has a lower expected remaining life compared to the other regions, which are all fairly similar.

4.4.2 Age profiles

Figure 4-1 and Figure 4-2 show the age profile of all transformers on the network by voltage and region, respectively. They show that although there are a number of relatively new assets that have been installed in the past 15 to 20 years, there are a large number of assets that are over 40 years of age and are likely to be approaching the end of their serviceable lives. The deterioration will be evidenced through condition assessments such as oil analysis (discussed in section 5.1.1 below) and eternally observed deterioration such as oil leaks and corrosion.

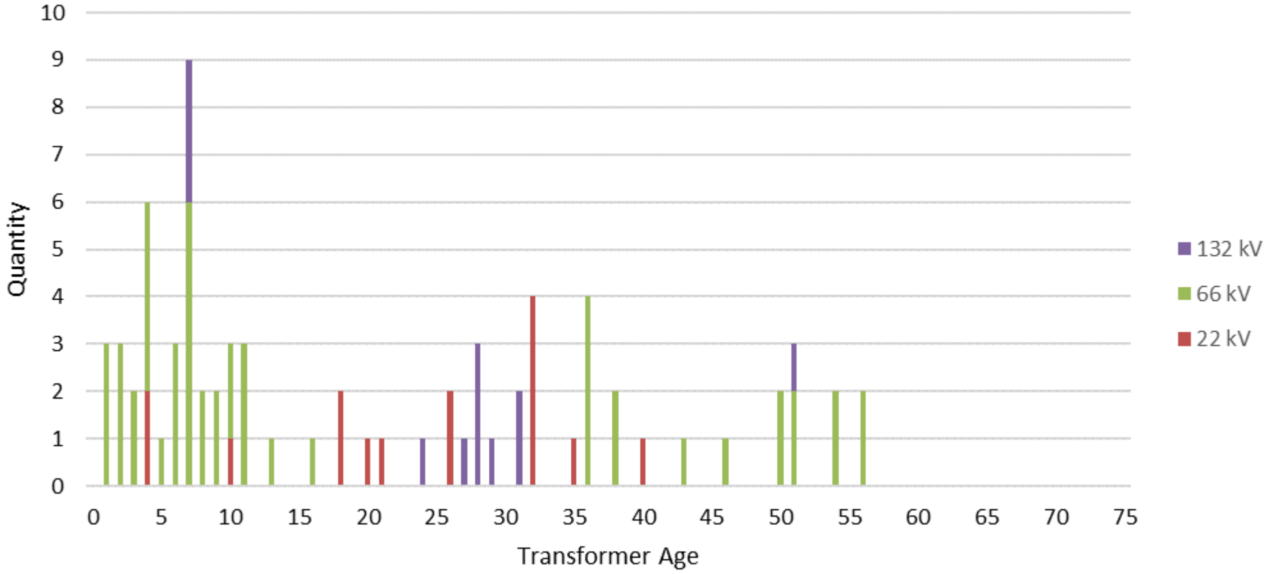


Figure 4-1: Transformer age profile by primary voltage

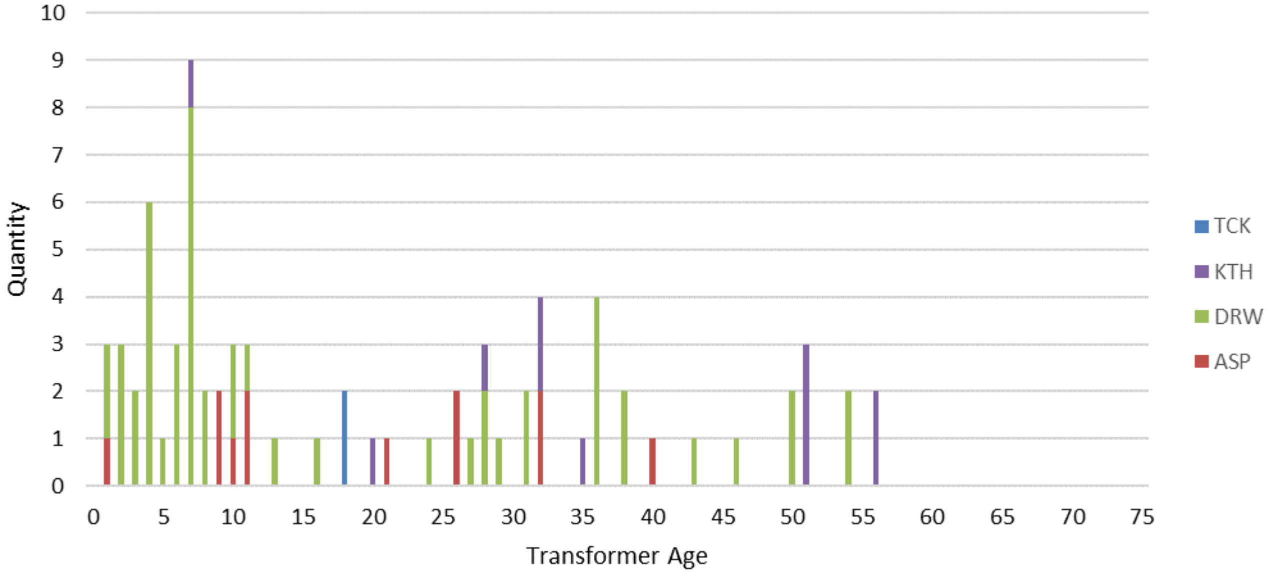


Figure 4-2: Transformer age profile by region

Figure 4-3 show the age profile of transformer OLTCs.

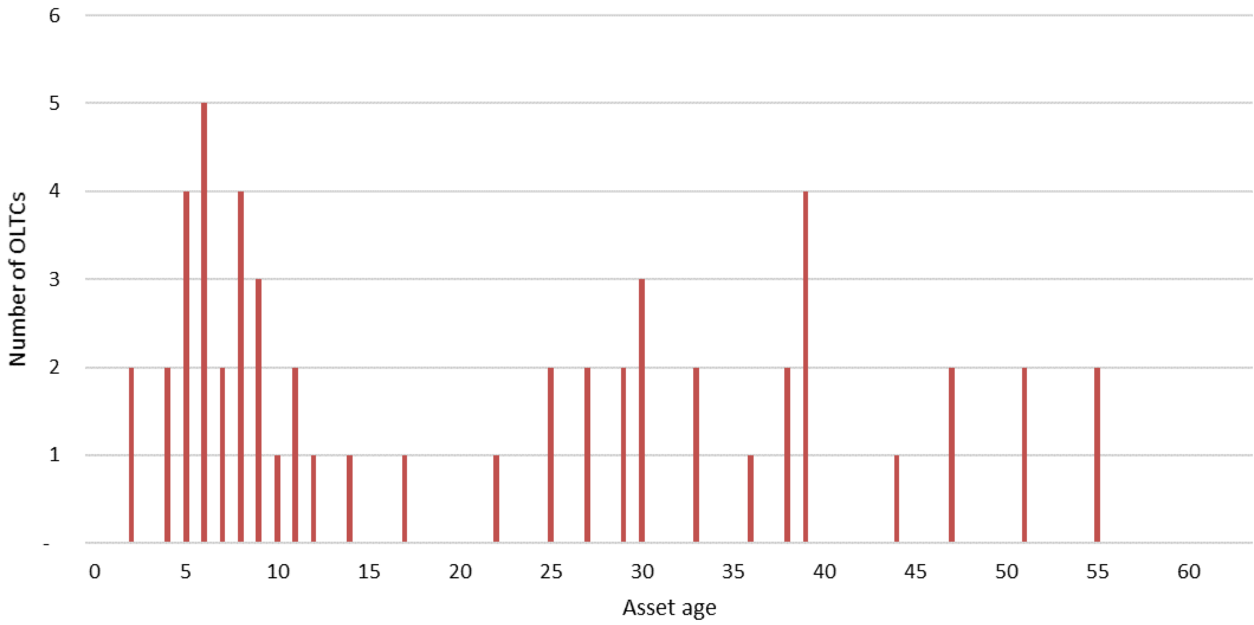


Figure 4-3: OLTC age profile

Appendix B – Asset data shows additional age profiles broken down by voltage level and region.

4.4.3 Expected life compared to NEM

Figure 4-4 below shows Power and Water's asset life compared to peer businesses throughout the NEM. The data for peer Distribution Network Service Providers (DNSPs) is publicly available data extracted from the RIN. It shows that Power and Water's transformers have a life that is comparable to other DNSPs.

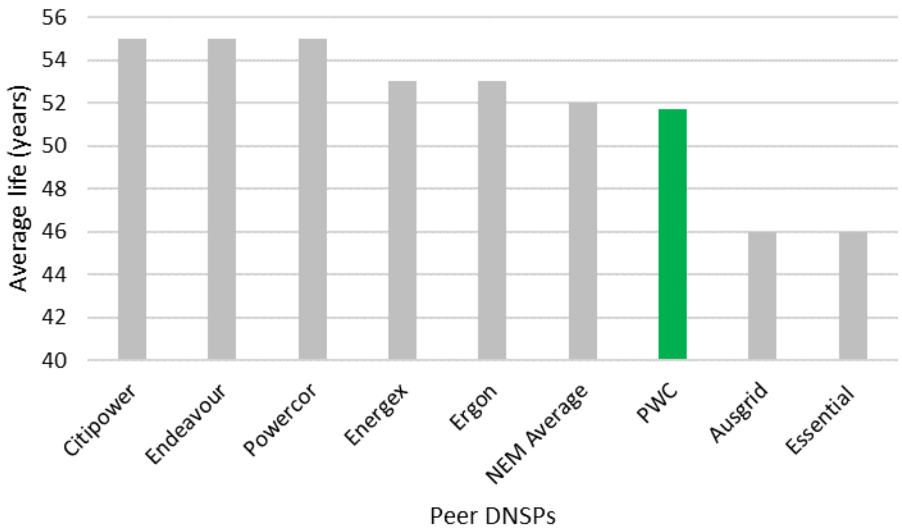


Figure 4-4 Comparison of expected transformer life

It is important to note that other DNSPs may have reported the economic life rather than the actual average replacement age of transformers. Additionally, transformers may be replaced due to demand growth rather than condition resulting in an apparent reduced average life.

5 Health and criticality profiles

This section discusses the health, criticality and resulting network risk of the power transformer fleet. This analysis informs the priorities for Power and Water with respect to where they should focus further condition assessment and plan future network investments.

The health and criticality framework provide the basis for calculating the risk associated with power transformer assets. Risk is the product of the probability of an event occurring (determined by asset health) and the consequence, should it occur (determined by asset criticality). Network risk can be reduced though improving the condition of assets (opex or repex) and/or by reducing the consequence of failure through changing the network topology/configuration.

Power and Water manages network risk so it can successfully operate the network safely and reliably at the lowest cost to the customer.

5.1 Asset health

As high value and critical assets on the network, transformers are inspected, tested and maintained in-line with strategies developed by Power and Water based on the manufacturers inspection and maintenance manual, Power and Water test and maintenance procedures, internal and external transformer and high voltage testing experts; as well as significant consultation with industry peers through regular asset management forums, industry working groups and continuous internal and external technical training. This ensures Power and Water is continually optimising its maintenance strategies with a clear understanding of industry best practice and taking advantage of technology advances of test equipment that reduces the time required for testing in the field.

Asset health is determined through assessments of multiple aspects of the transformer and associated equipment. Inspections include visual assessment of the external condition of the transformer, associated equipment and analysis of oil samples. These inspection methods are discussed further in the following sections.

5.1.1 Condition assessment

There are several external/observable metrics that are considered when assessing the overall condition of transformers:

- corrosion of the transformer tank;
- the extent of oil leaks of the transformer. Oil leaks reduce the amount of oil in the transformer and can impact cooling and insulation properties. In addition, the leaks provide a path for water to enter the transformer and dissolve into the oil;
- suitability of the transformer bunding. If the bunding does not contain the oil (for example, does not have a sealed base) or have appropriate water oil separation devices, then it can also result in an environmental issue through contamination of the local land. Although not a

strict driver for transformer replacement, it influences the options considered and possibly timing of replacement;
- condition of the tap changer; and
- condition of the transformer bushings.

Although these modes of deterioration influence the overall health of the transformer, most of them can be addressed through operational maintenance practices such as replacement of individual components or oil filtering and do not alone drive transformer replacement. The planned maintenance measures are outlined in Section 7.

However, when considering options to resolve network risk, the overall asset condition, and therefore maintenance requirements, are an important input to assessing the most prudent and efficient solution.

5.1.2 Type issues

Type issues are failure modes or modes of deterioration that are common to a specific type (manufacturer and model) of transformer.

Current type issues on Power and Water's network are transformers with integrated tap changers that cannot be removed or replaced separately to the transformer and, therefore, the risk cannot be mitigated through operational maintenance measures. These are typically found on older transformers, as set out in section 4.3.4.

Transformers that are currently affected by type issues are identified and discussed in Section 6.3.

5.1.3 Dissolved gas analysis and oil quality tests

Oil testing is the primary tool available to Power and Water to assess the condition of the internal components of the transformer at an early stage by monitoring oil quality and gases generated during transformer operation.

The gases normally measured in transformers are shown in Table 5.1. The quantities of the gases are analysed using various techniques and ratios to diagnose issues as they develop internally in the transformer.

Table 5.1: Key indicators identified from DGA and oil quality analysis

Item	What it means	Consequence
Polychlorinated Biphenyls (PCBs)	An organic compound used in dielectric i.e. mineral oils in electrical apparatus. PCB's have been banned since the early 1980's but remain in some older assets.	This is an environmental and OHS concern but does not impact transformer condition/operation. PCB's are carcinogens and toxic to the environment. PCB levels greater than 2ppm are classed as Scheduled substances
Acetylene	A dissolved gas created through arcing within the oil.	Indicates either arcing between windings which can be a serious issue, or can be a result of oil from the tap changer (where arcing is expected to occur during operation) into the main tank.
Other gases	Other gases include methane, ethane, ethylene, carbon monoxide, carbon dioxide, oxygen and nitrogen. These are used in Dissolved Gas Analysis (DGA) to assess	The ratios of these gases assist identification of internal condition.

Item	What it means	Consequence
	internal condition.	
Moisture	Presence of water in the oil due to ingress into the main tank or reservoir due to poor maintenance, leaks, a product of oxidation or cellulose degradation.	Reduces insulation integrity and significantly reduces life expectancy of the paper insulation system by accelerating the deterioration process.
Furans (Degree of Polymerisation)	As paper insulation degrades its mechanical properties reduce significantly. During this process furanic compounds are released into the oil. Measurement and trending of these compounds via oil sampling can be used as a useful indicator of remaining tensile strength of the paper insulation system.	Lack of mechanical strength within the paper insulation system reduces the ability to withstand system faults or events.
Oil acidity	Decreased pH level caused by oxidation of the oil	Causes degradation of the paper insulation, decreasing Inter Facial Tensions (IFT) and produces sludge in the transformers main tank

Each of these metrics is discussed in further detail below. However, it is important to note that the Degree of Polymerisation (DP) value is the primary metric used for asset condition assessment and replacement decisions.

PCBs

PCBs are a toxic chemical that develops in oil over time and results in increase health and environmental risks. Oil containing PCBs at a concentration of greater than or equal to 2ppm is classed to contain PCB and is subject to regulation. Once the concentration exceeds 5ppm, the requirements for disposal become more stringent. Oil contaminated with PCBs needs to be disposed of as a Scheduled Substance increasing disposal costs and difficulty.

Currently there is one transformer (Pine Creek Transformer 6) that has 8ppm PCBs and is therefore classed as containing PCBs. There are another five transformers with PCB levels below the unscheduled limit ranging between 0.6ppm and 1.2ppm.

Table 5.2 Transformers with PCBs

Transformer	PCB level ppm
Centre Yard Tx1	1.2
Centre Yard Tx2	0.7
Manton Dam Tx1	1
Palmerston Tx2	0.6
Pine Creek Tx6	8
Pine Creek Tx5	1

Oil Acidity

Oil acidity has multiple impacts that increase the rate of deterioration of the transformers. It creates sludge that accumulates in the tank and reduces the flow of oil and therefore cooling efficiency. The higher temperatures cause the paper insulation to deteriorate and the acidity of the oil further accelerates this process.

The result can be partial discharges and internal arcing which can develop into an internal fault.

Acetylene

The presence of acetylene can indicate internal arcing, but it is also commonly the result of gasses migrating from the tap changer tank into the main tank.

Where acetylene is identified in oil analysis, further inspection and monitoring of the transformer is undertaken to identify the cause.

Moisture content

High moisture content in transformers does not in itself result in transformer failure but it increases the rate of paper deterioration and therefore results in more rapid aging of the transformer and early failure.

Moisture content in the oil is a significant problem in Power and Water's network due to the high annual rainfall and humidity. It is typically treated through opex such as oil filtering, however, Power and Water has found that filtering of highly saturated transformers is not effective and is now installing permanent online filters on all new transformers to prevent saturation occurring.

In addition, Power and Water specifies sealed bag systems which use bladders to contain the oil to provide an additional barrier to water ingress. Transformers older than 30 years (except HC) do not have bladders.

These preventative measures will help prevent transformer core saturation and result in an improved life of transformers.

Degree of Polymerisation

The primary method Power and Water uses to monitor the life expectancy of its transformer fleet is through the Degree of Polymerisation (DP) of the paper insulation within a transformer.

Reduced DP is typically a result of heat produced by transformers while they are in service, however, is also influenced by the presence of water and oxygen in the oil and the degree of oil acidity. Over time, the heat causes the strength of the paper insulation around the windings to deteriorate. When the paper strength reaches a certain level, arcing can occur between windings or the mechanical forces caused by downstream faults can damage the insulation and windings and cause the transformer to fail.

The condition of the paper is assessed either directly by taking physical samples of the paper or indirectly by taking samples of the transformer oil. The samples are sent to a laboratory for analysis and the DP value is obtained. A DP value of 1200 or more indicates a new transformer. A DP value of 200 indicates a transformer at end of life.

Direct sampling is very accurate, but the ability to take paper samples is limited to during major overhauls which occur rarely for power transformers. Indirect sampling through oil analysis is reasonably accurate, but is affected by oil replacement or filtering processes. If the laboratory is aware of the oil treatment, then the DP value can be adjusted accordingly. As a result, the risk to Power and Water is an overstatement of the DP value which could provide false confidence in the condition of a transformer.

As shown in Figure 5-1, the DP value (shown as Calculated DP value due to adjustments made by the laboratory) varies approximately linearly with age. More highly loaded transformers will deteriorate more quickly than lightly loaded transformers.

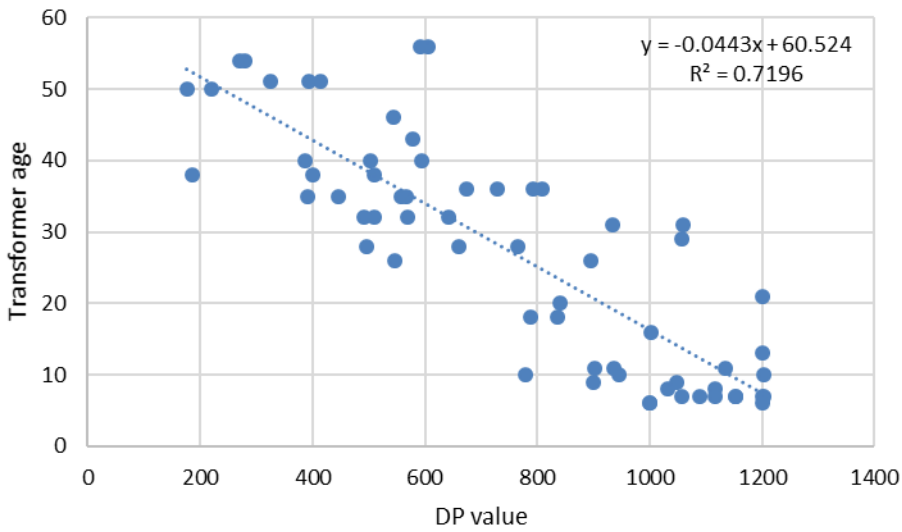


Figure 5-1: DP value trend against transformer age

The combined condition assessment is considered when prioritising and assessing risk mitigation on the network.

The current assessment of risk for transformers is based on a quantitative assessment of DP value as well as a qualitative assessment of moisture content, acetylene and external condition. Power and Water is investigating methods to include the additional metrics in the quantitative assessment and is an area identified for improvement during the next regulatory period.

5.1.4 Electrical tests

Electrical tests form an integral and essential part of power transformer health assessment. Combined with the OIL and DGA tests they give an overall and comprehensive picture of the transformers condition. Electrical tests can be categorised as follows:

1. Test on HV bushings (IR, DLA etc.)
2. Tests on OLTC (Dynamic resistance, Static resistance, Motor current)
3. Tests on Transformer Insulation (IR, DLA, Dielectric spectroscopy / Dirana)
4. Tests on Transformer core and winding (TTR, Static Winding resistance, SFRA, Magnetising current, Positive and zero seq. Impedances)
5. Test on Transformer Auxiliaries - OTI & WTI calibrations, Functional checks on Bucholz relay, Oil level indicators, Pressure release devices etc.)

5.1.5 Inspection and maintenance expenditure

Increasing annual expenditure on inspection, maintenance and other operational activities indicates there is an issue with the transformer and can be a lead indicator that the asset is approaching the end of its serviceable life. Figure 5-2 shows the per unit average annual maintenance expenditure over the past four years on transformer related opex at each substation.

The orange highlighted series identify the substations that will be replaced and/or remediated in the current and next regulatory period and the green highlights series identify where the substations will be augmented due to growth requirements.

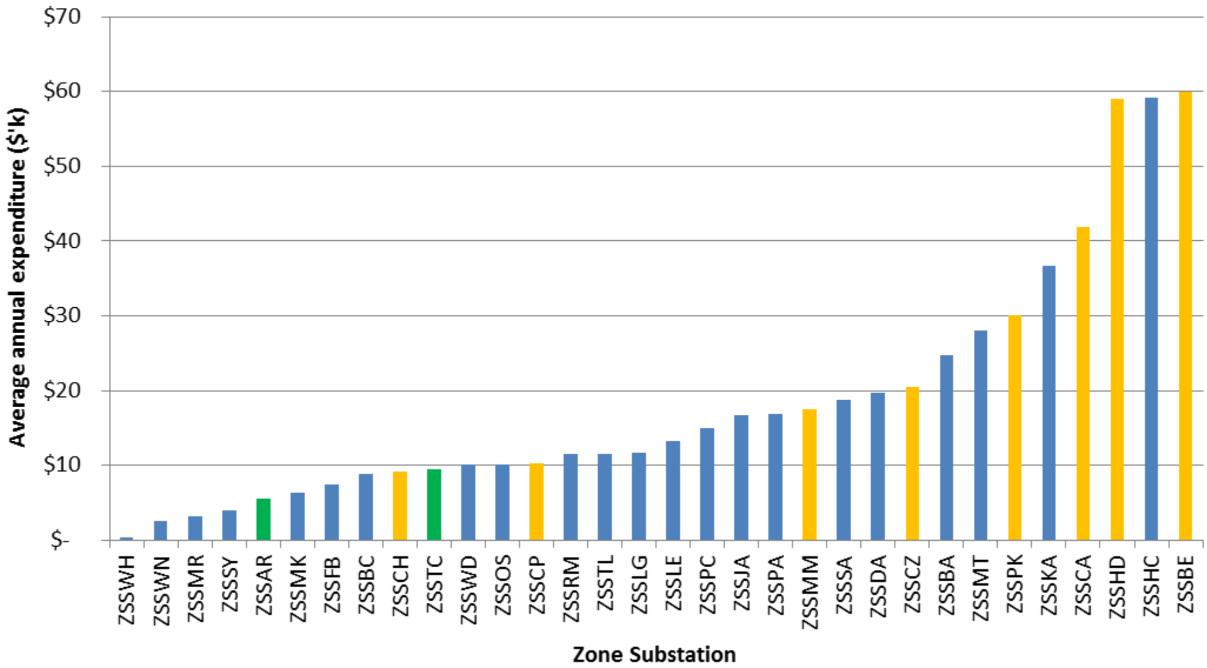


Figure 5-2 Average annual opex per transformer by substation FY14 to FY17

A base level of annual operational expenditure is expected for each substation that will vary according to the substation size and configuration, however, the chart shows a distinct increase for the eight substations on the right-hand side of the chart, indicating condition issues are likely to exist at those substations.

The main drivers of high opex, beyond routine inspection and maintenance tasks, in substations not being remediated in the current or next regulatory period, were:

- Hudson Creek (ZSSHC): is due to severe oil leaks. A project is underway to rectify the oil leaks through replacement of the bladders.
- Palmerston (ZSSPA): servicing and replacement of components of the radiator banks and some oil leak repairs.
- Katherine (ZSSKA): a number of oil leaks were repaired and replacement of components of bushings was undertaken.

These opex items are not expected to be annual recurring costs or to immediately identify these transformers as being in poor condition and requiring replacement. They will continue to be monitored as set out in Power and Water's inspection and testing procedures.

5.1.6 Asset health assessment

Power and Water undertakes an asset fleet health assessment, at portfolio level, based on modelling the remaining life of transformers using the DP value, as calculated through the relationship shown in Figure 5-1. Where assets are identified to be in poor condition, further assessments known as Condition Assessment Reports (CARs) are undertaken.

Modelled asset health

The first stage in asset health assessment for transformers is modelling using the DP value.

The remaining life is calculated based on the full data set of asset age and DP values for in service and decommissioned transformers. A regression of the data is taken, as shown in Figure 5-1 above, to determine the relationship between age and condition for transformers in the environmental and operational circumstances in the Northern Territory.

The regression calculated the expected life of a transformer to be 52 years based on reaching a DP value of 200. The effective age of each transformer is calculated by using the regression coefficients and the transformers DP value. The remaining life is calculated as the 52 year life expectancy minus the effective age.

The Asset Health Score is then allocated based on the following three categories:

- H1 – Good (greater than 40% life remaining)
- H2 – Average (between 10% and 40% life remaining)
- H3 – Poor (less than 10% life remaining)

If the Asset Score is H3, Power and Water undertakes a CAR (outlined below) for a detailed investigation into the asset. The CAR is then used to adjust the Asset Health Score if required.

Condition Assessment Reports

Condition Assessment Reports (CARs) are undertaken by field crews at each zone substation to provide an overall assessment of the state of the individual assets and the overall substation. They assess the physical condition of each asset as well as considering the historical test data from any oil or functional tests that are undertaken for the assets. These reports will be used to determine the asset health and set the health condition as Good, Average or Poor and adjust the outcomes of the portfolio level modelling analysis[1].

Outcome

Table 5.3 shows the output of the health assessment. The transformers identified to be in poor condition are:

- Berrimah Tx1 and Tx2 – both have 4% life remaining
- Centre Yard Tx1 and Tx2 – both have less than 2% life remaining
- Humpty Doo Tx1 and Tx2 – both have less than 8% life remaining

Table 5.3: Health Score Results

Health Rank	Health	Remaining Life	Number of substations	Number of transformers
H1	Very good	100% - 50%	21	42
	Good	50%-40%	3	4
H2	Moderate	40%-30	5	9
	Poor	10%-30%	4	6
H3	Bad	<10%	3	6

[1] Current versions of condition reports collated in container F2013/6409

Note: The substations may be counted multiple times if they contain transformers of different health status. Spare transformers and the Nomad transformers are not included in the table.

Figure 5-3 shows the expected remaining life of the transformer fleet, demonstrating that there are six transformers with less than 10% (less than five years) of their life remaining, and another four with less than 10 years remaining. Approximately 80% of the fleet is in Very Good to Moderate health. This reflects the renewals undertaken for zone substations and network growth in recent years.

The chart shows there is likely to be a consistent need for replacement over the next 20 years.

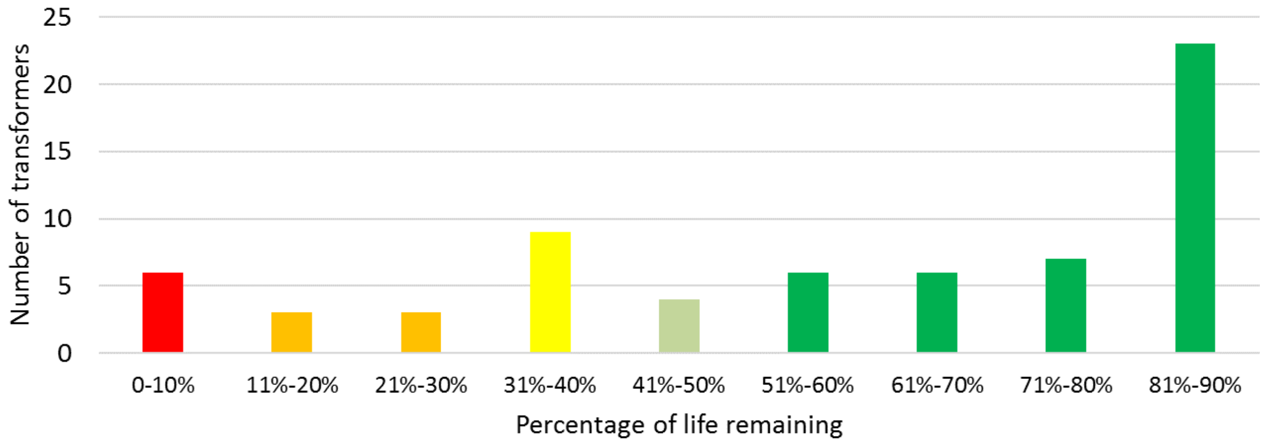


Figure 5-3: Transformer remaining life

Planning for replacement of transformers needs to be initiated early to ensure there is sufficient time to align replacement with other major works and to assess any risks that are unique to the individual transformer and substation.

These transformers are likely to deteriorate at different rates, and more detailed inspections are undertaken to refine the year in which remedial action is required.

5.2 Criticality

The criticality of a transformer is an assessment of its importance to the continued operation, reliability, stability and security of the power network. Criticality is dependent on the following key attributes which are assessed at the level of a zone substation:

- The type of customer they serve, typically broken down into:
  - CBD, Urban and Rural for reliability metrics, and
  - Residential, Industrial and Commercial for the value of lost load (VoLL) or Value of Customer Reliability (VCR)
- The redundancy of the substation, that is the number of transformers and their capacities compared to the demand
- Other mitigation factors that can be implemented in the case of transformer failure, such as transferring load to other substations
- Amount of time required to replace the transformer. Large transformers have a longer lead time, and the ability to undertake the installation and commissioning works is limited to the dry season.

These characteristics have been assessed to provide a ranking of the criticality of transformers, by substation, as shown in Table 5.4. The analysis shows that Hudson Creek is clearly the most critical substation, and out of the other 31 substations, there are six that rank highly, another five that rank moderately and the remainder are of low criticality. Details of how the criticality was assessed are shown in **Error! Reference source not found.**

Table 5.4 Criticality ranking of substations

Criticality Rank	Criticality	Number of substations	Number of transformers
C1	Very low	26	55
	Low	4	9
C2	Moderate	0	0
	High	0	0
C3	Critical	1	3

Note: The substations may be counted multiple times if they contain transformers of different health status. Spare transformers and the Nomad transformers are not included in the table.

The full criticality analysis is shown in Appendix B – Asset data.

5.3 Network risk

Network risk is the combination of the health and criticality of the transformer. It can be shown in either a qualitative or quantitative manner.

5.3.1 Qualitative risk assessment

The health and criticality rankings for each transformer are combined and shown in Table 5.5 as a qualitative overview using a risk matrix approach. This identifies there are no transformers with high or extreme risk, 10 transformer with moderate risk and the remainder are low and very low.

Table 5.5 Power transformer health-criticality matrix (quantity)

	H1	H2	H3
C1	39	21	4
C2	0	0	0
C3	3	0	0

The asset health and criticality is a function of time and is expected to change as the assets continue to age. With no investment over the next five year regulatory period the profile is expected to change to that shown in Table 5.6. The increase in risk is demonstrated in the increase in the number of assets that entered the H3 health category.

Table 5.6 Power transformer health-criticality matrix (quantity) with no investment.

	H1	H2	H3
C1	38	21	5
C2	0	0	0
C3	3	0	0

Network risk can also be shown by a quantitative assessment through the calculation of the Energy at Risk per zone substation.

5.3.2 Quantitative risk assessment

Energy at Risk is a representation of the economic cost to customers as a result of loss of supply. It is dependent on the criteria listed above under criticality and the probability of failure assessed using the transformers condition (DP value). CBD areas generally have a higher Value of Lost Load (VoLL) also called Value of Customer Reliability (VCR) than urban and rural locations.

The Energy at Risk is assessed at the substation level and is shown in Figure 5-4 and Figure 5-5 below. It is presented as the equivalent annual cost based on a net present value calculation over a 20 year period. The values of energy at risk are shown to be high as the analysis does not take into consideration any mitigation works, such as transformer replacement. The energy at risk can be used during options analysis to identify the optimal timing of replacement. However, in the charts below, it is used to identify and prioritise the risk on the network.

The analysis identifies high risk existing at Pine Creek, Humpty Doo and Berrimah, moderate risk at Humpty Doo, Centre Yard and Cosmo Howley and emerging risk at Lovegrove. This analysis identifies where risk exists and the magnitude of the risk so it is useful for prioritisation, however, further analysis is required at each substation prior to initiating a remediation project.

Figure 5-5 shows substations with lower amounts of energy at risk on a smaller scale.

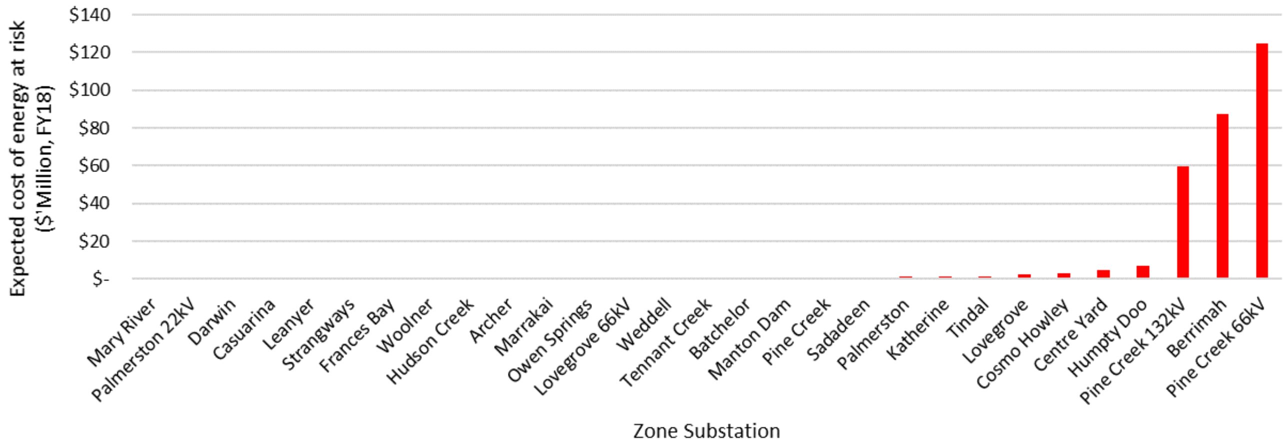


Figure 5-4: Network risk by substation (Energy at Risk)

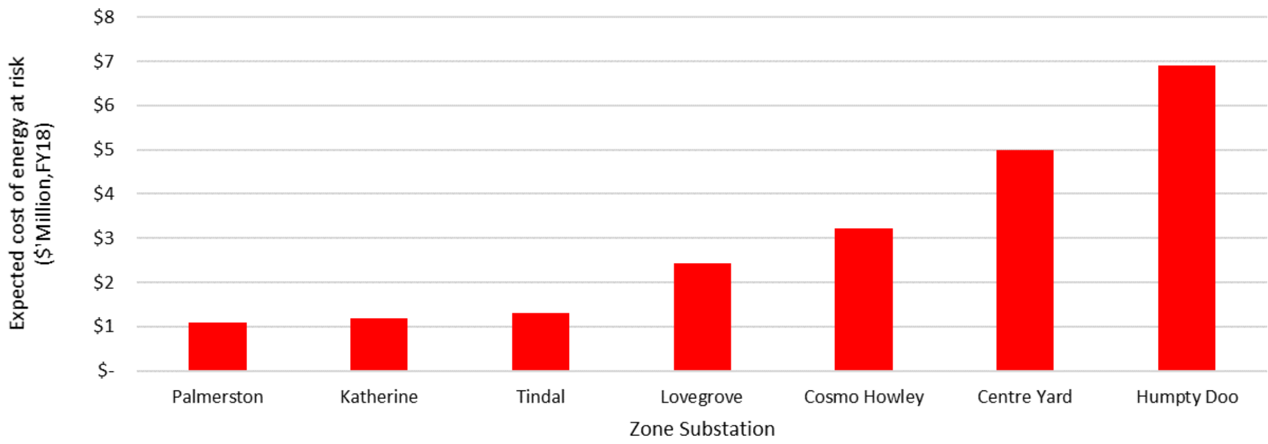


Figure 5-5: Network risk by substations (Energy at Risk) subset of Figure 5-5 for more granular scale

Key assumptions in the analysis are:

- The loss of a transformer results in two cost components – the value of lost load and the cost of restoration.
    - Load is assumed to be off supply for a short period of time before actions can be taken to restore it. This incurs a cost estimated based on the value of customer reliability.
    - There is a cost per substation for restoration of load to represent the cost of installing a spare transformer, installing temporary generation or other mitigation plans. The values vary by substation and are included as an input to the model and are based on Power and Water experience and estimates.
- The Value of Customer Reliability (VCR, also referred to as the Value of Lost Load, VoLL) has been estimated as $33,670 per MWh based on a report published by AEMO in 2014[2] and escalated for CPI using data from the ABS[3].
- Load growth is included as determined by AEMO's forecast. Load duration curves have been used based on meters at each substation.
- Transfer capacity has been included based on analysis of feeders and adjacent substation capacities
- The loss of the two largest transformers is modelled. The energy at risk is calculated as the sum of energy at risk in N, N-1 and N-2 scenarios
- The probability of a transformer failure is based on its DP value and the Weibull distribution. Conditional probability has been used.
- Does not consider failure modes that are common between two transformers at one substation that could result in higher probability of an N-2 event, i.e. where two transformers in a substation are the same model and age so would be expected to have a similar life or failure mode.
- The discount rate is the expected WACC for the FY18-FY24 regulatory control period.
- Existing local generation is included

2 Australian Energy Market Operator, Value of Customer Reliability Review, September 2014

3 Australian Bureau of Statistics, Darwin CPI, All Categories

6 Key challenges

This section summarises the current and emerging challenges faced by Power and Water. The section focuses on issues that are driving expenditure that are unique to Power and Water's network and environmental condition. Normal deterioration of assets is considered as business as usual and not discussed in this section.

The challenges are broken into categories of Environmental, Operational, Asset and Asset Management.

6.1 Environmental challenges

Table 6.1 summarises the four operating regions covered by the network, setting out the type of environment, unique challenges in that environment and the implications.

Table 6.1: Environmental challenges in relation to power transformers asset management

Region	Environment	Challenges	Expenditure / risk implications
Alice Springs	Desert	• Extreme temperature changes both high and low • Limited time periods available for testing and maintenance due to the load profile • Remoteness	• Heat related stresses and reduced productivity resulting in increased time to undertake maintenance and inspection tasks • Suitably qualified and experienced resources are limited or non-existent and must be brought in from Darwin or interstate. This results in higher opex costs due to travel costs and time • Equipment and plant must be mobilised from Darwin for even minor defects • Provision of adequate cooling • Difficulty of conducting some tests in high temperatures (Dirana, DLA, IR)
Tennant Creek	Desert	• as above	• as above

Darwin	Coastal / Tropical	• Corrosion of external tanks
		• High rain fall and humidity resulting in:
		  ◦ Land contamination from oil leaks escaping from bunding and/or oil water separation treatment
		  ◦ High moisture content of transformer insulating oil, increasing the rate of deterioration
		• High temperatures contributing to increased deterioration rate of transformer paper insulation
		• Access to substations and being able to work on assets during the wet season – heat and rain/flooding (safety issue and detrimental to assets)
			• Higher oil testing and filtering requirements
			• Increased importance of maintenance to address leaks
			• Upgrading/maintaining integrity of bunding
			• Loss of insulation resulting in arcing
			• Deterioration of internal paper insulation (water/heat)
			• Oil contamination of surrounding land

Region	Environment	Challenges	Expenditure / risk implications
Katherine	Desert / Tropical	• as above	• as above

Specific areas of environmental concern are:

1) Tropical environment

As noted in Table 6.1, approximately 80% of Power and Water's network is located in a coastal tropical environment that is prone to cyclones. High humidity and annual rainfall have multiple negative impacts on the condition of transformers. The issues are a challenge that is unique to Power and Water compared to other distribution networks throughout Australia. Specific modes of deterioration are discussed further in section 6.3.

The tropical environment increases the rate of deterioration of assets and also reduces the ability for Power and Water to undertake maintenance for six months of the year during the wet season.

The impact of the environment is a more rapid rate of deterioration and lower worker productivity (discussed below) compared to peer distribution businesses, driving an increased level of opex to maintain and manage the asset fleet.

6.2 Operational challenges

Operational challenges in relation to power transformers that pose unique challenges to Power and Water, and drive increased expenditure to manage the network, are listed below.

1) Accessing assets for maintenance

Power and Water is limited from accessing its assets due to both operational constraints imposed by System Control and environmental constraints during the wet season:

- Hudson Creek is the central node for conversion from 132kV to 66kV for distribution of electricity to Darwin. 310MW of generation is located at Channel Island and an additional 60MW is located at Katherine and Pine Creek, with 129MW is available at Weddell. Therefore, 75% of generation is connected to Hudson Creek at 132kV so any outage for maintenance puts the stability and security of the network at risk
- There are a number of remote substations with only a single transformer which are difficult for appropriately skilled field crews to access due to distance and/or monsoonal conditions. This can result in prolonged outages due to slow response times.

2) Operational effectiveness of field crews due to heat and humidity

Power and Water operates in hot and humid environments. The environments are not comparable to other networks around Australia and have a significant impact on the productivity of the field crews. To assess and quantify the impact of the climatic conditions, Power and Water undertook a study in selected locations across Australia.

Workability is the term used describe the productivity impact of climate in both Northern and Southern regions. It is the percentage of time for which work of different physical exertion can be effectively undertaken.

Table 6.2 describes the work rates used in the study along with a description and examples.

Table 6.2 Work rate descriptions

Work rate	Description	Work examples
Rest	Rest	Lunch and Crib Breaks
Low	Sitting with light manual hand/arm work. Driving. Standing with light arm work, occasional walking.	Driving, work planning, briefings and toolbox meetings, inspections
Moderate	Sustained moderate hand to arm work, moderate arm and truck work. Light pushing and pulling. Normal walking.	unpacking tools, spare parts, dismantle/ replace small electronic components, general switching from ground
High	Intense arm and truck work, carrying, shovelling, manual sawing, pushing and pulling heavy loads, walking at a fast pace.	Climbing ladders, working in trenches and cabinets, remove replace larger components
Very High	Very intense activity at fast to maximum pace.	Carrying larger tools and replacement components, lifting, carrying up ladders, digging trenches, hauling cables, moving cable, pillars, poles

The outcome of the study is shown in Table 6.3 with the impact on Power and Water highlighted in orange. It demonstrates that the climatic conditions, particularly in Darwin where the majority of Power and Water's network is located, result in an average Workability of 65% compared to other major cities in Australia. This would equate to a 35% escalation of labour hours compared with the southern states for similar work and therefore an escalation of opex.

This is supported by feedback received via a heat stress survey which identified that approximately 50% of workers report daily or weekly heat-related impacts on their productivity.

Table 6.3 Workability for selected Australian locations based upon moderate metabolic rate

Location	Month											
	J	F	M	A	M	J	J	A	S	O	N	D
Alice Springs	94%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Adelaide	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Brisbane	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Darwin	41%	44%	45%	60%	100%	100%	100%	100%	74%	46%	34%	32%
Hobart	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Melbourne	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Perth	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Sydney	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

3) Availability of capability and skills in remote areas

Due to the geographical regions that Power and Water's network services and where skilled staff and technicians are willing (or chose) to live, Power and Water has an ongoing problem with transporting staff and equipment to site.

Power and Water's work force is centred in Darwin. Most technicians with expertise in specialist areas, such as protection, are based in Darwin along with the majority of test equipment and plant required for normal maintenance tasks. Highly technical but generally low volume and low frequency repair and maintenance tasks (such as OLTC PM, OLTC to main tank gasket repair, internal inspections, bushing replacements) require OEM support and/or a technical specialist to be brought in from interstate as it is not possible to maintain appropriate experience levels with Power and Water's low fleet size.

As a result, there is an increased need for the skilled technicians to travel to remote sites in other areas of the network that can be up to 1,500 km away. This increases the time and cost of undertaking maintenance and/or installation of assets. This is a unique situation to Power and Water and is not experienced by the distribution businesses in the eastern states of Australia.

Plant mobilisation is also an issue. Plant and equipment required for basic repairs is based in Darwin and needs to be transported to remote locations.

4) Demand profile

The demand profile across the network is fairly flat and consistent across each day, as shown in Figure 6-1. The daily peak is fairly flat and consistent between 8am and 10pm, and is driven by the use of air conditioners. This shows that all assets are utilised consistently and therefore it is more difficult to remove assets from service for prolonged periods of time.

During the wet season the load profile becomes flatter (more consistent) with less difference between the peak and the trough and the demand is about 10% higher.

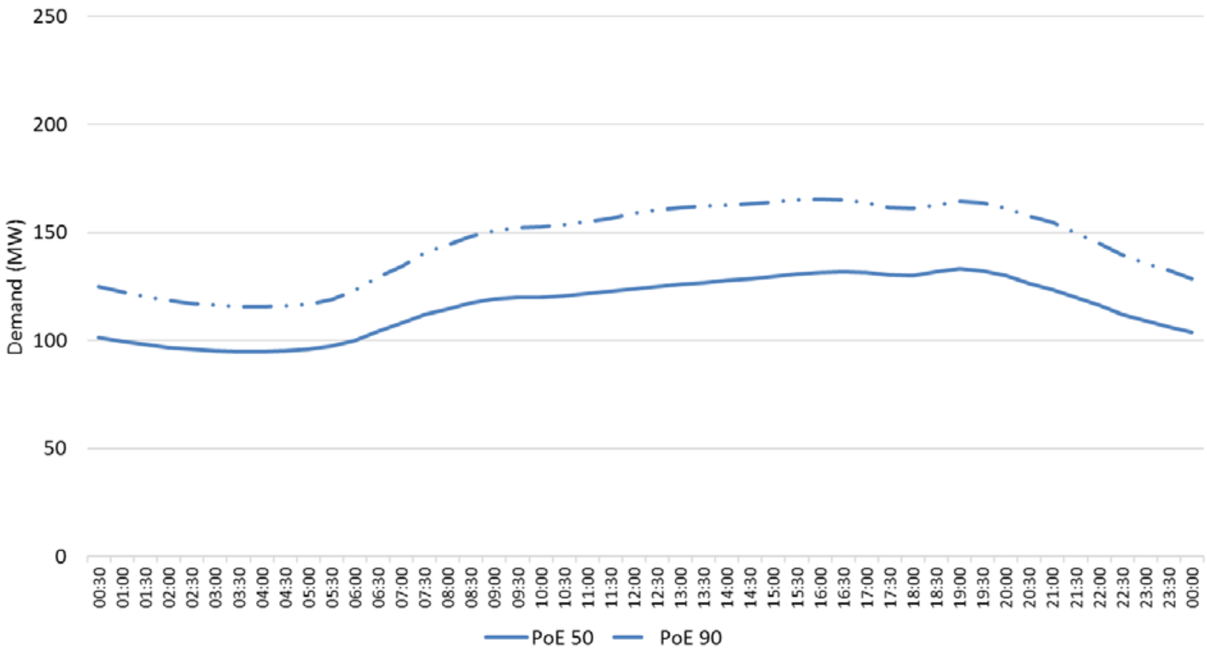


Figure 6-1 Darwin average daily demand profile (Hudson Creek ZSS) May to October

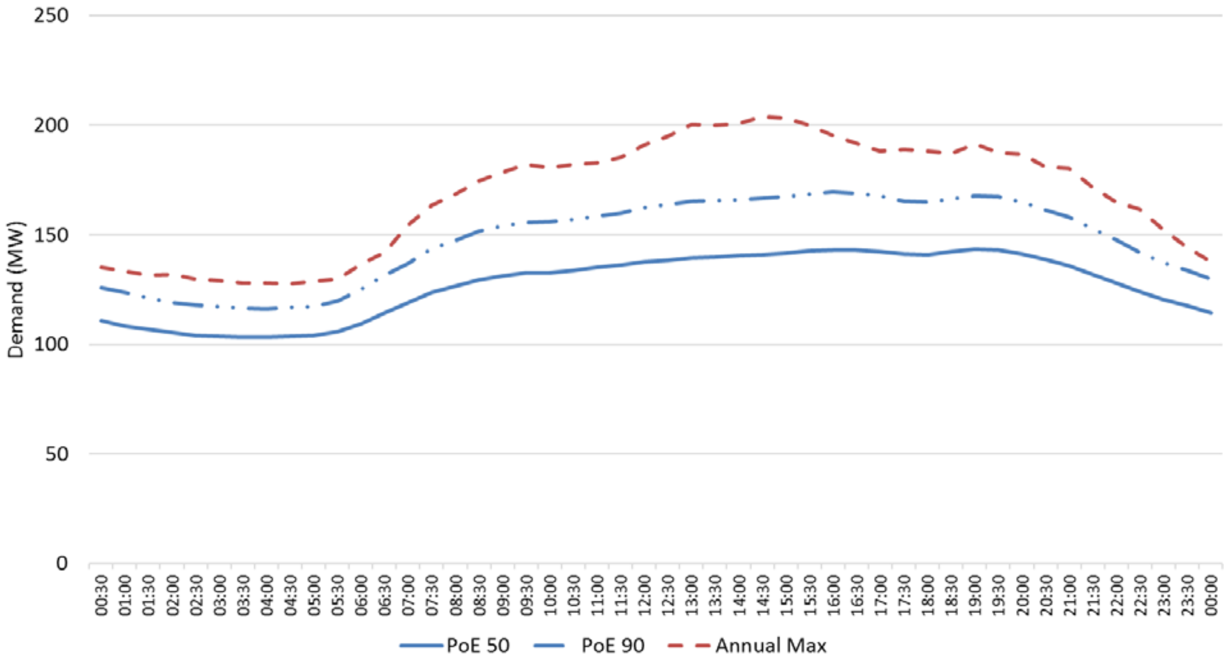


Figure 6-2 Darwin average daily demand profile (Hudson Creek ZSS) November to April

The annual maximum shows the demand for the highest half hour interval for the year. This shows that although the average peak was approximately 150 MVA, the maximum was 200 MVA, or 33% higher.

6.3 Asset challenges

This section identifies the current and emerging challenges in relation to Power and Water's power transformer assets. This section excludes normal wear and tear on assets and focuses on issues which drive asset expenditure beyond what is observed in other distribution networks.

1) Criticality of Hudson Creek transformers

Hudson Creek substation is the central node of Power and Water's network and is the primary supply point for Darwin. It comprises three 132/66kV and 75/125 MVA ONAN/ONAF transformers. These transformers have long lead times of 12 to 18 months and currently no strategic spare is held by Power and Water.

Figure 6-3 shows the network diagram for the Darwin – Katherine system. It clearly shows that all generators at Channel Island are connected via Hudson Creek transformers along with any excess generation from Pine Creek and Katherine. This accounts for 75% of generation at 132 kV.

Weddell is the only large generator that can supply Darwin independently of Hudson Creek and at 66 kV but has a history of being unreliable since construction.

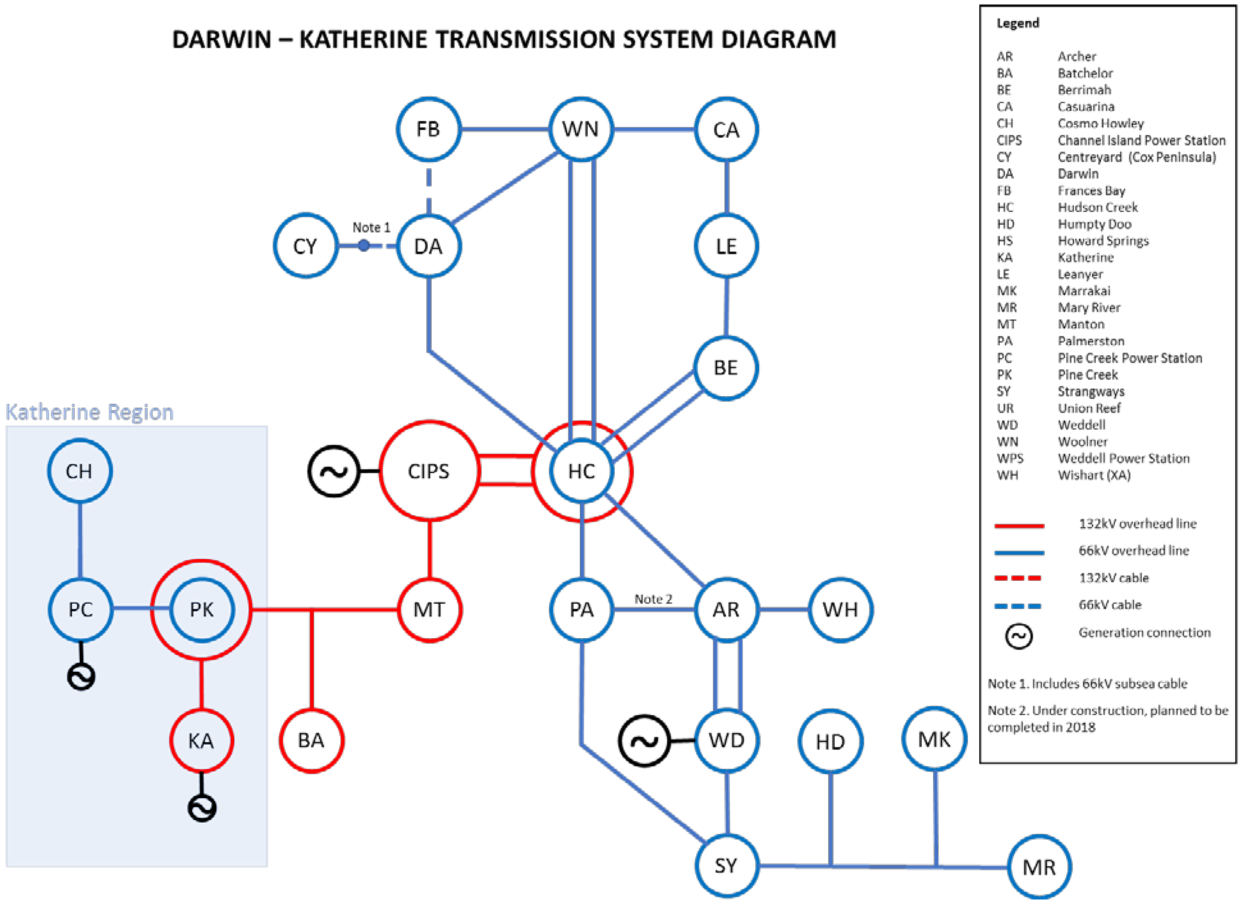


Figure 6-3 Simplified network diagram for the Darwin – Katherine System

Figure 6-4 shows the load duration curve for Hudson Creek (net of any generation supplied by Weddell Generator). It shows that the demand exceeds the N-2 capacity of the substation approximately 30% of the time. Power and Water has estimated that it will take approximately 18 months to receive a new transformer from the date of placing an order. This indicates there is a risk to network supply in this scenario.

Although the probability is Rare, the consequence is Severe, resulting in a Major risk to the network[4].

4 Refer to PWC risk frame work for definitions regarding the probability, consequence and risk rankings

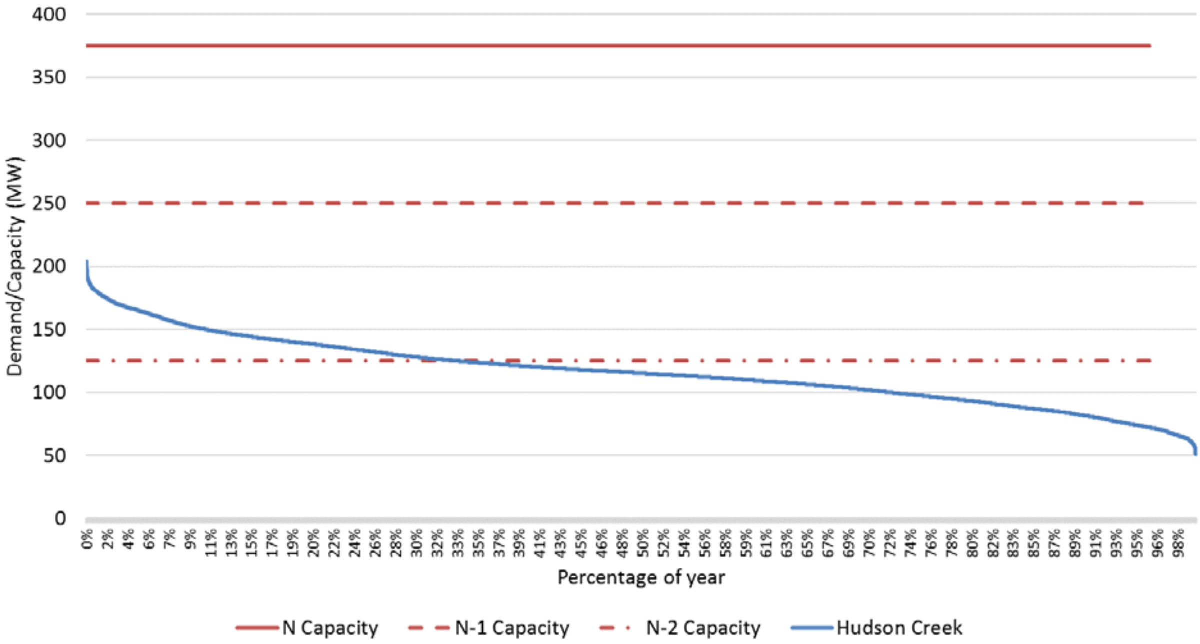


Figure 6-4 Hudson Creek load duration curve compared to capacity ratings

Figure 6-5 shows the average load across a 24 hour period during the wet season. It highlights that load will be at risk between 7am and 8pm and that the load will remain near the transformers maximum capacity during the night. This means there will be no significant time for the transformer to cool down as it is likely to be utilised at a minimum of 80%. High utilisation generates heat which causes deterioration of the internal components, particularly the paper insulation.

Figure 6-5 Average daily load forecast at Hudson Creek (wet season)

Hudson Creek transformers currently have severe oil leaks. This is reflected in section 5.1.4 through the high average annual opex expenditure. Oil leaks result in reduced insulation and cooling efficiency, increased moisture ingress, and therefore an increased rate of paper deterioration. Major leak repairs are scheduled for dry season 2018, including replacement of conservator bladders that have failed.

Although the transformers are currently assessed to have good DP value, the impact on the paper insulation due to the leaks is unknown and may take time to materialise.

In addition, the current issues have highlighted a risk of common failure modes in the three transformers as they are all the same manufacturer, model and age. If one reaches end of life, it is likely the others will also be at end of life.

Due to a long replacement time of 18 months for a transformer, if there one transformer fails there is an increased likelihood of a second event (N-2) occurring, in which case there is unlikely to be sufficient capacity to supply the demand. Power and Water would rely on Weddell Generator being reliably available and operating the remaining transformer at its maximum capacity.

During the transformer replacement time:

- supply to Darwin would be at risk due to an increased potential for a N-2 contingency occurring
- maintenance will be restricted on these highly critical transformers
- they will need to be operated at high utilisation to supply the demand

Power and Water has established a plan to mitigate this risk.

2) Accelerated deterioration of transformers due to moisture

Deterioration of the paper insulation inside transformers is the primary driver for transformer failure. The deterioration is measured through oil analysis and the presence of trace chemicals. When moisture dissolves into transformer oil, it acts to accelerate the rate of paper deterioration.

The high humidity and rain fall in the Northern Territory increases the ability of water to dissolve into the transformer oil as a result of normal transformer breathing, where there is not a conservator bladder. Additionally, as transformers age and corrode or seals deteriorate, the ability of water to ingress into the transformer increases, further deteriorating the transformer.

Traditional cork gaskets tend to deteriorate and become brittle at around 30 years and require replacement. If not replaced, the transformer will leak oil. Newer transformers use o-rings, however these have not been in service long enough to establish a baseline performance and life expectancy.

Operational measures such as oil filtering to remove contaminants (predominately water, but also other contaminants such as acetylene other gases) are undertaken. Online oil filtering has not been successful in the past. Although the oil has been dried, there is limited effect on drying the transformer core and the improvement is therefore negligible. Also, the filtering equipment has been damaged by the environmental conditions. Filtering oil is an expensive process and increases operational expenditure.

3) Declining network demand but with growth corridors

Demand is generally declining across the network except for growth corridors at Wishart Zone Substation with a forecast growth of 18% and Marrakai, Archer and Berrimah Zone Substations with growth of approximately 3%.

The mobile Nomad transformer and substation is currently deployed at Wishart. A permanent zone substation will be established due to forecast load growth.

4) Energy at Risk analysis

A number of transformers are approaching the end of their life in the next 10 to 15 years based on oil analysis and using the DP value to determine expected remaining life. On average, approximately one transformer per year will require replacement, however this is more likely to occur as several in some years and none in others.

Power and Water has undertaken an assessment of energy at risk to identify the areas of risk on their network. The energy at risk model is based on the demand forecast produced by AEMO, load duration curves obtained over a one year period for each substation, an estimated VCR based on the NEM values and risk of asset failure based on condition assessments.

During the next regulatory period, Power and Water plans to continue using the energy at risk model to improve it for forecasting future investment needs.

6.4 Asset management challenges

Power and Water faces a number of challenges with respect to managing their assets. The two key challenges are improving the asset data to enable more advanced analytics for forecasting investment needs and the challenge of decreasing demand impacting the economic benefits of asset replacement.

These two aspects are discussed below.

1) Improved collection and use of asset data

Power and Water typically has good asset data on their power transformer fleet. Since transformers are high value assets with relatively few individual units, it is economic to undertake diagnostic testing to track their condition. However, there are improvements that can be made with respect to the data captured:

- Improve the process to identify recent oil filtering that has occurred to ensure appropriate treatment during analysis by the laboratory
- Improve the analytics used on the data for predicting end of life and the rate of asset deterioration
- Improve the collection and allocation of financial information to individual transformers for inspection and maintenance activities

2) Assessing the need for transformer replacement

The forecast reduction in network demand means the economic value of transformer replacement is reducing while transformers are deteriorating in condition. Identifying the economic benefits of replacement versus managing or accepting a prudent level of energy at risk on the network will be a challenge.

Secondary impacts of a transformer failure, need to be considered. These may include:

- safety hazards of step and touch potential rises that could require implementation of operational restrictions for entering substations
- destruction of nearby equipment due to fault currents or fire in the case of catastrophic failure
- A combination of factors are considered when assessing transformers condition and assessing the need for replacement, including dissolved gas analysis, external condition, oil leaks and forecast demand. Currently, there are a number of transformers the have been determined to require replacement.

7 Performance indicators

Transformers are managed to ensure reliable, safe and sustainable distribution of electricity. To achieve these objectives, performance indicators will be established based on key risks and performance requirements. These indicators will be monitored and asset management strategies and plans are adjusted on a periodic basis to ensure the targets are met.

The key performance indicators will be aligned to the objectives set out in **Error! Reference source not found.** to ensure the management of power transformers will enable Power and Water to meet their overall network and corporate objectives.

This section of the asset management plan will set out the targets, actual performance and any gaps in the performance against the metrics. This will enable Power and Water to identify short comings in the asset fleet and develop or amend strategies and projects to close the gap.

While the performance indicators are currently under development, they are expected to cover the following general aspects:

- Transformer availability
- Contribution to network reliability
- Transformer condition such as the number in poor health
- Environmental requirements such as oil contaminants, leaks and noise
- Safety obligations, and
- Financial metrics to ensure efficient expenditure

These performance indicators will be developed and included in the next revision of this asset management plan.

8 Growth requirements

Power and Water plans their network to provide safe and reliable supply of electricity to customers. To achieve this, with respect to transformers, key inputs to the network augmentation planning process include:

- Requirements set out in the Technical Code
- Forecast load growth
- Substation capacities (and the limiting asset)

Technical Code (the Code)

During the planning process, Power and Water must have regard to the Code. Part C of the Code sets out the Network Planning Criteria, including the following key clauses:

Clause 13.8.1 sets out the requirement for Power and Water to undertake an annual planning review including to consider loads, generation and non-network solutions

- Clause 13.9 sets out the investment analysis and reporting requirements including the need to determine the least cost option on a present value basis and include in the analysis an estimate of system benefits and non-quantifiable economic benefits
- Clause 14 sets out the supply contingency (security) criteria which are summarised in Tables 13 and 14, including:
  - Specifying forecast demand is based on the coincident maximum demand with a 50% probability of exceedance
  - Restoration time targets for outages

An important outcome of these requirements is that an area with a forecast demand of over 50 MVA has a requirement to be restored within 5 hours for a second supply contingency. This requirement only applies to Hudson Creek as all other substations have demand of less than 50 MVA.

Forecast load growth

In 2017, Power and Water engaged AEMO to undertake a demand growth forecast for the network areas. The study outcome identified that there is one region of significant growth, three of low growth and demand for the remainder of the network is forecast to decline. The growth areas are summarised in Table 8.1.

Table 8.1 Zone substations with forecast growth (Summer, 10% PoE, FY18 to FY27)

Zone Substation	Region	Annual growth rate
Wishart ZSS (66/11 kV)	DRW	18%
Tennant Creek ZSS (11/22 kV)	TC	2.7%
Marrakai ZSS (66/22 kV)	DRW	2.5%
Archer ZSS (66/11 kV)	DRW	2%
Berrimah ZSS (66/11 kV)	DRW	2%

Capacity planning

Transformers in distribution networks can usually be operated above their nameplate rating due to the cyclic nature of the load. The magnitude of the increase depends on the transformer construction and load profile and is determined on a case by case basis

The various capacities assigned to power transformers in the Power and Water network include:

- Nameplate – the capacity value stated on the transformers technical data sheet
- Normal Cyclic – the maximum capacity available for permanent operation
- Short Emergency – the maximum capacity available for a 30 minute period of time without damaging the transformer
- Long Emergency – is not a standard time period, instead it is determined on a case by case basis for each transformer and load profile

If a condition issue exists on a transformer, Power and Water will de-rate the transformer to a lower capacity. Further, a transformers capacity will be limited so it does not exceed any downstream constraints should they exist, e.g. a transformer CB with low capacity.

Power and Water plans the network based on the normal cyclic rating, which is generally higher than nameplate unless a condition issue exists. The Network Management Plan outlines the capacities and ratings of the transformer fleet.

The requirements of the Code, as related to capacity and network planning, and the forecast load growth have resulted in capacity constraints that need to be addressed.

The following sections provide a summary of the project proposed to address the capacity constraints and growth areas of the networks. The detailed analysis and options analysis for each project are described in the BNI and/or PBC for the project.

8.1 Wishart

Full details of the Wishart substation are available in the document D2017/394282 PRD33001 - Preliminary Business Case PBC - Construct Wishart Zone Substation.

8.1.1 Network constraints

There has been ongoing development in the East Arm and Wishart areas during the past 10 years. Augmentation of infrastructure has been deferred through the implementation of temporary solutions, including the deployment of the Nomad modular substation at Wishart, to allow better assessment of network growth. There are currently a number of confirmed new developments planned for the Berrimah, Wishart, and East Arm areas, which will add approximately 46 MVA to the network. This is supported by the 18% load growth by the end of FY27 forecast by AEMO in their report “Power and Water Corporation maximum demand, energy consumption and connections forecast, September”.

8.1.2 Option considerations

Four options were considered:

1. Do nothing
2. Establishing a new Wishart Zone Substation consisting of 2 transformers
3. Install a third transformer at Berrimah
4. Implement demand management

8.1.3 Plan

Of these options, studies have shown that option 2, establishing a new Wishart Zone Substation will most efficiently address the needs of the area. It will also make the Nomad modular substation available for redeployment to other sites, therefore improving the ability of Power and Water to react to future network constraints.

Option 2 was preferred as it had the best strategic alignment and highest NPV.

8.2 Archer Zone Substation Augmentation

Full details of the are available in the document D2017/394304 PRD33002 - Preliminary Business Case PBC - Archer ZSS Augmentation.

8.2.1 Network constraints

Archer ZSS and Palmerston ZSS are interrelated as they supply the same load area and are connected at the 66 kV level via a new transmission line. Archer was initially built due to load growth and the need to provide additional capacity in the area.

Archer ZSS is still experiencing load growth, forecast by AEMO to be approximately 3% per annum. As the demand grows in the area, the available capacity of load transfers to Palmerston ZSS is decreasing. As a result, the firm (N-1) capacity is expected to be exceeded during the summer of 2019/20.

8.2.2 Option considerations

Five options were considered to resolve this issue:

1. Do nothing (deferral of the preferred option)
2. Upgrade Archer ZSS with a third power transformer
3. Uprating the capacity of the two existing power transformers
4. Add connection facilities for a Nomad modular substation
5. Demand Management/Non-network solution

8.2.3 Plan

A multicriteria analysis was undertaken to assess the five options. Option 4 was identified as the most efficient approach to resolve the capacity constraint.

8.3 Strategic spare for Hudson Creek

Full details of the Hudson Creek strategic spare are available in the document D2017/418175 PRD33230 - Business Needs Identification - Darwin - Hudson Creek Spare 132kV Transformer Capacity Upgrade.

8.3.1 Network constraints

As discussed in section 6.2, Hudson Creek substation is the central node of Power and Water's network and is the primary supply point for Darwin. All generators at Channel Island are connected via Hudson Creek transformers along with any excess generation from Pine Creek and Katherine. This accounts for 75% of generation at 132 kV.

Weddell is the only large generator that can supply Darwin independently of Hudson Creek and at 66 kV. However, Weddell Generator has a history of being unreliable, typically 90MW capacity available only 43% of the time[5].

The existing transformers are all the same manufacturer, model and age which means there is a risk of common failure modes across the three transformers. If one reaches end of life, it is likely the others will also be at end of life. This has been highlighted by the current severe oil leaks affecting all three transformers that are caused by the failure of the same component.

Although the transformers are currently assessed to have good DP value and a good health ranking, the impact on the paper insulation due to the leaks is unknown and may take time to materialise.

The risk this presents to Power and Water is insufficient capacity to supply all the load if two transformers were to be taken out of service (an N-2 scenario) and Power and Water would not be able to comply with its obligations under the Technical Code.

To mitigate this risk, and to ensure compliance with Part C Clause 14 of the Technical Code, Power and Water is planning to purchase a strategic spare transformer to reduce the period of time that the system will be in a N-1 or N-2 configuration and reduce the consequence of any type issue developing.

8.3.2 Option considerations

Four options were considered:

1. Do nothing
2. Establishing a new 132/66kV substation at Weddell
3. Establishing a new 132/66kV substation at Archer
4. Procure a fourth transformer at Hudson Creek
5. Implement demand management

8.3.3 Plan

Option 4 to procure a fourth transformer is currently assessed to be the preferred option for addressing the loss of a transformer and prolonged outages due to the long lead time of these large transformers.

[5] Based on performance since October 2016

Option 4 was preferred as it had the best strategic alignment and highest NPV.

8.4 Tennant Creek transformer upgrade

Full details of the Tennant Creek transformer upgrade are available in the document D2017/368108 NTC - Business Needs Identification BNI - Tennant Creek Transformer Upgrade.

8.4.1 Network constraints

An additional new large customer in Tennant Creek means the substation will no longer meet the requirements of the Class G supply criteria as set out in the Technical Code. The capacity of Tennant Creek will require at least an additional 0.8MVA to meet the maximum demand and remain compliant with the Technical Code

8.4.2 Option considerations

Three options have been considered:

1. Install radiator fans on existing transformers
2. Post contingency load shedding
3. Demand management

8.4.3 Plan

Initial investigations have found that Option 1 is most likely to achieve the required outcome in a cost effective manner. It will increase the transformer rating to 10 MVA (ONAF) which is expected to be sufficient for the new large customer and longer term growth forecast from AEMO.

8.5 Power transformer online moisture control (oil filtering)

Full details of the power transformer online moisture control program are available in the document D2017/462957 Program Business Need Identification BNI - NMP12/PRD33452 - Power Transformer Online Moisture Control Program.

8.5.1 Network constraints

The climatic conditions experienced in the northern region of the Northern Territory as a result its tropical climate, which bring high humidity and high rainfall, can result in a high water content in power transformer insulating oil.

Over time, the presence of high water levels in the insulating oil will reduce the serviceable life of the transformer and increase the likelihood of failure through normal operational pressures such as through-faults and lightning/switching surges.

Moisture content is identified through analysis of oil samples, measured as parts per million (PPM), and is currently managed through a combination of online and offline oil filtering. Due to mechanical problems with the filtering equipment (caused by the environmental conditions) and the operational costs to deploy it, Power and Water has assessed alternative approaches to manage oil moisture content.

There are 22 transformers on the network that currently do not have permanent online filters installed. The condition of the oil in these transformers must be managed to ensure the maximum serviceable life of the transformers can be achieved.

8.5.2 Option considerations

Four options were considered:

1. Do nothing: monitor the moisture connect but do not attempt to prevent saturation or remove moisture through operational means.
2. Business as usual using temporary online filers: only use the existing, unreliable temporary online filters on an ongoing periodic basis.
3. Use a combination of temporary and permanent online filters: initially filter with the temporary filters to reduce the moisture concentration, then rely on the permanent online filters to maintain the low moisture concentration.
4. Offline oil filtering: on a periodic basis, take the transformers out of service for approximately 3 weeks for filtering.

8.5.3 Plan

The preferred approach is Option 3. Option 2 is the current approach but the temporary filters have been unreliable and have resulted in high maintenance costs. All new transformers are installed with integrated permanent online filtering units, so option 3 will ensure standardisation across the transformer fleet.

Option 3 was preferred as it had the best strategic alignment and least net present cost.

8.6 Long term growth

The network demand forecast shows that the demand is expected to decline over the next 10 years. The four growth areas will be addressed within the forthcoming regulatory control period (FY19 to FY24). Once that demand growth is addressed, there is no need currently identified for additional augmentation of the transformer fleet.

Network demand will be reviewed on an annual basis as required by the Technical Code. Should there be a change in the forecast, appropriate analysis will be undertaken to identify the most efficient approach to address the demand growth.

9 Renewal and maintenance requirements

Power and Water routinely assesses asset condition to determine the risk each transformer poses to the network. The asset condition assessments cover the items listed in section 5 of this AMP. The data is analysed to assess the risk of asset failure, including energy at risk, and the criticality of the asset.

When condition defects or risks are identified, options are assessed on how to most efficiently manage the risk. This may include operational measures such as repairing oil leaks or filtering the oil, thorough to capital investments to replace part or all of the transformer. To identify the timing and scope of the preferred option, Power and Water undertakes a cost and benefit analysis and assessment of technical and economic benefits and risks, as required by Clause 13.9 of the Technical Code.

Considerations may include:

- Cost of replacement of different options
- The cost of Energy at Risk of each option
- Calculating the present value of each option
- Results of any oil testing and dissolved gas analysis
- Condition of the transformer and associated components
- Maintenance performance and expenditure history
- Environmental concerns

Power and Water takes a risk based approach to asset replacement. The assessment of when it is economic to replace an asset is based on the risk it presents (the product of consequence and likelihood). Energy at risk is a useful approach to assessing the timing and efficiency of replacing transformers as it provides an indication of the economic benefit of replacement which can be used to identify the optimal timing.

Analysis of the Energy at Risk is shown in section 5.3. An extract of that analysis is shown in Figure 9-1 below to highlight the substations with significant risk. Note it is shown below with a log scale to more clearly show the substations with lower risk.

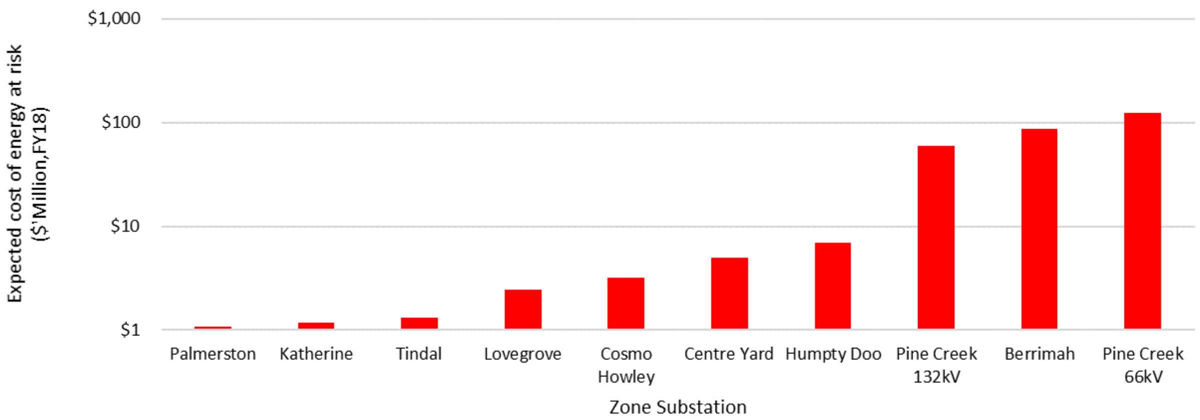


Figure 9-1 Extract of energy at risk by substation

In addition, the energy at risk has been used to identify the timing of when risk mitigation works need to be undertaken. For this analysis an indicative risk remediation cost has been used based on substation capacity and location.

The energy at risk analysis has been assessed in combination with a number of related considerations to identify the preferred remediation years as shown in in Table 9.1 below. The considerations included:

- condition assessments of the substations and transformers
- deliverability of the program of works given the labour resources availability and plant lead times,
- alignment with the replacement of other major assets within a zone substation (i.e., protection and switchgear) to ensure economic packaging of works and efficient operation of the network.

Table 9.1 Risk mitigation timing

Zone Substation	Optimal year (FY)	Refined year (FY)	Comment
Berrimah	2017	2019	Align with other works
Centre Yard	2017	2022	
Cosmo Howley	2017	2022	
Humpty Doo	2017	2023	
Manton Dam	2017	NA (Note 1)	
Pine Creek 132kV	2017	2020	
Pine Creek 66kV	2017	2019	
Tennant Creek	2019	2020	
Tindal	2026	TBA	
Lovegrove 66kV	2032	TBA	
Lovegrove	2037	TBA	
Batchelor	2039	TBA	

Note 1: the energy at risk for Manton Dam is due to it being a single transformer substation that has approximately 50% of its life remaining. Although the risk is starting to increase, the overall condition assessment of this transformer shows it to be acceptable and therefore no action is currently planned.

Note 2: Substations not listed above are forecast for replacement post 2040.

The following sections provide a summary of the project proposed to address risks that are identified on the network as a result of asset condition. The detailed analysis and options analysis for each project are described in the BNI and/or PBC for the project.

9.1 Pine Creek 66kV

Full details of this project are available in the document D2016/326577 PRK30110 - Sub10105 - Preliminary Business Case - Replace 66kV and 22kV Zone Substation Assets.

9.1.1 Overview

Pine Creek is comprised of a 132kV step up transformer connected to a generator and a separate 66kV/22kV switchyard.

The 66kV switchyard includes two 20MVA transformers and supply a forecast maximum demand of 43.46 MVA from FY18 through o FY24. The load duration chart with substation capacity is shown in Figure 9-2 below. To meet the peak demand, the transformers are operated at their short term cyclic rating.

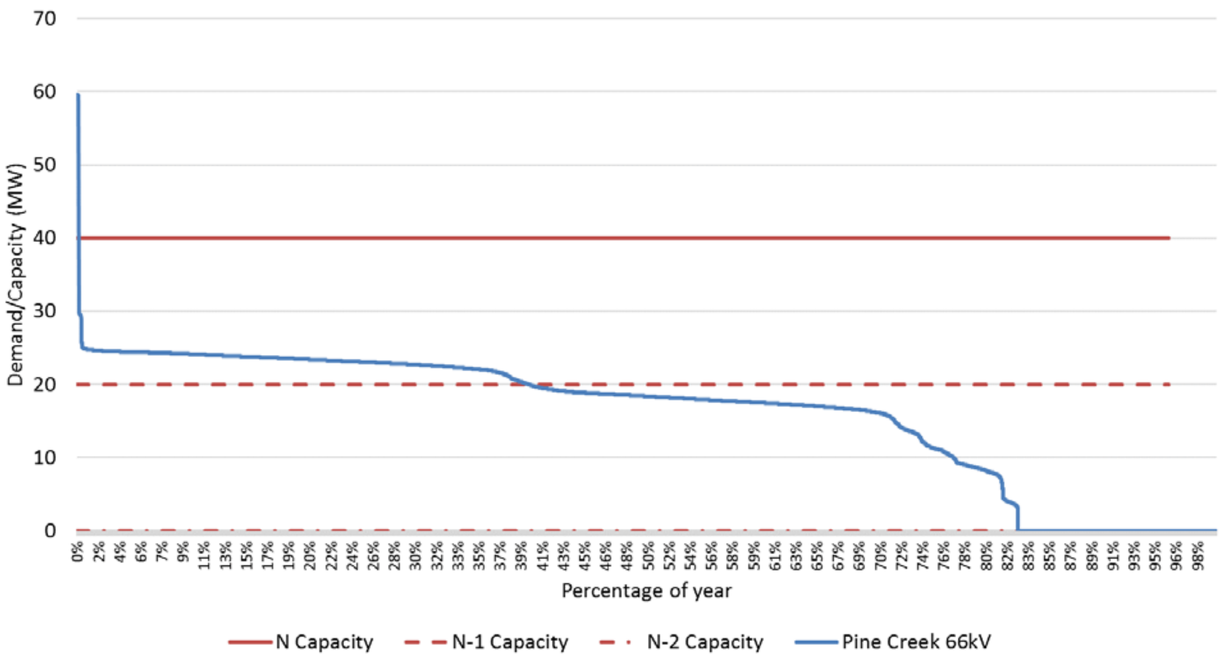


Figure 9-2 Pine Creek load duration curve

Both transformers are in Poor condition with DP values of 324 and 394, resulting in an estimated remaining life of 5 years and 9 years respectively. However, due to the short term cyclic loading of the transformers, it is likely their lives will be shorter due to the detrimental effect of heat on internal components.

This condition results in a high probability of failure, which will increase over time with the equivalent annual Energy at Risk calculated to be $1,604M over a 30 year period (assumes no mitigations implemented during the evaluation period).

9.1.2 Option Considerations

To address the risk posed by the poor condition of the transformers, the following options were considered:

1. Do nothing
2. Replace the transformers
3. Demand management
4. Install local generation

9.1.3 Plan

The preferred option was identified to be to replace both transformers and renew the zone substation. The project will be completed during FY18 and FY19.

9.2 Berrimah

Full details of this project are available in the document D2017/394263 PRD30402 - Preliminary Business Case PBC - Replace Berrimah Zone Substation.

9.2.1 Overview

The Berrimah Zone Substation was commissioned in 1981. It comprises an outdoor air insulated 66kV switchyard, two 66/11 kV 25/31.5/38 MVA power transformers, and an indoor metalclad 11kV switchboard and associated secondary systems.

It currently supplies over 30MVA of peak demand and AEMO has forecast an annual increase of approximately 3%. As a result, the peak demand is forecast to exceed the firm (N-1) capacity of the substation.

In addition, many of the assets are at or approaching the end of their serviceable life. All major assets within the substation have issues with condition or are obsolete technologies. The 66kV circuit breakers are in the poorest condition with a history of faults.

9.2.2 Option Considerations

There were seven options considered to resolve the issues at Berrimah ZSS:

1. Do nothing (continue to maintain/repair Berrimah ZSS)
2. In situ [‘brownfields’] renewal of the existing Berrimah ZSS with non-standard 38.1MVA 66/11kV Transformers
3. In situ [‘brownfields’] renewal of the existing Berrimah ZSS with non-standard 50MVA 66/11kV Transformers
4. In situ [‘brownfields’] renewal of the existing Berrimah ZSS with non-standard 50MVA 66/11kV Transformers
5. Construct a new air insulated switchgear (AIS) Berrimah Zone Substation
6. Construct a new gas insulated switchgear (GIS) Berrimah Zone Substation
7. Demand Management

9.2.3 Plan

The preferred option is Option 5, to construct a new zone substation. This is due to the risks and high cost of undertaking brownfield replacement works while ensuring the zone substation remains in service.

Additional benefits include:

- Using standard equipment and layout
- Lower cost
- Allows for the future expansion of the substation when demand requires a the installation of a third transformer.

9.3 Humpty Doo

Full details of this project are available in the document D2017/394662 PRD30401 - Preliminary Business Case PRC - Replace Humpty Doo ZSS.

9.3.1 Overview

Humpty Doo is a 66/22 kV rural substation in the Darwin-Katherine network. It consists of two 2.5 MVA transformers and two 22 kV circuit breakers that feed the distribution area. Both transformers have had oil leakage issues in the past and oil testing has identified poor insulation and high moisture content. Both transformers are supplied by a single oil filled 66 kV circuit breaker that has a history of operational issues and the secondary systems are identified as obsolete.

All aspects of the substation have been identified as being at end of life. There are no capacity issues identified.

9.3.2 Option Considerations

Three options were identified to remediate the issues:

1. Do nothing
2. Replace the existing switchyard on a like for like basis
3. Install a new AIS 66/22 kV zone substation and decommission the existing Humpty Doo ZSS
4. Demand management

9.3.3 Plan

Option 2 is the preferredoption. Deployment of the Nomad modular substation will enable efficient decommission and re-establishment of Humpty Doo without affecting customer supply.

9.4 Cosmo Howley

Full details of this project are available in the document D2017/394317 PRD33003 - Preliminary Business Case PBC - Replace Cosmo Howley Transformers.

9.4.1 Overview

Cosmo Howley Zone Substation was constructed in the 1980s and it is located about 150km south of Darwin. The zone substation consists of two 66/11 kV 7.5 MVA transformers connected in parallel, 66 kV and 11 kV switchgear, and is supplied via a radial 66 kV line of approximately 60 km that runs north from Pine Creek.

The transformers are identified to be at the end of their economic life. The remainder of the switchyard is considered to be in adequate condition. There are no capacity constraints identified.

9.4.2 Option Considerations

Four options were identified to remediate the issues:

1. Do nothing

2. Refurbish the transformers
3. Replace the two transformers with one larger transformer
4. Demand management.

9.4.3 Plan

Option 3 is the preferred option and would include configuration of the substation to be suitable for the Nomad modular substation to be connected as backup.

9.5 Centre Yard

Full details of this project are available in the document D2017/394625 PRD33125 - Preliminary Business Case PBC - Darwin - Replace Centre Yard Zone Substation.

9.5.1 Overview

Centre Yard Zone Substation is located in Cox Peninsula and consists of two 0.5 MVA 66/11 kV transformers connected to a single 66 kV ASEA HLC minimum oil circuit breaker. The substation is fed from Darwin Zone Substation by two 66kV undersea cables of approximately 8km in length, each with sections of 66 kV overhead line at each end.

The local distribution network operates at 22 kV and is supplied from Strangways Zone Substation.

Both of the subsea cables have experienced failures and one is permanently out of service as it was not economical to repair.

All assets in the zone substation are in poor condition. There are no capacity constraints identified.

9.5.2 Option Considerations

Five options were identified to remediate the issues:

1. Do nothing
2. Refurbish the existing substation
3. Construct a new 66/11 kV AIS ZSS to replace the existing substation
4. Construct a new 66/22 kV micro substation and convert the distribution area to 22 kV
5. Convert the 11kV distribution network to 22kV, supply the network from Strangways ZSS and decommission the substation
6. Demand management.

9.5.3 Plan

Option 4 is the preferred option.

9.6 Pine Creek 132 kV transformer replacement

Full details of this project are available in the document D2017/468423 Category C Business Case - Pine Creek 132kV Transformer Replacement.

9.6.1 Overview

The Pine Creek 132kV/66kV/22kV Lepper transformer is used to step down voltage from the Darwin-Katherine Transmission Line to supply local load, as well as step up the voltage from the EDL Generator to export load into the network. This transformer is critical for supplying system inertia to Crocodile Gold and supplying the approximately 15MVA of local load. The Lepper transformer was installed in 2008 as a refurbished second hand transformer.

There are three key issues that have been identified at Pine Creek 132kV Zone Substation:

1. Significant deficiencies have been identified on the 132kV/66kV/22kV 30MVA Lepper Transformer, in particular oil test results indicate severely degraded paper insulation and internal arcing. Reduced tensile strength in the paper insulation indicates end of life has been reached.
2. Inadequate bunding that is highly likely to result in hydrocarbons escaping and contaminating the ground and escaping into adjacent land should there be a major oil spill.
3. There is no water oil separation facility at the substation.

There is no capacity constraint identified.

9.6.2 Option Considerations

Two feasible options were identified to remediate the issues:

4. Do nothing
5. Replace the transformer and repair the bund

9.6.3 Plan

Option 2 is the preferred option. Power and Water already holds a spare transformer suitable for replacing the Lepper. Therefore, the only cost is transportation, commissioning and upgrading the bund.

An oil water separation facility will be installed as part of the Pine Creek 66/22 kV switchyard replacement (planned for completion in 2019) which will be sized appropriately for all transformers at Pine Creek.

9.7 Long-term (8-12 years) renewal needs

Our current analysis using the energy at risk model shows that there are a number of transformers approaching the end of their serviceable lives.

The condition of transformers will be regularly assessed and the latest results used to inform future risk mitigation needs. When a transformer is expected to require replacement, a full range of options is assessed to ensure future demand and customer needs are considered.

Power and Water will also aim to align transformer replacement with other major capital works such as switchboard and relay replacements.

The following table shows the transformers that are expected to pose a risk to the network in the 8 to 12 year horizon as they deteriorate and energy at risk increases. The list below is based on the current assessment of energy at risk but may change as more data becomes be available.

The transformers that are likely to be reaching the end of their serviceable lives after FY24 are identified to be:

- Lovegrove
- Tindal
- Katherine
- Palmerston

The condition of these substations will be investigated during the next regulatory control period and updated data used to identify the optimal timing for their replacement.

10 Investment program

The investment program is developed based on the:

- Continuation of the established lifecycle asset management approaches – discussed in Appendix A – Lifecycle asset management;
- Specific requirements related to growth in the asset class – outlined in Section 8; and
- Specific requirements related to renewal and maintenance of the asset class – outlined in Section 9.

10.1 Augmentation expenditure (augex)

Table 10.1: Augmentation expenditure forecast

Project/Program	Unit	FY20	FY21	FY22	FY23	FY24	Total
Construct Wishart Zone Substation	Cost ($ m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Archer ZSS 3rd. Transformer	Cost ($ m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Strategic spare for Hudson Creek	Cost ($ m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tennant Creek transformer upgrade	Cost ($ m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Power transformer online moisture control	Cost ($ m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Augex		$2.10	$0.50	$9.00	$11.85	$8.78	$32.23

10.2Replacement expenditure (repex)

Table 10.2: Replacement expenditure forecast

Project/Program	Unit	FY20	FY21	FY22	FY23	FY24	Total
Replace Berrimah ZSS	Cost ($ m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Replace Humpty Doo ZSS	Cost ($ m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Replace Cosmo Howley Transformers	Cost ($ m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Replace 66/11kV Centreyard ZSS	Cost ($ m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Replacement of Pine Creek 132/66/11 kV 'Lepper' transformer and bunding upgrade	Cost ($ m)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Repex		$9.45	$9.68	$5.23	$2.33	$-	$26.69

Note the replacement of Pine Creek 66kV substation will occur in the current regulatory period so it is not included in the table above.

The revised five-year forecast health and criticality profiles for power transformers following the proposed investments are shown in Table 10.3. The reduction in risk is demonstrated in the number of assets that move from the low health, H3 category to the high health category, H1 in comparison with the ‘current’ and ‘no investment’ risk scenarios provided in section 5.3.

Table 10.3: Power transformer health-criticality matrix (qty) with investment

	H1	H2	H3
C1	44	20	0
C2	0	0	0
C3	3	0	0

10.3Operational expenditure (opex)

The operating expenditure forecast for cables for the next regulatory period is provided in Table 10.4.

Table 10.4: Operating expenditure forecast

Asset Subclass	Expenditure category	FY14 (H)	FY15 (H)	FY16 (H)	FY17 (H)	FY18 (H)	FY19 (F)	FY20 (F)	FY21 (F)	FY22 (F)	FY23 (F)	FY24 (F)
Bushings	Routine	$0.32	$0.23	$0.02	$0.11	$0.14	$0.13	$0.12	$0.12	$0.12	$0.12	$0.12
	Non-routine	$0.16	$0.15	$0.03	$0.16	$0.13	$0.11	$0.10	$0.10	$0.10	$0.10	$0.10
	Fault and emergency	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total		$0.48	$0.39	$0.05	$0.27	$0.27	$0.24	$0.22	$0.22	$0.22	$0.22	$0.22
Main Tank	Routine	$0.80	$0.73	$0.70	$1.00	$0.66	$0.61	$0.56	$0.56	$0.56	$0.56	$0.56
	Non-routine	$1.04	$0.97	$1.47	$1.26	$1.16	$1.05	$0.93	$0.93	$0.93	$0.93	$0.93
	Fault and emergency	$0.26	$0.08	$0.08	$0.20	$0.14	$0.14	$0.13	$0.13	$0.13	$0.13	$0.13
Total		$2.09	$1.78	$2.24	$2.46	$1.97	$1.80	$1.63	$1.63	$1.63	$1.63	$1.63
OLTC	Routine	$0.29	$0.00	$0.00	$0.00	$0.06	$0.06	$0.05	$0.05	$0.05	$0.05	$0.05
	Non-routine	$0.08	$0.10	$0.16	$0.04	$0.09	$0.08	$0.07	$0.07	$0.07	$0.07	$0.07
	Fault and emergency	$0.00	$0.01	$0.00	$0.05	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Total		$0.37	$0.11	$0.16	$0.09	$0.17	$0.15	$0.14	$0.14	$0.14	$0.14	$0.14
Total	Routine	$2.94	$2.28	$2.46	$2.82	$2.40	$2.20	$1.99	$1.99	$1.99	$1.99	$1.99
	Non-routine	$0.32	$0.23	$0.02	$0.11	$0.14	$0.13	$0.12	$0.12	$0.12	$0.12	$0.12
	Fault and emergency	$0.16	$0.15	$0.03	$0.16	$0.13	$0.11	$0.10	$0.10	$0.10	$0.10	$0.10
Total opex		$2.94	$2.28	$2.46	$2.82	$2.40	$2.20	$1.99	$1.99	$1.99	$1.99	$1.99

11 Asset class outcomes

This section is closely related to Section 7. Where Section 7 sets out the targets, current performance and any gaps in the performance against the metrics, this section will identify the expected performance against the metric once the projects identified in Sections 8 and 9 have been implement.

The success of the strategies and project will be measured against these targets and intended performance. This will enable Power and Water to identify short comings in the asset fleet and develop or amend strategies and projects in order to achieve the desired fleet performance.

While the performance indicators are currently under development, they are expected to cover the following general aspects:

- Transformer availability
- Contribution to network reliability
- Transformer condition such as the number in poor health
- Environmental requirements such as oil contaminants, leaks and noise
- Safety obligations, and
- Financial metrics to ensure efficient expenditure

These performance indicators will be developed and included in the next revision of this asset management plan.

12 Performance monitoring and improvement

Ongoing condition and performance monitoring is a key part of Power and Water's performance evaluation and improvement strategy. Study of the condition and performance data captured over time assists in developing valuable insights on transformer defect modes and trends. These insights provide for informed decision making on whether to repair or replace assets. It assists in the continuous development of the asset management strategy for transformers.

12.1Monitoring and improvement

This Asset Management Plan will be reviewed at least every two (2) years or when there is a significant driver from the network or other events that requires revision.

Improving data resources, undertaking data analysis and deriving insights will be undertaken as business as usual activities. Any improvements in analysis of the transformer fleet will be included in this AMP when it is updated.

The RACI in section 3.2 allocates the responsibility for each task in the management of transformers, including performance monitoring and strategy revision.

13 Appendix A – Lifecycle asset management

Power and Water make great efforts to be a customer oriented organisation that provides a safe, reliable and efficient electricity supply in the Northern Territory. This is demonstrated in the approach Power Networks take in managing its assets. The life cycle asset management approach applied by Power Networks is aimed at making prudent asset management decisions such that its assets do not cause harm to any person, have minimal environmental impact, and meet agreed service performance outcomes, consistent with current and future needs.

The approach includes:

- Maximising the utilisation of its assets throughout its life cycle
- Optimising life cycle asset management costs
- Reducing asset risks as low as reasonably practical
- Continually improving its knowledge in respect of its assets

The following asset management activities detail Power and Water's life cycle management of its power transformer assets.

13.1 Planning (augmentation)

The asset planning stage defines the need for an asset to exist. It also establishes the functional requirements of the assets and ultimately the number of assets, design, function, criticality, configuration, level of redundancy, capability, and capacity.

During the planning process, Power and Water must have regard to the Code. Part C of the Code sets out the Network Planning Criteria, including the following key clauses:

Clause 13.8.1 sets out the requirement for Power and Water to undertake an annual planning review including to consider loads, generation and non-network solutions

- Clause 13.9 sets out the investment analysis and reporting requirements including the need to determine the least cost option on a present value basis and include in the analysis an estimate of system benefits and non-quantifiable economic benefits
- Clause 14 sets out the supply contingency (security) criteria which are summarised in Tables 13 and 14, including:
  - Specifying forecast demand is based on the coincident maximum demand with a 50% probability of exceedance
  - Restoration time targets for outages

An important outcome of these requirements is that an area with a forecast demand of over 50 MVA has a requirement to be restored within 5 hours for a second supply contingency. This requirement only applies to Hudson Creek as all other substations have demand of less than 50 MVA.

Key criteria to ensure establishment of prudent, cost efficient, intrinsically safe, and sustainable asset installations for the life cycle management of the power transformer assets include consideration of:

- Robust demand forecasting by zone substation
- Security requirements set out in the Code

- Optimised utilisation of existing transformers
- Load transfers available on a permanent or temporary basis to defer investment and manage risk
- Non-network solutions
- Schedule and cost impacts from existing adjacent infrastructure
- Transport and logistics
- Project cost implications
- Safety and reliability risks
- Environmental and approvals risk
- Stakeholder and community requirements
- Design and execution requirements
- Operation and maintenance requirements

13.2 Design

The design phase is where decisions around the physical characteristics and functioning of the asset is made. This life cycle stage defines the quality and reliability of the asset, and the whole of life cycle costs that can be realised. It influences the total cost and the level of service that the assets can deliver to customers and shareholders.

Power and Water's approach to the whole of life cycle prudent and efficient design of assets include the standardisation of zone substation designs as far as practicable given the broad range of capacities and locations. Standardisation is defined as the process of developing and agreeing on uniform technical design criteria, specifications and processes and is a key aspect of Power and Water's asset management process.

Along with continuity, leverage and scalability, standardisation enables consistent application of best industry practise and continuous performance improvement. It establishes technical commonality that allows for an off-the-shelf, best practice, and fit-for-purpose approach to engineering solutions. It also allows for interchangeability that provides operations and asset management benefits.

Power and Water's power transformer and zone substation design standardisation offers the following specific benefits to the business. It:

- Helps with the ranking and prioritisation of investment projects
- Gives confidence in the safe and reliable functioning of the assets
- Provides assurance that the assets will do the job they were intended for
- Boost production and productivity
- Encourages higher quality of engineering leveraging specialist knowledge and optimum solutions
- Allows for the uniform execution of projects
- Enables standardisation of construction equipment and processes

13.3 Operation

Asset operations include activities associated with the monitoring, operation and control of the asset to adapt to changing requirements of the network. This includes:

- Planned switching of the network for scheduled works (eg. maintenance)
- Emergency switching of the network in response to incidents (eg. fault events)
- Real time switching to operate the asset within its design parameters (eg. loading)
- Monitoring of the condition of the asset (eg. alarms)
- Adjusting tap changer settings to regulate voltage levels

13.4 Maintenance (opex)

Asset maintenance involves the care of assets to ensure they will function to their required capability in a safe and reliable manner from their commissioning to their disposal. The maintenance requirements evolve as the condition and performance requirements of the assets change through its life. It monitors and provides feedback on asset condition, it incorporates upkeep and repair activities to maintain the condition of the asset, and it also includes the monitoring and management of the deterioration of an asset over time. Three main types of maintenance activities are defined: preventative, corrective, and unplanned maintenance.

- Preventative maintenance involves the controlled care and repair activities carried out to reduce the probability of failure or degradation of asset performance. It includes routine inspection and monitoring, upkeep and repair, testing and component replacements. Preventative maintenance expenditure increases over time as assets age.
- Corrective maintenance involves activities to repair asset defects identified as result of condition assessments or failures. Corrective maintenance expenditure increases over time as assets age and deteriorate.
- Unplanned maintenance involves activities to immediately restore supply or make a site safe in response to unplanned failures. Unplanned maintenance expenditure increases over time as asset age and deteriorate.

Power and Water's test and maintenance procedures[6] set out the visual inspection and testing approach employed by Power and Water.

Opportunities to optimise the current strategies in relation to Power Transformer testing are being considered, in particular extension of the frequency for some tests such as frequency response which are time consuming.

13.5 Renewal (repex)

Asset renewal is the establishment of a new asset in response to an existing asset's condition. The need for the renewal of existing assets is identified in the asset maintenance stage and verified in the asset planning stage. Asset renewal aims to optimise the utilisation of an asset whilst managing the safety and reliability risk associated with the failure of the asset.

Power and Water has asset replacement programmes in place to renew assets of poor condition as close as possible yet prior to the asset failing.

The network risk posed by transformers is assessed on a qualitative basis using the transformer condition data and risk assessment framework and on quantitative basis using energy at risk.

[6] QDOC2010/37 Power Networks Asset Strategies Procedure, Revision 4

These two approaches enable Power and Water to identify assets in poor condition, prioritise the replacements and determine the optimal timing of replacement.

When replacing major assets such as transformers, Power and Water aims to align other related major works to gain efficiencies.

13.6 Disposal

The decision to reuse or dispose of an asset is made with consideration of the potential to:

- reuse the asset
- utilise the asset as an emergency spare
- salvage asset components as strategic spare parts.

The remaining asset is disposed of in an environmentally responsible manner and in compliance with all requirements related to scheduled substances (i.e. PCBs)

14 Appendix B – Asset data

14.1 Transformer fleet data

14.1.1 Transformer numbers, voltage and capacity

Table 14.1 Transformers details by zone substation

Zone substation	No. of transformers	Primary voltage (kV)	Capacity (MVA)
Archer	2	66	35
Batchelor	1	132	27
Berrimah	2	66	38
Casuarina	3	66	38
Centre Yard	2	66	0.5
Cosmo Howley	2	66	7.5
Darwin	2	66	38
Frances Bay	2	66	38
Hudson Creek	3	132	125
Humpty Doo	2	66	2.5
Jabiru	2	66	15
Katherine	2	132	33
Leanyer	2	66	38
Lovegrove	5	66	45
Manton Dam	1	132	27
Marrakai	2	66	2.5
Mary River	1	66	12
Owen Springs	2	11	35
Palmerston	4	66	40
Pine Creek	4	132	30
Ranger Mine	2	66	10
Sadadeen	3	22	24
Strangways	2	66	27
Tennant Creek	4	22	7.5
Tindal	3	22	4
Weddell	2	66	7.6
Wishart	1	66	10
Woolner	3	66	27

14.1.2 Transformer manufacturer data

Table 14.2 Summary of transformers by manufacturer

Manufacturer	Number of Transformers
ABB	20
Alstrom	1
Areva	2
Crompton Parkinson	2
English Electric	6
GEC	1
GEC Alsthom	2
Lepper	1
Pauwels	2
Tyree	3
Tyree Westinghouse	4
Westinghouse	3
Westralian	15
Wilson	11
Unknown	1
Total	74

14.2 OLTC fleet data

OLTC by substation by age (blank means age unknown, spares held as some sites).

Table 14.3 OLTC make, model and age by substation

Zone substation	Manufacturer	Model	Age
Archer Substation TF1	Reinhausen	VVIII400Y-40-12231W	10
Archer Substation TF2	Reinhausen	VVIII400Y-40-12231W	9
Batchelor Substation TF1	Reinhausen	MSIII Y300	29
Berrimah Substation TF1	Reinhausen	MIII 500 60/C 14271G	39
Berrimah Substation TF2	Reinhausen	MIII 500 60/C 14271G	39
Casuarina Substation TF1	Reinhausen	VVIII 400D-76-1223 1G	2
Casuarina Substation TF2	Reinhausen	VVIII 400D-76-1223 1G	2
Casuarina Substation TF3	Reinhausen	MR VVIII-400Y-40	8
Centre Yard Substation TF1	Crompton Parkinson	(blank)	51
Centre Yard Substation TF2	Crompton Parkinson	(blank)	51
City Zone Substation TF1	Reinhausen	VV III 600Y-76-10193G	17
Darwin Zone Substation TF1	Reinhausen	VVIII600D-76-10193GR	5
Darwin Zone Substation TF2	Reinhausen	VVIII600D-76-10193GR	5
Darwin Zone Substation TF3	Reinhausen	VVIII600D-76-10193GR	5
Frances Bay Substation TF1	Reinhausen	VVIII600Y-76-10193G	12
Frances Bay Substation TF2	Reinhausen	VVIII600Y-76-10193G	6
Hudson Creek Substation TF1	Reinhausen	3 x MI 802 60/B 10191W	30

Hudson Creek Substation TF2	Reinhausen	3 x MI 802 60/B 10191W	30
Hudson Creek Substation TF3	Reinhausen	3 x MI 802 60/B 10191W	30
Humpty Doo Substation TF1	AEI	type L	55
Humpty Doo Substation TF2	AEI	type L	55
Jabiru Substation TF1	Reinhausen	VIII 350 Y60 10171G	38
Jabiru Substation TF2	Reinhausen	VIII 350 Y60 10171G	38
Katherine Substation TF1	Reinhausen	MSIII 300 Y 60/B 10193G	25
Katherine Substation TF2	Reinhausen	MSIII 300 Y 60/B 10193G	25
Leanyer Substation TF1	Reinhausen	VVIII400Y-40-12231W	6
Leanyer Substation TF2	Reinhausen	VVIII400Y-40-12231W	6
Love Grove Substation TF1	Reinhausen	VIII 350 Y 14253W	39
Love Grove Substation TF2	Reinhausen	VIII 350 Y 14253W	39
Manton Substation TF1	Reinhausen	MSIII 300 Y/60 10193G	29
Marrakai Substation TF1	Reinhausen	VVIII400Y-40-12231W	9
Marrakai Substation TF2	Reinhausen	VVIII400Y-40-12231W	9
Mary River Nomad TF2	ATL	ATV 317 44/300 CF	7
Mary River Substation TF1	Reinhausen	VVIII250D-76-10193W	6
Palmerston Substation (11/22kV)	Reinhausen	VRC III 700Y-72,5/B-12 23 1G	5
Palmerston Substation TF1	ATL	AT317-66/400L	47
Palmerston Substation TF2	ATL	AT317-66/400L	44
Palmerston Substation TF3	ATL	AT317-66/400L	47
Sadadeen Substation TF1	Reinhausen	VIII 500 Y30 10193G	27
Sadadeen Substation TF2	Reinhausen	VIII 500 Y30 10193G	27
Spare	Reinhausen	VIII 350 Y/30 12211G	36
Spare	Reinhausen	VV 111 250Y 10193W	14
Strangways Substation TF1	Reinhausen	VVIII600D-76-10191G	4
Strangways Substation TF2	Reinhausen	VVIII600D-76-10191G	4
Tindal Substation TF1	Reinhausen	VIII 200 Y40 14273G	22
Tindal Substation TF2	Reinhausen	VIII 200 Y30 1425 3W	33
Tindal Substation TF3	Reinhausen	VIII 200 Y30 1425 3W	33
Weddell Substation TF1	Reinhausen	VVIII 250 Y 76/10 19 3W	11
Weddell Substation TF2	Reinhausen	VVIII 250 Y 76/10 19 3W	11
Weddell Substation TF3	Reinhausen	VVIII 250 Y 76/10 19 3G	6
Wishart Substation TF1	ATL	ATV 317 44/300 CF	7
Woolner Substation TF1	Reinhausen	VVIII400Y-40-12231W	8
Woolner Substation TF2	Reinhausen	VVIII400Y-40-12231W	8
Woolner Substation TF3	Reinhausen	VVIII400Y-40-12231W	8

14.3 ZSS Risk Mitigation Timing

Table 14.4 Risk mitigation timing

Zone Substation	Optimal replacement year
Humpty Doo	2017
Sadadeen	2017
Katherine	2017
Pine Creek 132kV	2017
Pine Creek 66kV	2017
Berrimah	2018
Manton Dam	2019
Cosmo Howley	2022
Tindal	2027
Tennant Creek	2030
Lovegrove 66kV	2033
Batchelor	2040
Archer	2044
Hudson Creek	2045
Darwin	2047
Lovegrove	2047
Owen Springs	2047
Palmerston	2047
Pine Creek	2047
Woolner	2047
Casuarina	2047
Frances Bay	2047
Weddell	2047
Mary River	2047
Leanyer	2047
Strangways	2047
Marrakai	2047
Palmerston 22kV	2047
Centre Yard	

14.4 Transformer criticality detail

Table 14.5 Criticality ranking of substations

Zone Substation	Security/ Compliance[7]	Demand	Mean Time To Replace[8]	Transmission Terminal	Other Mitigation	Result
Hudson Creek	5	5	5	5	1	25.0
Owen Springs	1	4	5	5	1	10.0
Pine Creek 132kV	1	3	1	5	5	8.7
Lovegrove 66kV	1	4	5	1	3	7.7
Pine Creek 66kV	1	4	3	1	5	7.7
Archer	1	4	3	1	2	4.9
Berrimah	1	4	5	1	1	4.5
Palmerston	1	4	5	1	1	4.5
Tennant Creek	1	2	3	1	3	4.2
Darwin	1	3	5	1	1	3.9
Frances Bay	1	3	5	1	1	3.9
Lovegrove	1	3	5	1	1	3.9
Casuarina	1	4	3	1	1	3.5
Woolner	1	4	3	1	1	3.5
Sadadeen	1	3	1	1	3	3.0
strangways	1	3	3	1	1	3.0
Leanyer	1	2	3	1	1	2.4
Jabiru	1	1	3	1	1	1.7
Katherine	1	3	1	1	1	1.7
Manton Dam	1	1	1	1	3	1.7
Batchelor	1	1	1	1	2	1.4
Mary River	1	1	1	1	2	1.4
Palmerston 22kV	1	2	1	1	1	1.4
Centre Yard	1	1	1	1	1	1.0
Cosmo Howley	1	1	1	1	1	1.0
Humpty Doo	1	1	1	1	1	1.0
Marrakai	1	1	1	1	1	1.0
Pine Creek	1	1	1	1	1	1.0
Ranger Mine	1	1	1	1	1	1.0
Tindal	1	1	1	1	1	1.0
Weddell	1	1	1	1	1	1.0
Tindal	1	1	3	3		3.0

[7] Based on planning criteria for N-2 where capacity greater than 50MVA

[8] Based on spare availability or NOMAD compatibility.

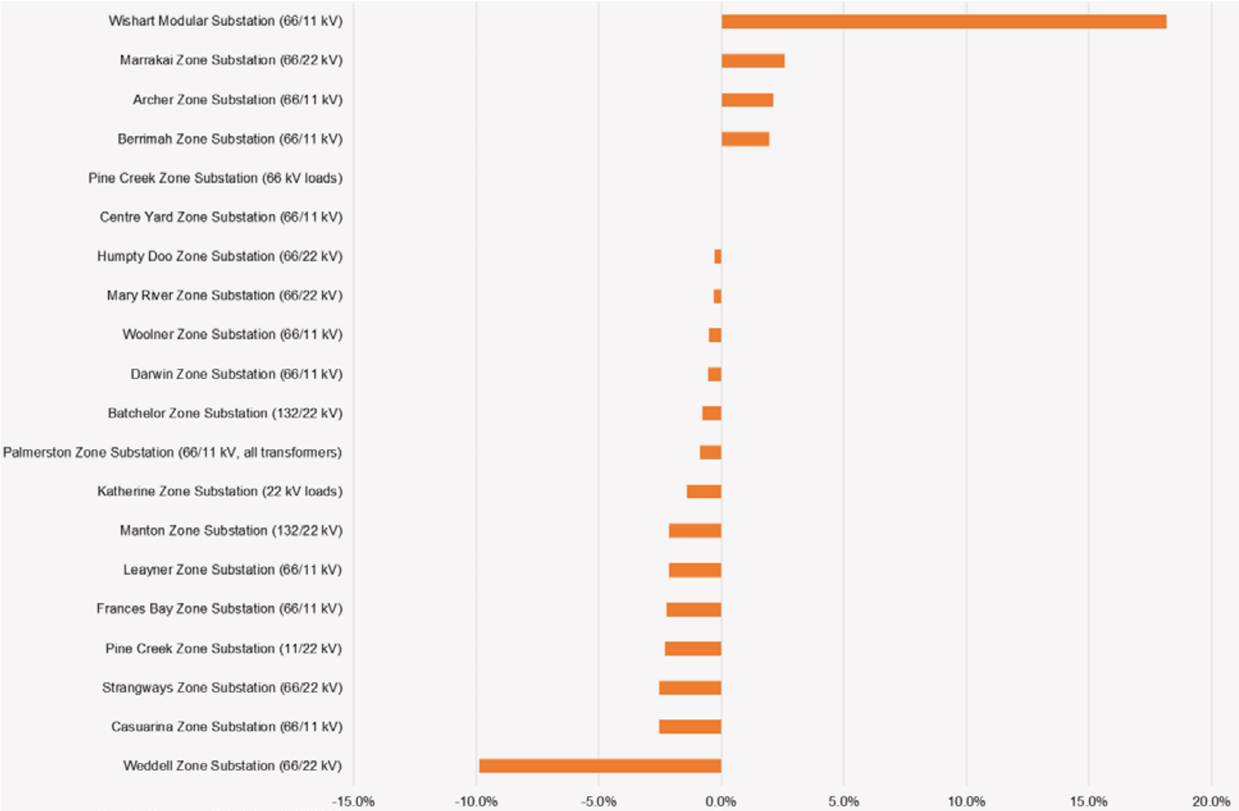
Table 14.6 Criticality assessment result mapping

Criticality	Result value
Critical	21-25
High	16-20
Moderate	11-15
Low	6-10
Very low	1-5

15 Appendix C – Demand Forecast

The following charts are extracted from the AEMO demand forecast, Power and Water maximum demand, energy consumption and connections forecasts, September 2017.

15.1 DRW-KTH region



15.2 ASP region

Substation Name	Rate (per annum)
Ron Goodin Zone Substation (11kV)	-1.80%
Lovegrove Zone Substation (22/11 kV)	-1.02%
Brewer + Sadadeen (22 kV loads)	-0.98%
Lovegrove Zone Substation (22 kV load)	-0.04%

15.3 TC region

Substation Name	Rate (per annum)
Tennant Creek Zone Substation (11/22 kV)	2.66%