Network Development Management Plan

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Authorisations

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Review cycle	2.5 Years	

Responsibilities

This document is the responsibility of the Network Planning Team, Tasmanian Networks Pty Ltd, ABN 24 167 357 299 (hereafter referred to as "TasNetworks").

Please contact the Network Planning Leader with any queries or suggestions.

- Implementation All TasNetworks staff and contractors.
- Compliance All group managers.

Record of revisions

Section number	Details
0.1	DRAFT circulated for comment
0.2	DRAFT circulated for approval
1.0	For issue

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1 Purpose

The purpose of this document is to define the management strategy for distribution network development. The plan provides:

- TasNetworks' approach to demand and performance driven reinforcement strategies, as reflected through its legislative and regulatory obligations and strategic plans;
- The key projects and programs underpinning its activities; and
- Forecast CAPEX and OPEX, including the basis upon which these forecasts are derived.

2 Scope

This management plan includes reinforcement programs and expenditure profiles associated with:

- Distribution assets and elements operating at 44 kV, 33 kV, 22 kV, 12.7 kV SWER, 11 kV and 400/230V; namely, the Distribution Network.

This management plan has been developed in conjunction with TasNetworks' suite of asset management plans and area strategy reports, with the objective of managing network capacity and performance levels through the planning period to 2026/27 in accordance with TasNetworks asset management objectives.

This management plan identifies the issues and strategies relating to distribution assets and details the specific activities, and associated reinforcement expenditure profiles, that need to be undertaken to address the identified issues, whilst ensuring the network evolves in an economically optimal way to sustainably meet our customer's needs.

This document excludes:

- Customer development works e.g. new or modified connections to the distribution network;
- Non-demand related customer activity e.g. asset removal and relocations as requested by customers or third parties (local councils, planning authorities, etc.);
- Renewal and preventative maintenance programs;
- Demand management development e.g. network support trials or development; and
- Power Quality rectification works.

3 Regulatory and Legislative Obligations

The Tasmanian electricity supply industry operates under both state and national regulatory regimes. TasNetworks, being a participant in the NEM, is required to develop, operate and maintain the transmission and distribution system in accordance with the National Electricity Rules (NER) and other local requirements under the terms of our licences issued by the Tasmanian Economic Regulator in accordance with the Tasmanian Electricity Supply Industry Act 1995. We are subject to a number of industry-specific, Tasmanian Acts and Regulations.

Network development (reinforcement) expenditure is associated with the construction (extension and augmentation) of network assets in accordance with our asset management plans, strategic area plans, network performance targets and obligations, and planning principles, to ensure that the distribution network delivers:

- Compliance with regulatory obligations; and
- Safety, reliability and security of supply outcomes that meet customers' needs, by maintaining asset utilisation rates at appropriate levels at the lowest whole of life cost.

If inadequate reinforcement work is undertaken then, as demand grows, customers may face increased risk of load shedding, asset failure or service performance and quality of supply issues.

As a joint transmission and distribution network service provider, network development strategies in the distribution network also takes into consideration TasNetworks' regulatory obligations at the transmission network. The regulations which are relevant to transmission and distribution network planning and development are:

- the National Electricity Rules (NER). These rules stipulate the requirements surrounding the electrical performance of the network. Of particular relevance to the distribution network is the Service Target Performance Incentive Scheme (STPIS);
- The NER (specifically Chapter 5 and 5.1) also stipulates our obligations for encouraging and managing new and modified customer connection services to the transmission and distribution networks;
- the *Electricity Supply Industry (Network Planning Requirements) Regulations 2007* (ESI) – (Note: not applicable to the distribution network). The ESI regulations define the minimum criteria for network performance following contingency events on the transmission network; and
- guidelines and standards applicable to the electricity industry as per the Tasmanian Electricity Code (TEC). The TEC contains arrangements for the regulation of the Tasmanian electricity supply industry which are not covered by the NER and are largely related to the distribution network. Of particular interest to network planning are the reliability requirements which outline the acceptable levels of reliability for various classifications of Tasmanian communities. Any excursions outside these requirements result in Guaranteed Service Level (GSL) payments to the impacted customers.

4 Strategic Alignment and Objectives

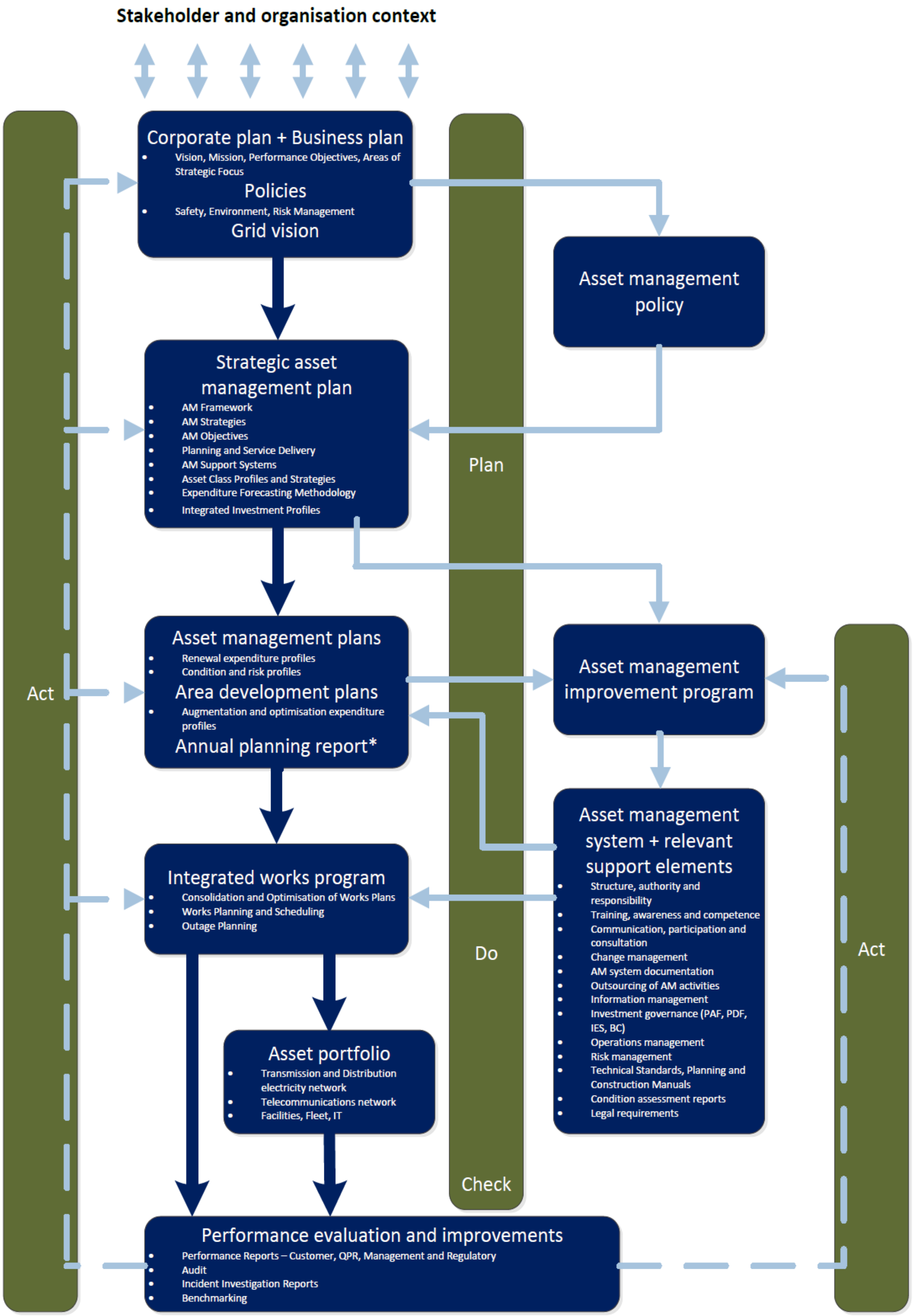
The business plan is the annual roadmap to support our corporate plan. It identifies responsibilities for the completion of initiatives identified in TasNetworks' corporate plan. The intent is to bring focus on priority initiatives that must be delivered to transform our business and achieve our strategic goals, whilst continuing to operate our business and achieve our targets.

The 2015-16 Business Plan focus on:

- Operate our business effectively;
- Transforming how we work; and
- Positioning our business for the future.

Table 1 represents TasNetworks' documents that support the asset management framework. The diagram highlights the links to from the business and corporate plans, and the existence of, and interdependence between, the Plan, Do, Check, Act components of good asset management practice.

Figure 1 – TasNetworks asset management documentation framework



* The Annual Planning Report (APR) is a requirement of sections 5.12.2 and 5.13.2 of the National Electricity Rules (NER) and also satisfies a licence obligation to publish a Tasmanian Annual Planning Statement (TAPS). The APR is a compilation of information from the Area Development Plans and the Asset Management Plans.

The asset management objectives focus on six key areas:

- Zero Harm will continue to be our top priority and we will ensure that our safety performance continues to improve.
- Cost performance will be improved through prioritisation and efficiency improvements that enable us provide predictable and lowest sustainable pricing to our customers.
- Service performance will be maintained at current overall network service levels, whilst service to poorly performing reliability communities will be improved to meet regulatory requirements.
- Customer engagement will be improved to ensure that we understand customer needs, and incorporate these into our decision making to maximise value to them.
- Our program of work will be developed and delivered on time and within budget.
- Our asset management capability will be continually improved to support our cost and service performance, and efficiency improvements.

4.1 Asset Management Plans

The suite of asset management plans have been developed to align with both TasNetworks' Asset Management Policy and Strategic Objectives.

The asset management policy, contained within the Strategic Asset Management Plan, states 'Consistent with our vision and purpose, we strive for excellence in asset management and are committed to providing a safe working environment, value for our customers, sustainable shareholder outcomes, care for our assets and the environment, safe and reliable network services, whilst effectively and efficiently managing our assets throughout their life-cycle'.

It is part of a suite of documentation that supports the achievement of TasNetworks strategic performance objectives and, in turn, its mission. The asset management plans identifies the issues and strategies relating to network system assets and detail the specific activities that need to be undertaken to address the identified issues.

4.2 Area Strategy reports (Area Development plans)

For planning purpose, the transmission and distribution networks are managed as seven planning areas. An Area Strategy report exists for each planning area, which are used to capture and summarise location specific network information, economic and demand forecasts, and emerging issues. These reports are used to develop our combined transmission and distribution APR.

The Area Strategy reports contribute to the asset management objectives by building understanding, capabilities and strategies to realise early opportunities, whilst delivering safe and reliable network services. We do this to meet our customers' needs and the Rules requirements. The Area Strategy reports form a part of the end to end works program process, which identify the need, timing and opportunity, in early parts of planning and network development.

The Business Plan states the key operational activities that are needed to operate our business effectively. These include:

- Forecasting of future network requirements;
- Develop solutions to network issues and manage design standards and policies; and
- Develop asset strategies including business cases for inclusion in the program of work.

The Area Strategy reports contributed directly to the above operational activities.

5 Support Systems and Applications

5.1 Asset Management Information Systems

TasNetworks utilises Asset Management Information Systems, which are maintained to contain up to date, detailed information with regard to assist network development planning and works.

The network asset information is managed using a spatial data warehouse (G/Tech). This data base stores critical attributes for each asset and element, including the location, construction, rating, and its interconnection to the network.

A works management system (WASP) is used to manage network development activities and for the recording of asset performance.

5.2 Asset Information

Asset related information is stored and accessed through the asset management systems. Where asset information is insufficient audits are undertaken to gather the information.

5.3 Asset Loading Information (Historian) Systems

TasNetworks utilises Asset Loading Information Systems, which are maintained to store historical system loading data at different network levels. This data is used for a range of network analysis and network development planning activities.

The network asset loading information is managed by the NOCS team, and made available through PI historian.

5.4 Tools and applications

TasNetworks utilises a range of applications for analysis of the distribution network to identify and evaluate network development related risk. The primary applications for distribution network analysis used by TasNetworks are:

- Siemens PSS SINCAL 10.5.
- Webmap – web based Geospatial information system;
- GeoMedia;
- Cymcap – cable loading assessment software
- TasNetworks Project Economic Evaluation Tool

6 Maximum demand forecasts

The maximum demand forecasts are an essential input to identify emerging issues and develop early strategies to address them through consultation. A 10 year connection site forecast is compiled annually by TasNetworks to meet distribution and transmission network demand planning needs, and support the Office of the Tasmanian Economic Regulator’s (OTTER) annual reporting requirements in accordance with NER schedule 5.7.

6.1 Methodology

The TasNetworks approach is to project load growth (or decline) at each connection site at a rate consistent with recent history, using weather corrected data and temperature-based 10%, 50%, and 90% Probability Of Exceedance (POE). Distribution planning is based on a 50% POE. The sources of input for this approach are as follows:

- State (TAS) maximum demand forecast produced by the National Institute of Economic Industry Research (NIEIR);
- Temperature data retrieved from the Bureau of Meteorology (BOM) web site;
- Terminal (distribution connection sites) and zone substation active and reactive power data obtained from asset loading information systems; and
- Load adjustment information received from internal process associated with new or augmented customer connections. Only committed connections over 0.5 MW are used as required.

These site or spatial forecasts, in maximum demand MWs, are based on the nature of customers in the region and their demand profiles taking into account subdivision and commercial development opportunities and economic indicators and relationships with energy demands.

The spatial forecasts at connection sites are aggregated together, using diversity factors, to a system level forecast (bottom-up).This bottom-up forecast is compared with and reconciled to a Tasmanian system level forecast that is prepared separately by NIEIR, a top-down approach. There is a review of the data to ensure that it is consistent with the expectations of the Network Planning staff.

The daily load profiles by season, working day and non-working days that are used to develop the forecasts are based on historic profiles.

To produce the connection site forecasts used for system augmentation planning, where appropriate the base-line demand forecasts are adjusted for demand side management initiatives and impacts of larger embedded generating units.

6.2 Linear regression methodology

The individual connection site forecasts are based upon linear regression methodology.

6.3 Temperature correction

Historic data is weather temperature corrected based upon Bureau Of Meteorology (BOM) temperature information across weather sites closest to each connection site.

6.4 Embedded generation

The impact of individual larger embedded generating units on connection site forecasts is only subtracted from the base-line load demand forecasts when the generator would be normally operating at the time of maximum demand on the relevant distribution zone substation or the transmission connection site. As such, for a single embedded generator within a geographical area its unavailability is not allowed for if outside its normal operation.

Should the situation arise where multiple embedded generators operate normally at time of local geographical area maximum demand, a probability based allowance will be made for generating unit unavailability.

The impact of multiple small-scale embedded generation, such as photo-voltaic systems, is included in that the contribution is an inherent part of historic connection point demands.

7 Network Performance

7.1 Service Target Performance Incentive Scheme

TasNetworks' Service Target Performance Incentive Scheme (STPIS), which meets the requirements of the Australian Energy Regulator's (AER's) Service Standards Guideline, imposes service performance measures and targets onto TasNetworks with a focus on outage duration and frequency. Good asset performance will have a significant impact on TasNetworks' ability to meet the STPIS targets.

STPIS parameters include:

- System Average Interruption Duration Index (SAIDI); and
- System Average Interruption Frequency Index (SAIFI).

Details of the STPIS scheme and performance targets can be found in the "*Electricity distribution network service providers - Service target performance incentive scheme - November 2009*".

7.2 Network performance management

A fundamental requirement of the operation of the distribution network is to ensure that a reasonable level of supply reliability is delivered to its customers. The expectation of a reasonable level of supply reliability has been defined in the Tasmanian Electricity Code (TEC) in two parts:

- System level expectations of service measured by SAIDI and SAIFI; and
- Localised or community based expectations of SAIDI and SAIFI.

While TasNetworks operates an extensive program of maintenance and renewal activities across the network; reliability cannot be managed solely at an asset management level, but requires a holistic approach to ensure activities are collectively targeted towards system performance levels as stated in our key asset management objectives:

- Service performance will be maintained at current overall network service levels, whilst service to poorly performing reliability communities will be improved to meet regulatory requirements.

At a system level, TasNetworks strategy is based on three principles:

1. Prevent outages from occurring;
2. Minimise the number of customers affected; and
3. Restore supply as quickly as possible.

The follow sections provide more details on these principles.

7.2.1 Prevent outages from occurring

The most effective method of maintaining reliability is to address the root cause of network faults that can result in customer outages. By preventing the outages occurring in the first place, other mitigation measures are avoided. The maintenance and renewal activities (refer asset management plans) are aligned to this objective

7.2.2 Minimise the number of customers affected

Despite measures to reduce the number of faults, outages will occur and impact customers. The next measure to achieving reliability performance targets is to use network configuration (feeders and interconnections) and protection design to minimise the number of customers affected when outages occur. This is achieved through reinforcement programs targeting the poor performing communities and worst performing feeders, by:

- Reducing feeder network area, and increasing/reinforcing network interconnections;
- Using appropriate electrical protection devices;
- Ensuring accurate protection co-ordination,

7.2.3 Restoring supply as quickly as possible

The third strategy to achieving reliability performance targets is to restore customers that have been affected by an outage as quickly as possible.

This requires Distribution Operations to have sufficient monitoring devices in the network to respond quickly and to target accurately field crews to the correct sites to expedite restoration.

It is also acknowledged that at a local level, parts of the network can be subject to varying levels of system outage that is driven by a number of issues. To ensure local clusters of customers are not subjected to sustained substandard network performance, localised or targeted, activities are required to address these customer groups.

8 Reinforcement Drivers

TasNetworks' requirements for developing the power distribution network are principally driven by five elements:

- Demand forecasts (refer Section 6) ;
- New load connection requests;
- New generation connection requests;
- Network performance requirements (refer TEC); and
- National electricity rules (NER) compliance.

These elements are used to guide network development strategies and ultimately reinforcement programs. The following sections provide more details on more general considerations that drive network development programs.

8.1 Security planning standards

TasNetworks has well established security planning standards based on the n-1 philosophy for zone substation assets and their sub-transmission feeders. This includes full firm and 'switched' firm arrangements where economical.

TasNetworks' distribution network zone substations are established where significant bulk load points exist and there is a need to further distribute the capacity requirements of customer loads at high voltage (HV). Zone substations are radially supplied by 1 to 3, 33 kV (or 44 kV on the west coast) dedicated, power-transformer-ended, sub-transmission circuits. These sites are generally located in the Greater Hobart area and supply large numbers of customers within reliability communities such as Critical Infrastructure – Hobart CBD, Hobart High Density Rural, and Hobart

Urban. Some critical customer loads in the network have a similar arrangement at a distribution feeder voltage.

TasNetworks distribution feeder strategy is to take a historic reliability-based approach to distribution feeder security.

For critical community infrastructure security planning standards are established on a case by case basis. This ensures that proposed solutions are tested and assessed against the targeted service levels by customer classification. It also allows sufficient freedom to explore non-traditional innovative solutions where they can represent a more cost effective solution.

8.2 High Voltage feeder and reliability community performance

Distribution network reliability performance can be influenced by focusing on the controllable aspects of reliability:

- prevention;
- minimising customer impact; and
- reducing outage duration through effective planning and restoration.

The most effective method of managing reliability performance is to address the root cause of network faults that can result in customer outages, and to ensure planned outages are undertaken in an efficient manner. However, despite best endeavours, outages will occur on the distribution network due to forces largely outside of TasNetworks control such as storms, fauna and flora.

In this regard, network development reliability programs are associated with improving outage prevention and minimising outage durations through targeted augmentation projects; with the objective of meeting the Distribution Network Reliability Management Strategy.

Network development strategies and associated augmentation programs aim to manage feeder and community performance issues through:

- effective network and asset designs;
- analysis of feeder and reliability area performance
- developing strategies to address areas of poor performance;
- implementation of innovative technology and other solutions for the improvement of network reliability.
- effective protection designs and coordination;
- effective isolation of faulted sections via network reconfiguration; and
- flexible and effective SCADA, remote control monitoring and distribution automation.

8.3 Suboptimal sizing of transformers, cables and conductors

HV and LV (including sub-transmission) cable and conductor assets are sized to manage:

- the network peak demand;
- the transfer capability between neighbouring network during planned and unplanned network reconfigurations;
- the system fault level;
- the voltage level (bandwidth) supplied to customers for variations in load due to daily and seasonal demand/generation changes, and load growth;
- the voltage level (transient) as a result of disturbing loads or transient load changes;
- Minimise network losses; and

- Cater for future growth.

These assets will have a set of thermal ratings or 'rated capacity' in terms of current (amps) that are determined based on various operating conditions, construction and manufacturers specification. The capacity ratings that are used in investigating risks and identifying and evaluating treatment options of the capability of assets is given in the following terms:

Planning rating	A nominal rating based upon design ambient temperature, wind speed, insulation or nameplate rating.
Cyclic rating	Based upon core hot spot temperature not exceeding design criteria and thermal loading over a 24 hour period.
Nameplate rating	The rating identified upon the equipment nameplate for normal operation

Generally:

- transformers will have a nameplate rating (manufacturers specification), and a normal cyclic rating;
- cables will have a nameplate rating (manufacturers specification), and a short term (1 hour) cyclic rating. Often the nameplate rating and planning rating are similar; and
- conductors will have seasonal planning ratings that are typical for standard pole top construction, taking standard height and clearances into account.

8.4 Circuit(s) not rated for load distribution

TasNetworks operates the HV and LV networks as a three-phase network, which also supplies small two-phase or Single Wire Earth Return (SWER) systems. These systems are transitioned to three-phase networks in response to:

- load growth;
- excessive feeder phase unbalance; and
- power quality issues.

8.5 Switchgear not appropriate for task

As feeder configurations change over time, often switchgear requires upgrading to meet operational requirements, coordinate effectively, and maintain network performance. This can include:

- upgrading single phase operation to three-phase operation;
- upgrading manually operated equipment to remote controlled devices; and
- upgrading protection devices to cater for load and growth.

8.6 Changing the nominal system voltage

Manage isolated, non-standard or suboptimal network voltages by migrating to more appropriate voltage levels i.e. migrating from 11 kV to 22 kV.

8.7 Quality of supply issues

Quality of supply issues including voltage flicker and waveform distortion associated with electrical loading of the network is dealt with in the Power Quality Management Plan[1].

9 Risk Based Management

For network development related work there is a high correlation between creation and augmentation of network assets and the treatment of network risks. The following sections describe the main processes that are used to identify network development risks, methodologies that are used to address the higher risks and options that are undertaken to apply treatment.

As each of the processes is targeted to each of the three levels of network management (refer Section 10.1) the risks may be similar but treatment is varied according to the elements addressed.

9.1 Risk Level Evaluation

Network risks associated with this management plan have been assessed, for the system as a whole, according to the TasNetworks Risk Management Framework Risk Rating Matrix[2].

The risk ratings used in the framework are:

- Low;
- Moderate;
- High; and
- Very High.

The application of TasNetworks Risk Management Framework portrays the level of risk associated with each of the three levels of network management should the risks go untreated.

Table 1: Network development risk assessment[3]

Consequence category	Description	Evaluated risk at network planning level		
		Major System	**HV System**	**LV System**
Safety & People Human safety both public & internal:	Decreased operating clearances Increasing risk of third party contact Electric shock or electrocution Explosion, Physical damage or harm.	Medium	High	Medium
Environment & Community Environmental	Increased risk of conductor clashing or failure leading to interruptions and fire ignition Explosion and expulsion of oil	Medium	Medium	Medium

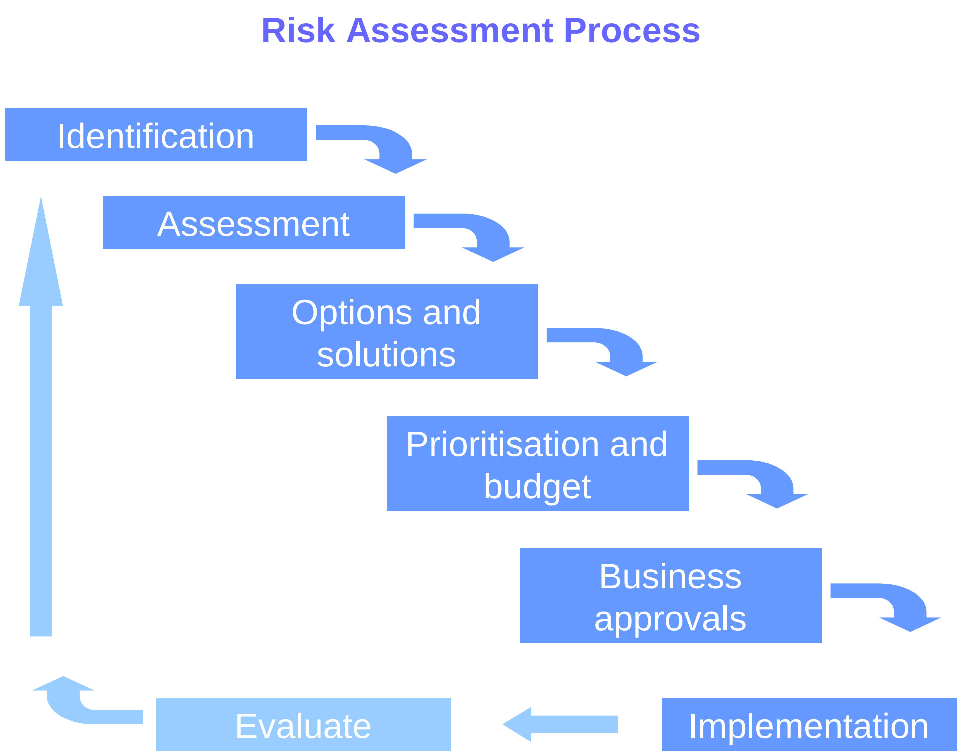
[1] Refer R/0000299031
[2] TasNetworks Risk Management Framework v1.0 March 2015 (R0000209871)
[3] Highest level of risk at each planning level as determined and described within the Network Development Risk Evaluation tables (refer Network Planning)

incidents:				
Regulatory Compliance Business or legislative standards:	Non-compliance with obligations fine, breach of code and standard or licence for TEC, NER, connection agreements, legislation and regulation; Failure of asset.	High	High	Low
Customer Customer outcomes:	substandard reliability (SAIFI and SAIDI) unavailability of network services inability to meet obligations to connect Community values and expectations Increased customer complaints reputation damage	Medium	Medium	Low
Financial	Higher cost associated with repairing equipment under fault, compensation payments, under regulatory regime - STPIS outcomes;	Medium	Medium	Low
Network Performance Loss of equipment life	decreased life expectancy of assets due to operating above design criteria overheating of transformers and switchgear leading to: flashover explosion oil spill reduced current ratings	Medium	Medium	Medium
Network Performance System stability / security	running the system in an insecure state or above its capability that may lead to consequential failures protection operation initiated interruptions to supply rotational interruptions to supply to manage equipment loadings	Medium	Medium	Low
Network Performance Quality of supply	electromagnetic interference damage to network and customer equipment increased customer complaints protection operation initiated interruptions to supply Operability of reticulation and system components Reduced capability to minimise impacts of planned outages contingency events sub optimal system design and / or equipment that cannot be operated.	Medium	Medium	Low

9.2 Risk Assessment & Treatment

The network development approach for assessment of risks and the identification, evaluation and implementation of treatment options can be illustrated by the process shown in Figure 2.

Figure 2 – Risk assessment process



9.2.1 Identification

Network development related risks are identified through a range of business processes. Forecast or emerging issues are identified through our annual demand forecasting processes, quarterly reliability performance reporting, and our resulting system investigation and analysis. Current issues are generally identified through customer engagement, field staff, and real time operations.

9.2.2 Risk assessment

The following are assessed in accordance with the risk evaluation tables (refer Section 9.1) to gain an understanding of the risks and to enable the evaluation of treatment options:

- Causative issues;
- Identification of magnitude and breadth of the issue; and
- Implication of not addressing the issue.

9.2.3 Options and solutions

A suite of options (generally 2-4 depending on the planning level and risk) is developed that will address the identified issue(s). Each option is assessed for treatment of the issue with consideration to its implementation, probability of success, business fit and financial requirements. Some projects are jointly attended with the transmission network.

Larger projects are subjected to the NER Regulatory Test process or Regulatory Investment Test for Transmission (RIT-T) where undertaken jointly with the transmission network.

9.2.4 Prioritisation and budget

An economic cost effectiveness analysis of possible options is carried out to identify options that meet the regulatory test. Budgets are refined and year of implementation identified.

Prioritisation takes account of:

1. Severity of the untreated risk;
2. Impact upon the business if left untreated;
3. Time of requirement;
4. Capital finance constraints; and
5. Business appetite.

9.2.5 Business approvals

The identified treatment option is approved according to the level of required expenditure conforming to the business delegation approval process.

9.2.6 Implementation

The project(s) are planned, designed and commissioned.

9.2.7 Evaluation

Following implementation of the solution to treat the risk, the project(s) is evaluated to confirm that the treatment has reduced the level of risk to an acceptable level.

Should the treatment option be unsuccessful the issue is reviewed and the planning process entered again.

10 Management Plan

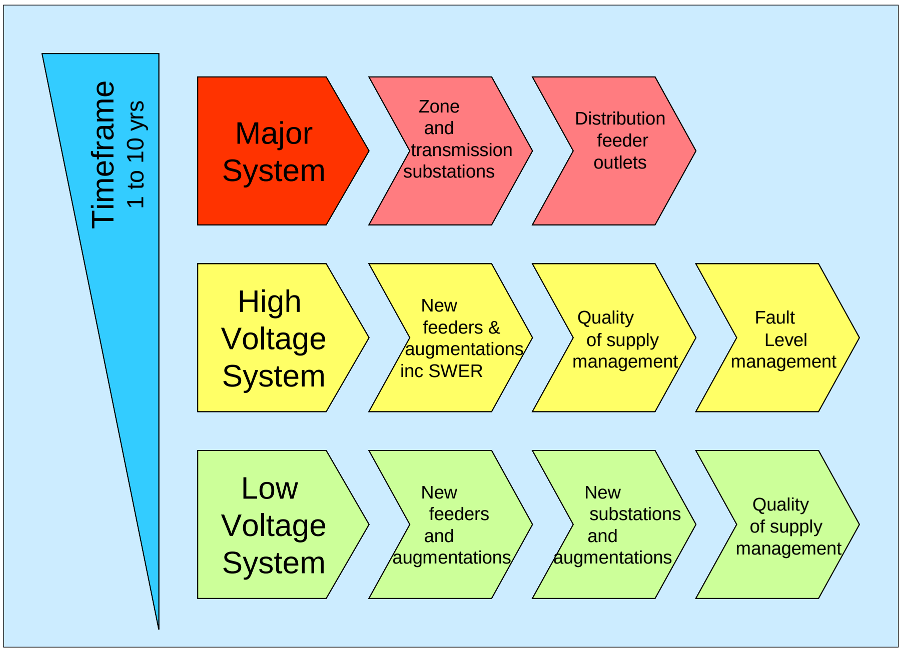
10.1 Network Planning Levels

Network development works are managed at three planning levels within the distribution network that reflect various levels of assessment, which include:

1. Major System;
2. High Voltage System; and
3. Low Voltage System.

Within each of these levels there are a number of assessment considerations that enable prioritisation for treatment. These are shown in Figure 3.

Figure 3– Network Planning Levels



10.1.1 Major System

The Major System primarily includes zone substations (urban and rural) and sub-transmission circuits operating at 33 kV and 44 kV. Feeder connection sites (to the transmission network) are also considered at this planning level.

Work within this level incorporates strategic planning outcomes associated with the transmission network. Additionally, incurs substantial project capital expenditure and as such regulatory tests are applicable in the majority of cases.

Common projects and programs within this planning level include:

- Upgrade or establishment of urban and rural zone substations including associated distribution feeder integration;
- Strategic acquisition of land associated with zone substation infrastructure corridors;
- Reinforcement or establishment of sub-transmission circuits including protection and communications;
- Establishment of HV feeders from terminal substations;

10.1.2 High Voltage System

The High Voltage (HV) [4] System planning level includes development of existing and new HV distribution feeders and associated elements operating at 6.6 kV, 11 kV, SWER voltages, 22 kV or 44 kV (assets that are not sub-transmission). This planning level represents the majority of the distribution network, and is the largest component of the Network Development expenditure forecast.

[4] TasNetworks HV feeders operate between 6.6 kV and 22 kV. Although these voltages are commonly referred as medium voltages by other Australian utilities, TasNetworks reference to HV reflects the legacy nomenclature used by Aurora Energy.

The main components of HV system includes:

- Overhead conductor
- Underground cable
- Voltage regulators
- Overhead switchgear (Reclosers, Gas Switches, ABS, Fuses, Links)
- Ground mounted switchgear (generally components of Distribution Substations)

Planning at this level also includes network development works associated with addressing and maintaining reliability performance. This includes:

- Addressing the worst performing HV feeders;
- Addressing the poorest performing Reliability Communities.
- Maintaining Reliability Category performance at a system level (refer TEC).

Generally the HV System is a radially operated system with varied levels of network interconnection depending on population density.

Work within this level incorporates strategic planning outcomes associated with the Transmission network. However, incurs low project capital expenditure where regulatory tests are not applicable in the majority of cases.

Common projects and programs within this planning level include:

- Reinforcement or establishment of overhead and underground conductors and cables to manage thermal loading of HV feeder elements;
- Reinforcement or establishment of underground conductors and cables to manage higher that rated fault level of HV feeder elements;
- Reinforcement or establishment of overhead and underground conductors and cables to manage low fault level or voltages along HV feeder elements;
- Reinforcement or establishment of voltage regulators, cap banks, Statcoms, or mobile generator connection sites to manage thermal loading or low voltage levels of HV feeder elements;
- Reinforcement or establishment of HV feeder interconnections to manage feeder network size, coverage, transfer capability and operational flexibility (planned and unplanned access and restoration);
- Reinforcing the feeder trunk to manage exposure of the main HV feeder elements (Feeder Trunk Strategy, bird strike mitigation);
- Upgrade, relocation, or establishment of protection devices and switchgear to manage coordination and network reconfiguration (planned and unplanned access and restoration);
- Upgrading distribution substations, where the HV switchgear is integrated, to manage HV feeder network access and reconfiguration.
- Transitioning single-phase or SWER systems to three-phase systems to manage load, voltage, or power quality regulations;
- Migrating 11 kV networks to 22 kV networks to manage load, voltage, or power quality regulations;

10.1.3 Low Voltage System

This covers Low Voltage (LV) feeders, switches, distribution substations and interconnections operating at < 1 kV i.e. 400/230 V.

This system planning level predominantly consists of upgrading distribution transformers (ground, or pole mounted) and augmenting LV circuits to manage asset loading and voltage. It should be noted that many of the voltage issues at this level of the distribution network are localised and generally managed through the Power Quality thread.

Common projects and programs within this planning level include:

- Upgrading, relocating or establishing distribution transformers, substations, and LV circuits to manage localised thermal loading, voltage, performance, or power quality regulations;
- Installation of HV and LV duct (conduit) with other TasNetworks or third party (local council, developments, etc) works for future network development. Typically for road crossings.
- Reinforcing localised supply feeds to manage exposure of the HV and LV feeder elements (bird strike mitigation, protection relocation, Local Reliability Program);

10.2 Reinforcement Strategy

The management of risk may require treatment by any of the following options:

1.	Do nothing	No action to be undertaken.
2.	Reduction in loading	Involves redirection of circuit loading to other circuits or units. Non-network solutions such as Demand Side Management and Embedded Generation are considered in this context.
3.	Increase utilisation	Involves re-rating, reducing clearances, improving control settings/limits, adding SCADA control/protection schemes, to operate assets close to operating/physical limits without comprising acceptable levels of performance and risk.
4.	Augmentation	Involves making the device stronger, bigger or replicated or addressing quality of supply issues.
5.	Removal from service	Involves removal of the asset in its entirety. Normally does not extend to conductors or transformers, given that if the component is heavily loaded it is needed, but can be associated with switches or other control devices.
6.	Network extensions/ interconnections	Establishing addition network to interconnect neighbouring systems – allowing transfer capability and operational flexibility.

10.3 Guiding principles

In addition to specific considerations applicable to each of the three Network Planning Levels (refer Section 10.1.2) and development strategies described in the Area Strategy reports, the following principles are common to all levels and aid the assessment of the level of untreated risk and action undertaken to treat any identified risk:

Safety	People must not be endangered by the operation of Aurora equipment or as a consequence of operating the system.
Sub-transmission, High Voltage & Low	Sub-transmission circuits should be operated with due regard to the cyclic rating of the asset or suite of assets. This

Voltage circuits	enables clearances to ground or other electrical structures to be safely maintained and components not to be unduly stressed e.g. connectors and fittings.
Switchgear	Switchgear should be operated with due regard to the rating of the asset or suite of assets. This enables components not to be unduly stressed causing mal-operation.
Transformers	Transformers should be operated with due regard to the cyclic rating of the asset or suite of assets. This enables components not to be unduly stressed and the transformer life expectancy not to be unduly shortened by its operation.
Customer outcomes	Interruptions and quality of supply are maintained so to not adversely affect the level of contracted supply.
Environmental	Relevant environmental standards are to be employed including Electro Magnetic Radiation (EMR) and noise. One of the higher risks is the expulsion of oil due to transformer failure. Management of load mitigates the consequence.
Standards	Relevant standards are to be complied with. Common standards used are: • Environmental Protection and Biodiversity Conservation Act 1999; • Environmental Management and Pollution Control Act 1994; • Electricity Wayleaves and Easements Act 2000; • Land Acquisition Act 1993; • AS/NZS 61000 Electromagnetic Compatibility (EMC) parts 3.6 & 3.7; • AS 2374.7 Power transformer loading -1997 • AS/NZS 3000 Electrical installations (known as the Australian/New Zealand Wiring Rules) • ENA CB(1) 2006; • AS 2067 Substations and High Voltage installations exceeding 1 kV ac; • TEC Chapter 8 sections 3, 6, 7 & 8; and • NER Sections 4.2, 4.6, 5.3, 5.5, 5.6, Schedules 5.1, 5.2, 5.3, 5.4, 5.5, 5.7.
Community values and expectations	The visibility and amenity of any infrastructure installed. Community reaction and appropriate consultation where necessary and the installation of equipment being undertaken with due regard to community values.
Loss of equipment life	Larger and more expensive infrastructure is to take into account loss of equipment life due to loading beyond nameplate ratings. This should mainly focus on power

	transformers and underground cables.
System stability	Loading beyond nameplate ratings and system design requirements will introduce elements of system instability and possible consequential supply loss and equipment failure.
Operability of components	Loading beyond nameplate ratings will cause reduction of operation capability e.g. switch contacts either welding shut or not being able to be closed. This has consequences of the component and the system being unable to be operated in its optimal state to ensure a reliable and quality outcome.
Fault rating	The designated fault rating for the component should not to be exceeded. Conditions to be assessed are steady state and transient modes of operation.
System voltage	System voltage output should be contained within its permitted range.

10.4 CAPEX Programs 2016/17-2026/27

10.4.1 Major System

10.4.1.1 Zone Substations (CAZNC)

With the exception of Richmond Rural Zone, which is being addressed as part of asset refurbishment project (Asset Strategy) there are no transformation capacity issues at Zone Substations under normal and contingency (N-1) conditions.

In previous regulatory submissions and strategies a number of forecast additional zone substation developments fell within the upcoming two year determination, including Austins Ferry Zone (including Bridgewater 110/33 kV development), Brighton Zone, Blackmans Bay Zone, Sandford Zone, Margate Zone; and Richmond Rural Zone conversion and upgrade.

Based on the demand forecast[5], it was determined that the proposed zone substation developments will not be required within the two year determination, and additionally may not be required within the regulatory period to 2027. As such, no additional zone substation projects have been proposed within the regulatory period to 2027.

10.4.1.2 Strategic Acquisition of Land (LANDZ)

Although it is likely that no zone substations will need to be established within the planning period, strategic acquisition of land is generally required to secure appropriate sites that will ensure future costs are known and economical. It is proposed to allow for the purchase of land for these future zone sites at a rate of one land purchase every two years.

[5] Demand Forecast - refer R0000141368

10.4.1.3 Sub-transmission Circuits (CAZNC)

There are no capacity issues (excluding fault level) associated with the sub-transmission feeders under normal configuration. However, under contingency analysis a large number of capacity issues were identified, particularly associated with the summer rated 33 kV overhead networks.

Generally the overhead sub-transmission feeders already utilise the largest conductor size (19/3.25 AAC equivalent) used in the distribution network. To manage these issues, we have proposed to re-rate relevant sub-transmission overhead feeder sections at a higher operating temperature. This will involve a line audit and minor augmentation (re-tensioning, reduced clearances, taller poles etc). As these constraints are existing, Network planning proposes to manage these augmentations during the two year determination. This includes:

- 16/17 – Line audit and design estimation 65.4 km
- 17/18 – Re-rating of OH Sections 31.2 km
- 18/19 – Re-rating of OH Sections 34.2 km

There are two sections of 33 kV underground cables that will be overloaded during the period to 2027. It is proposed to monitor and/or re-rate these sections using modelling software (CYMCAP) rather than address the constraints through augmentation.

Conductor sections that have been identified as operating above their fault withstand capacity have been addressed in by the *CAHVF Augment overhead feeder - Fault level* program; detailed in the HV System planning level.

Some 33 kV overhead sections will not be able to operate at a higher temperature due to pole top construction, conductor condition, and location/route limitations. These sections may need to be relocated (including undergrounding), or renewed as required.

This program has therefore allowed the following expenditure:

- 80% - re-rated by minor augmentation
- 15% - conductor renewal/relocation (OH)
- 5% - conductor relocation (UG)

10.4.2 High Voltage System

10.4.2.1 Install/Augment Voltage Regulator for Capacity (CAHVF)

These programs includes the installation of new, or the relocation and/or upgrade of existing regulators to manage asset loading, and/or feeder steady state voltage control under normal or contingent network configurations.

These assets can be pole mounted in an Open-Delta configuration (two single phase tanks to regulate a three phase system), or ground mounted in a Closed –Delta configuration (three single phase tanks to regulator a three phase system).

Closed Delta configurations have the benefit of an additional 5% of voltage regulation, can be paralleled though, and minimised neutral voltage shift. Consequently with the additional tank, this configuration must be ground mounted with appropriate oil containment, which has a substantial cost increase compared to pole mounted arrangements. For these reasons, a closed-delta configuration is only installed where a pole mounted unit is not suitable. This is generally required in normal or contingent network configurations where more than two voltage regulators will be configured in series.

Throughout the planning period to 2027, a total of 16 pole mounted sites and 7 ground mounted sites have been proposed.

10.4.2.2 Augment HV Feeder for Capacity (CAHVF)

This program includes the minor (conductor re-rating) and major (upgrade) augmentation of existing overhead conductors or underground cables where the peak loading is in excess of asset rating or results in excessive voltage and related power quality issues.

Throughout the planning period to 2027, a proposed program totalling 170 km of overhead conductor and 1 km of underground cable has been put forward.

10.4.2.3 Augment OH GI Feeder Spurs for Capacity (CAHVF)

This program includes the augmentation of existing large GI spur feeders where the connected loading on these feeder sections has significantly exceeded the capability of conductor type, resulting in unacceptable voltages and related power quality issues.

Throughout the planning period to 2027, a program totalling 100 km of overhead conductor is proposed, addressing the most significant GI feeder spurs.

10.4.2.4 Augment Feeder for Fault Level (CAHVF)

This program includes the proposed augmentation of existing overhead conductors to current period contract equivalents where the maximum system fault level is in excess of asset fault withstand rating.

The bulk of the program consists of the augmentation of small conductor (GI, Cu, and AAC) installed in close proximity to transmission (terminal) substations.

10.4.2.5 Augment Feeder for Capacity – Other (CAHVF)

This project includes the establishment of an 11-22 kV interconnection (HV padmounted transformer and switchgear) at the northern (radial) end of feeder 40002.

By establishing an 11-22 kV interconnection, transfer capacity between the 11 and 22 kV networks of Richmond Rural and Sorell respectively can be established, which will defer the need to augment the existing voltage regulator at Colebrook (T580156), identified as an existing constraint.

Additionally, this project will improve network performance at this end of the feeder – supporting economic growth for agricultural expansions on this network resulting from the Lower South Esk Irrigation Scheme[6], and assist distribution operations to manage the major renewal project of Richmond Rural Zone in 20/21.

Other projects under this program

Other projects under the *'Augment Feeder for Capacity – Other'* program can also include minor network reinforcement works to improve operational flexibility where limitations are identified from Distribution Operations during normal or contingency network restorations

[6] http://www.tasmanianirrigation.com.au/index.php/schemes/lower-south-esk-irrigation-scheme

Distribution Operations have the responsibility to manage the HV distribution network for system management, system access and fault restoration management. Throughout the year operators identify operational limitations in regards to network configurations that contribute to inefficient switching operations, unnecessary outages and long fault restoration times.

Historically, limitations have been formally (and informally) reported to Strategic Asset Management from Operations for evaluation, and consideration in future programs of work.

Through changes in business and group structures with the formation of TasNetworks in the recent regulatory period, this process has not been renewed. As such, the identification of operational limitations to be considered within future programs of works is currently limited.

10.4.2.6 Augment HV Feeder for Reliability - Trip P (PRHVR, PRLVR)

These reliability reinforcement programs include targeted augmentation projects to restore the performance of the poorest performing reliability communities and worst performing feeders towards the performance thresholds as described in the TEC, with the objective of meeting our Reliability Strategy[7].

The program is a bottom up build of reliability reinforcement projects, and allocated across the current regulatory period, and the subsequent two year and five year determinations. This approach concludes that:

- all existing worst performing feeders (worst 7) will be addressed over the 15/16, 16/17, 17/18 and 18/19 programs of work; and
- 50% of all existing non-compliant communities will be addressed within the 16/17, 17/18 and 18/19 programs of work (~20 communities);
- Remaining 50% of all existing non-compliant communities will be addressed within the 19/20 & 20/21 programs of work (~20 communities).
- any additional non-compliant communities will be addressed in subsequent determinations from 21/22 (Refer 10.4.2.6 Trip S).

Included in this program is a number of large augmentation projects, particularly to address the worst performing feeders. These projects include:

- Wesley Vale feeder development;
- Feeder development from Palmerston Substation;
- Feeder development from Railton Substation;
- Feeder extensions from Scottsdale Substation;
- Rosebery 44 kV sub-transmission reinforcement (remote controlled ABS deployment); and
- Bruny Island standby generation.

The majority of augmentation projects under this program are however associated with Feeder Trunk Strategies (reinforcement of the feeder trunk section between the substation circuit breaker and first or second protection device i.e. Protection Zones 1 & 2), which include:

- Visual audit of vegetation and asset condition of the feeder trunk section
- Targeted vegetation management;
- Targeted asset replacement/relocation;
- Protection coordination review;
- Protection Zone 2 device upgrades as required.

[7] Refer Reliability Strategy

10.4.2.7 Augment HV Feeder for Reliability - Trip S (PRHVR, PRLVR)

This program is proposed to undertake minor reinforcement to maintain communities that trend below performance targets throughout the period to 2027. This program will begin from 21/22, as the Trip P reliability reinforcement programs finish, which addresses existing poor performing communities and feeders.

10.4.2.8 Installation of HV and LV conduit with other underground works

This program incorporates the installation of underground conduit with other works (generally third party works by councils, planning authorities), allowing for:

- Savings in future expenditure associated with excavation and reinstatement civil works (including traffic management);
- Prevention of community inconvenience associated with repeat civil works along public roads and footpaths.
- Meeting the expectations of customers and community in regards to joint planning activities.

The approach to developing the forecast expenditure for this program is to continue historical volumes and historical expenditure throughout the period to 2027.

10.4.3 Low Voltage System

10.4.3.1 Distribution substations (CATXU)

This program consists of upgrading distribution transformers (ground, or pole mounted) for capacity. The approach to prioritising distribution substations for overloading assessment has been undertaken through a comparison of three estimation methods, including:

- Application of an average After Diversity Maximum Demand (ADMD) (4 kVA/customer)
- Application of an estimated ADMD, based on customer numbers and historical logging of +200 sites state-wide.
- Application of a calculated ADMD using Virtual Network Monitoring (Network Innovation)

The three methods provide a reasonable overview of the transformer fleet in terms of the likelihood that some sites may be overloaded. Further, a consequence assessment has been used for the fleet based on safety, environmental, and performance (customer) impact. The resultant prioritised list of distribution transformers forms the basis of targeted site logging assessment, and proposed investigations and augmentations for overloaded transformers.

The approach to developing the forecast expenditure for this program is to continue historical volumes and historical expenditure throughout the period to 2027.

This equates to the following annual volumes and forecast expenditure:

- Upgrade Ground Substation 3 sites
- Upgrade Pole transformer > 50 kVA 5 sites
- Upgrade Pole transformer < 50 kVA 5 sites

10.4.3.2 Augment Low Voltage Feeders for Capacity (CALVF)

This program consists of augmenting LV circuits to manage asset loading and voltage.

The approach to developing the forecast expenditure for this program is to continue historical volumes and historical expenditure throughout the period to 2027.

10.4.3.3 Local Reliability (PRTXI, PRHOS, PRSPT)

These programs address localised reliability issues that result in poor levels of service as experienced by customers, but may not be captured effectively at the HV system level (feeder and community performance). Still, these specific issues do contribute to poor community performance, GSL payments and represent the 'worst' customer service performance.

The main programs include:

- Rectification of multi-visit transformers;
- Install/upgrade control station;
- Install bird diverters and pole top reconfigurations;

10.5 OPEX Programs 2016/17-2026/27

There are no OPEX programs included in the network development management plan.

10.6 Program Summary

Table 2 provides a summary of all of the programs described in this management plan.

Table 2: Summary of Network Development (System Development and Reliability) reinforcement programs

Work Program	Work Category	Project/Program
Reinforcement	Zone Substation Upgrades - Capacity (CAZNC)	Major System - Augment 33 kV Sub-transmission Circuits (Capacity)
	Land Acquisition - Zone Substations (LANDZ)	Land Purchase associated with Zone Substations (Capacity)
	HV Feeder Upgrade – Capacity (CAHVF)	Install/Augment Ground Mounted Voltage Regulator for Capacity
		Install/Augment Pole Mounted Voltage Regulator for Capacity
		Augment HV Feeder (Capacity)
		Augment OH GI Feeder Spurs (Capacity)
		Augment OH HV Feeder (Fault Level)
		Augment HV Feeder for Capacity (Other)
		Install HV and LV Conduit with other UG works (Capacity)
		Install HV Switch for Capacity (Transfers)
	LV Feeders Upgrade – Capacity (CALVF)	Install/Augment LV Feeder

	Transformer Upgrades – Capacity (CATXU)	Install /Augment Pole Substation < 50 kVA (Capacity)
		Install/Augment Pole Substation (Capacity)
		Install/Augment Ground Substation (Capacity)
Reliability and Quality Maintained	Upgrade HV Fdrs (Reliability) (PRHVR)	Install/Augment HV Feeder (TRIP-P)
		Install/Augment HV Feeder (TRIP S)
	Install Reclosers (PRLVR)	Install/Augment Recloser/Sectionaliser (TRIP-P)
		Install/Augment Recloser/Sectionaliser (TRIP-S)
	Rectification work multi visit transformers (PRTXI)	Local Reliability (general)
		Rectification of Transformers (LAP)
		Rectification of Control Stations (LAP)
	Install HV Switchgear OH (PRHOS)	Install/Augment HV OH Switch (LAP)
	Install bird diverters & pole tops reconfigs (PRSPT)	Install/Augment OH Feeder for Bird Mitigation (LAP)

11 Financial Summary

11.1 Proposed CAPEX Expenditure Plan

The capital programs and expenditure identified in this management plan are necessary to manage operational and safety risks and maintain network capacity and performance at acceptable levels. All capital expenditure is prioritised expenditure based on current demand forecast data, reliability performance reporting data, and prudent risk management.

TasNetworks proposes a total capital expenditure of $52 million over the next 10 years, with an average expenditure of $5.2 million per annum.

Within the two year determination we propose to spend an average of $8.4m per year.

Table 3: CAPEX for period between 08/09 and 26/27 financial years

		Thread	
		Capacity ($000,000)	**Reliability ($000,000)**
Actual	2008/09	11.58	6.59
	2009/10	16.85	8.61
	2010/11	15.36	8.08
	2011/12	12.31	1.49
	2012/13	3.22	1.29
	2013/14	7.55	0.16
	2014/15	3.18	0.37
Forecast	*2015/16*	*6.67*	*1.86*
	2016/17	*7.01*	*7.03*
	2017/18	*5.64*	*3.02*
	2018/19	*5.34*	*2.79*
	2019/20	*3.45*	*2.91*
	2020/21	*2.92*	*2.91*
	2021/22	*3.20*	*1.00*
	2022/23	*2.50*	*1.00*
	2023/24	*3.20*	*1.00*
	2024/25	*2.50*	*1.00*
	2025/26	*3.33*	*1.00*
	2026/27	*2.33*	*1.00*

Figure 4: Expenditure profile

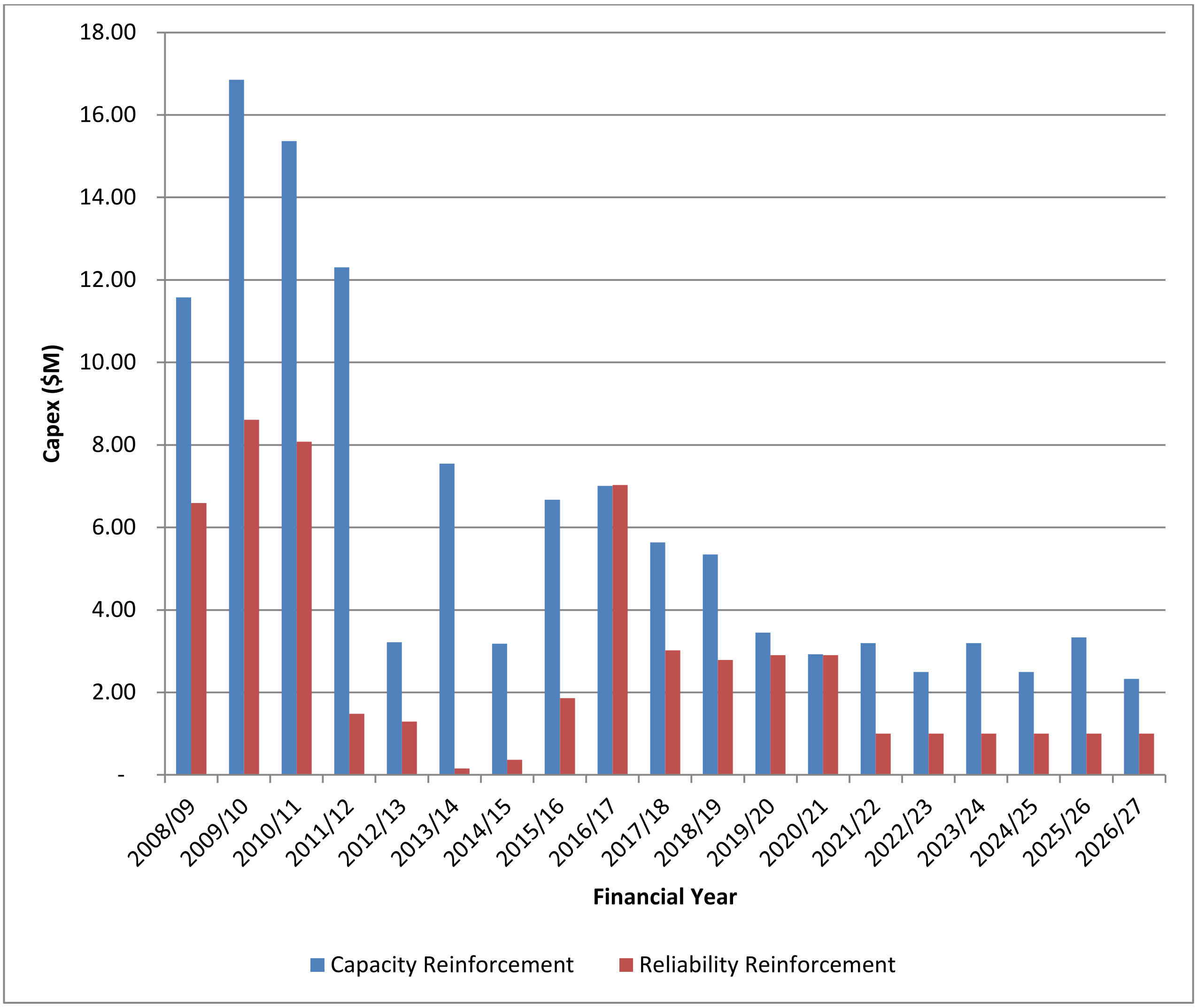


Figure 4 above describes our capital expenditure profile since 2008 and forecast to 2027 for capacity and reliability reinforcement.

11.1.1 Capacity

The forecast expenditure for capacity reinforcement (system development) within the two year determination (17/18-18/19) is on par with the current regulatory period (12/13-16/17), and substantially less than historical regulatory period (07/08-11/12). This substantially reducing forward into the planning period.

This is driven primarily by:

- a large volume of reinforcement works associated with managing overloaded HV feeder elements (particularly overloaded GI spur sections) and HV elements operating in excess of their rated fault withstand capability. The high volume of these programs is complimented by the zero expenditure on establishing or upgrading zone substations, which have contributed to a high capital spend in previous years.

11.1.2 Reliability

The forecast expenditure for reliability reinforcement is higher than with previous regulatory period (on par with historical regulatory period) within the two year determination, and remaining higher (although reducing) into the planning period.

This is driven primarily by large targeted reinforcement projects associated with managing the worst performing feeders, and the majority of the poor performing reliability communities in accordance with our jurisdictional regulatory requirements detailed in the TEC.

This is a change from the previous regulatory period where we had limited expenditure and observed a resulting high trend in additional poor performing communities over that period.

11.2 Proposed OPEX expenditure plan

There are no proposed operational programs as part of the network development management plan.

12 Related Standards and Documentation

The following documents have been used to either in the development of this management plan, or provide supporting information to it:

- Asset Management plans
- Area Strategy reports (Area Development plans)
- Demand Forecasts
- Distribution Network Reliability Management Strategy

13 Appendix A – Summary of Programs and Risk

Description	Work Category	Risk Level	Driver	Expenditure Type	Residual Risk	16/17	17/18	18/19	19/20	20/21	21/22
Major System - Augment 33 kV Sub-transmission Circuits (Capacity)	CAZNC	Medium/ High	Security	CAPEX	Low/ Medium	0.15	0.86	0.95	0.0	0.0	0.0
Land Purchase associated with Zone Substation (Capacity)	LANDZ	Low	Strategic (Acquisition)	CAPEX	Low	0.0	0.0	0.7	0.7	0.0	0.7
Install/Augment Ground Mounted Voltage Regulator for Capacity	CAHVF	Medium	Load/Voltage	CAPEX	Low	0.67	0.34	0.67	0.34	0.34	0.0
Install/Augment Pole Mounted Voltage Regulator for Capacity	CAHVF	Medium	Load/Voltage	CAPEX	Low	0.86	0.51	0.17	0.0	0.17	0.17
Augment HV OH Feeder (Capacity)	CAHVF	Medium	Load/Voltage	CAPEX	Low	3.31	2.24	1.39	0.78	0.78	0.78
Augment HV UG Feeder (Capacity)	CAHVF	Medium	Load/Voltage	CAPEX	Low	0.0	0.12	0.0	0.0	0.0	0.0
Augment HV Feeder for Capacity (Other)	CAHVF	Medium	Load/Voltage	CAPEX	Low	0.0	0.11	0.0	0.0	0.0	0.0
Augment HV Feeder (Capacity)	CAHVF	TBC	Load/Voltage	CAPEX	TBC	-	-	-	-	-	-
Augment OH GI Feeder Spurs (Capacity)	CAHVF	TBC	Load/Voltage	CAPEX	TBC	-	-	-	-	-	-
Install HV Switch for Capacity (Transfers)	CAHVF	Medium	Transfer/ Security	CAPEX	Low	0.11	0.0	0.0	0.0	0.0	0.0
Augment OH HV Feeder (Fault Level)	CAHVF	High	Safety/ Reliability	CAPEX	Low	0.89	0.45	0.45	0.62	0.62	0.53
Install HV and LV Conduit with other UG works (Capacity)	CAHVF	Low	Strategic (Opportunity)	CAPEX	Low	0.08	0.08	0.08	0.08	0.08	0.08

Install/Augment Ground Substation (Capacity)	CATXU	Medium	Load/Voltage	CAPEX	Low	0.42	0.42	0.42	0.42	0.42	0.42
Install/Augment Pole Substation (Capacity)	CATXU	Medium	Load/Voltage	CAPEX	Low	0.17	0.17	0.17	0.17	0.17	0.17
Install /Augment Pole Substation < 50 kVA (Capacity)	CATXU	Medium	Load/Voltage	CAPEX	Low	0.12	0.12	0.12	0.12	0.12	0.12
Install/Augment LV Feeder	CALVF	Medium	Load/Voltage	CAPEX	Low	0.23	0.23	0.23	0.23	0.23	0.23
Install/Augment HV Feeder (TRIP-P)	PRHVR	Medium	Reliability	CAPEX	Low	5.91	1.85	1.99	1.92	1.92	0.0
Install/Augment HV Feeder (TRIP S)	PRHVR	Low	Reliability	CAPEX	Low	0.0	0.0	0.0	0.0	0.0	0.26
Install/Augment Recloser/Sectionaliser (TRIP-P)	PRLVR	Medium	Reliability	CAPEX	Low	0.62	0.62	0.30	0.49	0.49	0.0
Install/Augment Recloser/Sectionaliser (TRIP-S)	PRLVR	Low	Reliability	CAPEX	Low	0.0	0.0	0.0	0.0	0.0	0.24
Local Reliability (general)	PRTXI	Low	Reliability	CAPEX	Low	0.1	0.1	0.1	0.1	0.1	0.1
Rectification of Transformers (LAP)	PRTXI	Low	Reliability	CAPEX	Low	0.1	0.1	0.1	0.1	0.1	0.1
Rectification of Control Stations (LAP)	PRTXI	Low	Reliability	CAPEX	Low	0.1	0.1	0.1	0.1	0.1	0.1
Install/Augment HV OH Switch (LAP)	PRHOS	Low	Reliability	CAPEX	Low	0.1	0.1	0.1	0.1	0.1	0.1
Install/Augment OH Feeder for Bird Mitigation (LAP)	PRSPT	Low	Reliability	CAPEX	Low	0.1	0.1	0.1	0.1	0.1	0.1