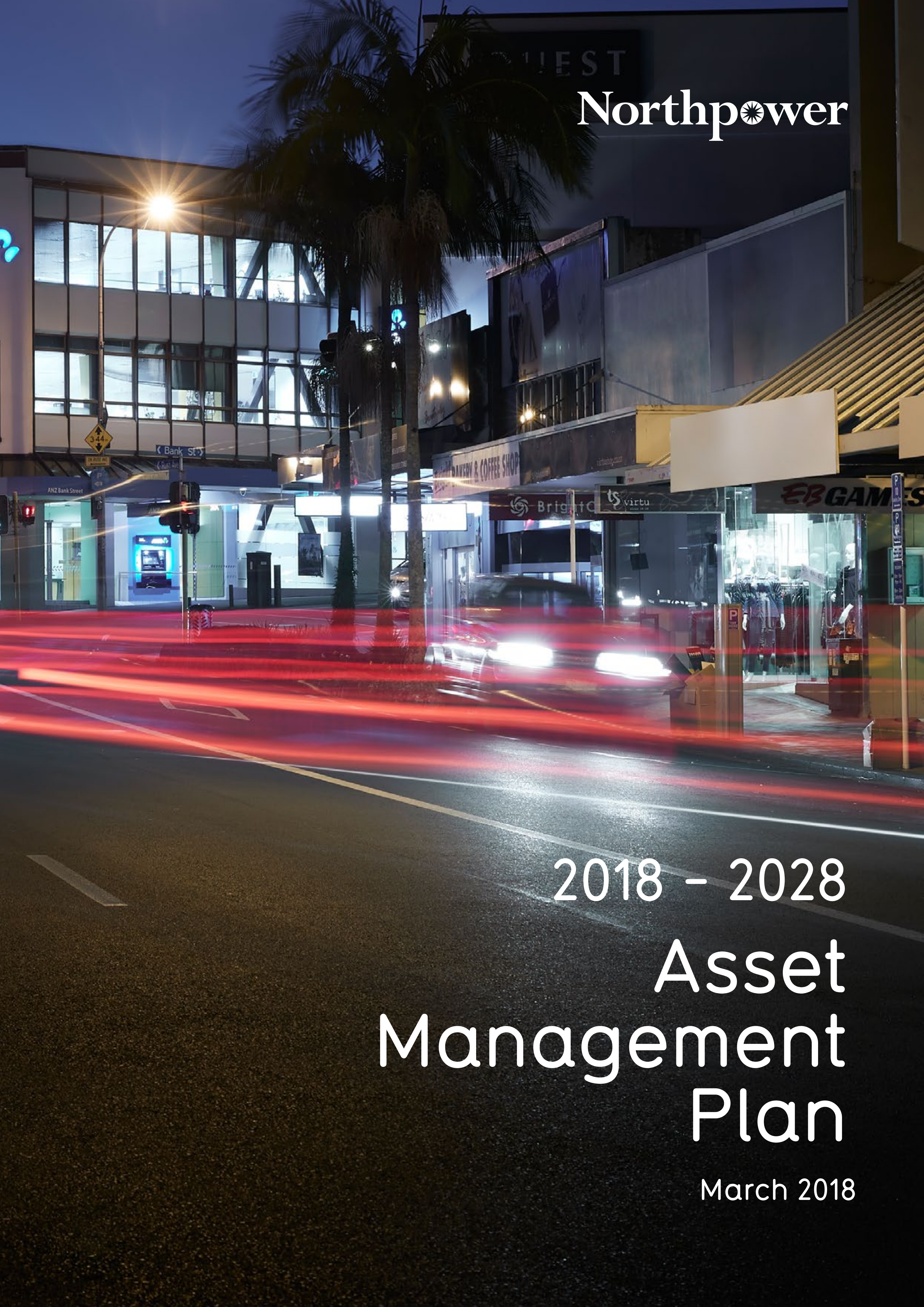

Northpower

2018 - 2028 Asset Management Plan

March 2018

Northpower

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Asset Management Plan

2018 - 2028

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Section 1: Summary

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Summary - Section 1

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Section 1: Summary

1.1 Purpose of the Plan

The purpose of this Asset Management Plan (AMP) is to set out our approach to managing our assets and delivering the planned programmes of capital and operational spend, as well as planned maintenance work for the period from 1 April 2018 to 31 March 2028. The work programmes are set in accordance with Northpower's Statement of Corporate Intent and aim to meet the Strategic Objectives for the business. The AMP is produced to comply with the requirements of the Commerce Commission's Electricity Distribution Information Disclosure Determination.

The AMP sets out the initiatives we will take to facilitate the management of our Network assets for the efficient delivery of electricity to consumers. This AMP will ensure we continue to meet our customers' expectations of a safe and reliable supply.

1.2 Northpower's Electricity Network

Northpower's electricity network extends across central Northland, covering the Whangarei and Kaipara Districts as shown in the following map.

Key Network Statistics as at 31st March 2017.

Number of Consumer Connections (ICPs)	57,954
Peak Demand	177 MW
Energy Supplied	1,056 GWh
Length of overhead lines and underground cables	6,380 km
Number of Zone Substations	20
Number of Distribution Transformers	7,209

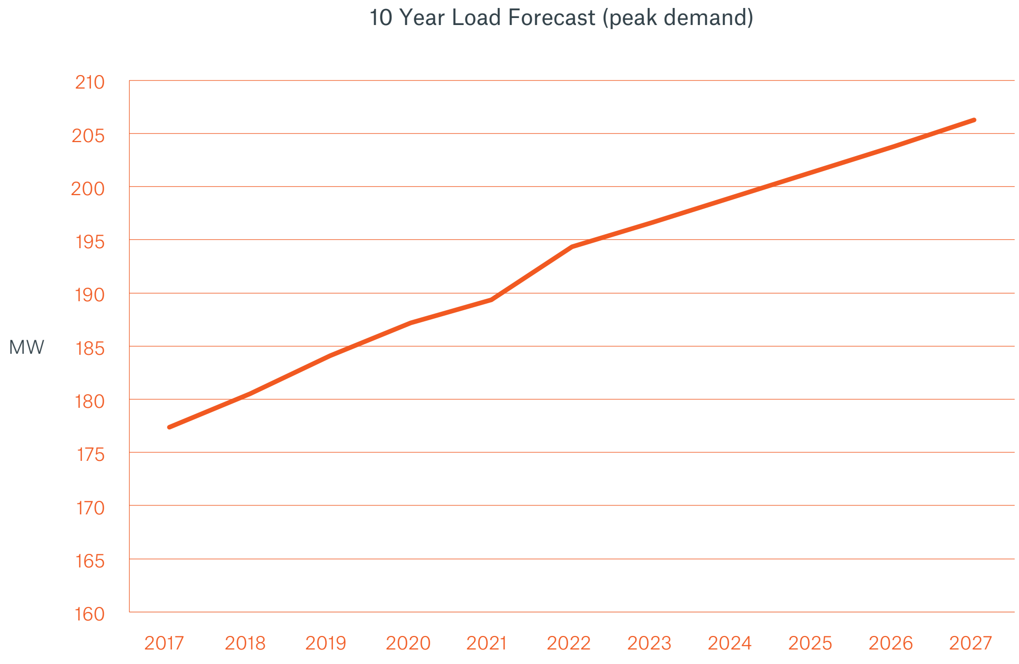
The AMP provides a detailed description of the types of network assets and their respective age profiles, together with an overview explaining how the acquisition of new or replacement assets are managed.

1.3 Supporting Growth in Electricity Demand

Northpower is committed to providing a reliable and safe electricity supply to customers, however this requires ongoing investment to meet the demands of sustained growth in demand and the number of connections, in addition to planning for renewal of an aging network.

Northpower's network has absorbed increases in connections and in demand, we are now at a point where we need to lift investment to ensure an ongoing secure supply. Whilst over the past two years there have been no major industrial growth initiatives in the region, ongoing growth in residential and commercial developments, especially around Whangarei, has resulted in the need to build three new zone substations and maintain security through construction of new trunk feeders.

In the graph below, the network peak demand forecast shows continuing linear growth at a rate of approximately 1.5% per annum. The steady increase is driven largely by residential growth into areas around Whangarei and there is an expected increase in 2022 due to expansion of New Zealand Refinery operations. Catering for this ongoing growth is a critical element of Northpower's role in supporting growth in the Northland region.



Network Load Forecast 2017-2027

1.4 Network Development

Our network assets are well maintained and Northpower has been managing a reliable network over past years. However, the performance of some assets is at risk due to ageing and in some cases obsolescence. Northpower intends to increase asset investment levels over the next ten years by approximately 17% more than the previous AMP. Around 60% of the Capex expenditure will be for asset renewals. The asset management processes are explained throughout the AMP.

Our investment and operational initiatives cover a number of themes and in aggregate are designed to ensure a resilient energy system that serves the needs of our customers and the communities we serve, now and into the future. The focus for our investments is as follows:

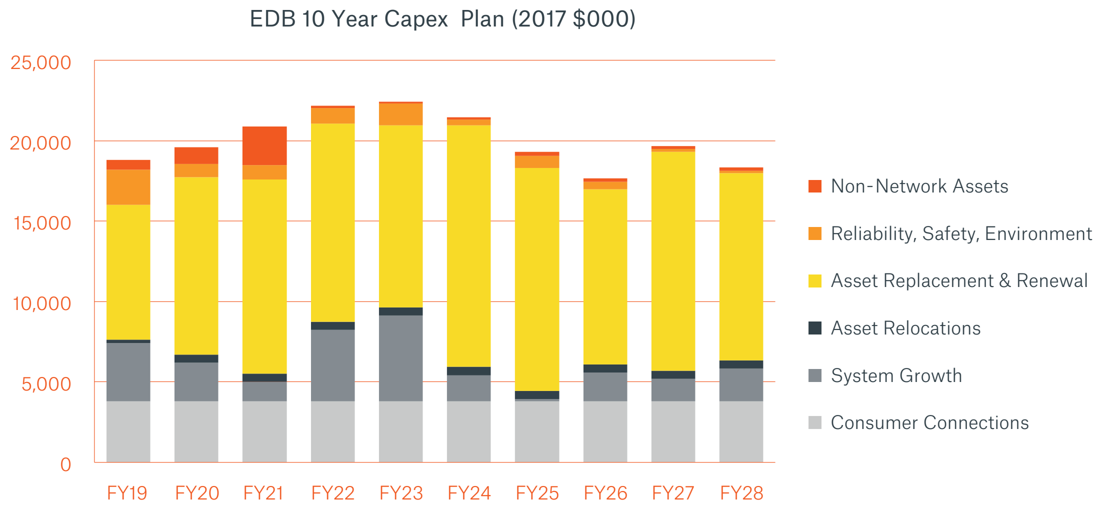
- Safety is our highest priority; public as well as contractor and staff safety. We will continue to emphasise safety in performance and strengthen our "safety in design" practices. Initiatives planned include upgrade of the construction standards and specific safety initiatives such as mitigating effects of potential asset failure in some urban zone substations.
- We will continue to improve our network performance, focusing on areas of critical risk, replacing ageing assets and minimising network outages through duplication and improved security standards. We will further identify investment areas to ensure the consequences of loss of supply are acceptable to our customers.
- Northpower has embarked on a project to step-up asset management practices, to enable better decisions around timing of replacement or new builds and managing our network risks. This is an important area of focus for us, to ensure that we are as efficient as possible in renewing and enhancing our assets, and can support our customers' energy choices.
- We want to provide sufficient capacity to meet increased peak demands, and enable resilient network connections with adequate back-up supply. It is important that our networks are resilient to low probability but high impact events and asset failures, to minimise disruption to our customers.
- Electric Vehicle (EV) ownership nationally is doubling each year and it is estimated that EV charging at home will increase annual consumption of the average home by around 50%. For the Northpower area, EV uptake is expected to lag the national growth and because there is sufficient capacity in our distribution transformers, the impact on the Network can be managed. We see electric vehicles as a positive development for our customers and expect to see a lift in our network utilisation.
- We want to give our customers better control of their energy use decisions, making technology choices that will not be constrained by limitations in the network. Northpower is intending to embark on projects to improve visibility and control of our low voltage networks, addressing market changes due to:
    - Electric vehicles
    - Photovoltaic cells
    - Home battery storage solutions
    - Advanced energy management systems
- Targeted end of life asset replacements are planned for zone substation switchboards, zone substation transformers, overhead line conductor and cross arms, poles, distribution transformers as well as subtransmission oil cables.

1.5 Ten Year Expenditure Programme

Key aspects of the ten year capital programme include:

- A programme of zone substation transformer and switchboard renewals and refurbishing.
- Distribution transformers that are at or close to end of their predicted life and are planned for replacement. We plan to replace an average of 95 distribution transformers per annum.
- Two oil filled subtransmission cables will be replaced during the planning period.
- Three new zone substations are planned at Maunu, Waipu and Helena Bay; these projects were deferred from the previous AMP dates but load growth now requires construction to take place within the next six years.
- Some additional mitigation work (including safety, environmental and security) is being factored into the transformer replacement programme, delivering risk mitigation such as construction of blast walls in some locations and oil bunding around seismic strengthened transformer foundations.
- The upgrade and eventual replacement of our SCADA system as well as the implementation of an advanced distribution management system to facilitate a safer network and better monitoring and response to market changes.
- Variations in annual expenditure forecasts in years 4 to 6 reflect the higher costs associated with 110kV transformer renewals.

Section 1 - Summary

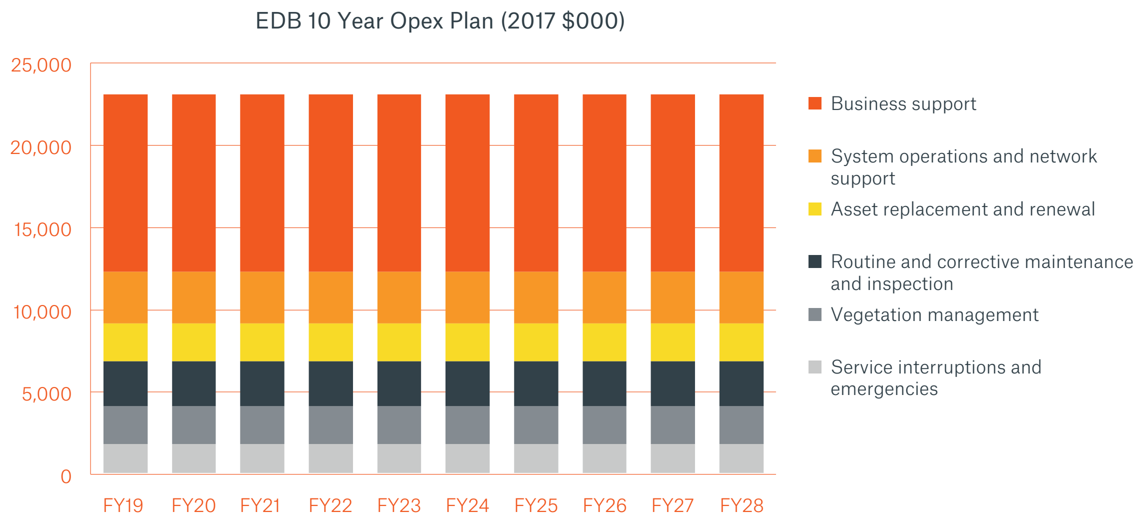


Proposed 10 year Capex Programme

Northpower's operational expenditure is not forecast to increase in real dollar terms and new asset management practices will:

- Establish improved inspection techniques. An increased level of renewal Capex will help reduce maintenance expenditure in some areas as ageing assets are removed from service;
- Continue with our enhanced vegetation management programme at current levels; and
- Promote efficiencies in the planning and scheduling of work.

Asset inspection, condition monitoring and routine maintenance practices and processes are described in section 6 of the AMP. An overview of asset replacement and renewal by asset category is provided with non-network assets also being discussed. The 10 year (FY2019-28) Opex forecast is provided below.



Proposed 10 year Opex Programme

1.6 Capacity to Deliver

We have reviewed our resourcing and system needs to ensure we can deliver the investment programmes set out in this AMP. Our proposals involve increased levels of investment, so it is important that we have access to resources to deliver these proposals in an effective cost efficient way.

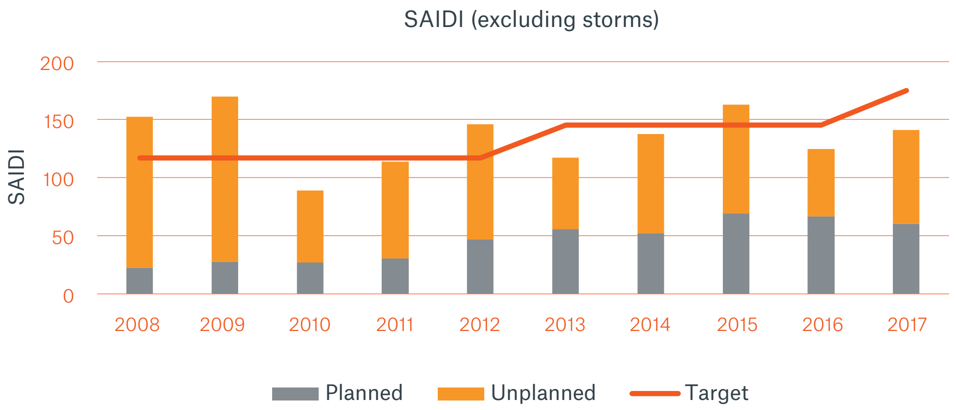
A skills and resourcing gap analysis has been carried out and as a result, Northpower has increased technical resourcing levels to provide certainty around design and delivery of projects. We have also considered the field resource required to deliver increased levels of work and have plans in place to build our internal resources to manage a wider range of specialist service providers.

Northpower has embarked on an upgrade and replacement project for its asset management system. The existing asset management system restricts robust condition based monitoring and analysis of the network assets. The company plans to implement a new system, commencing in 2019. The company recognises the importance of having good back office systems and processes to support the engineering and field staff in their respective roles to develop, manage, maintain and operate the network assets.

1.7 Services and Performance

Section 5 of the AMP shows performance against 2017 plans and budgets covering both Opex and Capex. The section provides a comparison of performance against service level targets. A gap analysis is provided and asset management improvement initiatives are identified.

A common measure of network resilience to unplanned fault conditions is the number of consumer interruption duration minutes (SAIDI). SAIDI, for the past 10 years for both planned and unplanned, is shown over below, noting that the unplanned outage target is to be below 90 minutes per annum. We have seen a favourable improvement in performance over time, relative to our targets which increased in 2017 due to a move away from live line maintenance activities.



SAIDI (unplanned interruptions) 2008-2017

Section 5 of this AMP also describes Northpower's customer service performance indicators, including the number of faults per 100km of line as well as the network's historical expenditure on a per-customer connection and per-kilometre of line basis. These measures are disclosed and compared with other Electricity Distribution Businesses (EDB's) in New Zealand.

Northpower conducts an annual Residential and Commercial customer survey to measure satisfaction. The survey indicates a high level of satisfaction with Northpower. The overall satisfaction measure for commercial customers for 2017 showed that 89% of surveyed customers were satisfied (compared to 79% in the previous year). Over the past year, Northpower's overall Residential satisfaction has improved to 92% in 2017 (from 88% the previous year). Our aim is to continue to provide a high level of stakeholder satisfaction with our levels of performance.

1.8 Risk Management

Northpower has adopted a risk management framework based on the principles of AS/NZS ISO 31000 and the company maintains a risk register that is regularly reviewed by the Board and Senior Management. Northpower risk management practices ensure that risks are identified, investigated and documented. Plans and work programmes are implemented to control and mitigate risks. Where necessary, contingency measures are developed to further manage mitigations.

Training of staff and contractors is viewed as a critical part of risk management. Staff and contractors are regularly tested for competencies to be authorised to work on the network. Safety-in-design practices are used to manage project risks and mitigate operational risks after projects are complete.

The key business risks and complete schedule of risks to assets are set out in section 9 of the AMP. Section 4 describes the life cycle asset management policies that are used to mitigate risks to assets.

1.9 The Changing Environment

The core assets that form a distribution network have remained largely unchanged for decades. What has changed over the past decade is the advent of more options for monitoring and controlling network assets. Distributed automation is regularly used to mitigate fault events thereby minimising disruption to customers' supply. Northpower actively monitors these developments and will implement increased levels of network automation over the next 10 years.

The biggest change on the planning horizon is likely to be customers' desire to have a choice around use of electricity. Modern whiteware appliances will be enhanced with various modes of remote control and home automation systems, enabling time-based load shifting of many of those devices. Northpower has experienced the impact of energy efficient lighting which has mitigated the growth in load over recent years and is planning for significant numbers of electric vehicles charging on the network within the next few years. Northpower embraces the changing environment and looks forward to providing a reliable and resilient network to meet customers' future requirements.

Northpower have always been closely connected to our customers and the communities we serve. As energy markets evolve and change, we are planning to place an even greater focus on active engagement and discussion to understand our customer needs. By working closely with our customers and stakeholders, we aim to ensure that our networks continue to play an enabling role in the economic growth of Northland.


Northpower

Section 2: Asset Management Framework

Northpower

Asset Management Framework - Section 2

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Section 2: Asset Management Framework

2.1 Purpose

2.1.1 Purpose of the Asset Management Plan (AMP)

The AMP documents Northpower's key objectives, network planning techniques, asset management practices and investment forecasts to key stakeholders. The AMP addresses strategic asset management goals and objectives that focus on levels of service, life cycle asset-management planning and the resulting long term cash flow requirements. The AMP further establishes and evaluates performance benchmarks and demonstrates responsible ownership and management of assets to the wider community. Public comment and feedback is both welcomed and valued.

Northpower's AMP is updated and published annually to satisfy the regulatory requirements, describing the methodology adopted to manage the assets in accordance with information disclosure requirements under Part 4 of the Commerce Act for EDB's.

Northpower's asset management philosophy is encapsulated in Northpower's vision to deliver enduring value by enabling customer choice and thus improving the prosperity and well-being of the people of Whangarei and Kaipara regions through our business activities, investment in profitable growth and distribution of profits to our shareholders.

A key to the delivery of our vision is to exercise robust asset management and ensure appropriate investment in our Network as well as our capability to provide sustainable network services. Effective asset management is at the core of all levels of our company.

The relationship between this philosophy, planning processes and company objectives collectively forms the Northpower concept of best practice asset management.

This is achieved by:

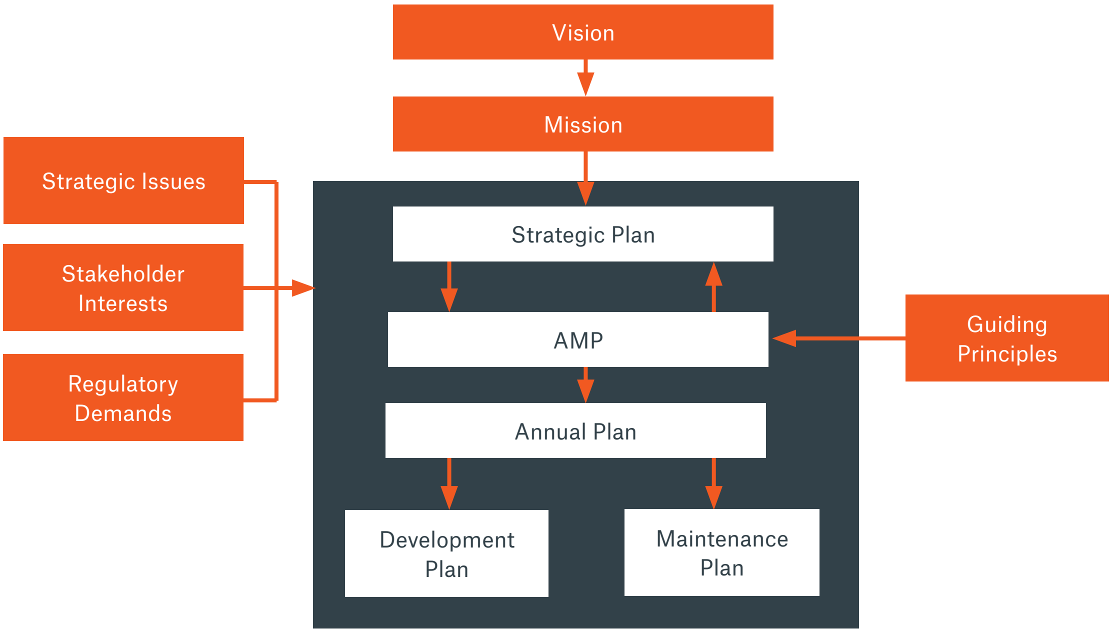
- Ensuring that the performance of the assets meets the needs of broad customer groups;
- Ensuring that the long term functionality and value of the assets is maintained;
- Understanding and mitigating network risks;
- Being responsive to individual customer's needs;
- Maintaining ongoing price stability; and
- Focusing on operational efficiency and performance improvement.

2.1.2 Objectives of Asset Management Planning

The AMP, which includes the Development and Maintenance Plans and associated expenditure forecasts, is updated and published annually.

Northpower has a continuous improvement philosophy and is a process driven organisation. The company is ISO9001 and ISO14001 certified and the network is certified to NZS7901. The asset management processes are aligned within these standardised frameworks. Planning is supported by the ongoing development and integration of core information systems together with the continuous improvement of the asset data (including type, volume, age and condition).

Section 2 - Asset Management Framework



AMP Planning Process

2.2 Relationship with Other Business Plans and Goals

2.2.1 Our purpose

Northpower's purpose is communicated in the Statement of Corporate Intent which is "To improve accessibility, opportunity and prosperity for the people and communities we serve" in the Kaipara and Whangarei areas.

We recognise power supply is an essential service and ensure we continue to prudently and efficiently deliver safe and reliable electricity to the communities we serve. Our direction and priorities strike the right balance of investments which we believe will support the safe and cost effective supply of electricity and address the current and future needs of the Kaipara and Whangarei communities.

2.2.2 Who we are

Northpower has been serving the Kaipara and Whangarei districts for over 90 years with provision of a safe and reliable supply of electricity.

As the region's electricity network provider, Northpower operates and manages electricity assets valued at $258m. We take a long term view to ensure we make the right decisions on investments which will best serve our communities for decades into the future.

Our business is about connecting residential and business customers to a safe and reliable electricity supply. Northpower key activities include:

- Maintaining the network's safety and reliability to meet the current and future network supply needs of our customers while delivering any investment in our infrastructure on an economic (cost effective) basis;
- Operating the networks on a day to day basis; and
- Connecting new customers to the network.

2.2.3 Our focus

Northpower is focused on creating long term value which extends beyond the services we deliver. It encompasses the wider benefits we bring to the region through the training, employment and career opportunities we create for Northlanders while also contributing positively to the spirit of the Northland community.

2.2.4 Our vision

Northpower's vision is to provide a safe, reliable and cost effective electricity network infrastructure including leadership for the introduction of new technology, when applicable, for our business, for the long term benefit of the community.

2.2.5 Documented Plans Produced in Annual Planning Process

The relevant documented plans that Northpower produces as part of the annual business planning process are:

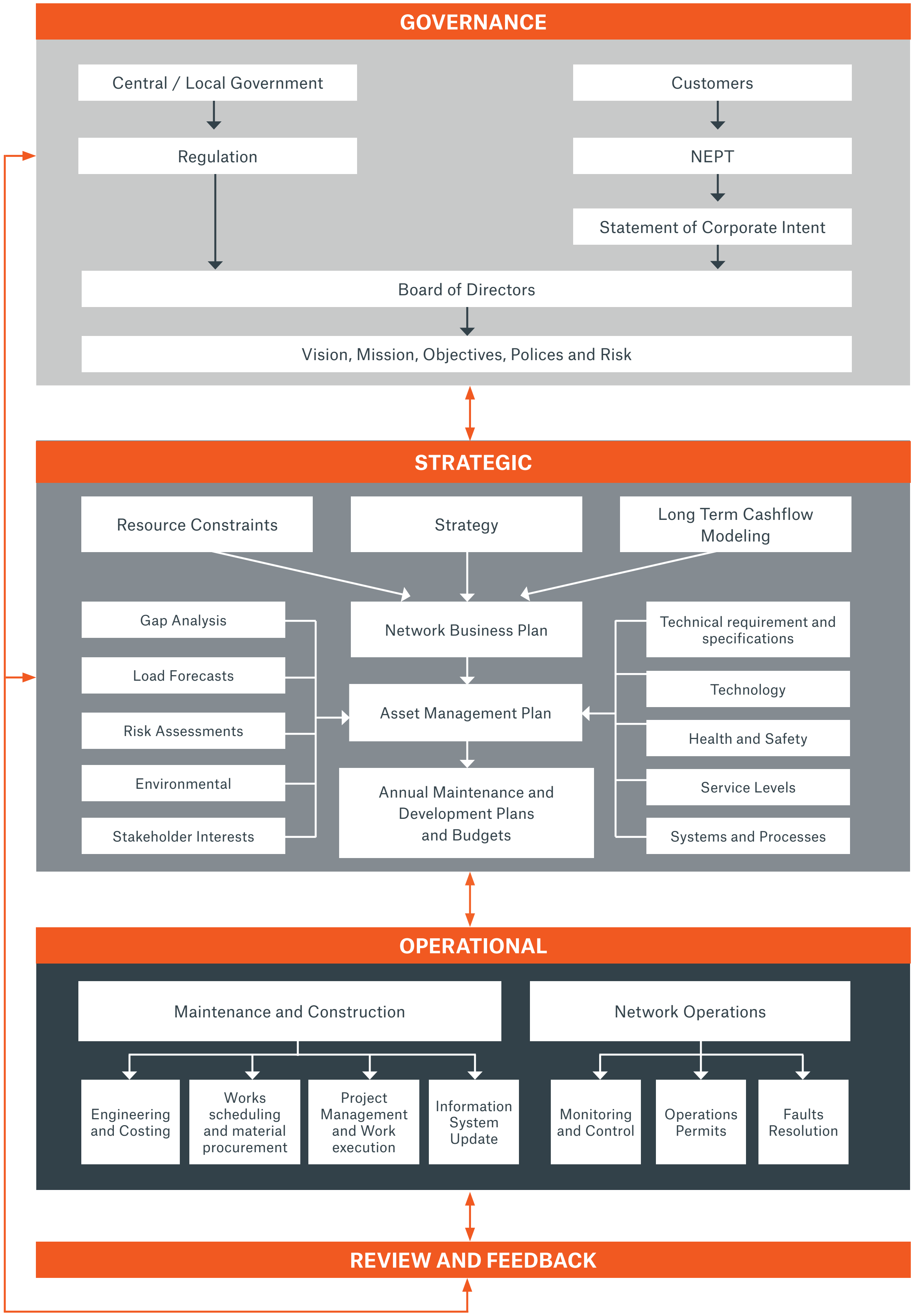
Annual Planning Document	Description	Relationship with AMP
Statement of Corporate Intent (SCI)	Northpower's SCI is published annually and approved by the Northpower Electric Power Trust (NEPT) on behalf of the customers. The SCI sets out the goals and objectives for the business.	The AMP describes the way in which the goals and objectives embodied in the SCI will be achieved from an asset management perspective.
Strategic Plan	The Strategic Plan sets goals, objectives and key performance indicators for the business.	The forecasts in the AMP are approved annually by the Board of Directors.
Asset Management Policy	The policy sets out guidance for the development of asset management strategies and objectives.	Provides guidance and rules for the development of the AMP.
Annual Network Management Plan (NMP)	The internal NMP includes policies, standards and strategies, and is published annually.	The NMP informs section 3 (Assets) section 4 (Life Cycle Asset Management Plan) and section 6 (Network Development Plan) of the AMP.
Company Risk Register	The Risk Register is a live database that is used to document key business risks. Risk mitigation strategies are reviewed annually.	Risks related to asset management within the Risk Register inform Section 9 of the AMP.

Annual Planning Process Plans

2.2.6 Relationships between Plans, Processes and Stakeholders

The following diagram shows the relationship between key stakeholders and the strategic building blocks of the AMP together with the Network Maintenance, Construction and Operations elements of the business.

Section 2 - Asset Management Framework



Relationship between plans, process and stakeholders

2.3 Period Covered by the Plan

The planning period covered by this AMP is the 10 year period from 1 April 2018 to 31 March 2028. The 2018 AMP was approved by Northpower's Board of Directors on 28 March 2018 and made available for public disclosure on 31 March 2018.

Specific projects and activities included in this AMP represent Northpower's best estimates of optimal solutions based on projections of present day drivers, technologies and available network data. Given that drivers and network data will change over time, inclusion of specific activities and projects, particularly towards the end of the planning horizon, does not represent a firm commitment by Northpower to proceed with those activities and projects which will be subject to ongoing review.

Network development plans and associated financial forecasts and budgets are essentially determined by load growth. Developments at sub-transmission level tend to have more long term inertia and therefore tend to be less dynamic and more predictable than those at distribution level, with the result that projects relating to the former tend to have longer planning lead times and can normally be fairly accurately defined 5 years out. On the other hand, projects at distribution level are more closely linked to short term economic activity, with the result that beyond two to three years plans may change.

Network maintenance related activity is far more predictable than development needs, and plans can be developed with a fair degree of confidence as there is a direct relationship with historical expenditure and present network performance. However, to ensure optimal long term maintenance planning it is essential that a good asset knowledge base exists, together with appropriate maintenance regimes.

2.4 Stakeholder Interests

2.4.1 Identification of Stakeholders

Stakeholders are persons, groups, organisations, or systems, who affect or can be affected by Northpower actions, activities and or performance.

The following table identifies the major stakeholders associated with the electricity lines business and which of our six key principles apply to our relationship with each stakeholder.

Stakeholder	Health / Safety	Customer Satisfaction	Financial Strength	Environment / Communities	People and Commitment	Operational Excellence
Customers	✓	✓	✓	✓	✓	✓
Northpower Trust and Board	✓	✓	✓	✓	✓	✓
Energy retailers		✓	✓	✓		✓
Transpower	✓		✓		✓	✓
Suppliers	✓	✓	✓			✓
Staff and Contractors	✓	✓	✓	✓	✓	✓
Public and Communities	✓	✓	✓	✓	✓	✓
Land owners	✓			✓		✓
District Councils	✓		✓	✓	✓	
Regional Council	✓		✓	✓	✓	
New Zealand Transport Agency	✓			✓	✓	✓
Telco's	✓	✓		✓	✓	✓
Commerce Commission	✓	✓	✓	✓		✓
Electricity Authority		✓		✓		✓
Transpower – Grid owner		✓	✓	✓		✓
Transpower- systems operator	✓	✓			✓	✓

Identification of Stakeholders Table

Section 2 - Asset Management Framework

In all projects and activities we take into consideration who and what will be affected.
The following table provides an overview of each stakeholder's interest and how each is identified.

Stakeholder	Key Interest	Method of Interest Identification
Customers Including: Domestic, Commercial, Lifeline groups, Large Customers (Oil Refinery, Cement Works, Milk Production etc.)	Safety. Network reliability. Quality of supply. Speed of restoration. Hassle free service. Line charges. Reliability/price balance. Tariff options.	Annual Northpower Customer Perceptions Monitor survey. Monthly surveys. Feedback received by Customer Advisors. Dedicated Communications Manager. Dedicated Network Commercial and Operations Managers. Relationship meetings. Trade shows. Line function service agreements with large industrial sites. Faults free phone directly to dispatch/ network System Operators.
Northpower Electric Power Trust	Health and safety. Fair commercial return on investment. Sustainability of business. Performance of Directors. Achievement against the Statement of Corporate Intent. Security of supply to region. Protection of shareholder's interests.	Pentennial ownership review. Triennial Trustee elections. AGM. Annual review with Directors. Six monthly meetings with Directors and Executive Team. Monthly meetings. Direct feedback from customers. Setting Statement of Corporate Intent Quarterly NEPT business updates
Northpower Board of Directors	Health and safety. Performance of business operation. Long term business direction and outcomes. Performance of Chief Executive and Executive Leadership Team. Creation of shareholder value.	Annual review by Trust. Annual review with CEO. Business strategy sessions. Quarterly risk reviews. Regular field visits. Monthly meetings with Executive Team.
Electricity Retailers	Contractual relationship. Clear data to support billing. Accurate and timely billing. Minimisation of line losses. Risk mitigated network. Timely response to service and information requests.	Use of System Agreement. Annual relationship meetings. Direct consultation periodically throughout the year.
Suppliers	Network standards. Advance notice of Network requirements. Payment in accordance with the terms of trade. Partnership approach.	Regular relationship meetings with Procurement Manager. Supply agreements. Structured terms of trade. Survey feedback.
Staff	Risk mitigated network and work practices. Forward visibility of requirements. Involvement in company direction. Challenging work. Fair reward.	Biannual engagement. Annual strategic planning sessions. Communication roadshows/forums. Monthly Safe Team meetings. Risk framework and incident reporting processes. Team meetings. Regular relationship meetings with Union representatives. Employment contract negotiations.

Stakeholder	Key Interest	Method of Interest Identification
Contractors	Visibility of forward work load. Network standards. Risk mitigated network. Return on investment. Partnership approach.	Contractor review process. Monthly Safe Team meetings. Monthly relationship meetings with major contractors. Regular relationship meetings with minor contractors.
Communities and Public	Risk mitigated network. Responsible corporate citizen.	Annual Northpower Customer Perceptions Monitor survey. Formal and informal feedback from interest groups. Dedicated Customer Advisor and Customer Care Manager. Joint support of community sponsorship initiatives such as the Rescue Helicopter, Taitokerau Education Trust and Healthy Homes programme.
Land owners	Protection of property values and amenity. Protection of areas with cultural or historical significance.	Direct consultation with interest groups. Consultation with affected or potentially affected landowners. Dedicated lines inspectors and vegetation officers in the field.
District Councils	Capability of network to service growth. Forward visibility of significant Network additions/alterations. Environmental impact of the network is in accordance with district plans and is minimised.	Direct consultation between CEO's. District plan. Joint planning sessions.
Regional Council	Environmental impact of the network is in accordance with regional plans, the Resource Management Act and is minimised. Emergency response capability.	RMA. Growth strategy documentation. Direct consultation. Member of Northland Lifelines Group (Civil Defence and infrastructure disaster relief planning).
NZ Transport Agency	Risk mitigated asset. No harm to public from actions of Network contractors. Value added propositions.	Regulations. Direct consultation and co-operation.
Telco's	Protection of their assets from electrical interference. Protection of their assets from physical interference. Synergies regarding access and asset placement.	Regulatory and legislative protection. Relationship meetings. Information sharing sessions. Co-location agreements.
Commerce Commission	Legislative and regulatory adherence. Information disclosure.	Legislation – laws and regulation. Disclosure documentation.
Electricity Authority	Legislative and regulatory adherence. Information disclosure.	Published rules. Electricity Authority updates published weekly.
Transpower - Grid Owner/Operator	Payment in accordance with commercial terms. Provision of connection assets.	Annual notification of prices. Relationship meetings and consultation processes. Price/quality trade off consultation. Monthly monitoring. Direct contact with local network System Operators.

Stakeholder interests and method of interest identification

2.4.2 Accommodating the Interests of Stakeholders into Asset Management Planning

Northpower has a number of systems and processes which assist with the accommodation of stakeholder interests. These include plans, policies and procedures along with relevant standards, legislation and regulations.

Northpower is ISO 9001 and ISO 14001 certified and Northpower's network is certified to ISO 7901. Work is currently underway to align Northpower's asset management with PAS 55 (ISO55000).

2.4.3 Managing Conflicting Interests

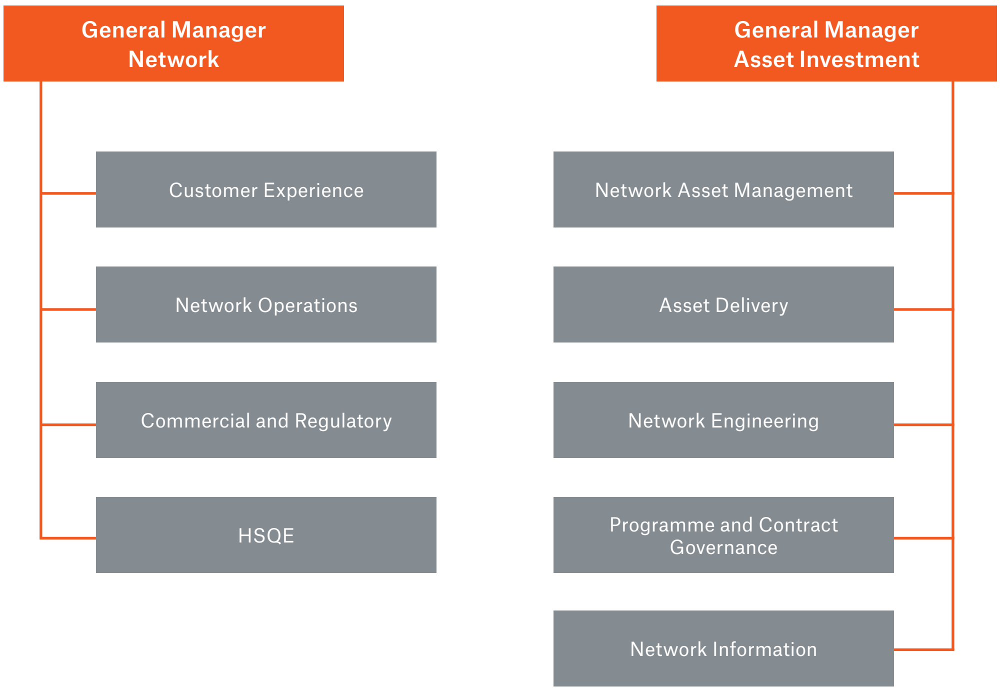
Northpower understands the importance of appropriate stakeholder consultation in order to ensure proper planning coordination, dissemination of information and maintenance of good relationships. Conflict of interest is treated seriously at Northpower. Wherever possible, Northpower will endeavour to resolve conflict of interest in a responsible, consultative, and amicable way.

In the event of a major conflict of interest, where an amicable solution cannot be found, Northpower is obliged to follow approved policy and process in order to discharge its responsibilities and obligations with regard to electricity supply.

In general, when there is a conflict between the interests of stakeholders, Northpower will prioritise interests in the following way:

- Decisions and actions required to ensure safety take priority over other interests at all times.
- Electricity distribution is a core activity. Northpower is committed to delivering high quality electricity to customers, therefore decisions and actions which protect supply quality and safety are fundamental. Decisions taken to protect supply quality must be financially responsible and meet compliance requirements. These interests form the parameters around which supply quality is prioritised.
- Financial interests will be considered on their merits and outcomes will depend on the overall best position for Northpower.
- Northpower is committed to compliance with the law and relevant industry regulations. The only acceptable reason for a compliance breach is emergency action necessary to ensure safety in unforeseen circumstances.

2.5 Accountabilities and Responsibilities



Responsibilities Structure

The Northpower functional structure is shown in the diagram above. This shows asset ownership, customer engagement and operation under the General Manager Network and planning, engineering support and asset replacement/renewal and future development under the General Manager Asset Investment.

2.5.1 Governance of Asset Management

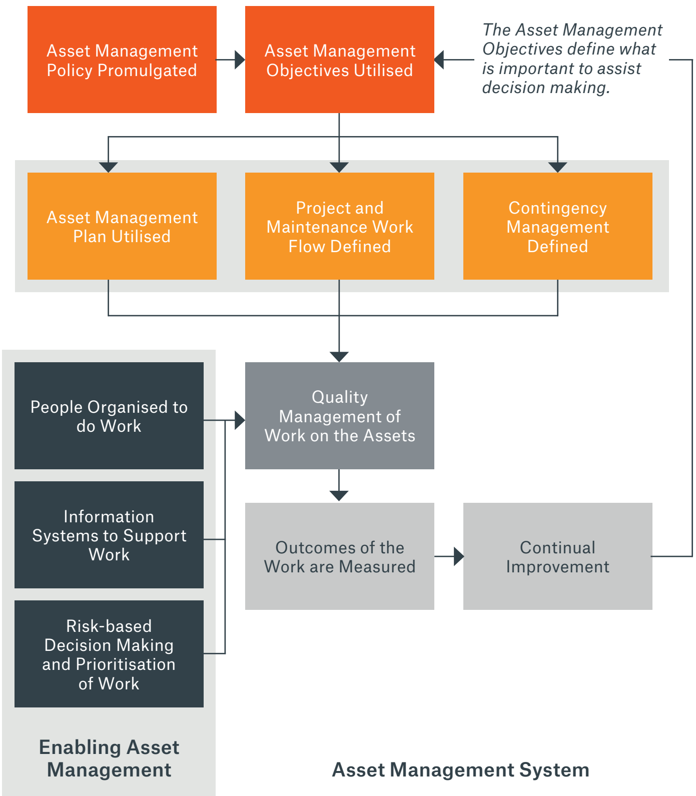
The Board of Directors is ultimately responsible for governance at Northpower. Board approval is required for:

- 10 year AMP.
- Maintenance Plan.
- Development Plan.

Expenditure for significant projects and for expenditure that exceeds approved budgets have approval processes. Examples include:

- Switchboard upgrades.
- Power transformer upgrades.
- New zone substations.
- New technologies.
- Research and development projects.
- Safety, reliability and security of supply initiatives.

The establishment and ongoing governance around asset management is depicted in the following diagram.



2.5.2 Northpower Network Executive Management Team

The Network division carries responsibility for the Asset Management functions at Northpower. Responsibilities within the division are as follows:

The General Manager Network is the asset owner, responsible for customer, commercial and operational functions. The General Manager Network owns the asset policy and approves key asset investment initiatives. Responsibility includes managing Northpower's relations with the Northpower Trust, community and other key stakeholders. The General Manager Network is accountable to the Chief Executive for meeting the network operational and financial targets.

The General Manager Asset Investment is responsible for the network asset framework, standards, asset fleet investment and maintenance, as well as distribution management and asset management systems, together with the network development and maintenance plans on behalf of the asset owner.

2.5.3 Managing Field Operations

The Network Contracts Manager manages the interface with the Northpower Contracting division, by means of a Service Level Agreement (SLA).

Northpower Contracting is the primary contractor operating on the Northpower network. This is advantageous, firstly because the values, standards and operating practices are aligned with Northpower's asset management practice and governance and secondly, a large and mobile workforce is available if additional resources are necessary.

From time to time external contractors provide services that are not available internally, for example, civil engineering and construction services. These contractors are subject to the same safety and work criteria expected of Northpower Contracting, and must be authorised to work on the Northpower network.

2.6 Asset Management Systems and Processes

2.6.1 Asset Management Systems

Network Data is managed in five core separate systems (OSISoft PI, Siemens SCADA, Intergraph GIS, EMS Works, Maintenance Management (WASP) and Gentrack Billing). These are supported by a number of MS SQL Server databases. Data from each of the above repositories is replicated to a data warehouse environment with analysis and operational visibility provided via structured reports and ad hoc queries. The structure of the systems is illustrated in the diagram below.

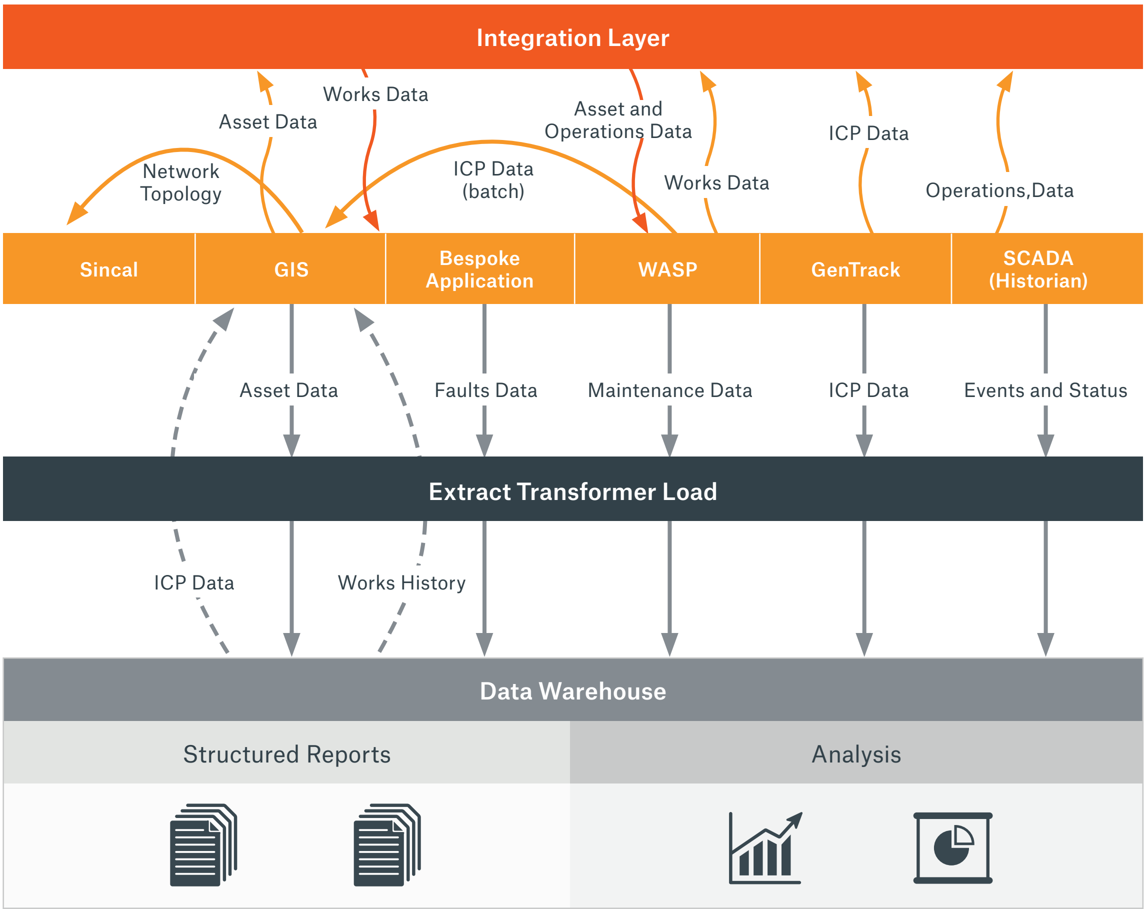
The recent purchase and partial implementation of the JD Edwards ERP system by Northpower Corporate, coupled with the end of life status of the WASP system, has led Northpower Network to consider purchasing a new Asset Management system. To this end, an asset strategy consultant has been engaged to review Northpower's asset management practices and processes, as well as advising on a suitable asset management system as a replacement for EMS WASP.

It is intended that this replacement system for the EMS WASP system be implemented during 2018/19, with the implementation objectives being to:

- Replace existing WASP maintenance management functionality;
- Create and implement the planned maintenance schedule in JDE for all network assets;
- Implement an agile and effective process and system for capturing reactive maintenance.
- improved capture of asset condition data.

Northpower has adopted a 'de-coupled' integration philosophy based on Microsoft BizTalk Server, use of a 'service oriented architecture' (SOA) and industry standard tools and protocols. The net result is a configurable, reusable and scalable integration architecture that has a lower cost of ownership. Leveraging this framework enables Northpower to continue with a 'best of breed' approach without compromising systems inter-operability.

The ongoing development of these systems particularly the GIS, together with related applications development, will continue to extend into the medium term.



Systems Integration Structure

A wide range of structured and ad hoc reports are available via an Intranet portal. Additionally, specialised geospatial software is used to drive inspection regimes and provide analytical support for defect processing.
The proposed asset management system will integrate into this system.

2.6.1.1 Document Management System

System	Purpose	Data Stored
Sharepoint	Repository for scanned records, currently held in paper archives. Offers enhanced search and retrieval, linking to GIS	Historic construction plans and connections records

Microsoft Sharepoint has been progressively integrated with business processes. Northpower has initiated a program to scan, catalogue and archive paper records to this environment. Given the high volume of historic records, this work is expected take a number of years to complete. Cataloguing and linking where possible to GIS will simplify the search and retrieval of historic records significantly.

2.6.1.2 Geographical Information System (GIS)

System	Purpose	Data Stored
Hexagon	Repository for Master Asset Data and Electrical Connectivity to support Records Management, Planning and Analysis.	Zone Substation assets, Subtransmission, HV and LV Distribution Assets

The Geographic Information System (GIS) acts as the master repository of asset data, the basis for asset planning and GIS data forms the basis of a number of downstream activities including planning, design, analysis and asset maintenance. Asset Data for distribution and most substation assets is mastered in GIS with a subset of this data replicated in the Maintenance Management System.

2.6.1.3 Asset Management

EMS WASP supports asset maintenance (Works, Assets, Solutions, and People).

System	Purpose	Data Stored
EMS WASP	Asset Management	Assets and associated data required to drive maintenance. Condition data, test and inspection results. Maintenance/inspection regimes, triggers and tasks. Maintenance history. Capital projects

WASP supports the following functions:

- Storage of maintenance history for individual Network assets
- Forward planning of capital works programmes
- Automatic generation of regular tasks including preventative maintenance, inspections and testing tasks
- Recording test and inspection data
- Defect capture from asset inspections
- Task planning, packaging and scheduling using various criteria

Data held in WASP also includes some assets condition data and test and inspection results that drive maintenance management regimes.

2.6.1.4 Data Historian

System	Purpose	Data Stored
OSISoft PI	Real time System Data Acquisition and Analysis.	System events, plant status and loading, busbar voltages

The PI system provides a Data Historian and analysis tool kit. Interfaces have been set up between the Siemens SCADA system, Communications Systems and other data repositories. The information is mainly used for reporting and network planning/modelling purposes.

2.6.1.5 SCADA

System	Purpose	Data Stored
Siemens PowerTG	Real time System Control & Data Acquisition	System events, plant status and loading, busbar voltages, bulk power flows

The SCADA system records and stores time stamped event, status, loading and voltage data for the purpose of analysing system events (e.g. faults) and capturing network loading and voltage conditions for network modelling purposes.

2.6.1.6 Network Modelling

System	Purpose	Data Stored
PSS/Sincal	Network load flow and fault level analysis	Network models and case studies

PSS/Sincal is used as Northpower's power system analysis tool. It is used to model the subtransmission and distribution networks. Network models are developed from GIS extracts and loading data is obtained from the SCADA system.

The software is also used to simulate future loading scenarios and network strengthening options.

Sincal is currently being extended to hold all the protection details and setting information and it will provide discrimination tools for coordinating protection across the network.

2.6.1.7 Billing

System	Purpose	Data Stored
Gentrack	Network Billing	ICPs & Billing information

Gentrack maintains detailed network connection (ICP) records for billing purposes and automatically synchronises its installation data with the national registry. In addition, retailers' customer data for each ICP is received via the national registry to automatically notify customer and retailer changes (start dates and end dates). Retailers send a file of Northpower network ICPs for monthly billing which contains dates, tariffs and consumption.

2.6.1.8 Outage Recording

System	Purpose	Data Stored
HV & LV Faults Database (MS SQL Server)	Network Performance Data Capture	Fault records and outage imperials

The HV Faults database produces network performance reports which include:

- SAIDI, SAIFI and CAIDI results for any selected time period
- The daily outage and incident report which is circulated to interested parties and key managers
- Outage causes sorted by various selected parameters

All unplanned outage causes are categorised as per the Electricity Industry Information Disclosure Regulations. Northpower's disclosure information is audited annually by PricewaterhouseCoopers.

2.6.2 Business Processes

2.6.2.1 Managing routine asset inspections and network maintenance

Northpower uses the EMS WASP asset management software to support routine asset inspections and network maintenance management activities.

WASP is primarily driven by cyclical triggers which initiate work requirements. Event related data is also used to trigger work. The system captures and manages asset condition data and defect tasks. WASP operates as a slave to the GIS master data repository and generates event driven maintenance triggers based on data provided from the SCADA system.

2.6.2.2 Planning and Implementation of Network Development Processes

Network development projects are grouped according to the following four main investment drivers:

Growth (new customer connection and growth of existing load). The network load forecast is used to identify future capacity constraints and possible solutions are identified. Technical and financial analyses are carried out in order to identify the most suitable long term solution. Projects are then defined and planned.

Replacement and renewal (asset deterioration or obsolescence). Assets requiring upgrading or replacement due to end of life or condition (safety, performance, maintenance costs) are identified and their replacement planned.

Improvement (safety, reliability, environmental). Projects required to improve public and employee safety, network reliability and performance as well as reducing environmental impact where possible are identified, defined and planned.

Relocation (relocation of existing assets). Assets required to be relocated for road works, property owner requests, network reconfiguration or safety reasons.

Optimum solutions are based on minimising capital outlay and life cycle costs without compromising safety, quality and performance.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Section 3:
Network Assets

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Section 3: Assets

3.1 Distribution Area

3.1.1 Area Covered

As at 31 December 2017, Northpower supplied 57,843 customers spread over an area of some 5,700 square kilometres covered by the Whangarei and Kaipara Districts. This area includes Whangarei District and the towns of Dargaville, Hikurangi, Kaiwaka, Maungaturoto, Ruawai and Waipu. The main depot and head office for Northpower is located in Whangarei. Sub-depots are located in Dargaville and Maungaturoto. The map below shows the area supplied by Northpower and the location of the main towns.

Northpower geographical area of supply and major substations

3.1.2 Northpower's Large Customers

Customers with high consumption (either maximum demand (MW) or annual energy consumption) are defined as large industrial loads. These customers generally have special requirements with regard to security of supply (typically duplicate transformers and lines or cables) as their loads are too large to supply with emergency standby or backup generation. These loads are normally supplied directly from the sub-transmission system at 33kV or by one or more dedicated 11kV distribution feeders emanating from a nearby zone substation.

Northpower currently connects to five large industrial consumer loads, together they consume approximately 50% of the electricity supplied via the Northpower network.

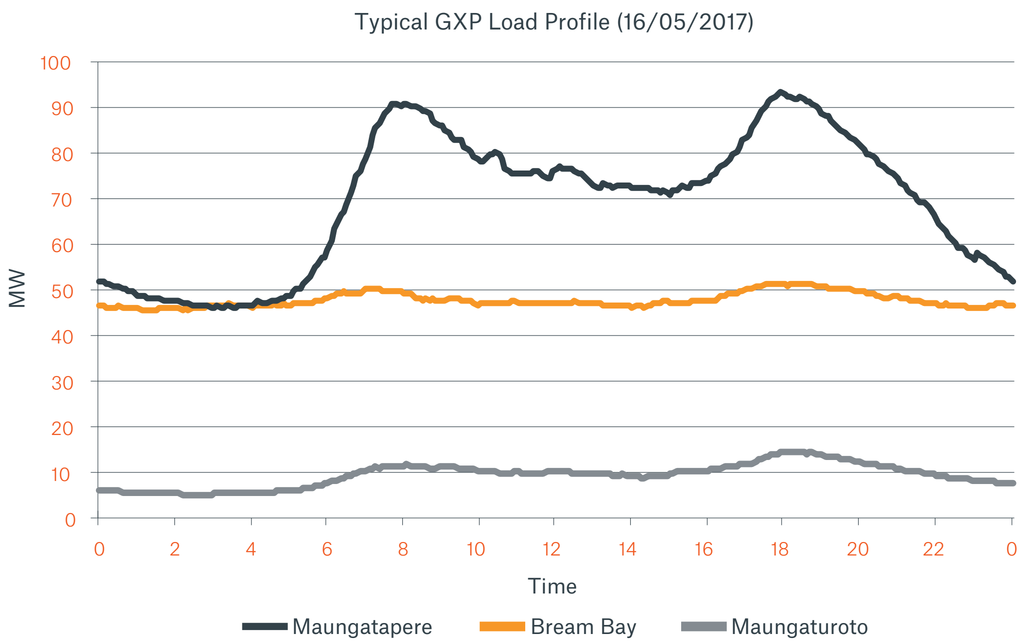
3.1.3 Load characteristics for different parts of the network

The table below identifies the electricity load characteristics for the five regional bulk supply points.

Major Station	Load Characteristics
Bream Bay (GXP)	• Fairly constant load throughout the year • Predominantly industrial load with some residential and commercial
Dargaville	• Peak load in winter • Predominantly rural dairy, residential and commercial load with some industrial
Kensington	• Peak load in winter • Predominantly residential and commercial load but also significant industrial and some rural
Maungatapere (GXP)	• Fairly constant load throughout the year • Mixture of all load types with significant large industrial
Maungaturoto (GXP)	• Peak load in spring • Predominantly dairy and industrial load • Increasing coastal settlement load

Northpower's electricity network is predominately rural. Apart from the major urban centre of Whangarei, and the smaller regional centres of Dargaville, Kaiwaka, Ruawai, Maungaturoto, Mangawhai, Ruakaka, Hikurangi and Waipu, the balance of the load is comprised mainly of dairy farming, small sawmills, townships and coastal settlements. Hikurangi Zone substation is noteworthy as it supplies a significant amount of flood-pumping.

Typically the load peaks in winter, usually late July or early August. A typical daily profile of the three grid exit points during May 2017 is shown below. The combined evening peak demand across all three Transpower supply points on this day is approximately 170 MW.



3.1.4 Peak demand and Total Electricity Delivered

3.1.4.1 Peak Demand

Peak demand on the network is caused by coincident consumer activity. For example, demand will increase in residential areas in the mornings and in evenings at the end of the business day. Residential demand is also highest in winter.

Peak demand is an important consideration when managing electricity assets as the electricity network must have the capacity to meet the peak demand to ensure uninterrupted delivery of electricity. Northpower operates a ripple control system to interrupt supply to hot water cylinders during peak load periods, to manage the peak load. This helps to reduce/defer investment in increased capacity of substations, lines and cables.

The peak demand on Northpower's network in 2017 was 177MW (which occurred on 9th Aug 2017) and the total energy delivered the last financial year ended March 2017 was 1,056GWh. This compares with the 2015 peak of 173MW and energy delivered for year ending March 2015 of 993GWh.

3.1.4.2 Total Electricity Delivered

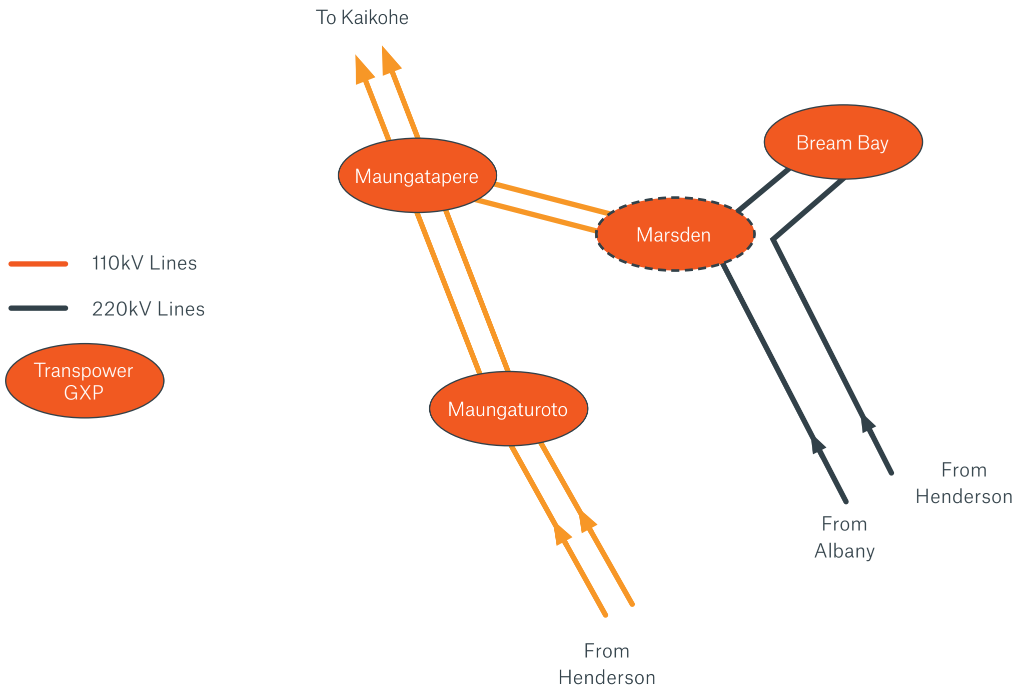
Energy Consumption by Region (FY17)

Transpower Grid Exit Point	MWhrs	% of Total
Bream Bay	399,854	36.5%
Maungatapere	599,337	54.8%
Maungaturoto	94,838	8.7%
Total	**1,094,029**	**100.0%**

3.2 Description of Network Assets

3.2.1 Grid Exit Points and Embedded Generation

Supply is taken from three Transpower Grid Exit Points (GXP's), namely Bream Bay GXP (supply taken at 33kV), Maungatapere GXP (supply taken at 110kV) and Maungaturoto GXP (supply taken at 33kV). Transpower's regional transmission network is shown below. There are two generating stations connected to Northpower's network, namely Northpower's 5MW Wairua hydro power station and Trustpower's 9MW diesel powered peaking plant (Whangarei Hospital has an emergency backup diesel plant but this does not generate into Northpower's network). In addition, as at December 2017 there were approximately 649 small privately owned solar PV embedded generators (average installed capacity 3.7kW) connected to the network.



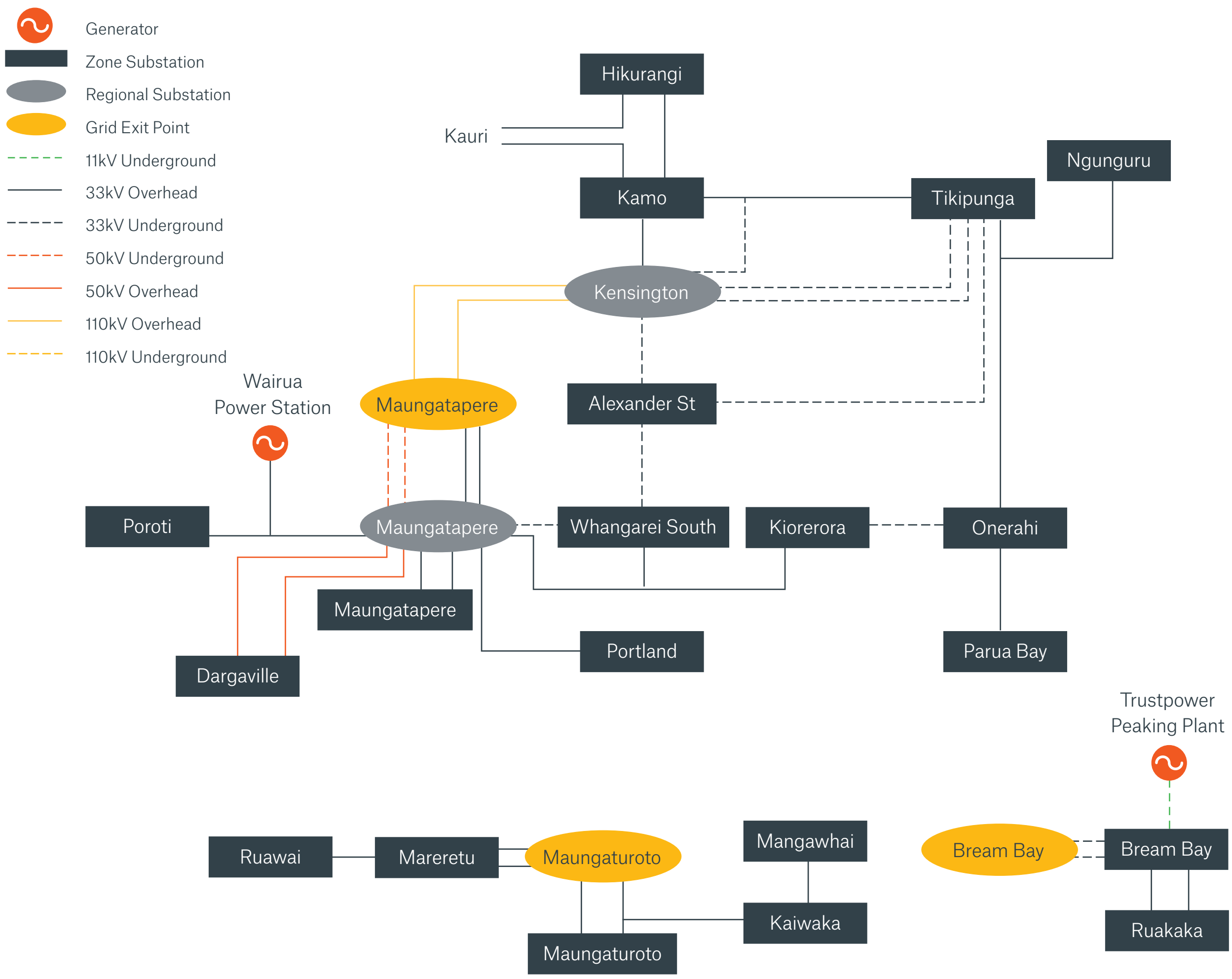
3.2.2 Subtransmission Network

Northpower's Subtransmission network is shown schematically below, it comprises regional substations and zone substations interconnected by 110kV, 50kV and 33kV lines and cables.

A key feature of the subtransmission network is a 33kV ring between Maungatapere and Kensington regional stations, which allows load to be transferred between the 110/33kV transformer banks at these stations.

Northpower owns and operates one 50/11kV zone substation, eighteen 33/11kV zone substations and one dedicated 33/11kV substation (Chip Mill) which supplies an industrial load. Zone substations comprise HV bus bars, one or two step down transformers with on load tap changers, HV switchgear, associated protection and tap change relays and SCADA remote Terminal units.

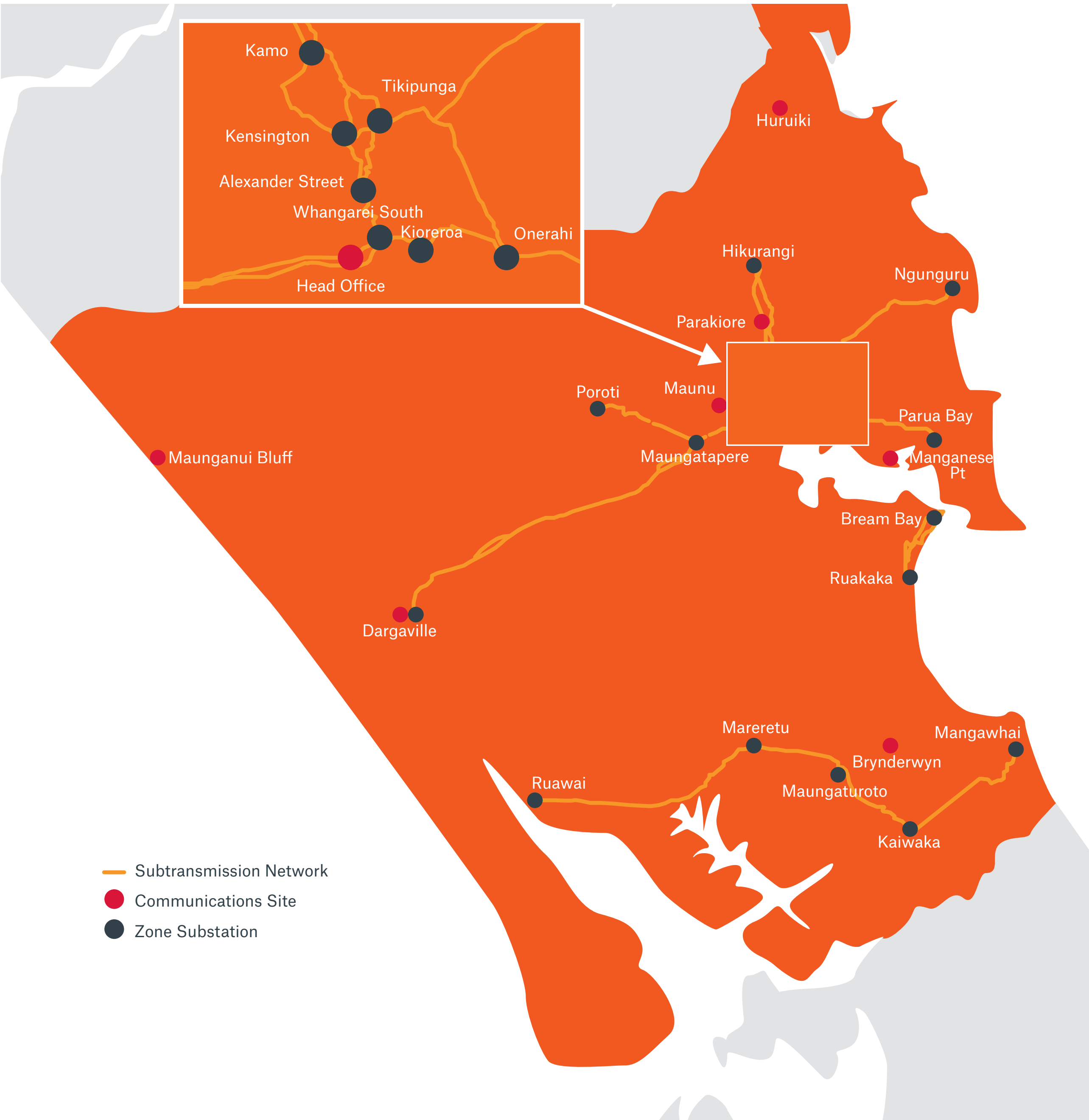
Detailed information on substation transformer capacity, loading and security of supply is provided in section 6 Network Development Plan.



Northpower Subtransmission Network Single Line Diagram

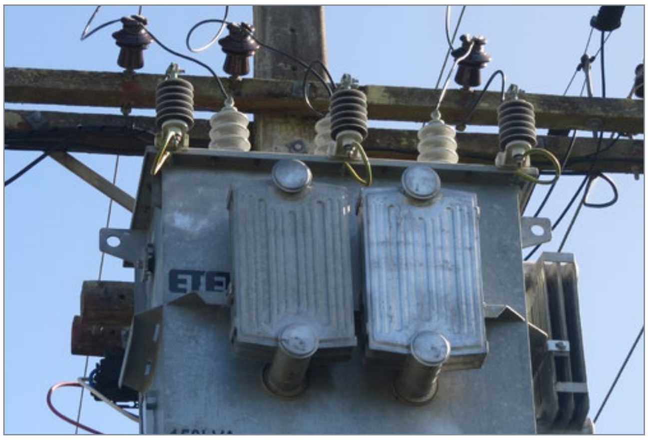
The map below shows the Northpower distribution area and geographical location of zone substations and communication sites.

Most remote zone substations are fed by a single 33kV line with reasonable back-feeding capability on the 11kV network. Where back-feeding capacity is not adequate, mobile generation is used for voltage support and Northpower own a 500kVA purpose designed mobile generating system (including transformer) for this purpose.



Northpower's Subtransmission Network Shown Geographically

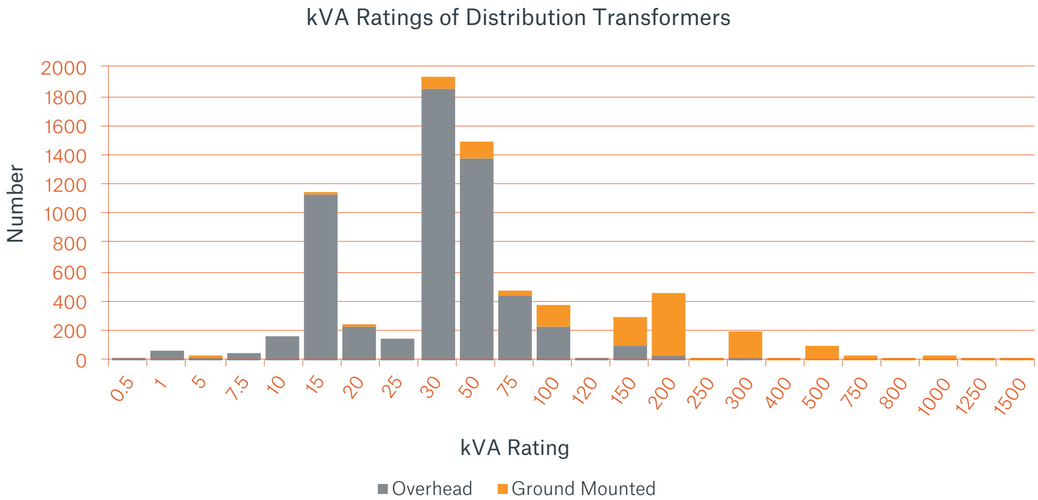
3.2.3 Distribution Substations



With the exception of a number of large customers supplied directly at 33kV, electricity is distributed to customers via 94 high voltage (11kV) feeders emanating from the zone substations. Some customers are supplied directly at 11kV but the majority are supplied via 11,000/415V distribution transformers (either pole or ground mounted) ranging in size from 5kVA to 1,000kVA.

Distribution substations comprise of an 11,000/415V transformer with an off-load tap changer, high and low voltage fuses, associated earth mats and in some cases high voltage surge arrestors. Fuses on the high voltage side of the transformer provide fault protection for the transformer. Fuses on the low voltage side provide both transformer overload and downstream fault protection for cables or lines.

Transformers with a rating exceeding 150kVA are normally ground mounted due to their weight and size. Transformers with a rating of 50kVA and below can be either 2 phase or 3 phase while those larger than 50kVA are all 3 phase. The number of customers supplied by a distribution substation typically range from 1 to 100. Shown below is Northpower's transformers grouped by kVA rating and orientation. There are a large number of overhead 30/50kVA units in service due to the high proportion of overhead network.



3.2.4 Low Voltage Network

The Northpower low voltage (LV) network is a mix of overhead and underground circuits operating at 400/230V. The LV feeders distribute power from distribution transformers (connected to the 11kV network) to customers service lines. In most cases this will be from poles or pillars near property boundaries. Each LV circuit is protected by fuses at the transformer and at (or as near as practical to) each customer point of supply (POS). Electricity meters and ripple relays or pilot control contactors (for control of water heating load) are generally located at the end of the service line or cable on the customer's premises.

Where increased security of supply is required, the LV network is configured in a ring, to allow an alternative supply should it be required. This type of arrangement is common in the central business district and residential areas.

Description	Quantity (km)	Underground (km)	Overhead (km)
Low Voltage Lines 2017	1,874	682 (36.4%)	1,192 (63.6%)

3.2.5 Secondary Assets

Metering equipment is located at strategic points to continuously measure, record and control (using ripple injection to control hot water load relays) the network load on the Northpower network.

Northpower's six ripple signal generation plants (located at Maungatapere, Tikipunga, Bream Bay, Maungaturoto, Dargaville and Ruakaka) transmit at 283Hz and inject into the 33kV network, except for 3 plants which inject into the 11kV network. Ripple control is used to manage GXP loadings by means of hot water and priority channel load control, street lighting, automatic load shedding and time of use metering.

The ripple system is also made available to the Northland Regional Council to use as a Tsunami warning system.

As Northpower is charged for reactive power demand by Transpower, reactive power compensation (power factor correction) in the form of fixed capacitor banks are utilised. At present, Northpower has 22 x 750kVAr, 5 x 150kVAr and 2 x 200kVAr (switched) capacitor banks (total 15.6MVAr) connected to the network. More will be installed as the load grows, to manage the reactive power imported from the national grid.

Northpower owns a 500kVA mobile diesel generator (with associated 400/11,000V transformer) which is used to reduce the number of planned maintenance and fault shutdowns on the 11kV network.

Northpower operates a supervisory control centre in Whangarei, which is attended 24 hours a day. A SCADA system continuously monitors load pulses, alarms and indication from equipment in the 33/11kV zone substations as well as reclosers, sectionalisers and switches on the network.

The communications network for SCADA makes use of microwave, UHF and VHF radio links, as well as copper and optical fibre cable links.

3.3 Network Assets

Network assets are summarised below, including age profile, numbers of assets, and also information on the average condition of the assets.

The condition of each group of assets has been ranked as follows:

"good" means new or as new with no known maintenance issues

"fair" means normal deterioration requiring regular monitoring

"poor" means material deterioration but asset within serviceable parameters. Replacement or extraordinary maintenance likely within 3 years.

Northpower's current asset management system WASP has reportable asset condition and defect information for assets such as poles and cross-arms. However the system is not currently set up to report on asset condition for other major assets. However in the for reporting asset condition in Schedule 12a, asset age against equipment industry standard lives has been used as a proxy for condition. When asset age data is invalid or non-existent then associated assets are used to determine a possible age. If this technique fails then a default value is used and this is noted in the associated graphs.

Section 3 - Network Assets

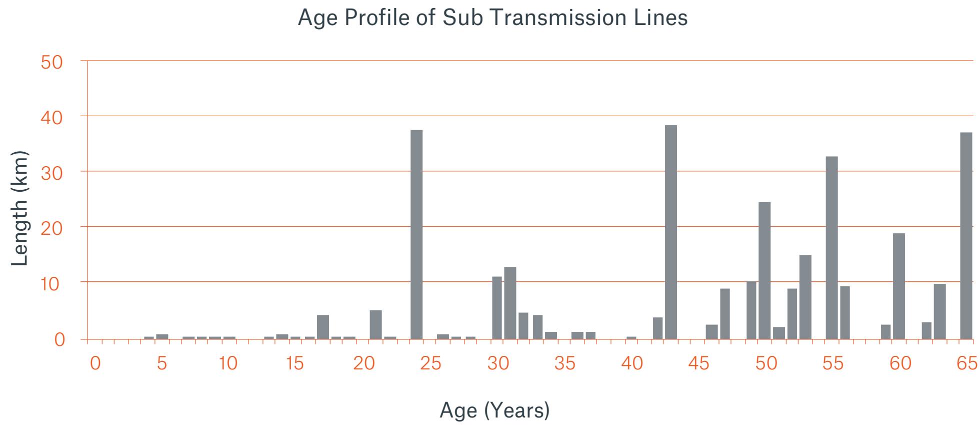
3.3.1 Subtransmission Overhead Lines

3.3.1.1 Description of Asset

Description	Quantity (km) in 2017
Subtransmission lines	321

Electricity is transmitted at high voltages to reduce the energy lost in long distance transmission. The sub-transmission network connects the GXPs to the zone substations. Further interconnections may exist with sub-transmission lines or cables between zone substations. Northpower's sub-transmission network is operated at 110kV, 50kV and 33kV.

3.3.1.2 Age Profile



Note: Where the age of the asset is unknown an age of 48 years is assumed.

3.3.1.3 Condition

The condition of the sub-transmission network varies between fair to good. Regular preventative maintenance inspections which include a helicopter patrol of the lines provide regular condition assessments and follow up maintenance is carried out with some urgency given the strategic importance of this portion of the network. The helicopter patrols are used to identify vegetation, cross arm, insulation, guy wire problems and can also be used, with thermovision cameras, to identify connector issues.

3.3.2 HV Overhead Lines

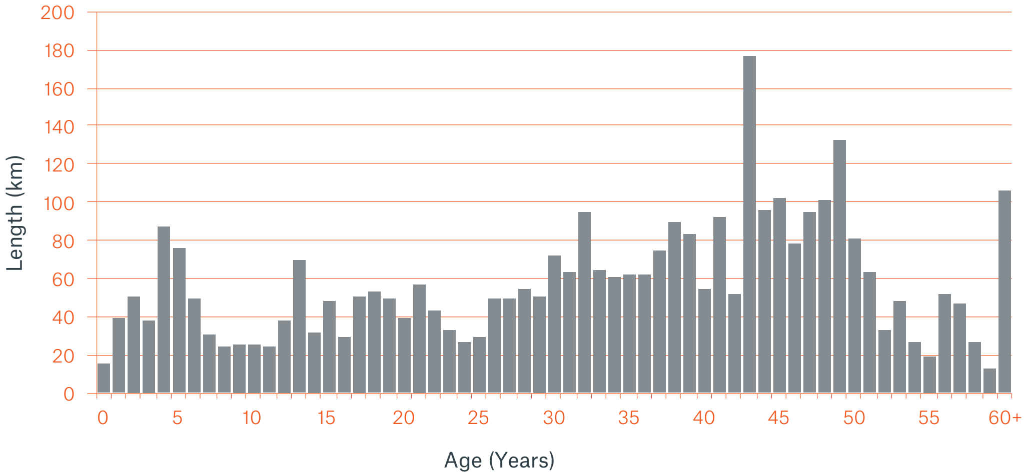
3.3.2.1 Description of Asset

Description	Quantity (km) in 2017
High Voltage Lines	3,499

Northpower distributes electricity from zone substations to local distribution transformers at 11kV (HV). Over 90% of this distribution network is overhead HV lines.

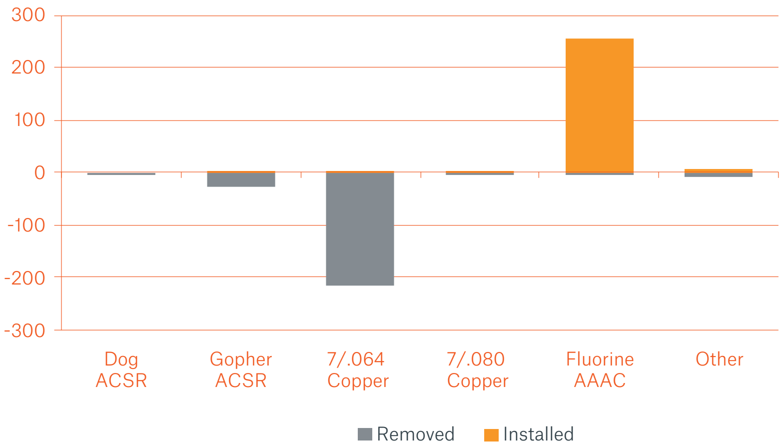
3.3.2.2 Age Profile

Age Profile of HV Lines



Note: Where the age of the asset is unknown an age of 40 years is assumed for open wire conductors and 43 years for aerial cable and SWER conductors.

HV Line Change in Length 2012 - 2017



The reduction in copper and ACSR conductor and increase in AAAC conductor is part of an ongoing conductor replacement programme (replacement of 7/.064 copper and ACSR Gopher) due to risk of failure from corrosion or work hardening of aged conductors.

3.3.2.3 Condition

The HV network (11kV overhead lines) has been assessed as being in generally good condition. The conductor replacement program focussing on specific copper and ACSR conductor has been in progress for a number of years and is being complemented with targeted end of life replacement. A conductor testing standard has been developed to further understand the condition of the conductors and prioritise replacement. Pole and crossarm replacement is ongoing based on preventative maintenance defect identification and a targeted end of life replacement program is being implemented in FY19.

3.3.3 LV Overhead Lines

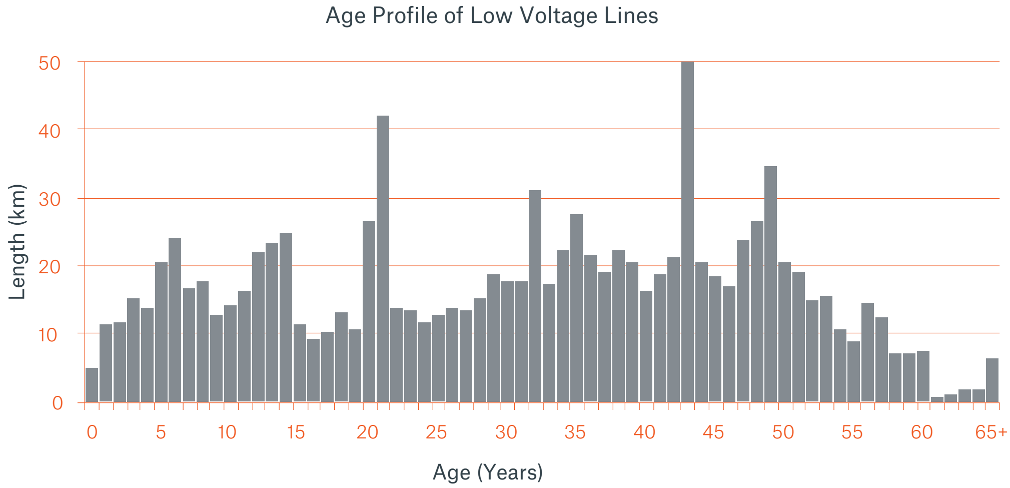
3.3.3.1 Description of Asset

Description	Quantity (km) in 2017
Low Voltage Lines	1,192

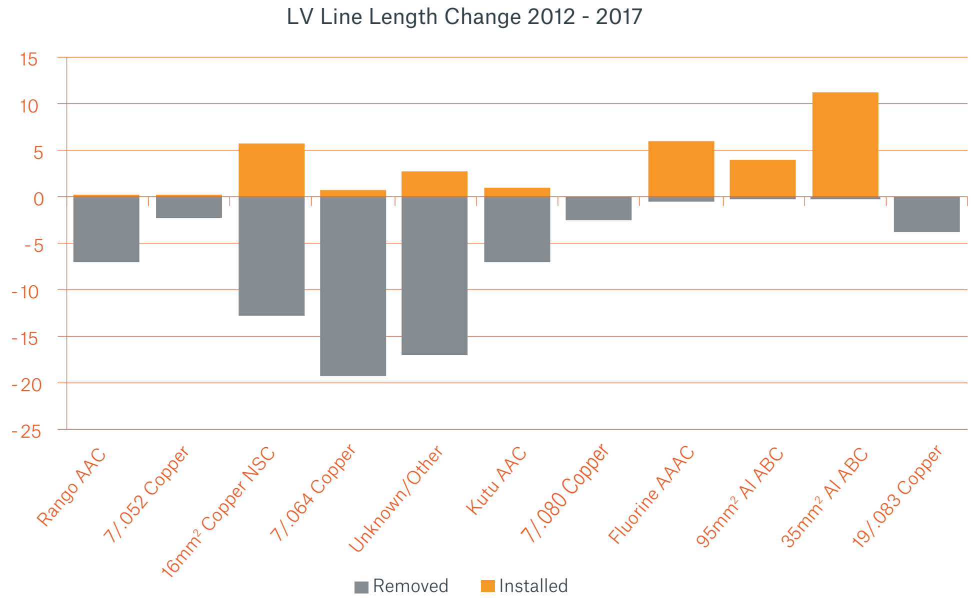
About 65% of Northpower's low voltage network is overhead and consists of a range of conductor types including copper, AAC, AAAC and aluminium aerial bundled conductor (ABC).

3.3.3.2 Age Profile

The age profile of the low voltage lines is shown in the graph below for the past 65 years, however, where the age of lines is unknown the default value of 43 years has been assumed.



Note: Where the age of the asset is unknown an age of 39 years is assumed.



3.3.3.3 Condition

The LV network is in many places contiguous with the HV network. The age profile and condition therefore is very similar to that of the HV network, similar inspection and maintenance regimes are applied for corresponding improvements in performance. A program of works comparable to that of the HV network is to be undertaken on the LV network.

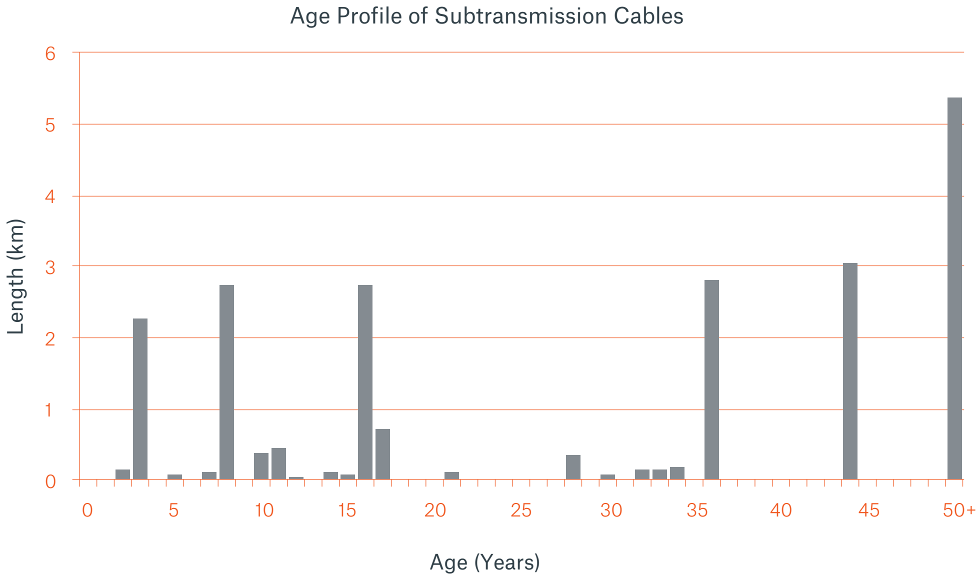
3.3.4 Underground Subtransmission Cable

3.3.4.1 Description of Asset

Description	Quantity (km) in 2017
Subtransmission Cables	22

About 10% of Northpower's sub transmission network is 33kV underground cables. Cables installed in the last 30 years have modern XLPE / PVC insulation, and the remaining are either PILC or oil filled cables.

3.3.4.2 Age Profile



Note: Where the age of the asset is unknown an age of 30 years is assumed for XLPE, 46 years for oil pressurised cables, 43 for gas pressurised cables, 36 for PILC cables and 23 years for submarine cables.

3.3.4.3 Condition

The sub-transmission cable routes are regularly patrolled and checked for any excavation or fill activity. Sub-transmission cable condition have been assessed as good to fair. Several oil filled sub-transmission cables have however reached near-end of life with cable renewals planned within a ten year period. The cables are tested on a 3 yearly cycle. Standard electrical testing is carried out by Northpower's contractors and PDC (Polarisation/ Depolarisation and Partial Discharge) tests are carried out by a consultant engineer involving the use of specialist equipment. This ensures that the integrity or rating of the system has not been compromised.

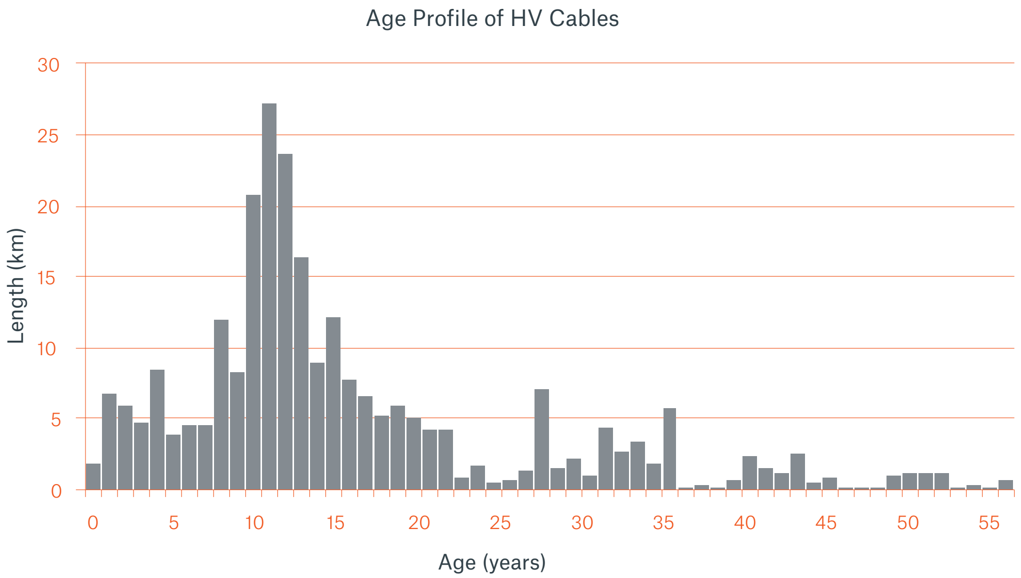
3.3.5 Underground HV cables

3.3.5.1 Description of Asset

Description	Quantity (km) in 2017
High Voltage Cables	265

Typically for HV cables it was common for paper insulated lead covered (PILC) multi-core with copper conductors to be installed. Improvements in manufacturing technology have resulted in cross linked polyethylene (XLPE) cables becoming more prevalent and these cables have been used for the past 30 years.

3.3.5.2 Age Profile



Note: Where the age of the asset is unknown an age of 28 years is assumed for XLPE or PVC cables, 36 years for PILC cables and 41 years for submarine cables.

3.3.5.3 Condition

The average overall condition of HV cables is reasonably good in that a large percentage of the asset fleet (XLPE cable) was installed relatively recently. However, there is a significant quantity of aging paper lead cable in CBD areas (mainly Whangarei) and zone substations which will need to be replaced due to end of life. Condition assessment and an associated targeted replacement is being planned.

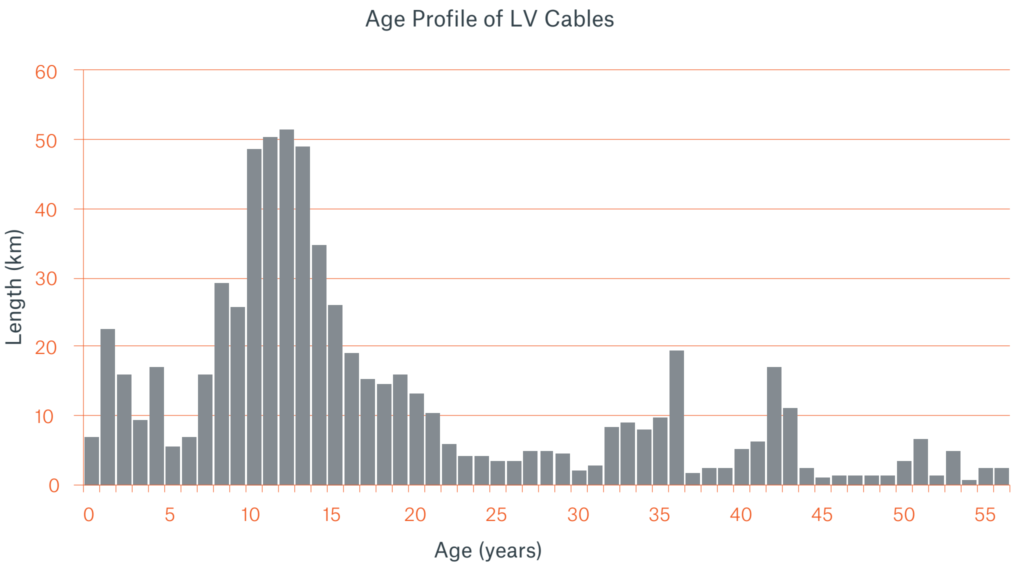
3.3.6 Underground LV cables

3.3.6.1 Description of Asset

Cables on the LV network mostly consist of single core PVC sheathed cables with either aluminium or copper conductors typically run inside a PVC duct. Recently XLPE sheathed sector cables have been used. These cables typically have aluminium conductors.

Description	Quantity (km) in 2017
Low Voltage Cables	682

3.3.6.2 Age Profile



Note: Where the age of the asset is unknown an age of 36 years is assumed.

3.3.6.3 Condition

The 400V cables have proven to be very reliable. Failures, when they do occur, tend to be at terminations or joints. However, underground "tee" joints are showing an increasing incidence of failure due to ingress of moisture through the epoxy joint; the volume of faults is being closely monitored. There is nothing to suggest that it is a widespread issue and replacement occurs as a result of failure or in conjunction with other work on the asset.

Cable risers, terminations and joints are more prone to failure than the cable itself.

3.3.7 Poles

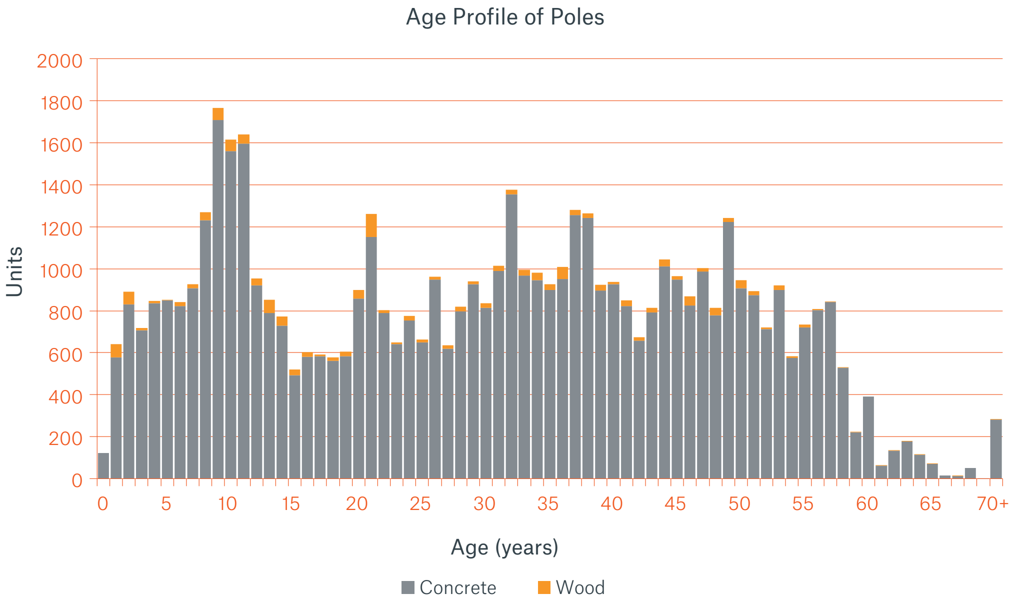
3.3.7.1 Description of Asset

Description	Quantity (units) in 2017
Wood	1,467
Concrete	52,883

Northpower's overhead network is supported predominately by concrete poles. The wooden poles in use on the network are largely hardwood.

The crossarms used to separate and support the insulators/conductors are typically 100mm x 75mm hardwood on the HV network and 75 x 75mm hardwood on the LV network. The cross arms vary in length depending on the pole spacing to provide sufficient conductor spacing. Northpower now uses galvanised steel cross arms for the most common sizes crossarms on the Northpower HV Network. The goal is to achieve a longer asset life together with more detectable modes of failure.

3.3.7.2 Age Profile



Note: Where the age of the asset is unknown an age of 40 years is assumed for concrete/steel poles, 36 years for wood poles and 40 years for other pole types.

3.3.7.3 Condition

The average condition of these assets is fair but there are a large number of old poles which are in relatively poor condition. Concrete poles tend to spall with age. The number of poles to be replaced is largely determined by the age profile. Current levels of pole replacement do not reflect the rapid increase in population reaching end-of-life time when the number of pole renewals will increase significantly.

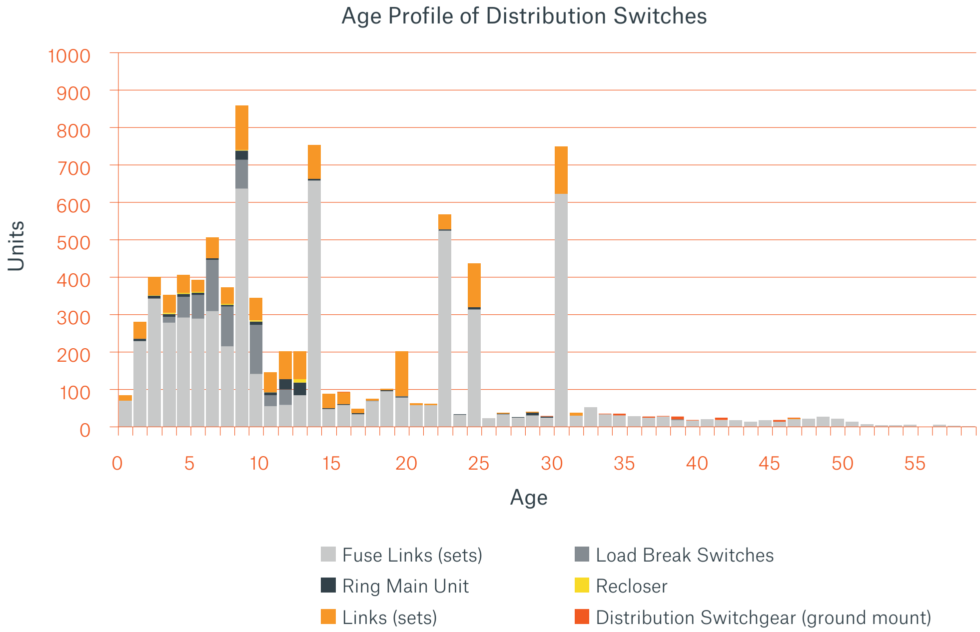
3.3.8 Distribution Switchgear

3.3.8.1 Description of Asset

Description	Quantity (units) in 2017
Links (sets)	1,313
Load Break Switches	653
Fuse Links (sets)	6,308
Reclosers	29
Distribution Switchgear (ground mount)	30
Ring Main Units	193

Given that most of the HV network is overhead, the majority of the HV switchgear consists of fuse links for overhead transformers and load break switches or reclosers for network sectionalising. Ring main units are typically used for protecting ground mounted substations and sectionalising the underground HV network.

3.3.8.2 Age Profile



Note: Where the age of the asset is unknown an age of 7 years is assumed for pole mounted reclosers and sectionalisers, 43 years for indoor circuit breakers, 31 years for pole mounted switches and fuses, 39 years for ground mounted switches (except RMU) and 26 years for RMUs.

3.3.8.3 Condition

Pole mounted switches and fuses are in good condition with only about 4% in fair condition. The distribution switchgear (ground mounted) is relatively old and has been reliable but because of the consequences of a failure there is a programme to replace this equipment. Reclosers and disconnectors are all in good condition as are the RMUs. Although the condition of the load break switches is good, there is a design issue relating to moisture ingress affecting the operating mechanism which is being attended to with the assistance of the supplier.

3.3.9 Voltage Regulators

3.3.9.1 Description of Asset

Description	Quantity (units) in 2017
Regulator Stations	5

An automatic voltage regulator is a tap changer equipped autotransformer that maintains the voltage level within a certain range, regardless of the load variations. The units in place on the network are typically on long, predominantly rural feeders that have a relatively high load characteristic.

As with other network hardware, there have been a number of different manufacturers who have supplied this type of equipment to Northpower.
Units manufactured by McGraw Edison and Turnbull and Jones are currently in use.

3.3.9.2 Age Profile

Of the five regulator stations one has been installed in the last two years, one is 12 years old, one is 15 years old and the other two are 46 years old.

3.3.9.3 Condition

Given the low numbers of assets in this category, condition monitoring is uncomplicated. The overall condition of these units is considered to be good and the 55 year expected life should be achievable.

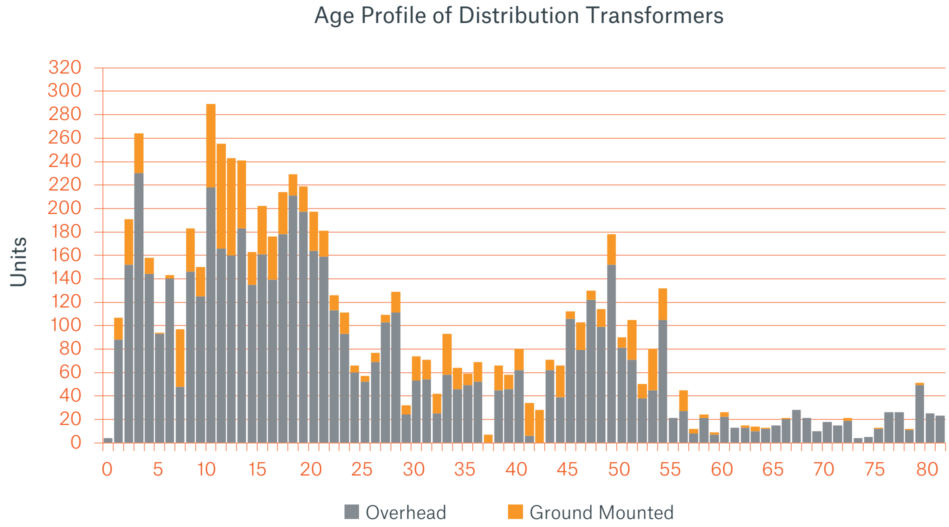
3.3.10 Distribution Transformers

3.3.10.1 Description of Asset

Description	Quantity (units) in 2017
Pole Mount	5,842
Ground Mount	1,367

About 80% of Northpower's 11kV/400V distribution transformers are pole mounted. While these can range in size from 1 kVA to 150 kVA, the most common transformers installed on the network are 15 kVA, 30 kVA and 50 kVA. In urban areas, ground mounted substations are more prevalent and typically range in size from 100 kVA to 500 kVA reflecting the increased density of residential and commercial customers in these areas.

3.3.10.2 Age Profile



Note: Where the age of the asset is unknown an age of 39 years is assumed for both pole and ground mounted transformers.

3.3.10.3 Condition

The average condition of the bulk of these assets is fair however there are a significant number of old assets in relatively poor condition. This AMP proposes to increase replacement rates over the next ten years. Field inspections look for corrosion and defects on distribution transformers. Units in poor condition are brought back to base for refurbishment and to be repainted.

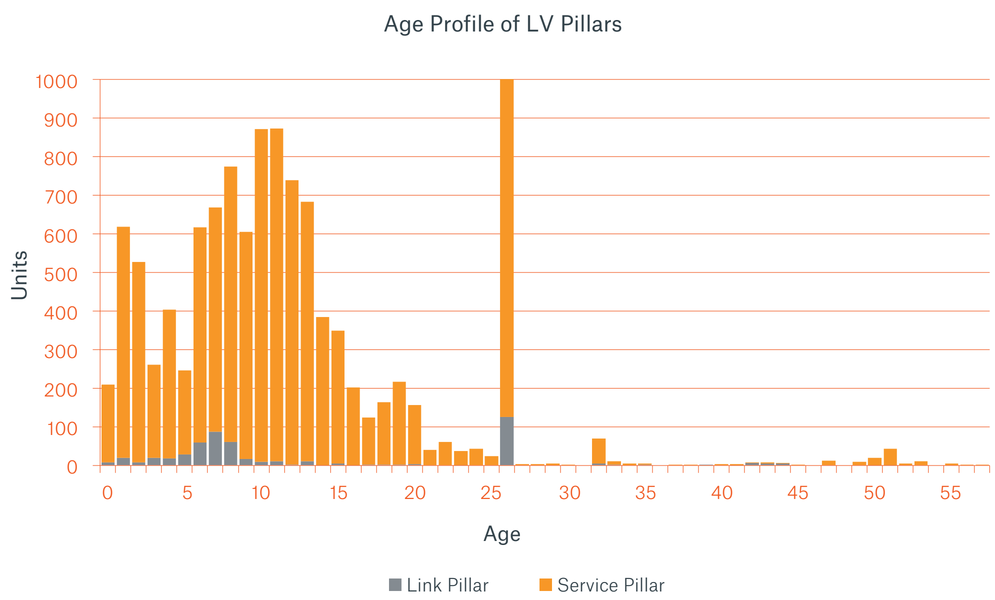
3.3.11 Low Voltage Pillars

3.3.11.1 Description of Asset

Description	Quantity (units) in 2017
Link Pillar	523
Service Pillar	11,600

LV service pillars are the point of connection between the low voltage cable network and a customer's buried service cable. Link pillars provide (open) connection points between LV cables from adjacent transformers and enable the ability to back feed should one transformer fail. Northpower has a mix of pillar construction from older concrete type pillars with steel or aluminium face caps to the more common polyethylene type shown in the photograph above.

3.3.11.2 Age Profile



Note: Where the age of the asset is unknown an age of 26 years is assumed.

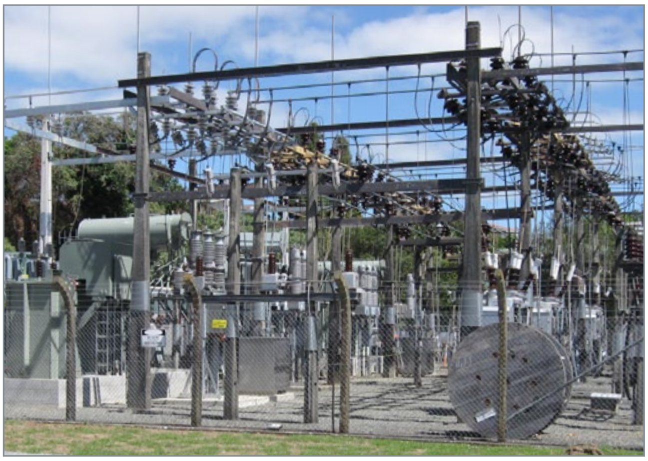
3.3.11.3 Condition

A visual inspection of all service pillars is undertaken on a biennial cycle and annually for our link pillars. The visual inspection identifies any safety issues which are remedied in a timely manner. Overall the condition of the pillars is fair. A number of the older concrete type pillars have been identified as having a potential safety issue due to moisture which can cause tracking and potentially liven the concrete. The steel plate and frame is unearthed and if physically damaged could become live. A programme is well underway to replace the concrete pillars with our standard plastic pillars.

3.3.12 Zone Substation Sites

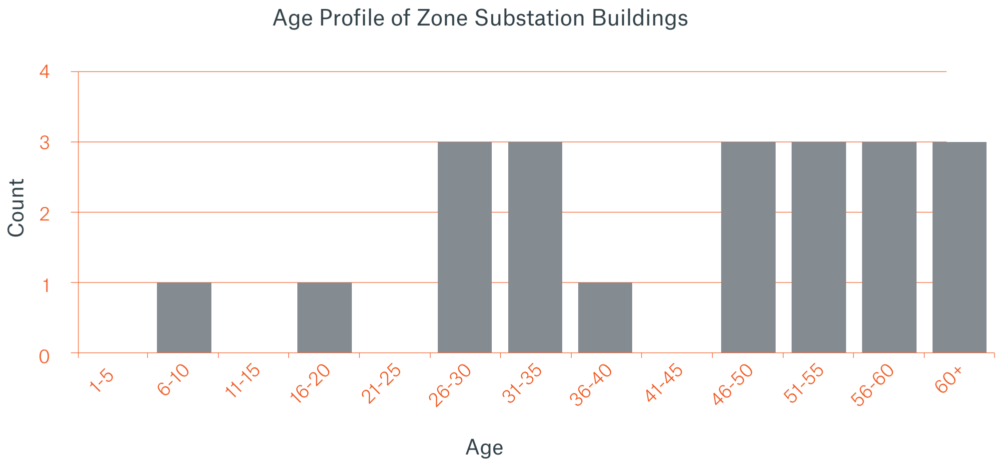
3.3.12.1 Description of Asset

Description	Quantity (units) in 2017
Zone Substation Land	20
Zone Substation/GXP Buildings	21



Northpower's zone substations typically consist of a block building housing 11kV switchgear, protection panels and auxiliary DC equipment. 33/11kV transformers, 33kV switchgear and bus bars are located in a securely fenced outdoor yard.

3.3.12.2 Age Profile



3.3.12.3 Condition

Monthly inspections of the zone substation buildings and equipment ensure that they are maintained in an overall good condition. Although the standard life for buildings is assumed to be 50 years, buildings that are regularly maintained tend to last significantly longer than that (as evidenced by the number of buildings that are older).

3.3.13 Zone Substation Battery Banks

3.3.13.1 Description of Asset

Description	Quantity (units) in 2017
110V Battery Bank	24
48V Battery Bank	1
24V Battery Bank	16

All zone substations are equipped with battery banks which provide auxiliary DC supplies. These supplies are used to operate closing coils, tripping coils and spring release charging motors, as well as the transformer tap changer motors of the 33kV and 11kV circuit breakers. An age profile of the batteries is not available at this juncture as some records are incomplete.

3.3.13.2 Condition

The condition of zone substation battery banks is good with regular preventative maintenance program checks and tests ensuring that defects are identified early and where necessary followed by prompt replacement.

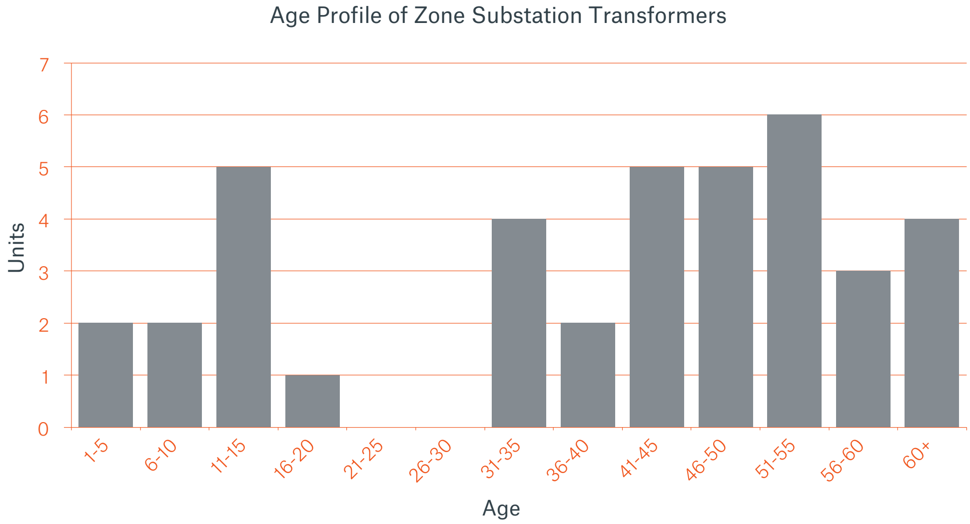
3.3.14 Zone Substation Transformers

3.3.14.1 Description of Asset

Description	Quantity (units) in 2017
Zone Substation Transformers	39

Northpower's 33/11kV zone transformers range in size from 3.75 - 5 MVA at the remote rural zone substations such as Ngunguru, Parua Bay to 15-20 MVA at urban substations e.g. Tikipunga, Kioreroa.

3.3.14.2 Age Profile



3.3.14.3 Condition

The average condition of these assets is fair to good, with the exception of a number of end of life units that are in a relatively poor condition. Transformers are inspected annually and oil tests carried out to check for dissolved gases. While the transformers have been reliable, the age profile has a number of units beyond end of life. The next ten years will see an increase in substation transformer renewals.

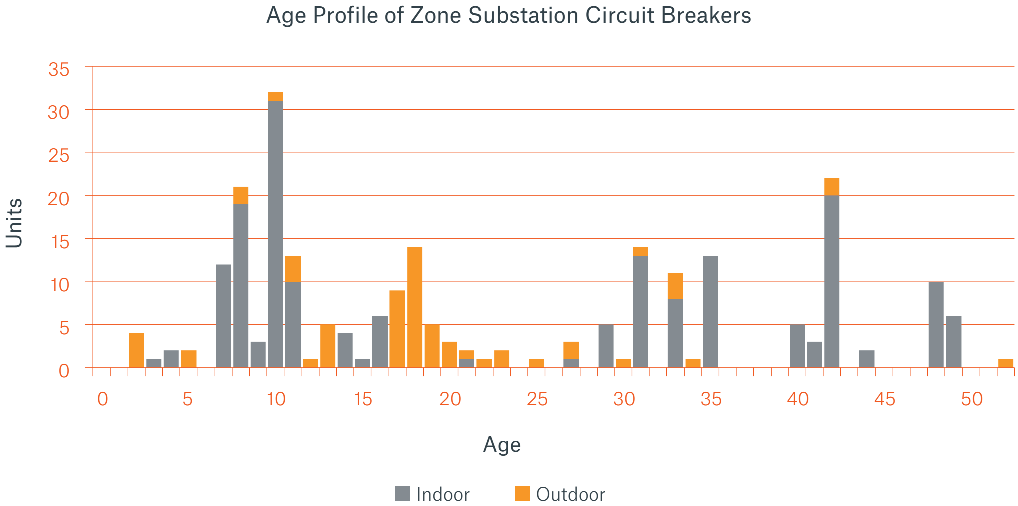
3.3.15 Circuit Breakers

3.3.15.1 Description of Asset

Description	Quantity (units) in 2017
Indoor circuit breakers	175
Outdoor circuit breakers	65

Northpower has an ongoing programme to replace aged oil filled 11kV circuit breakers in its substations with modern 11kV vacuum breakers over the next 10 years. The only major 33kV indoor switchboard replacement project in the AMP timeframe is at Kensington substation.

3.3.15.2 Age Profile



Note: Where the age of the asset is unknown an age of 43 years is assumed for 50/66/110kV indoor breakers, 60 years for 50/66/110kV outdoor breakers, 32 years for 22/33kV indoor breakers, 25 years for 22/33kV outdoor breakers, 41 years for 3.3/6.6/11/22kV ground mounted breakers and 43 years for 3.3/6.6/11/22kV pole mounted breakers.

3.3.15.3 Condition

The average condition of these assets is fair to good, although there are a number of aged units which are scheduled for replacement.

3.3.16 Zone Substation Earthing

3.3.16.1 Description of Asset

Description	Quantity (units) in 2017
Zone Substation Earthing	19

3.3.16.2 Age Profile

As the earth mat was installed at the time of the construction of each zone substation, the age profile is the same as that of the zone substation.

3.3.16.3 Condition

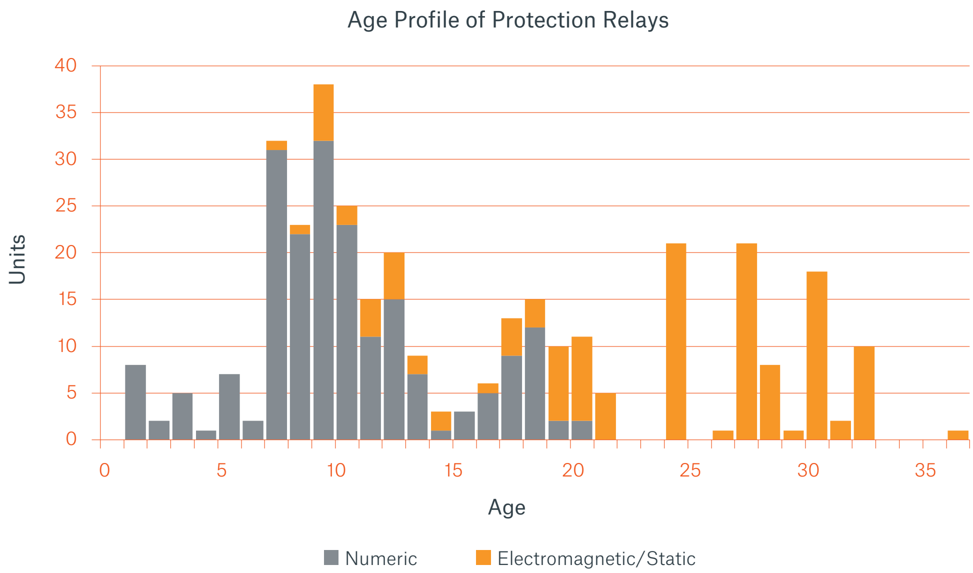
The preventative maintenance inspections and any follow up maintenance undertaken as a result of the inspections have maintained the condition of the zone substation earthing as good.

3.3.17 Protection Relays

3.3.17.1 Description of Asset

Description	Quantity (units) in 2017
Numeric Relays	204
Electromagnetic/Static Relays	153

3.3.17.2 Age Profile



Note: Where the age of the asset is unknown an age of 25 years is assumed for both numeric and electromagnetic/static relays.

3.3.17.3 Condition

The average condition of these assets is fair to good with older electro-mechanical relays gradually being replaced with modern numeric relays as part of the 11kV and 33kV switchboard upgrades.

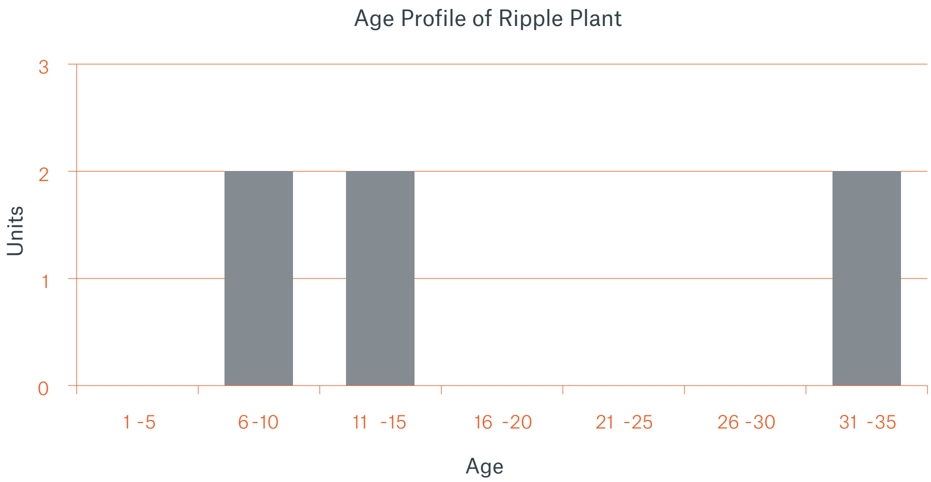
3.3.18 Ripple Plant

3.3.18.1 Description of Asset

Description	Quantity (units) in 2017
Ripple injection plants	6

Of the six plants three inject at 33kV (Maungaturoto, Tikipunga, Maungatapere zone substations) and three at 11kV (Dargaville, Ruakaka, and Bream Bay zone substations). All six ripple plants are static type using a 283Hz injection frequency. Each ripple plant consists of a coupling cell, transmitter and control system.

3.3.18.2 Age Profile



3.3.18.3 Condition

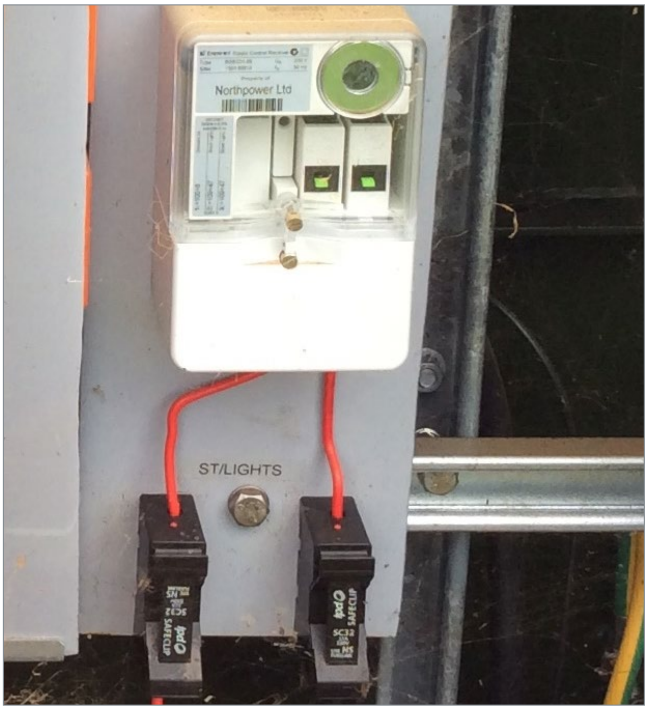
All ripple plants are in good condition with the exception of the Dargaville plant which is in the process of being replaced. The ripple plants all use static technology and therefore have low maintenance requirements. There is a support agreement in place with the manufacturer that includes a fault response and requirement that spares are held in stock.

3.3.19 Ripple Relays

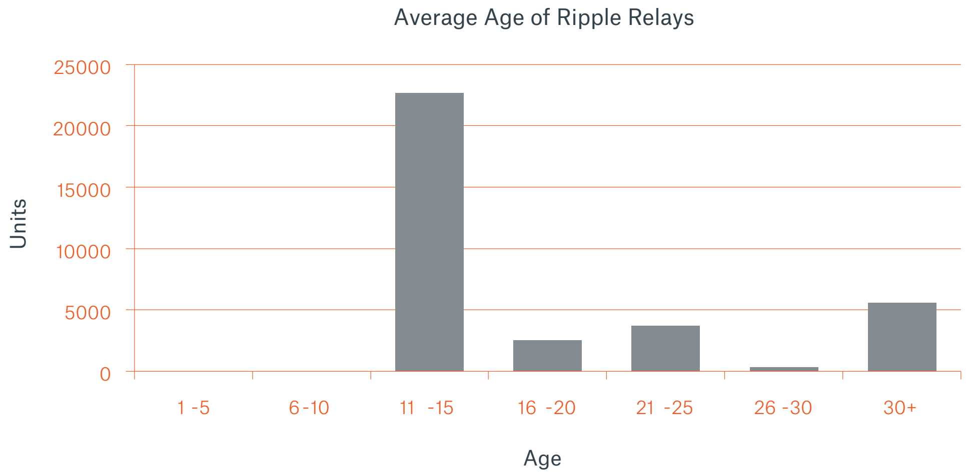
3.3.19.1 Description of Asset

Description	Quantity (units) in 2017
Ripple Relays	34,768

Relays controlled by Ripple Injection Plants are used for load control of hot water heating, street lights and to initiate tsunami warning sirens.



3.3.19.2 Age Profile



3.3.19.3 Condition

Ripple relays are in fair to good condition.

3.3.20 SCADA and Communications

3.3.20.1 Description of Asset

Description	Quantity (units) in 2017
SCADA master station and backup	1
Zone Substation RTU's	25
Fixed Radio Links (point to point)	37
Mobile Radios	140
Radio Stations and associated Assets	5
Standby diesel genset	1

3.3.20.2 Age Profile

Due to the nature of the electronic hardware and changes in technology, the SCADA system together with the associated radio stations and remote terminal units have a wide spread of age profiles.

3.3.20.3 Condition

The condition of these assets is fair to good with investigations planned to upgrade or replace the SCADA and to investigate replacing all remaining analogue radio systems with digital systems.

3.4 Supporting and Secondary Systems

3.4.1 Distribution Management System

Asset Description

The distribution management system (DMS) is a collection of applications used to manage, monitor and control the Network and applications used by Northpower which include:

- Geographical Information Systems (GIS)
- Supervisory Control and Data Acquisition (SCADA)
- Data Historian
- Interactive Voice Response System (IVR)

The GIS system serves as Northpower's master repository of asset data and provides the ability to graphically display the configuration of the network. The information is used to plan, design and document the electricity network and its connectivity. Asset data retrieved from the field is validated and imported directly into the GIS system.

The system allows for two different graphical views of the network, 'schematic' for the 11kV network and 'geographic' at all voltage levels. The GIS also forms the basis of an intelligent model of the network by capturing the connectivity between components, allowing the impact of changes in the network to be visually displayed. A web based GIS viewer provides desktop users, including control room operators, with direct access, while spatial data is extracted for uploading to field mapping devices used by contractors in the field.

The SCADA system provides a real-time view of the status of the network, including switch position and energization, loading and voltage levels, alarm status and event logs. It does this in a dynamic fashion through the use of graphical displays in the form of network schematics combined with active tables and charts. The SCADA system is comprised of a number of parts which include:

- Remote Terminal Units (RTUs) – Field devices that concentrate sensor/actuator information;
- Communications Network – Provides the link between the field and the central server (comprising fibre as well as radio links and associated switching facilities);
- Communications Server – Manages communications with the field and acts as a temporary data repository; and
- SCADA Workstations – Provides the human machine interface (HMI).

The core of the SCADA system is the communications server, which Northpower has designed to be fully redundant, with mirror systems housed at separate locations.

Asset Capacity Performance

Northpower use the Hexagon Intergraph GIS system, used widely within the electricity distribution industry in New Zealand. Northpower use the GIS system to record all network asset data. Northpower has achieved the following levels of data completeness in GIS, across all attributes:

- Subtransmission Lines and Cables: 98%
- High Voltage Lines and Cables: 92%
- Low Voltage Lines and Cables: 84%
- Subtransmission and Distribution Switchgear: 99%
- Distribution Substations and Transformers: 83%
- Poles: 94%
- Pillars: 93%
- Zone Substations Assets: 78%

Northpower uses the Siemens Spectrum Power TG application for its SCADA and Load Management System. The system can be used with a range of RTUs from different vendors. The Spectrum Power TG product is designed to be implemented in a networked environment with the ability to separate out individual system functions across multiple servers. This allows the system to accommodate the inclusion of a large number of data points.

The Spectrum Power TG communications servers support a wide range of protocols to communicate with RTUs, IEDs and other field equipment. For connection with Transpower's SCADA the Spectrum Power TG system also supports the ICCP protocol but there is no immediate need for a connection.

We have implemented our SCADA on dual redundant servers, each connected by a ring of network switches. Most communication links from the field connect to two of these switches to provide alternate paths to each of the servers.

The hardware running the core SCADA system is housed in dedicated data centres that are environmentally controlled, have mains fail power supplies with backup generation for extended outages.

Asset Condition

The SCADA and GIS servers are approximately 9 years old and whilst not at end of life are at the review stage of their life cycle. The RTUs vary in age from around 15 years to near new.

Standards & Records

All Northpower's planning, design and network management functions rely on accurate GIS information. In addition, Northpower's ability to fully implement an automated outage management system is contingent on developing an accurate GIS model of the network.

Information from the GIS system is made available to the business through a Data Warehouse facility. Data is routinely extracted from the GIS system and other information systems and aggregated in the data warehouse, where it can be accessed through a combination of structured and ad hoc reports.

3.4.2 Metering Systems

3.4.2.1 Power Quality Metering

Power quality metering is installed at key substations to monitor and record system waveform and voltage disturbances (sags, swells and other transient phenomena) as well as voltage and current harmonic distortion

3.4.2.2 Revenue Metering

Revenue metering (including check metering) is installed at Transpower GXP supply points to record energy delivered to the Northpower network from the National Grid.

3.4.3 Telecommunications

Asset Description

Northpower has both data and voice communication systems. Our communication network is integral to the remote monitoring and control of network equipment. Separate radio networks provide contact with operating staff and contractors in the field.

The voice communication systems use very high frequency (VHF) radio repeaters in the form of a private network, complemented by use of public telephone and cellular networks. The data communication systems use various technologies running over ultra-high frequency (UHF) radio, copper wire cables, as well as fibre links used for zone substation SCADA and pole top communications.

Northpower's SCADA communications network is made up of a mix of broadband connections to seven substation sites within the Ultra-Fast Broadband (UFB) fibre network area, and narrowband connections over radio to sites outside of Whangarei. At present sites are connected via the UFB fibre network. It is planned to migrate these substation sites onto a dark fibre ring topology and eliminate single points of failure in the existing network topology. Planning for migration of Dargaville onto dark fibre is well advanced. Other substation sites in the smaller centres will be progressively added to the fibre core ring network as the UFB extends beyond Whangarei.

Northpower are currently keeping narrowband connections as a backup for critical SCADA services in the event of UFB service outages (planned and unplanned).

The SCADA radio network has been further supplemented by a number of licenced microwave links to key sites including Bream Bay / Marsden Point and Dargaville. A number of other microwave links that operate in shared spectrum are also used to provide broadband access to remote sites where a high capacity data link is required. The remaining sites are connected via licenced narrowband links operating at UHF frequencies and supporting a serial data interface.

Northpower owns and operates its own private land mobile radio network to provide a Radio Telephone (RT) service for the exclusive use of its network staff and contractors. The network consists of five VHF analogue repeaters that are linked via a radio dispatch system located in Whangarei. These repeaters provide effect coverage across 80% of Northpower's distribution area.

Asset Capacity Performance

As remote terminal equipment (RTUs) and intelligent electronic devices (IEDs) are replaced the preferred type of communication interface becomes IP based rather than a serial data format. IP connections, generally require a higher bandwidth to operate effectively, which can mean using a broadband connection (fibre, DSL, 3G/4G cellular) or upgrading the type of narrow band technology used to maximise throughput. For most SCADA connections either of these options are usually sufficient, however when there are additional requirements that include the transmission of large amounts of graphical data, broadband becomes the only option.

All substation sites that are connected via fibre have more than sufficient data capacity to meet current and future requirements. The migration of these sites from a UFB service to a dark fibre connection relates primarily to eliminating single points of failure and establishing physical separation rather than virtual separation from other types of traffic for improved cyber security.

A number of sites are connected using microwave radio links operating in shared spectrum. These sites have sufficient capacity to meet current demand and future applications that require significant bandwidth which may also be accommodated on a site by site basis depending on the quality of the radio link. Use of shared spectrum is becoming more heavily used, particularly by wireless internet service providers (WISPs), which is resulting in a continual rise of the noise floor in these shared bands. This increase in noise results in existing connections slowing down to mitigate the higher noise levels. It can be expected that this will impact on the capacity of Northpower's links using shared spectrum, although the extent is difficult to predict and likely to be very local in nature.

Most narrow band radio links will only support legacy serial data connections and need to be upgraded to support IP data traffic. In 2015, the SCADA radio network connections to the west coast, from Ruawai to Maunganui Bluff, were upgraded with new point-to-point UHF digital radio equipment capable of supporting both IP and serial data communications. Northpower has also recently deployed high capacity point-to-multipoint radio systems that operate in licenced narrowband UHF channels. These latest deployments support IP traffic and meet current capacity requirements for SCADA, but would not support future graphics based applications that require broadband connections.

Northpower's radio telephone (RT) network is a legacy analogue network that provides basic voice services only. It has no provision for enhanced features like GPS location tracking, or man-down alarming. In terms of providing basic voice services, the network has proven to perform reliably, although gaps in the coverage limit its availability. The relatively recent addition of a new repeater near Whangarei has improved coverage within the urban area, but coverage issues still remain in the rural northwest of Northpower's distribution area. We are planning to upgrade our coverage capabilities and RT services in the 10 year AMP cycle.

Asset Condition

Northpower Network uses some fibre network infrastructure owned by Northpower Fibre Ltd (NFL), whose network presently covers the Whangarei urban area. This is a new fibre network deployed in the last 7 years as part of the Government's sponsored ultra-fast broadband initiative. Northpower Network also owns some fibre that is used for protection and control communications. Both the NFL and Northpower Network fibre assets have an expected life beyond the 10 year period covered by this asset management plan.

The assets in the SCADA radio network are of a variety of ages however, the condition of these assets is more closely aligned to the environment in which they are housed. Not all radio equipment enclosures are controlled for temperature and humidity and this is particularly the case for smaller radio sites and pole top enclosures. In these situations where equipment is subject to significant temperature and humidity variations over the course of a day, it is important that the equipment be of a high specification.

The repeaters in the RT network are nearing the end of their operational life, although the Tait radio equipment used was manufactured to a high standard and, consequently, is still in a relatively good condition. The RT sets in Northpower's vehicle fleet are in a range of conditions.

Standards & Records

Northpower is moving to a standards based, all IP, packet network for both voice and data. This involves the replacement over time of serial data connections, used for legacy SCADA communications and analogue voice connections, used by the RT network.

The licenced narrowband radio links used by the SCADA network employ a range of digital radio standards and adhere to their respective radio licence conditions that restrict emissions. The broadband wireless access (BWA) links used by Northpower have a proprietary air interface and operate in shared spectrum. The use of this spectrum is governed by the general user radio licence (GURL) for short range devices and fixed links. Separate to these BWA links are the licenced band digital microwave radio links which have their own dedicated radio channels and specific radio licence conditions.

The RT network uses standard analogue FM technology, which gives it a high degree of compatibility with a range of vendor's products. However, this type of analogue technology is being progressively phased out for more feature rich digital standards like digital mobile radio (DMR) and the APCO P25 standard.

Northpower keeps static CAD drawings of its communications networks, including network schematics, pole elevation drawings, equipment layout drawings and site plans. The accuracy and age of these drawings is of a reasonable standard.

3.4.4 Backup Control Room

Northpower has a backup control room located at Tikipunga zone substation, approximately five km from the main control room. Whilst the HV network can be operated remotely the LV network cannot be operated as the LV Network is not fully integrated into the SCADA. It is not practical to transfer the paper LV network wall mimics from the main control room at short notice. The GIS information can be taken to the backup control room on a laptop. Recently, the VHF communications to the backup control room have been upgraded in order to provide good communications to field staff.

3.4.5 Power Factor Correction Plant

Northpower currently has 22 x 750kVAr 11kV fixed capacitor banks installed at zone substations to improve power factor for the upper North Island grid. There are also 5 smaller 11kV capacitor banks (one of which is auto-switched) installed on distribution feeders for voltage support purposes.

3.4.6 Mobile Substations and Generators

Northpower owns and maintains a 500kVA 400V mobile distribution substation with a 500kVA generator. This unit is used to provide supply in the event of either an unplanned shutdown or planned shutdown. There are three modes of operation:

- Direct connection onto the LV network.
- In parallel with 11kV network via a transformer
- Supplying an islanded 11kV network via a transformer

Section 4: Lifecycle Asset Management Plan

Northpower

Lifecycle Asset Management Plan - Section 4

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Section 4: Lifecycle Asset Management Plan

4.1 Planning Criteria and Assumptions

4.1.1 Objective

Our lifecycle asset management planning objectives support Northpower's strategic goals. We apply the following criteria to drive asset maintenance and renewal:

- Safety and environment – for the public and those working on the network
- Reliability – meet or exceed the expectation of our customers
- Economic efficiency – operation in accordance with cost/benefit objectives
- Foundation for growth – provide for expansion without compromising flexibility
- Long term sustainability – no degradation of the owners' investment in the asset

Lifecycle asset management optimises the performance of an asset between the time of commissioning and its eventual renewal.

Northpower's asset renewals tend be based on asset age with the exception being sub-transmission and zone substation assets which tend to be managed through condition monitoring processes. We intend to strengthen our whole asset management approach more towards condition monitoring, and in this ten year period will be replacing a number of assets that are at or beyond end of life.

4.1.2 Determining the Optimal Level of Maintenance Expenditure

Management of an asset through its life begins with categorising into one of three defined practices: preventative, follow-up, and remedial maintenance.

Preventative maintenance – the systematic inspection and detection of incipient failures through the recording of changes in equipment condition. The inspections are refined as more knowledge is gained based on good engineering practice, manufacturer's recommendations and technology improvements. Preventative maintenance activities also include partial or complete refurbishment at specified intervals.

Follow-up maintenance – a corrective action for a defect that is identified as a result of a preventative maintenance inspection or a remedial maintenance attendance. Follow-up maintenance may be further categorised as operational expenditure or capital expenditure in accordance with the business rules. Follow-up maintenance is an area of increased focus to improve processes and categorisation in order to increase network performance.

Remedial maintenance – maintenance which must be performed immediately or urgently to protect any person or property from imminent harm or danger, restore electricity supply, perform work after power restoration to restore the electricity network to normal operating condition and to Northpower's standards, protect the electricity network from imminent damage, or ensure that Northpower complies with any legal obligation or generally accepted industry standards. To support Northpower's lifecycle asset management planning the assets have been grouped into fleets that have common technical characteristics and share some investment drivers. The fleets groupings below have been developed to improve capital planning, monitoring, analysis and maintenance. Northpower is in the process of re-defining groups and cross arms will be one new group.

Distribution and Sub-transmission Assets:

- Overhead structures
- Overhead conductors
- Distribution switchgear
- Distribution transformers
- Distribution earthing
- Distribution voltage regulators
- Cables and pillar boxes

Zone Substation Assets:

- Buildings and grounds
- Power transformers
- Indoor switchgear
- Outdoor switchgear
- Outdoor structure
- Earthing
- Outdoor voltage transformers
- Outdoor current transformers
- Load control plant

Secondary Systems Assets:

- SCADA and communications
- Protection relays
- Tap changer controllers
- Auxiliary supplies
- Metering

4.1.3 Maintenance Strategies

Northpower adopts a range of network maintenance strategies for each asset fleet. A risk-based approach to maintenance gives priority to assets serving either large numbers of customers, specific high electrical demand and critical customers, or where public safety is a concern (for which, condition based maintenance is the most likely strategy). This also means that assets serving only a small number of non-critical customers are likely to receive a lower priority (with a higher risk of failure and associated reactive repair). High priority is given if safety may be compromised, in which case our response is immediate.

4.2 Routine Preventative Inspection and Maintenance Practices

Northpower has a robust, planned approach to the routine and preventative maintenance inspections undertaken on the various categories of assets that make up the network. Inspections are targeted to the asset fleet, with those that have a higher consequence of failure (e.g. sub-transmission assets) being subject to a more comprehensive inspection regime (or an increased level of monitoring).

Each category of asset is governed by a maintenance strategy which explains the purpose, the strategy, the technical standards and the identified risks that apply to the particular asset class.

Each asset class is further supported by a work instruction, that includes a data capture sheet to be completed by the person undertaking the field maintenance activity.

The existing strategies are currently in the process of being translated from routine condition based maintenance to risk based asset condition maintenance.

A more detailed analysis of the routine preventative inspection and maintenance regimes for each of the asset categories is shown in the following table. Frequency of inspection and the scope of work are also shown. The scope of work briefly outlines the actions to be taken for each asset category.

Distribution and Sub-transmission Assets Preventative Maintenance Program

Preventative Maintenance	Timing	Scope of work
Overhead Structure and Conductors		
Overhead structure & Overhead Conductors	5 yearly	Visual check of OH lines, poles, and all pole hardware including switches.
Helicopter Survey of Sub-transmission Overhead structure & Overhead Conductors	As required, approx 2-3 yearly	Survey overhead subtransmission lines from a helicopter. Capture any defects and vegetation concerns.
Wood pole testing	5 yearly or condition based	Wood pole testing with DDD200 micro-drill and a visual hardware inspection.

Preventative Maintenance	Timing	Scope of work
Overhead pole mounted substations/ transformers	5 yearly	Visual inspection.
Overhead Switchgear		
Remote switchgear operation	6 Monthly	Operational check of remote controlled switchgear overhead.
Overhead Remote Switch Battery Change	2 yearly	Change the battery on all remote switch control units. Check alarms. Visual inspection.
Oil Recloser oil change	8 yearly	Recloser refurbishment at workshop.
Ground Mounted Switchgear and Transformers		
Weed control of distribution substations	6 months	Vegetation control at distribution substation.
Distribution substations MDI checks	Annual	Check, record value and reset MDIs at selected distribution substations.
Inspect ground-mounted distribution substation	2 yearly	Visual inspection. Paint touch-up. Remove litter & cobwebs. Thermal imaging and partial discharge diagnostic tests. Check signs/labels, lightbulbs.
Ground mounted Oil filled HV switch service.	8 yearly (20 per year)	Service Oil Switches and check operation.
Distribution Earthing		
Distribution earthing inspection	5 yearly	Inspect and test earthing of overhead switches (ABS, sectionalisers & reclosers), distribution substations, regulators, out of service overhead lines and associated lightning arrestors plus any stand alone lightning arrestor installations e.g. cable terminations.
Voltage Regulators		
Regulator Inspection	Annual	Visual inspection. Paint over graffiti and treat and paint surface rust. Remove rubbish, cobwebs and vegetation. Check Signs/labels and Silica gel condition. Record tap changer operations. Check regulating Voltage as per standard.
Regulator Thermal Image Survey	Annual	Thermal image survey of regulator and all associated equipment and connections.
Regulator Ultrasonic Survey	Annual	Ultrasonic survey of regulator and all associated equipment and connections.
Regulator Controller Test	2 yearly	Operation and alarm test.
Regulator Oil Change	4 yearly	Change the oil in all regulators/refurbishment.
Cables		
Subtransmission cable patrol of key circuits	Weekly	Drive through inspection to check for any excavation or encroachment activity.
Check and record oil pressure readings and maintenance	Monthly	Read and record pressure readings (including spare cables). Clean out pressurisation pits, test gauge calibration and transducer alarms.
Pillar visual Inspection	2 yearly	Visually identify any hazards or defects (e.g. damage, screws missing, damaged hinges, pillar not straight, burial depth too great or too little). Includes opening pillars that have key locks and doing a thermographic (hand held) survey.
Cable cover protection unit (SVLs), cross bonding link boxes and serving tests on key circuits.	3 yearly	Undertake all SVL, cross bonding and serving tests on cables.

Zone Substation Assets Preventative Maintenance Program

Task	Timing	Scope
Buildings and Grounds		
Zone Substation building maintenance	Monthly	Inspect buildings, fittings, fencing. Check for damage, leaks and security. Check internal fittings and trench covers. Clean floors, toilet etc as required. Restock toiletries, replace blown light bulbs. Log defects.
Zone Substation grounds maintenance	Monthly	Mow lawns, trim edges, unblock drains, trim trees, remove rubbish, weed control, and maintain gardens (if any).
Security system test	6 monthly	Check operation and service as necessary.
Smoke detector testing	6 monthly	Check operation and service as necessary.
Air conditioning unit service	Annual	Check operation, clean filters and service.
Power Transformers		
Routine equipment inspections and checks	2 monthly	Routine visual equipment inspections and checks.
Thermal Image survey Acoustic Inspection Partial Discharge testing	Annual	Acoustic emission, thermal imaging and external partial discharge diagnostic tests on cable box.
Transformer oil test	Annual	Test oil for acidity, power factor, breakdown voltage, moisture content, interfacial tension, colour and DGA.
Tap changer service	4 yearly	Clean out tap changer to ensure free of arc products and deposits. Replace insulating oil. Check contact alignment and correct operation of tap changer. Check operation of tap changer control relay and secondary protection devices.
Transformer maintenance	4 yearly	Close visual inspection, insulation resistance, impedance and Winding Capacitance and power factor test, Buchholz and pressure relief operational test, temperature gauge check, Neutral Earth Resistor test.
Indoor Switchgear		
Routine equipment inspections and checks	2 monthly	Routine visual equipment inspections and checks.
Thermal Image survey Partial Discharge testing	Annual	Thermal imaging and partial discharge diagnostic tests.
Indoor 11kV Oil Circuit Breaker major servicing	4 yearly or condition	Circuit breaker timing and operational test. Visual inspection of switchgear condition. Breaker service oil change, inspect contact.
Indoor 11kV Vacuum and SF6 Circuit Breaker servicing	4 yearly	Circuit breaker timing and operational test. Visual inspection of switchgear condition, check SF6 gas pressure.
Indoor 33kV SF6 Circuit Breaker servicing	4 yearly	Circuit breaker timing and operational test. Visual inspection of switchgear condition, check SF6 gas pressure.
Outdoor Switchgear		
Routine equipment inspections and checks	2 monthly	Routine visual equipment inspections and checks.
Thermal Image survey Acoustic Inspection	Annual	Acoustic emission and thermal imaging.
Outdoor 33kV SF6 Circuit Breaker servicing	4 yearly	Circuit breaker timing and operational test. Visual inspection of switchgear condition, check SF6 gas pressure.

Task	Timing	Scope
Outdoor Oil Circuit Breaker major servicing	4 yearly	Circuit breaker timing and operational test. Visual inspection of switchgear condition. Breaker service oil change, inspect contact.
Outdoor Structures		
Routine equipment inspections and checks	2 monthly	Routine visual equipment inspections and checks.
Thermal Image survey Acoustic Inspection	Annual	Acoustic emission and thermal imaging.
Close inspection of outdoor structure	4 yearly	Shut down and close inspection of structure and hardware.
Zone Substation Earthing		
Test Zone substation earthing system	4 yearly	Test zone substation earth mats. Test bonding of equipment and structure.
Outdoor Current Transformer and Voltage Transformer		
Routine equipment inspections and checks	2 monthly	Routine visual equipment inspections and checks.
Thermal Image survey Acoustic Inspection	Annual	Acoustic emission and thermal imaging.
33kV outdoor oil filled VT's & CT's	4 yearly	Insulation resistance test, oil change.
Load Control Plant		
Routine equipment inspections and checks	2 monthly	Routine visual equipment inspections and checks.
Equipment test	Annual	Check operation and signal strength.

Secondary Systems Assets Preventative Maintenance Plan

Task	Timing	Scope of Work
SCADA and Communications		
Radio site checks	4 monthly	Visual inspection and tidy. Battery charger and battery impedance tests.
Radio tests	Annual	Visual inspection and tidy. UHF signal strength, frequency tests and compliance.
Auxiliary Supplies		
Battery maintenance	2 monthly	Battery impedance test and charger test. Visual inspection.
UPS battery change	4 yearly	Visual inspection. Change rack mounted battery packs in rack mounted UPSs.
Protection Relays		
Routine equipment inspections and checks	2 monthly	Routine visual equipment inspections and checks.
Protection testing for electromechanical/ static relays	2 yearly	Secondary injection tests and check operation.
Protection testing for numerical relays	4 yearly	Secondary injection tests and check operation.
Protection review	2 yearly	Relay attributes check including settings, standards, discrimination and records checks. Check for the impact of any changes in the Network.

4.2.1 Process for Rectification of Defects

In the course of field inspection, varying levels of priorities are assigned to different defects; the priorities are identified, which sets the urgency of scheduling of follow-up maintenance.

Individual defects or tasks are collated into a work pack which is created in the EMS WASP (Works, Assets, Solutions, and People) system.

Upon completion, the contractor returns the work pack along with any as built information, attributes or data required to be captured.

Through condition assessment we can categorise assets to a grade of condition, which is the base of a risk profile. We also use asset age, benchmarked against electricity industry accepted useful lives. While a number of assets (even without some form of mid-life refurbishment) can remain in operation beyond the "end of life", in many cases it is difficult to predict the risk of future outage, except as identified through the asset life definitions.

Northpower is increasingly moving towards a condition based work programme and many of our assets are currently renewed based on age. Grade 1 is end of serviceable life – immediate intervention required; Grade 2 is material deterioration but still serviceable; Grade 3 is normal deterioration requiring regular monitoring and Grade 4 is good or as new condition. The table below shows asset groups that have assets in grade 1 and 2 and which feed into our ten year capital replacement programme.

Asset				Quantities			
Categories	Class	Quantity	Unit	grade1	grade2	grade3	grade4
Overhead Line	Concrete poles / steel structure	52781	no	722	804	35,999	15,256
Overhead Line	Wood poles	1467	no	166	91	827	383
Overhead Line	Other pole types	104	no	27	19	53	5
Subtransmission Line	Subtransmission OH up to 66kV conductor	293	km	37	35	218	3
Zone Substation Buildings	Zone substations up to 66kV	21	no	-	1	16	4
Zone Substation Switchgear	22/33kV CB (Outdoor)	59	no	1	2	47	9
Zone Substation Switchgear	3.3/6.6/11/22kV CB (ground mounted)	145	no	16	2	58	69
Zone Substation Transformer	Zone Substation Transformers	39	no	-	2	27	10
Distribution Line	Distribution OH Open Wire Conductor	3499	km	65	54	2,680	700
Distribution Cable	Distribution UG XLPE or PVC	225	km	1	0	114	109
Distribution Switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	8277	no	283	112	4,308	3,574
Distribution Switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	30	no	5	6	19	-
Distribution Transformer	Pole Mounted Transformer	5842	no	425	161	3,224	2,032
Distribution Transformer	Ground Mounted Transformer	1367	no	23	49	745	550
Distribution Substations	Ground Mounted Substation Housing	118	no	15	6	84	13
LV Line	LV OH Conductor	1192	km	10	16	896	270
LV Streetlighting	LV OH/UG Streetlight circuit	399	km	37	7	292	61
Scada and Communications	SCADA and communications equipment (system)	1	no	-	1	-	-
Load Control	Centralised plant	6	no	2	2	2	-
Load Control	Relays	34768	no	9,070	3,142	18,739	3,817

Industry methodology identifies (by age characteristics) replacement amounts. Grades 1 and 2 assets are at or well beyond end of life and subject to condition should be replaced within five years. Replacement timing will be changed if suitable condition assessments are available. As noted previously, Northpower is adopting greater levels of condition monitoring and reporting, which over time will lead to a refinement of renewal volumes.

4.2.2 Systemic Issues and Addressing Actions

Northpower has developed sets of Maintenance Guidelines which identify systemic issues with assets on the network and provides a series of actions to address these. The guidelines are integrated in the asset specific maintenance Network Standards.

The following table shows the current list of defect items.

Asset Type	Equipment Type	Equipment Sub-type	Issue/Replacement Criteria	Replacement Type
Overhead structure & Conductors	General		When carrying out renewal work on a section of line/feeder, items that are not likely to last to the next maintenance cycle – typically 5 years should be replaced.	As required for the situation
	Dropout Fuses	All types	Fuses have a common fault problem, e.g. the steel bands at top and bottom are held by bolts that corrode and fail. Replace with modern cut-out wherever the opportunity arises. Note: Spur lines should be isolated with solid links if all transformers are individually fused and there are no vegetation issues.	Current approved model
	Lightning Arrestors	All types	Replace any 9kV rated lightning arrestors except lightning arrestors specific to overhead switchgear. Or replace if older than 10 years and the opportunity arises.	Current approved model
	Insulators	33 kV brand D	These are at risk of cracking at the joint between the two halves. Take every opportunity to remove any "brown – 2 part type" 33 kV insulators from the network.	Current approved model
		33kV clamp top	Clamp top connection known to fail. Take every opportunity to remove them from the network with the exception of Brand E.	Current approved model
		Kidney type	The age of the insulators presents a risk of electrical discharge tracking across the surface. Corrosion of the connection points could also result in failure. Replace in conjunction with other work and if replacing the crossarm.	Current approved model
		Pin types	Replace with approved post insulator when crossarm or insulators are replaced.	Current approved model
	Crossarms	-	Replace crossarm if changing the pole or the insulators and the crossarm condition is mid life or worse. Do not replace a crossarm on a pole classed near end of life.	Current approved model
	Connections	PG clamps	Replace PG clamps with approved Wedge when other work is done onsite.	Current approved model
		Transition (Copper to Aluminium)	Replace uncovered Wedge connectors and PG clamps if used for transition (copper to Aluminium). Use correctly sized wedge with standard gel airtight cover.	Current approved model
		Live Line Type	Replace connectors if 'live line' type, when the opportunity arises.	Current approved model
	Possum Guards	-	Possum guards are generally removed by third parties. Replace where missing on HV poles only but also include stub poles.	Current approved model

Asset Type	Equipment Type	Equipment Sub-type	Issue/Replacement Criteria	Replacement Type
	Pole	Wood	Wooden pole failure generally due to decay. Replace pole in accordance to the notes if a crack in the head extends to the crossarm bolt or if rot exists at or below ground level or if a test with the wood drill shows excess decay. The use of softwood poles will be limited due to the harsh coastal environment. General Notes: For all situations pole design/calculation will be carried out as per the Network Standards.	Current approved model (concrete preferred)
		Concrete	Spalling causes a structural strength risk and potentially a risk from falling debris. Replace the pole if there is excessive spalling and other work is happening at the same site. Poles in marine environments, particularly estuaries, can absorb salt water below the high water table and can decay. Replace the pole if there is evidence of rust leaching and or cracking below the high water level. Apply the General Notes as per above.	Current approved model (concrete preferred)
		Concrete slab	Possibly insufficient engineering design was carried out when poles were originally manufactured. Recent testing shows that concrete slab poles still exhibit good strength characteristics. They are only required to be replaced when spalling is evident. Apply the General Notes as per above.	Current approved model (concrete preferred)
		2-pole transformer structure	Due to the prevalence of this type of structure installed in close proximity to kerbsides, there is a greater susceptibility of being hit by large trucks and coupled with potentially decayed timber, in greater danger of failing. If major maintenance is required then investigate a ground mount transformer option. Apply the General Notes as above.	Current approved model
		Telecom (especially Larch type)	Potential failure of pole as the mechanical strength may exceed design criteria due to presence of Northpower LV conductors. Engineer a solution and replace. ('Vesting Form' required). Apply the General Notes as above.	Current approved model
		All types	Shoulder of pole is exposed by stock rutting around the base of the pole. In extreme cases the stability of the pole could be compromised. Backfill with compacted limestone hard fill.	Current approved model (concrete preferred)
	HV Fuse Link	-	Nuisance tripping can occur due to incorrect fuse element having been installed. Solid links can be installed for spur lines with all transformers individually fused, if there are no trees in the vicinity of the line.	Current approved model
		-	Knife links fail when operated. Manufacturer defect. Replace in conjunction with other work.	Current approved model
	Overhead LV Jumper Leads to Service Connection	-	Potential safety hazard to line mechanics as bare LV jumpers to the service connection may have been fitted in the past. Upgrade jumper leads to insulated conductor wherever upgrade work is taking place or other work is carried out and it is practical to upgrade the jumper.	Current approved model of Cu PVC conductor
	400V Fuses	Rewireable	Corrosion may exist at conductor termination on the fuse causing a burn off of the conductor. Replace fuse when other work is happening at the same site.	Current approved model
		Brand G	Corrosion may exist at conductor termination on the fuse causing a burn off of the conductor. Replace fuse when other work is happening at the same site.	Current approved model

Asset Type	Equipment Type	Equipment Sub-type	Issue/Replacement Criteria	Replacement Type
	Conductor	11 kV jumpers	Corrosion may exist at the aluminium connection to the dropout fuse due to the presence of dissimilar metals. Replace with a copper jumper using correct bimetallic connectors at the main line connection.	Current approved model of Cu PVC conductor and connector
		11 kV 7/.064 HDBC	Due to the age of the conductor there is an increased risk of failure due to corrosion or work hardening. A long term replacement strategy with a priority based on risk, likelihood, potential for public harm, risk to property and the impact of a fault has been implemented.	Current approved model of AAAC conductor
		11kV ACSR	Due to the age of the conductor there is an increased risk of failure due to corrosion particularly in coastal environments. A long term replacement strategy with a priority based on risk, likelihood, potential for public harm, risk to property and the impact of a fault has been implemented. Some ACSR conductor has been found lacking in grease – look for visual signs of corrosion.	Current approved model of AAAC conductor
		Linking of LV Neutrals	Unlinked neutrals and undertake linking when the opportunity arises or in conjunction with other work.	Current approved model
		Joins	Replace section of conductor if there is a significant number of compression joins.	Current approved model
	Conductor Clamping System	Wraplock tie	Failure of the binding to the insulator due to corrosion of the wraplock tie may cause the conductor to clash. Replace wraplock ties with approved preform ties when other work is happening at the same site or a site immediately adjacent.	Current approved model
		Binder Wire	Binder wire is to be replaced with approved preform distribution ties when the insulators or crossarm is replaced.	Current approved model
	Cable Conduits on Pole Riser		Broken cable conduits up poles due to third party vandalism is a potential safety hazard. Provide additional mechanical protection if replacing the cable or the conduit or as notified. Note: A wooden cable trough in accordance Network Standard ENS 3.3.85 can be fitted.	Current approved model
	HV Cable Termination	Cast iron pot head	If removing pot head, install 11 kV working sealing end. In service pot heads to be replaced if in poor condition, e.g. badly rusting, leaking etc. Recommendation is NOT to re-terminate old cable, but cut in a new pole riser from in ground or near ground level, with approved cable.	Current approved model
		Termination without crucifix	Mechanical stress on termination hardware may cause premature failure. There is no program for a retrospective replacement but a crucifix should be fitted in conjunction with other work if it is cost effective.	Current approved model
		Heat shrink or cold shrink cable termination	In high pollution areas a premature breakdown of the insulation may result in a flashover. Replace the termination if it is in poor condition, e.g. signs of tracking or physical damage or decay. Re-terminate if the XLPE end is practical, otherwise cut in a new section of cable. Replace with an approved cable termination.	Current approved model
		Existing termination onto O/H lines that do not have surge arrestors	Add surge arrestors if doing other maintenance, e.g. pole cross arm replacement, etc., only if practical to do so. Refer to Network Standard ENS 3.1.25 surge arrestor requirements.	Current approved model
	Guy	Stiles	Stock may damage the guy due to deterioration of the timber stile. Replace with new timber stile to network standard where required.	Current approved construction standard
			Guy termination may rust off or be removed by third party from guy rod causing pole to lean. Reterminate guy when other work is happening in the vicinity.	Current approved model

Asset Type	Equipment Type	Equipment Sub-type	Issue/Replacement Criteria	Replacement Type
Pillars	Pillars	General	Pillars that have had gardens created around them are not considered a high maintenance priority unless this poses a safety risk or it is likely to cause damage to the components within the pillar. Rectify any dangerous or unsafe pillars.	Current approved model
		Temporary supply pillars	No isolation point exists at the boundary of properties fitted with an aged temporary supply pillar within private property. Fit fuse pillar on boundary to allow removal of the temporary supply pillar. Minor lid repairs can be fixed on site without replacement of the complete pillar.	Current approved model
		Concrete with steel face plate	Potentially unearthed metalwork is accessible to third parties. Replace the complete pillar in conjunction with other substantial repairs or if an upgrade is required at the same site.	Current approved model
		Concrete with aluminium cap	Potentially unearthed metalwork is accessible to third parties. Replace the complete pillar in conjunction with other substantial repairs or if an upgrade is required at the same site.	Current approved model
		Stud pillar	Studs may fail, disconnecting the supply and causing an outage. Replace the complete pillar in conjunction with other substantial repairs or if an upgrade is required at the same site.	Current approved model
		Neutral bars	Some pillars have only been fitted with a small single neutral stud which does not provide sufficient room for multiple neutral connections. A separate multi stud neutral bar should be fitted.	Current approved model
		Service fuses	Tails (supply or load) are corroded causing potential burn off issues. Re-terminate at existing fuse or replace complete fuse in conjunction with any other work at the same site.	Current approved model
		Meter pillars	The Retailer's meter reading contractor is unable to read the meter due to the window in the pillar becoming opaque. Where retaining the old meter pillar and replacing the window is not practical, the pillar should be replaced with a new pillar. Also, if the metering is uncertified, new meters should be installed and the metering certified. Cases where the meters would be shifted to the house are:- - When the old house is removed and a new house built. -Where there is a major alteration to the electrical mains to the installation. For minor repairs to the metering pillar, the metering does not have to be upgraded or certified.	Current approved model

Asset Type	Equipment Type	Equipment Sub-type	Issue/Replacement Criteria	Replacement Type
Ground mounted distribution transformers and switchgear	Transformer	Pad mounted	Rusting of the transformer may allow an oil leak which cannot be repaired easily on site. Extensive rust also may not be able to be repaired on site. Additional electrical load of which the network may not be aware may overload the transformer causing unplanned outages. Engineer a solution and replace the transformer.	Current approved model
		11 kV bushings	A risk of contact with live parts exists from exposed and uninsulated transformer bushings for electrical workers accessing the transformer enclosure. Fit a shroud or replace the transformer while undertaking other substantial repairs or if an upgrade is required at the same site.	Current approved model
		Neutral bars	The potential exists for high resistance neutral connections where neutral lugs have been "stack" connected on stainless steel studs. Lugs are to be fitted directly back to back when carrying out other work within the transformer enclosure.	
		Old kennel type	Access issues may exist due to tight tolerances between the transformer and the kennel cover. If the transformer and/or LV distribution panel needs to be replaced, then upgrade to a standard mini sub and LV panel. Minor maintenance, including kennel repairs and earthing work, can still be carried out without requiring the replacement of the kennel.	Current approved model of mini sub and LV panel.
		Room type	Non standard LV panels compromise the ability to cost effectively add additional outgoing circuits. If the transformer needs to be replaced or the existing LV panel needing significant maintenance, then upgrade the complete unit. Note: Transformers and LV panels are separate items. The upgrading of one does not necessarily mean that the other should be upgraded.	Current approved model of room type transformer. Current approved model of standard LV panel.
		All	Graffiti may cause offense to certain sections of society. This is a social problem as opposed to a systemic equipment issue however graffiti is to be removed or painted over when identified.	
	11 kV Switchgear	All	Excessive partial discharge may indicate catastrophic failure of switch unit is imminent. Replace equipment.	Current approved model
		Wilde unit	Excessive partial discharge may indicate catastrophic failure of unit is imminent. Replace equipment. The current capital project underway will see all of this type removed from system.	Current approved model
		Fuse links	Striker may fall apart. Manufacturer's defect. Reactive replacement upon failure.	
Distribution earthing	Earthing and Bonding	Distribution earth mats	High resistance earth mat may cause electric shock hazard. Upgrade to the current standard and regulatory requirement if not legally compliant or in conjunction with other work, e.g. a replacement or upgrade of the transformer, pole or earthmat.	Current approved practice
		Equi-potential bonding	The potential exists for a third party to sustain an electric shock due to all metalwork not being bonded together. Bond ground mounted equipment to metal covers, if found to be not bonded. Directly bolted on covers are deemed to be electrically bonded. Doors of mini/micro sub to be bonded if found to be not bonded. Note: For the size of earth and bonding conductor as per Network Standard ENS 3.1.95.	Current approved practice

4.3 Asset Replacement and Renewal Policies

Northpower utilises a number of policies, guidelines and processes relating to asset replacement and renewal. These are regularly reviewed and network standards set against them. Consultation with suppliers has resulted in an approved suppliers list and a list of approved equipment.

4.3.1 Policy on Redeployment and Upgrade of Existing Assets

Northpower considers redeployment and upgrade of existing assets to be preferable to the purchase of new assets. The decision on whether to relocate or acquire is based on risk evaluations as well as cost/benefit. We use three primary classes of assets deployed on the network and each class is treated differently with regard to redeployment.

1. Expendable
   Typical expendable items includes cross arms and line hardware. These items are not generally reused largely because they are of relatively low value and their integrity cannot be relied upon once they have been initially deployed. Conductors could be included in this category because generally a long length of conductor replacement is driven by the existing conductor reaching end of life. Alternately, conductor that is replaced due to line alterations is typically of relatively short lengths and good a engineering practice suggests multiple joints are undesirable. There are limited occasions such as in emergency fault conditions or where a temporary line is required, where these items may be redeployed for a short, finite time.
2. Rotable
   The second class of assets are what is termed 'rotable distribution assets'. These are broadly defined as assets that are traceable by way of an individual identifier, such as a serial number, these can be redeployed on the network after having been recovered and refurbished. These include items such as distribution transformers, reclosers and some poles. Generally these items have a relatively high capital cost and a relatively long lifespan or a combination of these criteria.
3. Re-deployable
   The third class of assets that are considered for re-deployment or reuse as an upgrade option are generally those high value items associated with zone substations. Items such as 33/11kV transformers fall into this category. Due to the high capital cost of a new zone substation transformer, a cost benefit analysis is undertaken to evaluate the merits of the refurbishment of a unit approaching end of life. The decision to re-deploy depends on the cost of the refurbishment and the extended life achieved relative to the cost of purchasing a new unit. There are additional zone substation assets of low value which may be kept as strategic spares and included in this are electronic circuit boards for SCADA, communication or protection relay systems.

4.3.2 Policy on Acquisition of New Assets

Northpower will ensure that unless a risk review identifies unacceptable risk and assets have to be replaced, new assets are acquired only when existing assets cannot be redeployed or if using recovered assets would be inappropriate. The guiding principle is to achieve the least lifecycle cost, which includes an implicit recognition that employing used assets carries the risk of higher operating or maintenance costs at a later date.

A policy is in place that governs the acquisition of a third party constructed distribution network. This policy also contains details of capital contributions and transformer capacity charges and is supported by technical and engineering standards to ensure the guiding principle of least lifecycle cost is preserved.

4.3.3 Policy on Adoption of New Technology

Our approach to adopting new technologies is to evaluate the risks associated with the introduction of such technologies against the potential benefits before proceeding. Technologies that Northpower has reviewed in detail and subsequently pursued are trialled to confirm feasibility, meets Network Standards, International Standards and meets health and safety requirements. Northpower endeavours to be a leader in technological improvements in the electrical distribution business.

A change management procedure is used to ensure that the adoption of any new technology or change in existing technology, whether brought about by internal or external influences, is subjected to a robust assessment prior to any implementation. A Network Standards process is in place to assess any suggested or required change, whether it is new technology or modified work practices. The process is cross functional, engaging with network engineers, contractors, procurement and Health and Safety expertise, as required. Any recommended change is required to have final approval from the Network Engineering Manager.

4.3.4 Policy on Disposal of Assets

Northpower will always aim to dispose of surplus assets in a responsible and environmentally appropriate manner. Northpower will ensure that materials such as oil, lead, PCB's and asbestos which may cause harm are disposed of in accordance with ISO 14001.

4.4 Asset Replacement and Renewal by Network Category

Preventative maintenance inspections highlight areas where renewal and refurbishment is required. Historical information also provides some indication of likely expenditure for any particular category on the assumption that the preventative maintenance inspections or remedial maintenance responses do not identify any potential systemic issues. The history of performance for each asset fleet will establish a reliability profile. Northpower has commenced a move towards condition based management, which will lead to more optimal renewal timelines for assets. To date much of our renewal work has either been driven by rectification of defects, addressing risks associated with deteriorating condition (e.g. Cu and ACSR conductor replacements) or age based replacement based on accepted industry standard asset lives.

The sections below discuss renewal approaches by asset category.

4.4.1 Distribution Network:

4.4.1.1 Overhead Structure & Conductors

The renewal and refurbishment expenditure on the distribution network mostly include poles, cross arms, insulators, fuses and conductor. Expenditure on vegetation control is also included in the broad category of 'asset refurbishment' (separate to the reactive vegetation management).

Pole replacements result from preventative maintenance inspections. The replacement target for wood poles was reduced in past years, as a direct result of focus on the health of these assets. Spalling concrete poles continue to be routinely renewed as a result of the preventative maintenance inspections.

Typically identified through the preventative maintenance inspections, cross arms are usually renewed on the basis of "opportunity maintenance" and replaced in association with related assets. The majority of the crossarm replacement work has been reclassified as a project with the associated expenditure capitalised. This aligns with our moves to establish crossarms as a separate asset category.

Insulator replacements are driven by preventative maintenance inspections and replacements typically occur as a result of age related potential failures such as cracking. Asset renewals for these items are conducted in conjunction with other maintenance tasks on associated structures.

The majority of conductor renewal is covered in the capital expenditure table. Northpower has a budgetary allowance for conductor testing, to determine replacement requirements.

Northpower has continued to apply a more proactive approach to vegetation management, under the framework of the Tree Regulations. The aim is that all Northpower feeders are inspected and the required follow up work executed within each three year period. We co-operate with landowners along the targeted feeder to ensure effective vegetation clearance.

4.4.1.2 Distribution Switchgear

Northpower's fleet of overhead switchgear is largely made up of enclosed gas filled switches (load break switches), which were introduced to phase out air break switches over the last 10 years. At present, a significant proportion of the expenditure is targeted at dealing with design defects (weather tightness of operational mechanism and orientation of the control module).

4.4.1.3 Distribution Transformers

Distribution transformers can be pole or ground mounted. Pole mounted transformer replacement and renewal is determined through assessment of the condition, alternatively through customer load growth. Failures resulting from lightning strikes are another reason for replacement.

For ground mounted transformers there is ongoing incremental expenditure on aspects such as lock replacements, labelling and signage. A significant proportion of the expenditure is targeted at dealing with graffiti and vandalism on this asset group.

4.4.1.4 Distribution Earthing

The level of maintenance expenditure for replacement and renewal of distribution earthing continues to sit at lower levels than the historical annual expenditure. The bulk of expenditure in this area is capitalised.

4.4.1.5 Distribution Regulators

Preventative maintenance inspections on regulators highlight issues such as corrosion or paintwork deterioration. Where this defect is greater than can be remedied on site, the unit is swapped out and refurbished back in the work shop. The level of expenditure on regulators is consistent with maintaining regulators in good condition through timely follow up maintenance as unplanned regulator outages are difficult to repair without impacting supply to customers.

4.4.1.6 Cables and Pillar Boxes

Replacement of distribution cables is mostly driven by condition and defects identified through inspections e.g. signs of tracking.

The key driver for the refurbishment and renewal of low voltage pillars is safety. These pillar box units are in readily accessible areas as well as road frontages and are vulnerable to damage when located alongside driveways. A programme is in place to replace known defective pillars that are identified through the preventative maintenance inspections. The majority of expenditure with pillar replacement is capitalised.

4.4.2 Subtransmission Network

Northpower's subtransmission line and cable assets are well maintained, however a significant component of these assets is approaching end of life and provision has been made in the 10 year plan to effect replacement of end of life overhead conductor and underground cable. Approximately 25% (70km of a total of 293km) of subtransmission overhead line conductor is 60 years or older and sample testing of this conductor will be carried out starting in 2018 to determine the condition of the conductor for replacement planning purposes. Similarly, there are 4 x 33kV paper-oil cable circuits (a total of 8.3km) that form part of the Whangarei City subtransmission network that are approaching end of life. The oldest of these cable circuits were commissioned in 1965 work will be carried out during the course of the next few years to accurately establish cable condition and risk of failure in order to plan for their replacement.

4.4.3 Zone Substation Assets:

4.4.3.1 Building and Grounds

Follow up maintenance attending to gate, fence, lock, signage and earthing refurbishment and renewals, reflects our priority for safety related maintenance.

4.4.3.2 Power Transformers

A major focus with these assets continues to be with rust treatment, painting, and panel repairs. Transformer oil is tested annually and oil found to be out of specification is routinely replaced. Dissolved gases found in the oil will generate a more detailed inspection and maintenance.

Northpower's policy of rotating transformers between zone-substations means that the power transformers are ageing. In addition, the smaller remote substations have ended up with the older and smaller transformers. A number of these substations are single transformer sites, increasing risk of outage. While the transformers are subject to a rigorous inspection and servicing regime, the risk of component or winding failure increases over time.

The table below lists substations with ageing power transformers. The traffic light colours reflect the age of transformers with respect to end of life condition over the 10 year planning period. Where the transformer life expectancy has been extended due to mid-life refurbishment, this has been taken into account.

Substation		FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
Hikurangi	T1	🟢	🟢	🟢	🟠	🟠	🟠	🟠	🔴	🔴	🔴	🔴
Hikurangi	T2	🟢	🟢	🟢	🟠	🟠	🟠	🟠	🔴	🔴	🔴	🔴
Kensington	T1	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟠	🟠
Kensington	T2	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟠	🟠	🟠	🟠
Maungaturoto	T1	🟢	🟢	🟢	🟢	🟢	🟢	🟠	🟠	🟠	🟠	🔴
Maungaturoto	T2	🟢	🟢	🟢	🟢	🟢	🟢	🟠	🟠	🟠	🟠	🔴
Ngunguru	T1	🟠	🟠	🔴	🔴	🔴	🔴	🔴	🔴	🔴	🔴	🔴
Onerahi	T1	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Onerahi	T2	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Parua Bay	T1	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Poroti	T1	🟢	🟢	🟢	🟠	🟠	🟠	🟠	🔴	🔴	🔴	🔴
Portland	T1	🟠	🟠	🔴	🔴	🔴	🔴	🔴	🔴	🔴	🔴	🔴
Ruakaka	T2	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Whangarei South	T1	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Whangarei South	T2	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢

🟢 *Good condition* 🟠 *Nearing end of life* 🔴 *End of life*

The 10 year plan includes projects to replace end of life transformers and the transformer age traffic light colours in the following table show the results of the planned replacement program (new transformers only) over the 10 year period. The program includes the purchase of new transformers as well as refurbishment of existing units together with rotation of transformers at some stations to satisfy future capacity requirements.

Substation		FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
Hikurangi	T1	🟢	🟢	●	●	●	●	●	●	●	●	●
Hikurangi	T2	🟢	🟢	🟢	●	●	●	●	●	●	●	●
Kensington	T1	🟢	🟢	🟢	🟢	🟢	🟢	🟢	●	●	●	●
Kensington	T2	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟠	●	●	●
Maungaturoto	T1	🟢	🟢	🟢	🟢	🟢	●	●	●	●	●	●
Maungaturoto	T2	🟢	🟢	🟢	🟢	🟢	🟢	●	●	●	●	●
Ngunguru	T1	🟠	🟠	●	●	●	●	●	●	●	●	●
Onerahi	T1	🟢	●	●	●	●	●	●	●	●	●	●
Onerahi	T2	🟢	●	●	●	●	●	●	●	●	●	●
Parua Bay	T1	🟢	🟢	🟢	🟢	●	●	●	●	●	●	●
Poroti	T1	🟢	🟢	🟢	🟠	🟠	🟠	●	●	●	●	●
Portland	T1	🟠	🟠	🔴	🔴	🔴	🔴	●	●	●	●	●
Ruakaka	T2	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	●
Whangarei South	T1	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	●
Whangarei South	T2	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢	●

🟢 *Good condition* 🟠 *Nearing end of life* 🔴 *End of life*

Other items, such as renewal of cable terminations, refurbishment of cooling fans and the replacement of silica gel, typically fall into the renewal and refurbishment category.

4.4.3.3 Indoor Switchgear

Northpower is replacing old oil insulated 11kV switchboards with modern fixed pattern vacuum or SF6 switchboards. The first six boards were completed in 2007-2010. Eight 11kV switchboards are scheduled to be replaced over the next 10 years.

In addition, there are three 33kV switchboards are planned for replacement.

A number of 11 kV switchboards will reach end of life within the next 10 years and a programme has been developed to replace ageing assets as shown below. Ngunguru, Poroti and Whangarei South substations all have reused switchgear. The table shows the risk profile (age related) currently, in year 5, and at the end of the 10 year period. The red colouring indicates beyond end of life assets, based on a 45 year asset life.

Substation	Current Risk	FY 2023 (year 5)		FY 2028 (year 10)	
		Do Nothing	Proposed	Do Nothing	Proposed
Alexander St	🟢	🟢	🟢	🟢	🟢
Bream Bay	🟢	🟢	🟢	🟢	🟢
Dargaville	●	🟢	🟢	🟢	🟢
Hikurangi	🔴	🔴	●	🔴	●
Kaiwaka	🔴	🔴	●	🔴	●
Kamo	●	●	🟢	🟢	🟢
Kioreroa	🟢	🟢	🟢	🟢	🟢
Mangawhai	🟢	🟢	🟢	🟢	🟢
Mareretu	🟢	🟢	🟢	🟠	●
Maungatapere	●	🟢	🟢	🟢	🟢
Maungaturoto	🟢	🟠	🟠	🔴	●
Ngunguru	🟢	🟠	●	🔴	●
Onerahi	●	🟢	🟢	🟢	🟢
Parua Bay	●	🟢	🟢	🟢	🟢
Poroti	🟢	🟠	●	🔴	●
Portland - Chip Mill (Marasumi)	🟢	🟢	🟢	🟢	🟢
Ruakaka	●	🟢	🟢	🟢	🟢
Ruawai	🔴	🔴	●	🔴	●
Tikipunga	●	🟢	🟢	🟢	🟢
Whangarei South	🟢	🟠	●	🔴	●

🟢 *Good condition* 🟠 *Nearing end of life* 🔴 *End of life*

4.4.3.4 Outdoor Switchgear

Northpower has been replacing 33kV breakers that have reached end of life since 2000 and plans to continue this practice.

4.4.3.5 Outdoor Structures

The thermal imaging, acoustic and partial discharge testing accounts for the majority of the tasks completed for this group. The balance is primarily concerned with the physical refurbishment of the structure, replacing rusting or corroded components.

4.4.3.6 Earthing

Almost all of the forecast spend for earthing is safety related. Items such as connections, labels and signage make up the follow up work for this asset class.

4.4.3.7 Outdoor voltage and current Transformers

Thermal imaging and acoustic testing accounts for the majority of the tasks completed for this group.

4.4.3.8 Load Control Plant

The forecast refurbishment and renewal spend in this area will remain fairly stable as the plant age profile improves. The preventative maintenance checks will highlight any potential issues and allow a timely resolution prior to them manifesting as faults.

4.4.4 Secondary System Assets:

4.4.4.1 Distribution Management System

Maintenance Plan

Northpower makes extensive use of electronic field capture devices. These can validate data at the source and electronically send it to backend systems. Data accuracy is also monitored by random monthly audits, while data completeness and timeliness are monitored using internal system checks.

Replacement Plan

Replacement of the Spectrum Power TG system will be contingent on whether the system in its current state of development can continue to meet Northpower's ongoing business requirements. This would include the support for an Advanced Distribution Management system (ADMS) which will include an outage management system that will more quickly identify the location of faults and provide enhanced reporting to customers.

Northpower will replace RTUs as part of other network projects where the requirements of the network equipment being installed cannot be met by existing RTUs. Otherwise we progressively replace the older RTUs at end of life.

GIS technology will continue to be monitored and a review of any replacement options is planned as part of the implementation of a ADMS.

4.4.4.2 Telecommunications

Maintenance Plan

All fibre assets are maintained by Northpower's fibre division.

Northpower maintains its own radio network assets, which involves periodic visits to each radio site for proactive maintenance. In these visits, visual inspections are performed, alarm logs checked and performance histories are reviewed. In most cases remote monitoring of radio equipment is limited.

Northpower's technicians also respond to faults on the radio networks, which includes the SCADA and RT networks, from their base in Whangarei. To support this capability Northpower maintains a small holding of essential radio spares.

Replacement Plan

Most communications assets are not proactively replaced due to age. Where economic, faulty equipment is repaired and returned to service. Outside of equipment failure, communications equipment is usually replaced due to technical obsolescence.

If not replaced earlier, as legacy serial data equipment reaches the end of its serviceable life, it will be replaced with standards based IP equipment. A replacement plan for the analogue RT network is to be developed by Northpower in 2018.

4.4.4.3 Backup Control Room

Northpower is reviewing the capability of the backup control room at Tikipunga. The control room does not have the full operating capability of the main control room and the plan is to establish a fully functional backup control room.

4.4.4.4 Protection Relays

Relay indication and setting adjustments to ensure the components remain in specification for the network requirements accounts for the forecast refurbishment spend in this area. Northpower is in the process of replacing electromechanical relays with numeric relays.

4.4.4.5 Auxiliary Battery Supplies

Although there is a capital replacement program for battery banks the renewal and refurbishment, maintenance is driven from condition assessment identified through the routine preventative maintenance inspections.

4.4.4.6 Mobile Substations and Generators

Consideration will be given to the purchase of further mobile substations and/or diesel generators to be used to mitigate single line planned outages and unplanned outages within the planning period.

4.5 Non-Network Assets Development, Maintenance and Renewal

Non-network assets include items such as IT systems, asset management systems, office buildings, depots and workshops as well as furniture and equipment, motor vehicles, tools, plant and machinery.

Short to medium term capital expenditure on Network related systems include:

- replacement of the existing Outage Management tools for planning, notification and management of outages and outage statistics; and
- replacement of the existing Asset Management System and expansion of formal document and records storage systems.

The policies that guide the approach, maintenance and replacement of these non-network assets are all based on GAAP. From a maintenance perspective, the likely expenditure over the AMP period is consistent with that undertaken currently. Other than the expenditure mentioned above, no material capital expenditure is planned for these classes of assets other than that which could normally be expected following disposal of aged assets in accordance with company policy.

A company motor vehicle policy aims to meet the company's operational and financial objectives and to achieve consistency in the way vehicles are purchased, leased, assigned and used throughout the company. Northpower has a policy of NCAP 4 or better safety standard for vehicles.

Security and access control has been implemented at the main office and at a number of zone substations. It is planned for the system to be rolled out across the balance of the zone substations over the next few years.

4.6 Operational Expenditure per Asset Fleet or Activity

The following table provides a breakdown of operational expenditure by asset fleet or activity for each of the maintenance categories.

Expenditure Category	Budget*	Percentage
Follow Up Maintenance		
Battery Banks	10,000	0.2%
Circuit Breakers	40,000	1.0%
Communications	10,000	0.2%
Dist Earthing	10,000	0.2%
Grnd Mount Subs	100,000	2.4%
Multiple Assets	120,000	2.9%
Outdoor CTs VTs	2,000	0.0%
Outdoor Structures	40,000	1.0%
Overhead Lines	750,000	18.2%
Overhead Switches	420,000	10.2%
Pillars	130,000	3.2%
Protection Relays	5,000	0.1%
Regulators	5,000	0.1%
Ripple Plant	3,000	0.1%
Subtrans Cables	15,000	0.4%
Vegetation	2,300,000	55.8%
Zone Sub Earthing	3,000	0.1%
Zone Sub Buildings and Grounds	70,000	1.7%
ZSub Transformers	90,000	2.2%
	4,123,000	**100.0%**

Preventative Maintenance		
Circuit Breakers	112,796	6.3%
Communications	15,687	0.9%
Dist Earthing	430,320	24.2%
Grnd Mount Subs	164,500	9.2%
Oil Containment	450	0.0%
Overhead Lines	529,648	29.7%
Overhead Switches	3,578	0.2%
Pillars	195,752	11.0%
Protection Relays	45,800	2.6%
Regulators	7,923	0.4%
Ripple Plant	22,945	1.3%
Subtrans Cables	31,356	1.8%
Zone Sub Buildings and Grounds	182,791	10.3%
ZSub Transformers	37,227	2.1%
	1,780,773	**100.0%**
Remedial Maintenance		
Battery Banks	10,000	0.8%
Capacitor Banks	1,000	0.1%
Circuit Breakers	10,000	0.8%
Communications	30,000	2.3%
Dist Earthing	1,000	0.1%
Grnd Mount Subs	8,000	0.6%
Multiple Asset	5,000	0.4%
Oil Containment	2,000	0.2%
Outdoor CTs VTs	1,000	0.1%
Outdoor Structures	1,000	0.1%
Overhead Lines	800,000	60.5%
Overhead Switches	10,000	0.8%
Pillars	35,000	2.6%
Protection Relays	5,000	0.4%
Regulators	1,000	0.1%
Ripple Plant	2,000	0.2%
Subtrans Cables	12,000	0.9%
Underground Cables	125,000	9.5%
Vegetation	200,000	15.1%
Voltage Complaints	2,000	0.2%
Zone Sub Earthing	1,000	0.1%
Zone Sub Buildings and Grounds	35,000	2.6%
ZSub Transformers	25,000	1.9%
	1,322,000	**100.0%**

Value Added Work		
Cable Location	180,000	19.1%
Customer Equipment	450,000	47.8%
Data Capture/Retrieval	18,000	1.9%
High Loads	18,000	1.9%
Load Checks	20,000	2.1%
NW Initiated Field Switching	2,000	0.2%
Safety Disconnects	200,000	21.2%
Vegetation	54,000	5.7%
	942,000	**100.0%**

** Dollar amounts exclude Management Fee*


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Section 5: Service Levels and Performance

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Service Levels and Performance - Section 5

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Section 5: Service Levels and Performance

5.1 Introduction

Northpower's vision is to be a high performing utility network, providing a safe and reliable service. This is reflected in the set service level targets which are monitored. Targets have been classified into two principal groups: customer orientated and reliability performance. Both groups include subjective service levels (measured by way of surveys) as well as technical service levels, which are based on statutory or regulatory service level requirements.

5.2 Network Customer Satisfaction

Northpower's owners are also its end-use customers represented by the NEPT and the network performance targets are reflective of the input provided by the NEPT. The needs of customers/owners are understood by way of regular customer surveys (monthly and annually), market research, convening special interest/community groups as well as direct consultation and feedback.

Customer Perception

Each year Northpower undertakes an extensive survey of Commercial and Residential customers, by which it derives its annual customer satisfaction metric. The following two graphs are from the 2017 Customer Survey and indicate that Northpower has a strong reputation with Commercial and Residential customers with its focus on providing high quality service as being a key driver. In the graphs the Impact % is the relative impact on the business of each performance attribute and the performance % is the measured customer assessment.

The two most important elements influencing reputation are 'Being professional', and 'Focus on delivering quality services', and importantly, performance is strong on both of these

Performance measurement: Commercial image and reputation(1)(2)(3)

Commercial

	Impact	Performance	2016	Whangarei	Kaipara	Urban	Rural
Overall image and reputation	60%	80%	n/a	78%	82%	81%	76%
Being highly professional	31%	76%	73%	72%	82%	76%	74%
Their focus on delivering quality services	30%	77%	n/a	73%	82%	79%	71%
That they can be trusted to do the right things for the community	17%	79%	n/a	75%	86%	84%	69%
Caring about the environment	12%	72%	63%	63%	90%	77%	57%
Caring about the local Northland community	5%	75%	72%	75%	76%	78%	68%
Being progressive, positive and up with the times	5%	79%	68%	79%	80%	81%	76%
Having strong leadership	NCI(4)	77%	n/a	74%	81%	79%	69%
Their commercial performance	NCI	75%	69%	75%	76%	82%	58%

NOTES:

1. *Sample: Total commercial= 100, Commercial urban n=74, Commercial rural n=26, Commercial Whangarei n=57, Commercial Kaipara n=43*
2. *IR1. For the next few questions I'd like you to think about Northpower's image and reputation. Using a 1-10 scale where 1 means 'Extremely poor' and 10 means 'Excellent', how would you rate Northpower for each of the following?*
3. *IR9. And when you think about all of these things, the quality of their service, their leadership, vision, how they contribute to the community and the trust you have in them, overall how would you rate the image and reputation of Northpower?*
4. *NCI: No current impact*

Residential customers also have a positive view of Northpower's reputation and in particular, evaluate performance highly on the two key drivers, professionalism and focus on quality

Performance measurement: Residential image and reputation[1][2][3]

Residential

	Impact	Performance		Whangarei	Kaipara	Urban	Rural
Overall image and reputation	60%	75%	n/a	75%	76%	77%	73%
Being highly professional	31%	78%	79%	78%	79%	79%	78%
Their focus on delivering quality services	30%	76%	n/a	76%	77%	76%	77%
That they can be trusted to do the right things for the community	17%	77%	n/a	77%	79%	77%	77%
Caring about the environment	12%	66%	64%	65%	72%	69%	63%
Caring about the local Northland community	5%	77%	75%	77%	77%	79%	74%
Being progressive, positive and up with the times	5%	71%	76%	70%	76%	74%	69%
Having strong leadership	NCI[4]	76%	n/a	76%	76%	77%	75%
Their commercial performance	NCI	77%	76%	76%	80%	77%	77%

NOTES:

1. *Sample: Total Residential n= 300, Residential urban n=164, Residential rural n=136; Whangarei n=160, Kaipara n=140;*
2. *IR1. For the next few questions I'd like you to think about Northpower's image and reputation. Using a 1-10 scale where 1 means 'Extremely poor' and 10 means 'Excellent', how would you rate Northpower for each of the following?*
3. *IR9. And when you think about all of these things, the quality of their service, their leadership, vision, how they contribute to the community and the trust you have in them, overall how would you rate the image and reputation of Northpower?*
4. *NCI: No current impact*

As shown below Northpower customers continue to rate reliability of supply and fast restoration of power when outages occur as the most important service attributes. Northpower therefore continues to make these requirements a priority. This trend is unchanged from previous years.

The majority of both residential and commercial customers state that the reliability of supply and avoidance of power outages is far more important to them than other service attributes

Importance sought in a lines company: Stated[1][2]

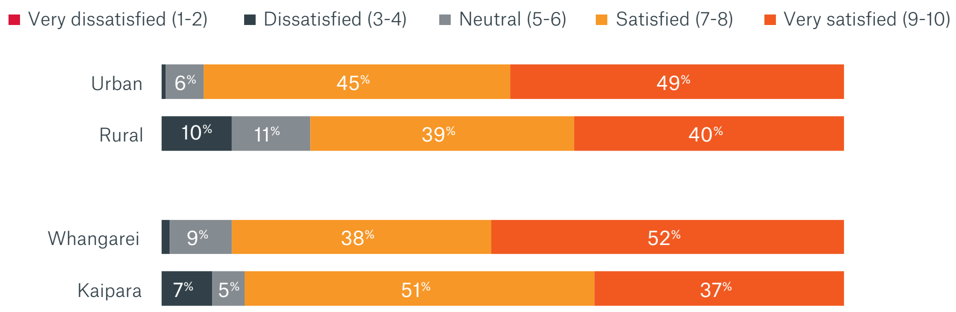
	Commercial: % Identifying as important	Residential: % Identifying as important
Reliable/no power cuts	71%	68%
Quick response/fix cuts quickly	25%	38%
Fair pricing or line charges/cost efficient	26%	26%
Maintaining lines and	16%	27%
Friendly/helpful/hassle free service	20%	19%
Provide information/communication	9%	15%
Power quality (e.g. flickers, dips, voltage	11%	13%
Safety	5%	12%
Pay dividends (Northpower Trust	6%	10%
Forward	4%	9%
Easy to contact	3%	9%
Environmentally friendly	4%	7%
Involvement in the local community	5%	6%
Other (SPECIFY)	9%	8%
Don't know	10%	3%

NOTES:

1. *Sample: 2017 Total n=400, Commercial n=100, Residential n=300*
2. *CP2. Remembering that Northpower is an electricity lines company and is not your energy retailer (or responsible for your energy bill), what are the most important things you look for in a lines company? What else?*

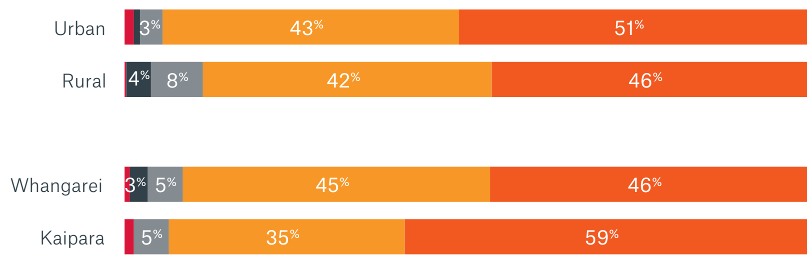
5.3 Customer Satisfaction Survey

The 2017 Customer survey shows a high level of overall satisfaction with Northpower across both commercial and residential customers. In particular, the overall satisfaction measure for commercial customers showed an improvement in 2017 from the past year to 89% satisfied from 79% the previous year. The graph below shows the commercial survey results broken down by urban / rural and by district segments.



Overall Satisfaction Commercial

The graph below shows the residential customer satisfaction survey results. Over the past year Northpower's overall Residential satisfaction has improved from 88% to 92%, which is shown in the graph below, broken down by urban / rural and by district segments.



Overall Satisfaction Residential

Improvement Initiatives

Feedback from customers, including those from the 2017 Customer Survey, consistently indicates that the key attributes valued by customers are reliability of supply, responsiveness (quick restoration), fair pricing and the maintenance of infrastructure. Customer feedback has further indicated that they are seeking real time information of network outages, planned works, and of service requests by way of communication channels that we are still developing.

In terms of improving fault response, two main initiatives continue to be rolled out across the 11kV network. These are the installation of remote controlled switches and of fault passage indicators at strategic locations on the network. The technology allows a more rapid isolation of the faulted section of line. Supply can also be restored more rapidly to the unaffected sections of the network impacted by the original fault.

Security of supply is closely allied with reliability and fault response time. Higher levels of supply security enable supply to be restored via an alternative route or source while the fault is located and repaired. In other cases planned redundancy enables an asset outage to avoid interruption to supply.

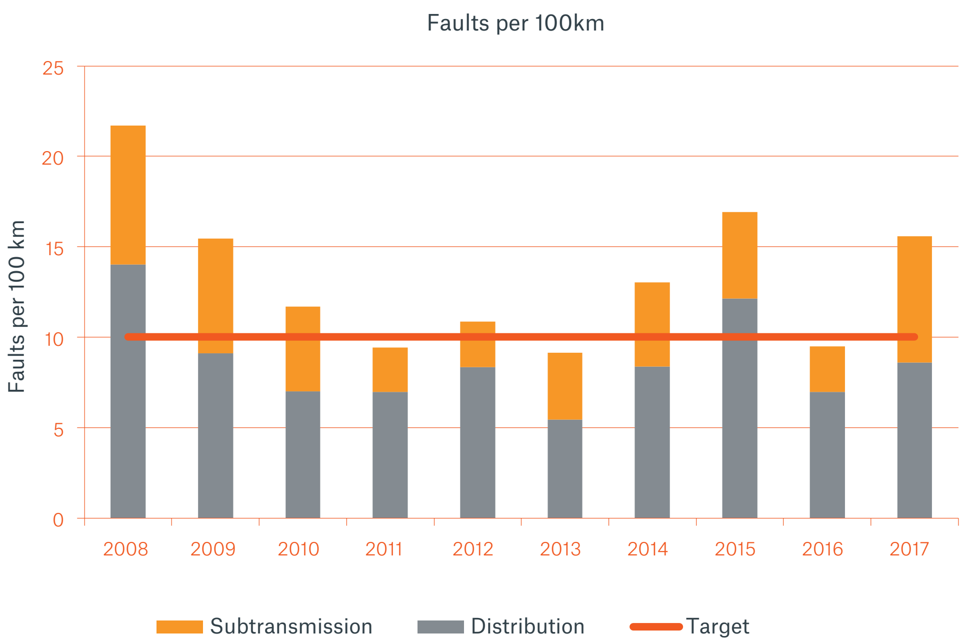
5.4 Network Outages and Restoration

5.4.1 Planned Outages

Northpower advises customers of planned shutdowns for maintenance or other planned work, by way of shutdown notification. Mail outs provide the reason for the shutdown as well as the planned start and finish times. For our customers, the restoration of power on or close to the advertised time is very important. Planned shutdowns not completed within 15 minutes of the advertised restoration time are deemed to have failed to meet customer requirements. The target is to have less than 50 shutdowns (5%) per annum that exceed the 15 minute limit with a long term goal of reducing the number to 30.

5.4.2 Faults

A fault is classified by the Commerce Commission as "a physical condition that causes a device, component or network element to fail to perform in the required manner". Northpower reports on the performance measure of customer faults per 100km, based on the Commerce Commission specifications for fault outages. Northpower's target for faults per 100km is 10 or less per year. As can be seen in the following graph, the average number of faults per km is generally higher on the distribution network than on the subtransmission network. Over the last 10 years the reason the target of less than 10 faults per 100km was not achieved was due to extreme weather conditions.

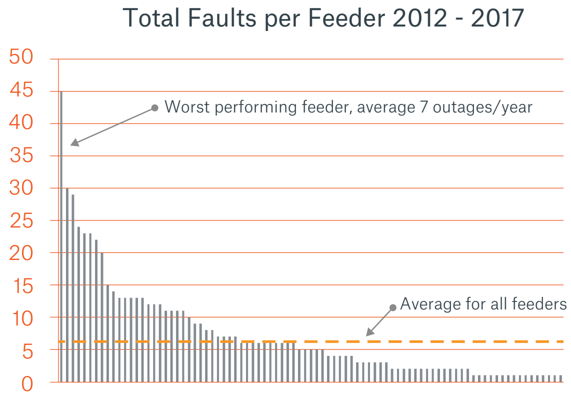


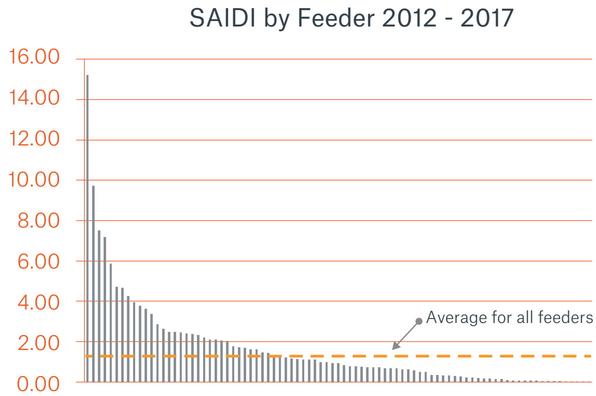
Faults per 100km 2008 to 2017

Future years targets will be similar to or the same as current targets, largely due to feedback from customers who have indicated that the current level of service for the price paid is acceptable.

Targets are set for the network as a whole (rather than different targets for different parts) and Northpower strives to meet these targets understanding that some areas may be more challenging to manage and may therefore require additional resources or effort.

A number of customers are connected to relatively unreliable feeders. The graphs below summarise outage information by feeder. The worst performing feeder has approximately seven outages per year, whereas the average is close to one per year. We have increased our annual vegetation management spend and are increasing our overhead line replacement budgets to target improvements to reliability, particularly for these feeders.





Total faults and SAIDI over five years, by feeder

5.4.3 SAIDI, SAIFI and CAIDI Indices

Reliability of supply (frequency and duration of faults) is measured by Network performance indicators SAIDI, SAIFI and CAIDI. Northpower's current targets for SAIDI are as follows:

SAIDI (planned interruptions): less than 85 per year

SAIDI (unplanned interruptions): less than 90 per year

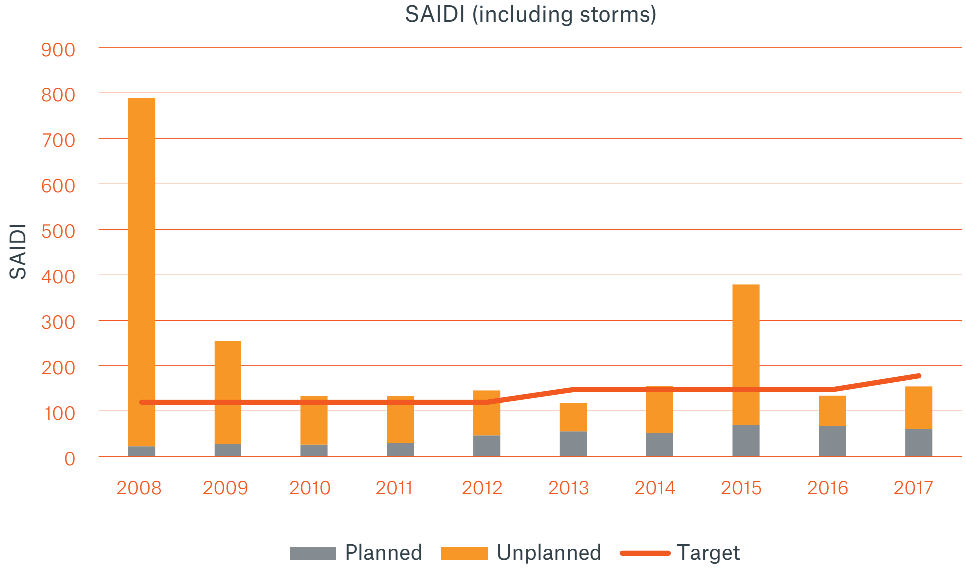
SAIDI (total interruptions): less than 175 per year

The change of approach may impact the Planned and the Total SAIDI numbers in future years and Northpower increased its planned SAIDI target in 2017 in anticipation of these changes taking effect.

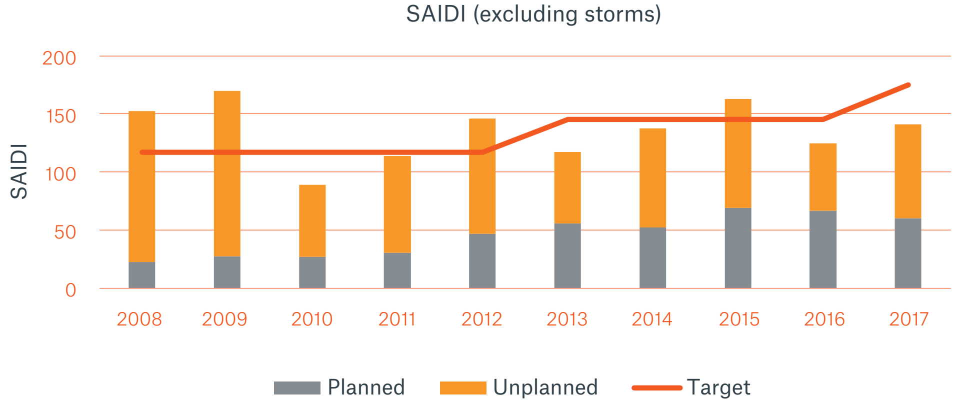
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
SAIDI	761.0	226.5	105.3	102.3	99.5	61.2	103.6	310.0	67.3	94.4
SAIFI	4.5	3.1	2.2	2.1	2.3	1.6	2.1	3.3	1.89	2.7
CAIDI	170.4	73.8	48.0	49.7	43.1	39.2	49.4	93.0	35.6	34.6

Unplanned SAIDI, SAIFI and CAIDI trends (note these are financial reporting years i.e. April to March)

The following graphs show annual planned and unplanned SAIDI results with and without the effect of major storms.

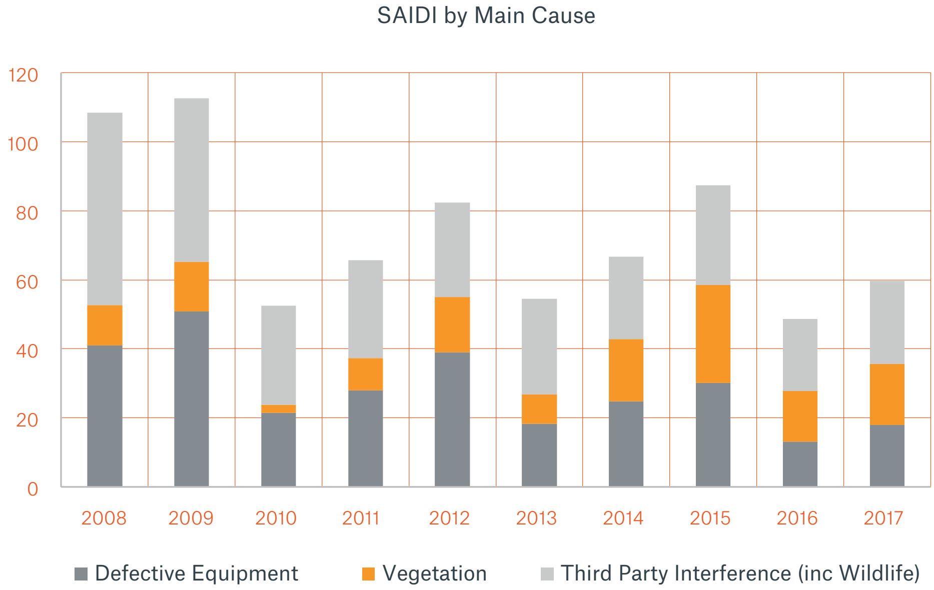


SAIDI Including Storms



SAIDI Excluding Storms

With the impact due to storm damage removed (second graph) it can be seen that total SAIDI has shown an increasing trend since 2010. This is partly due to an increase made in the target, after 2013 to accommodate a greater number of planned shutdowns associated with a programme of switch upgrades and conductor replacements.



Analysis by Cause of Interruption for 2017				
Cause of Interruption	No. of Interruptions		Impact of Duration	
	No.	Proportion of Total	Customer Minutes	Proportion of Total
Unknown/Other	79	23%	709,322	13%
Vegetation	51	15%	1,017,556	19%
Lightning	16	5%	58,952	1%
Defective Equipment	101	29%	1,031,598	19%
Adverse Weather	38	11%	1,082,238	20%
Adverse Environment	5	1%	51,648	1%
Human Error	5	1%	97,074	2%
Third Party Interference	37	11%	904,647	17%
Wildlife	13	4%	471,296	9%

Northpower has historically focused on SAIDI as the high level key performance indicator, as it reflects network reliability and response time.

In order to meet the customers' most important requirements Northpower continues to make a concerted effort to improve reliability of supply and fault restoration times. To this end we:

- Continue to focus on best practice asset management with a view to improving preventative maintenance routines, reliability of supply and fault response are closely linked to the quality of asset management;
- Continue to review our Service Level agreement to Northpower Contracting to encourage continual improvement of service delivery;
- Comply with our Tree and Vegetation Policy ENS 09 01 005, that requires pruning to ensure vegetation does not grow into the Growth Limit Zone through a programme of regular inspections;
- Continue to monitor improvements in technology and plan and initiate projects designed specifically to improve reliability; and
- Proactively work with tree owners to mitigate the potential impact of vegetation growth on the network.

Section 5 - Service Levels and Performance

The targets for SAIDI and SAIFI are presented in Schedule 12d of Appendix C. The targets for the next 6 financial years are presented for both planned and unplanned in the table below.

		2018	2019	2020	2021	2022	2023
SAIDI	Planned	85.00	95.00	100.00	100.00	100.00	100.00
	Unplanned	90.00	90.00	90.00	90.00	90.00	90.00
SAIFI	Planned	0.24	0.27	0.30	0.30	0.30	0.30
	Unplanned	2.00	2.00	2.00	2.00	2.00	2.00

5.5 Safety

To ensure that Northpower's network does not present significant risk in terms of public safety and complies with the Electricity Safety Regulations 2010, Northpower has chosen to certificate to NZS 7901:2008 Electricity and Gas Industries – Safety Management Systems for Public Safety. Compliance with this safety standard requires an audit by an accredited auditor to be carried out at least once every 3 years. This ensures we comply with the Electricity (Safety) Regulations 2010.

Northpower is committed to zero harm targets. We want to keep people safe from the electricity network and we operate a number of safety programmes to protect customers, the wider public, children and people working around our assets from the dangers of electricity. In addition, safety incidents are monitored and reviewed to ensure learnings are captured and continuous improvement.

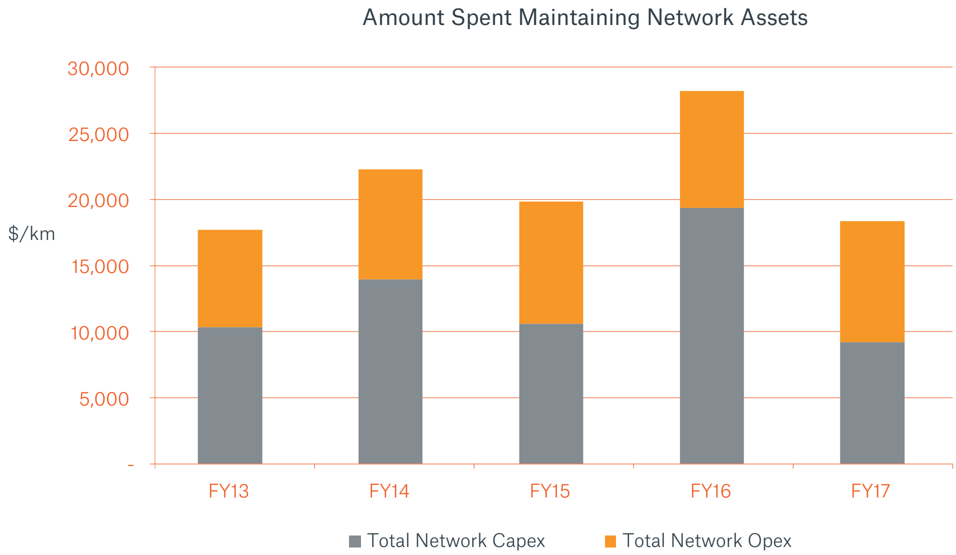
Our preventative maintenance inspections will often identify and attend to unsafe service lines. However there are a large number of privately owned service lines which are not maintained by Northpower. Where an unsafe customer owned service line is identified, we work with the owner and if necessary involve Energy Safety to reach a satisfactory outcome.

There appears to be a lack of understanding among the public that the line supplying low voltage electricity within their property is generally their responsibility. In addition, we promote public awareness of unsafe service lines at community events, newspapers and via other media avenues.

5.6 Financial Performance

5.6.1 Expenditure Metrics

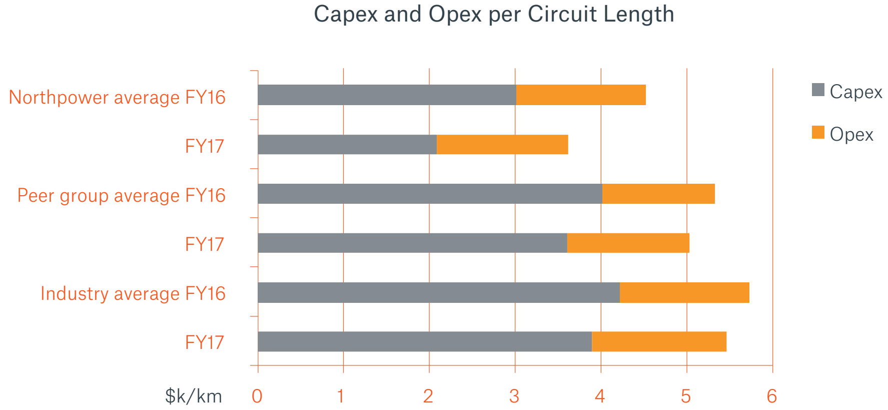
We monitor and benchmark our regulatory reporting indicators such as expenditure per kilometre circuit length and expenditure per customer connection. The following graph shows the annual Opex and Capex for the last 5 years.



Network Expenditure Metrics

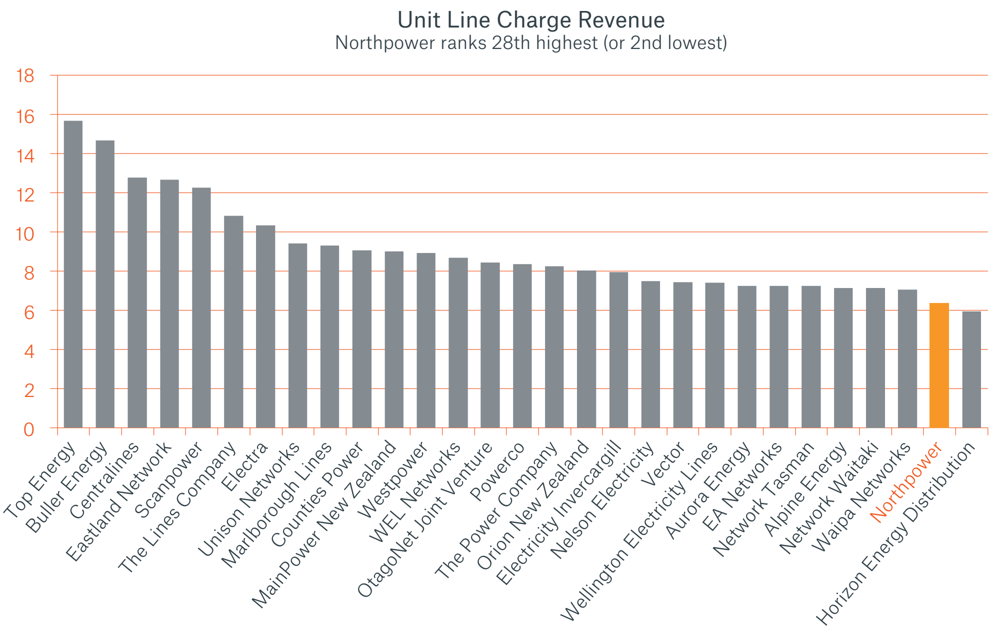
5.6.2 Financial Metrics Compared to Other EDBs

The following graph provides a comparison of Northpower's expenditure against other EDB's as provided through Information Disclosures.



Industry Opex and Capex on a per km basis (Source: PWC ELB Information Disclosure Compendium 2017)

Our position compared to other EDB's in terms of financial performance is summarised in the comparator graph below.

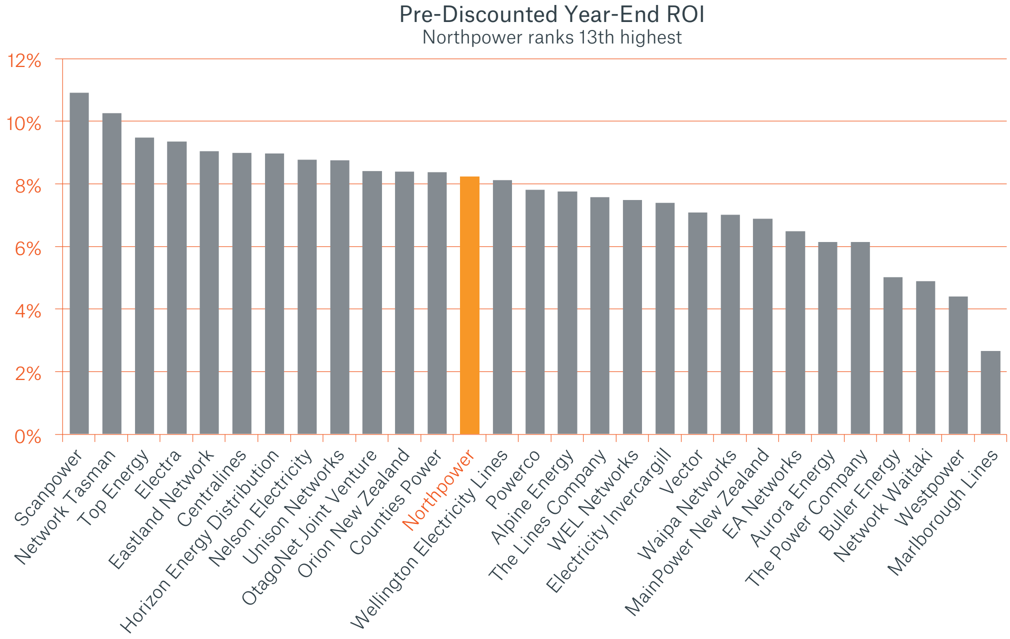


Comparison of Industry Unit Line Charges for 2017 (Source: PWC ELB Information Disclosure Compendium 2017)

5.6.3 Annual Financial Performance Review

The statement of corporate intent, a requirement of the Energy Companies Act 1992, reflects the objectives for the company as required by legislation and the owners. The required return on investment objective set by the owners and Northpower's current SCI specifies an EBIT/Assets of 6% per annum for the network.

The following graph shows Northpower's ROI compared with other EDB's for the 2017 financial year.



Comparison of Industry ROI for 2017 (Source: PWC ELB Information Disclosure Compendium 2017)

5.7 Capital Works Programme

5.7.1 Expenditure Plan

The table below compares actual expenditure with forecast expenditure for the 2016/17 financial year.

Customer connections expenditure (mainly capital contributions) exceeded forecast expenditure due to a significant increase in subdivision activity and inadequate budget provision. System growth expenditure exceeded the forecast mainly due to the delay (and subsequent carryover from the previous financial year) in commissioning the new voltage regulator on the Waipu feeder. Asset replacement expenditure exceeded the forecast due to additional Follow Up asset replacement work being completed to reduce backlog. The large variance in Reliability, Safety and Environment expenditure was due to a significant number of planned projects being delayed due to lack of engineering resource and in some cases a review of requirements. The Dargaville ripple plant relocation to the substation switchroom was delayed due to resource constraints and the deferment of the anticipated Whangarei roading works resulted in under expenditure on asset relocation.

CAPEX Category	Actual ($000)	Forecast ($000)	Variance (%)
Customer Connections	$3,453k	$803k	330%
System Growth	$547k	$238k	130%
Asset Replacement and Renewal	$7,683k	$7,056k	9%
Reliability, Safety and Environment	$627k	$2,629k	(76%)
Asset Relocations	$138k	$258k	(47%)
TOTAL	**$12,448**	**$700k**	**13%**

5.7.2 Physical Performance

The following summary outlines ongoing project work progressed through FY17 and FY18.

5.7.2.1 Asset Replacement and Renewal

- Replacement of 7/064 copper and ACSR 'Gopher' conductor
- Replacement of overhead line poles, cross arms and insulators
- Replacement of underground cable low voltage pillars
- Replacement of earthing systems
- Zone substation RTU upgrades
- Zone substation protection relay upgrades
- SCADA and communications system hardware and software upgrades
- GXP ION meter upgrades
- 33kV circuit breaker replacements
- 11kV ground mounted switchgear replacements

5.7.2.2 Reliability, Safety and Environment

- Zone substation and distribution network security improvements
- Communications network upgrades
- Zone substation oil, fire and explosion risk mitigation
- Remote control of motorised distribution switches
- Distribution feeder reconfiguration and backstopping improvement
- Distribution transformer demand metering
- Fault passage indicator deployment (distribution and subtransmission lines)
- Replacement of 33kV air break switches with enclosed gas switches
- Mareretu substation 33kV switch upgrades
- Busbar arc flash protection installation
- Maungatapere-Dargaville fibre link

5.7.2.3 System Growth

- Zone substation power factor monitoring meter installation
- Distribution transformer and low voltage feeder optimisation
- Waipu feeder 11kV voltage regulator

Progress on Specific Initiatives

A number of projects were aimed at improving reliability and safety on the Northpower network.

Initiative	FY17	FY18	Notes
Urgent safety needs including low lines	Highest priority for resources	Highest priority for resources	On-going
Conductor replacement project *(Capex for safety)*	Year 6 Target 76km of conductor p.a. Plus cross-arms + poles as required	Year 7 Target 76km of conductor p.a. Plus cross-arms + poles as required	In progress
Cross-arm replacements *(Capex for reliability)*	Target is 1900 p.a. including those on conductor project	Target is 1900 p.a. including those on conductor project	In progress
HV switch remote control. *(Capex for SAIDI reduction)*	Year 6 of a 7 year program. Install comms to 30 motorised switches	Year 7 of a 7 year program. Install comms to 30 motorised switches	On-going
RTU upgrades. *(Capex for asset replacement)*	Year 8 of 9 year program	Year 9 of 9 year program	In progress
Red tag poles	Process well established	Process is well established	On-going

Projects deferred

Projects were deferred in the 2017 financial year for reasons including change of regional demand, customer requirements and deferred to review technology or other options. One typical example is the replacement of our asset management system. A project to procure and install a new system has been deferred, enabling Northpower to reset asset management processes and develop a clear understanding of system requirements.

A list of key deferred projects are listed in the following table.

Project	Expenditure Category	Budget (2017) $(000)	Comment
Maunu substation	System Growth	$5,100 (over 2 years)	Was deferred due to reduced level of growth, current projection is it will be required by winter 2020.
Whangarei South – Kioreroa 33kV T stage 2	Reliability, Safety & Improvement	$850	Design started, planned to complete in FY19.
Whakapara feeder express line extension	Reliability, Safety & Improvement	$515	Will need to be completed before Helena Bay zone substation, progressive project starting FY19.
Hikurangi 11kV switchboard upgrade	Asset Renewal	$1,400	An assessment was made on this based on other similar switchgear. Now incorporated into a 11kV switchboard upgrade programme, this switchboard in planned to be upgrade in FY21.
Zone substation neutral earthing resistors	Reliability, Safety & Improvement	$80	Being low risk it was incorporated into the 33/11kV transformer replacement / upgrade programme as there is an overall cost saving to do this. This project will occur progressively in the next 10 years.
Chip Mill substation transformer replacement	Asset Renewal	$394	A strategic spare is available, but has been incorporated into the 33/11kV transformer replacement / upgrade programme. Proposed to be renewed FY24.
Zone substation risk mitigation	Reliability, Safety & Improvement	$700	Delays due to complexity with the civil engineering design. Some substations will have the risk mitigation built into other planned projects e.g. transformer and switchboard upgrades.

Section 7.1 details summarises the capital expenditure and provides details for the capital projects.

5.8 Operational Programme

5.8.1 Expenditure

The table below shows the forecast and actual operational expenditure for the 2017 financial year. As can be seen, with the exception of routine and preventive maintenance, the actual expenditure closely matched the forecasts for each category and overall the expenditure was within 3% of forecast.

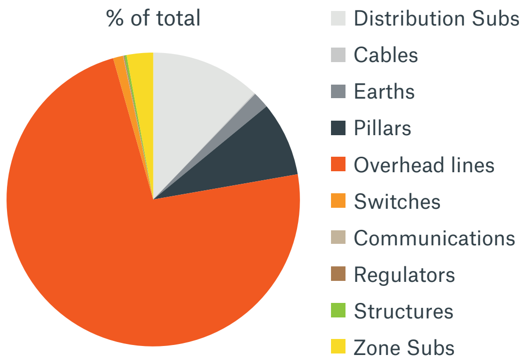
OPEX Category	Actual ($000)	Forecast ($000)
Routine and preventative maintenance	$2,232	$2,657
Refurbishment and renewal maintenance	$2,495	$2,393
Vegetation maintenance	$2,120	$2,010
Fault and emergency maintenance	$1,997	$2,057
TOTAL	**$8,844**	**$9,117**

5.8.2 Routine and Preventative Maintenance

Preventative maintenance inspections are progressing to schedule, with planned maintenance and inspection targets being met. The interval for pole inspections was last year reverted back to a 5 year cycle, down from 7 years and is now in line with accepted practice. Pole inspections continue to identify a large number of equipment defects, where practicable these are rectified in conjunction with the Conductor Replacement and the Reliability Improvement Projects.

The number of known defects on the network are summarised below on an asset group basis, as at the end of the 2017 financial year. As can be seen overhead line defects comprise more than 73% of the total number of defects.

Asset Group	Defects	% of total
Distribution Subs	1,953	12.1%
Cables	20	0.1%
Earths	295	1.8%
Pillars	1319	8.2%
Overhead lines	11,826	73.3%
Switches	179	1.1%
Communications	9	0.1%
Regulators	15	0.1%
Structures	38	0.2%
Zone Subs	470	2.9%



The electronic data capture in use for logging overhead line asset is currently being extended to other asset groups. Northpower is also, as part of the asset management review, now investigating options for further improvements data and asset information capture.

5.8.3 Refurbishment and Renewal Maintenance (Follow Up Maintenance)

The overall quantity of outstanding overhead line defects has not decreased significantly despite a high asset replacement rate, however the planned escalation of the conductor replacement programme is expected to improve the defect rate. During the conductor replacement programme we will rectify any line structure defects.

Following a more concerted effort replacing wooden poles in recent years there has been a significant reduction in urgent replacements.

End of life cross arm and insulator replacement remains a high expenditure category with an estimated 15% of cross arms considered to be end of life and 50% considered to be half-life at the end of 2011. A target replacement rate of 1,800 to 1,900 per annum will prevent further increase in end of life assets. The introduction of steel cross arms in place of hardwood arms in specific applications is underway. This is seen as a long term solution for extending cross arm operational life.

The bulk of poles are concrete, however there are still in excess of a thousand Northpower-owned wooden poles on the network. The number of wooden poles has increased slightly due to a number of shared-service lines being transferred to Northpower ownership. The average life expectancy for wood poles has been established as 40 years, resulting in an average target replacement rate of approximately 75 poles per year over the next 15 years.

The 33kV insulator replacement project has been completed and all 11kV air-break switches have been replaced with fully enclosed SF6 gas switches. Many of the older concrete type 400V pillars have potential for being defective, compromising long term safety. A programme to replace these is ongoing and well advanced and all high risk units have been replaced.

Distribution earthing continues to require increased oversight due to bonding defects and instances of copper theft. The introduction of copper coated steel for earthing requirements helps reduce theft as well as cost.

Ground mounted distribution substations continue to require attention for corrosion, oil leaks and graffiti removal.

The conductor replacement project had been restricted over the last two years due to resource issues, but the project is expected to track back to the original plan starting in the first year of our plan. The planned replacement quantities in the current FY17 year are:

Replacement of 7/.064 HDBC (415km remaining) at 50km per annum

Replacement of ACSR Gopher (1125km remaining) at 10km per annum

5.8.4 Vegetation Maintenance

Vegetation continues to be the largest cause of network outages and despite efforts made to reduce tree contact, the incidence of trees that regularly contact low and high voltage lines remains material. The increased focus on vegetation management has however resulted in a reduction of the number of faults caused by trees. Feeder prioritisation for line patrol by vegetation staff is determined through a reliability improvement project with criteria and priorities reviewed regularly. The vegetation budget will continue to be higher than previous years, following a plan to complete a full cycle of vegetation clearance before further growth dictates the commencement of a new cycle. We expect the vegetation budget to be maintained at current levels for several years.

5.8.5 Fault and Emergency Maintenance (Remedial Maintenance)

Faults associated with overhead lines make up approximately 70% of remedial maintenance expenditure. Improvement in line reliability (pertaining to faults caused by asset condition) and associated decrease in remedial expenditure (excluding severe weather incidents) are expected over time.

Our expenditure on remedial maintenance has been relatively stable over the last years, with the exception of a sharp one year increase in 2014/15 due to significant storm demage. Forecast expenditure (excluding severe weather incidents) is maintained at current levels.

5.9 Asset Management

5.9.1 Benchmarking

Northpower is certified to ISO 9001, ISO 14001 and the network is NZS 7901 certified which underpins a commitment to continuously improve systems and processes. For this purpose Northpower also works in and with the electricity supply industry to share knowledge and implement improvements wherever possible.

Benchmarking to ISO 55000 (international asset management standard) is seen as a way of measuring Northpower's asset management systems against international best practice and one of Northpower's objectives is to be in a position to achieve ISO 55000 accreditation.

Northpower undertakes detailed reviews of its asset management system every two years and updates systems based on recent learnings and best practice within the distribution industry.

Northpower also completes an Asset Management Maturity (AMMAT) assessment every two years as part of the AMP preparation. Schedule 13 of Appendix contains the self-assessment. Generally Northpower scores a three out of four on questions with some scores of two and some good scores of four. There has been a slight improvement from the 2016 assessment.

5.9.2 Asset Management Improvement Project

Northpower has engaged a consultant to provide the following services:

- Improvement of the Northpower Asset Management System (AMS) such that:
    - Will be efficient and effective to deliver Northpower's corporate objectives;
    - All stakeholders understand the AMS and their role within it; and
    - Provide a basis for ongoing continual improvement to better manage risk, drive out waste and meet external stakeholder requirements.
- Improve asset planning practices to ensure the capital portfolio is optimal for risk management; and
- Strengthen work management in project delivery and maintenance services.

The process is aligned with ISO 55001:2014 and can be directly utilised in future Northpower AMPs.

The programme comprises a six-month body of work, which commenced in November 2017, to get to an initial outcome whereby:

1. The Northpower AMS framework is established, which leads to the specification of the AMS in detail as a second stage;
2. The Northpower AMP is established and work has commenced on risk profiling to confirm future work which requires funding; and
3. The Northpower work management manual is written, confirmed and socialised, which will lead to ongoing workflow improvement.

On completion of the initial 6 month program of work an Asset Management Continuous Improvement Plan (CIP) will be established in order to implement the improvement requirements identified. The following table outlines both the short term deliverables as well as the longer term goals.

Work Item	6 Month Deliverables	Long-term Goals
Asset Management Framework	• Overview of the Northpower AMS • Alignment of teams and their outcomes • Establish asset management policy and asset management objectives • Statement of current issues with the Northpower AMS	• Strategic Asset Management Plan • Improved coordination of the internal and external stakeholders • Possible ISO 55001 certification
Asset Management Plan	• Assessment of capital work flow inefficiencies • Establishment of risk profiling for nominated asset class • Establishment of Asset Management Plan • Commence loading proposed short-term work • Risk analysis of short term work	• Extensive risk profiling of all asset classes leading to improved forward planning and defensible budgets • Executive reporting on expenditure versus risk • 10 year forecast of future work with 2 year forecast of budget surety • Reduction of strategic risk in the asset portfolio • Optimisation of the overall capital expenditure
Work Management (Deferred for the moment)	• Assessment of work flow inefficiencies • Work management manual • Standard meeting interfaces • Key Performance Indicators • Initial coaching of monthly planning meeting	• Service provider interface improvement • Backlog management • Improve project delivery work flow • Improve contractor agreements • Address maintenance deficit • Improve preventive maintenance and feedback on asset health • Reduce fault rates

Areas within Northpower's internal systems and processes where recent improvements have been made include:

Initiative	Status
Introduction of a Safety Management System in accordance with the Electricity (Safety) Regulations 2010	Completed
Implementation of OSISoft PI System to facilitate real-time data acquisition for network data recording, storage and analysis	Completed
Reviewing maintenance standards and practices and improving systems and processes	Project initiated October 2017
Improving network asset quantity, age and condition data	Asset management review programme underway
Adoption of condition based risk management in asset replacement decision making policy	Asset management review programme underway
Increased use of Smart Systems for enhanced operational control and network monitoring	Future initiative
Increased focus on employment of non-network solutions where viable	Ongoing
Development of aerial and advanced acoustic asset inspections	Foresight acoustic inspection service in use, UAV aerial outdoor zone substation surveys in place
Increased power system data acquisition (e.g. power factor and harmonic distortion)	Future initiative
Improved substation and communications security	Ongoing
Continued support for the commissioning of electric vehicle infrastructure assets	Several fast charging sites established to help facilitate EV take-up. Actively supporting third party installs.
Ongoing improvement in the quality of asset management in terms of meeting the ISO 55000 standard by addressing those aspects identified in the gap analysis and asset management self-assessment	Commenced the asset management review
Establish structured project governance and project management framework	Commenced
Increased application of risk analysis and management in projects	Commenced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Section 6: Network Development Plan

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Network Development Plan - Section 6

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Section 6 - Network Development Plan

6.1 Planning Criteria and Assumptions

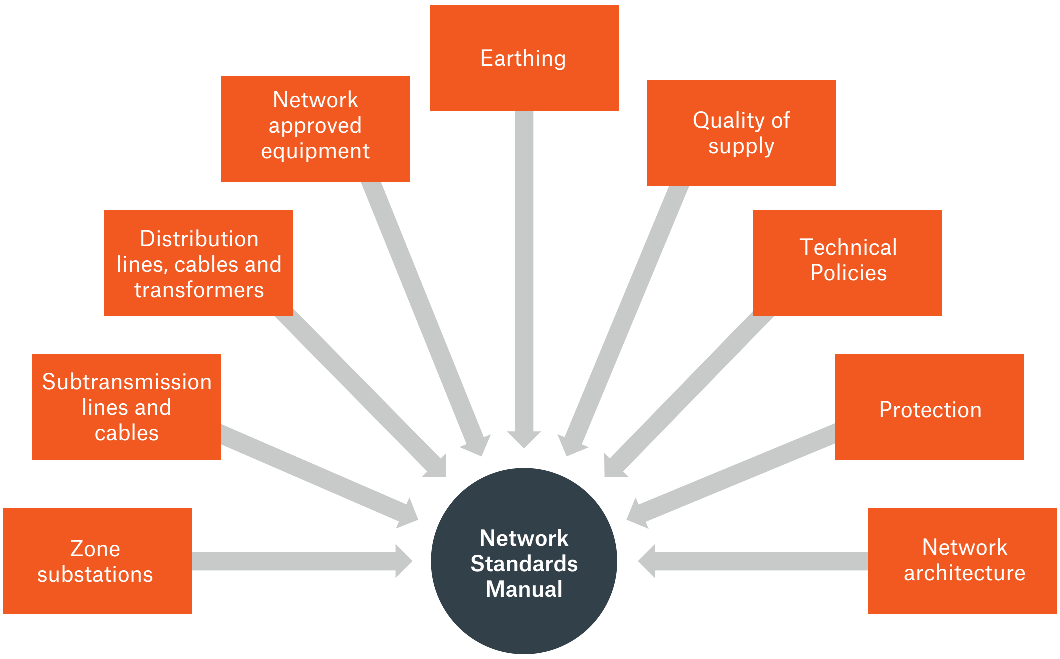
Planned network assets are proposed in order to ensure customer requirements and expectations with respect to capacity, reliability and security of supply are met at an affordable cost. Northpower has adopted various engineering standards and policies to ensure that it can satisfy customer requirements in line with the following guiding principles:

- Minimisation of over-investment;
- Optimisation of operational efficiency and flexibility;
- Minimisation of long-term stranding risks;
- Maximisation of return on investment (lifecycle cost analysis); and
- Compliance with legal, regulatory, environmental and safety requirements.

Ongoing and exclusive investment in long term traditional network assets only makes sense if there is an adequate supply of low cost grid generation. The continued evolution of small scale solar panels, wind turbines and battery technologies could reduce the demand on traditional electricity networks. However an increasing number of electric vehicles has the potential in the medium term to significantly increase the demand on electricity networks. Northpower recognises the importance of monitoring technological developments and has the ability to rapidly respond to the implementation of new or alternative technologies and minimise the risk of stranded assets or changing load patterns.

For this reason, all new network investment requirements need to be carefully scrutinised to ensure best practice investment. Similarly, possible changes in the regulatory environment could require a different approach to investment decisions.

Planning and design parameters, as well as equipment rating criteria are set out in Northpower's Network Standards Manual. These include the components identified below:



Network Standards Manual Sources of Information

Section 6 - Network Development Plan

6.1.1 Capacity Determination

Capacity and subsequent rating of new equipment is generally determined by the magnitude of the load to be supplied and the prevailing fault level, whereas reliability and security of supply aspects are based on the number of customers, the nature of the load, susceptibility of the network to faults in the particular area and affordability of contingent capacity margins or duplication of assets.

Technical specifications for the range of equipment used on Northpower's network are detailed in the Network Approved Equipment section of the Network Standards Manual.

6.1.2 Performance and Quality of Supply

Northpower has a range of criteria that represent planning rules for different categories of fixed assets, refer to the table below:

Category of asset	Capacity criteria	Reliability criteria (worst case)	Security of supply criteria
400V distribution network	Statutory voltage level	Supply restoration within repair time or within switching time where 400V link pillars present	(n) security of supply for standard residential or commercial connection (n-1) where link pillars present and backstop capacity available
11kV/400V distribution substation	Transformer continuous rating	Supply restoration within fuse or transformer replacement time or within switching time where 400V link pillars present	(n) security to most urban distribution networks (n-1) where link pillars present and backstop capacity available
11kV distribution network	Maximum operating load 80% of lowest segment rating	Supply restoration of 80% within switching time	(n-1) security except for spurs
11kV distribution equipment	Regulator rating RMU rating Cable rating	Supply restoration within switching time	(n-1) security except for spurs
33/11kV zone substation	80% of firm maximum load relative to firm capacity	100% load restored within 30 min for >5MVA , 80% within 1 hr for <5MVA	(n-1) >5MVA (n) <5MVA
33kV sub-transmission network	110% of overhead line rating 80% of cable thermal rating	100% load restored within 30 min for >5MVA , 80% within 1 hr for <5MVA	(n-1) for dual circuits (n) for single circuits
33kV assets within Transpower GXP	CB load and fault level rating	Supply restoration within switching time	(n-1) >5MVA (n) <5MVA

Actions to change the parameters of individual assets within these categories, so as to ensure compliance with the planning rules, can take the following forms:

- Construct new distribution assets that will move (generally increase) an asset's capacity to a level at which the planning rule is not contravened. An example would be to replace a 300kVA transformer with a 500kVA transformer so that the 100% expected maximum demand criteria is not exceeded. Other examples would be installing a voltage regulator on a feeder to ensure that statutory voltage levels are maintained or upgrading switchgear to meet increased fault level requirements.
- Modify distribution assets so that the assets' attributes will move to a level that no longer contravenes a planning rule. This is essentially a sub-set of the above approach, but will generally involve less expenditure. An example would be installing forced cooling on a 33/11kV transformer to allow a greater maximum demand at a lower cost than installing a larger transformer that might be under-utilised most of the time.
- Retrofitting high-technology devices that can make use of and enhance the features of existing assets. For example replacing air break switches with gas enclosed switches to improve reliability. Other examples might include SCADA monitoring of transformer core temperatures to enable higher cyclic loadings instead of installing a higher rated transformer or using remotely controlled switches to improve reliability.
- Operational activities, in particular switching on the 11kV network (reconfiguration) to shift load from heavily-loaded to lightly-loaded zone substations to avoid new investment. The downside to this approach is that it may increase line losses, reduce security of supply or compromise protection settings.
- Feeder reconfiguration to mix different load categories e.g. urban and domestic load, so as to obtain the benefit of load diversity.
- Construct or contribute to the development of distributed generation so that associated distribution asset performance is restored to compliance with the planning rules. Distributed generation would be particularly useful where additional distribution assets could eventually be stranded or where primary energy is going to waste.
- Influence customers to alter their utilisation so that assets perform at levels which comply with the planning rules. Examples might be to shift demand to different time periods, negotiate interruptible tariffs or incentives with certain customers so that overloaded assets can be relieved or assist a customer to adopt a substitute energy source or encourage energy conservation initiatives to avoid new capacity (the required separation of lines and energy functions does, however, make demand management more difficult).
- In identifying solutions for meeting future demands for capacity, reliability and security of supply, Northpower considers options that cover the above range of categories. The benefit-cost ratio (including capitalised electrical losses and estimates of the benefits of environmental compliance and public safety) of each option is considered and the option yielding the most cost effective outcome in the longer term is adopted.

6.2 Network Investment Framework

Network development projects are grouped according to 3 key categories:

- **Growth** – these projects relate to network capacity and are driven by new customer connections and growth of existing load.
- **Replacement and renewal** – these projects are driven by asset condition due to deterioration or end of life impacting on safety, performance and maintenance costs.
- **Improvement** – these projects are driven by the need to maintain or improve reliability, public and employee safety and environmental impact.

The prioritisation of projects has to take into account the following constraints:

- Availability of funds and the need to smooth annual capital expenditure
- Availability of design, construction and other resources
- Acquisition of resource consents and permissions
- Equipment lead-times
- Risk associated with project deferral

The methodology employed to prioritise or rank projects across the network is based on the analysis of risk as it pertains to Northpower's obligations in terms of the following aspects:

- Safety
- Regulatory compliance and environmental impact
- Network capacity, reliability and security of supply
- Cost-benefit analysis

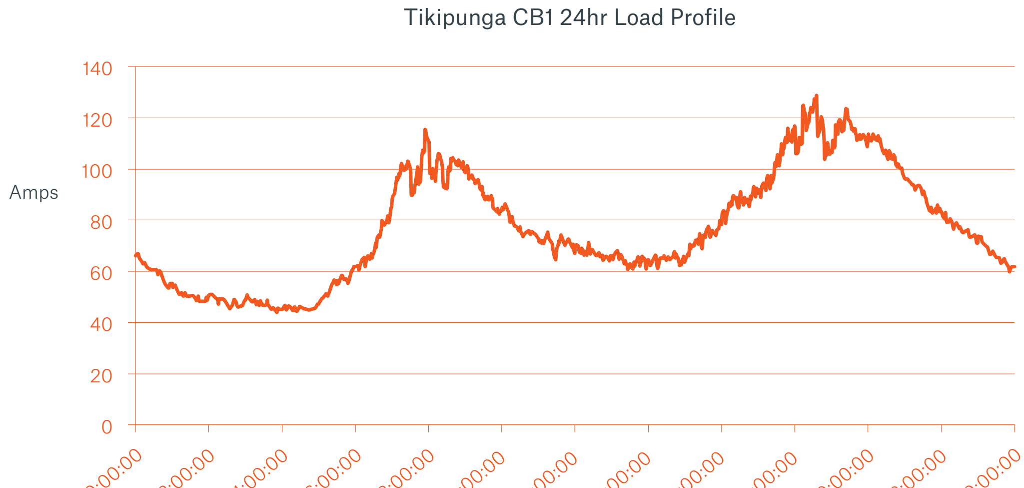
Where necessary (usually undertaken for larger high value projects), a cost-benefit comparison of projects can also be carried out using net present value (NPV) and internal rate of return (IRR) techniques to assist with project ranking decisions.

6.3 Demand Forecast and Capacity Constraints

6.3.1 Network Capacity

Network components such as circuit breakers, isolators, transformers, cables and lines need to have sufficient capacity to ensure overloading does not occur during peak load periods. In addition to this, allowances need to be made for contingencies that may arise during peak load periods as a result of equipment failure. This additional capacity is termed N-1 which expresses the ability of the network to lose a component without causing an overload failure elsewhere on the network. This usually takes the form of duplicate power lines and transformers, or the ability to redirect power flows using the spare capacity in other circuits. Northpower's network only has full N-1 capacity in certain strategic areas such as high density urban areas, supplies to critical loads or where a customer has requested and paid for it.

A typical 24 hour residential feeder load profile is shown below. The 'spiky' nature of the load peaks is due to the operation of hot water load control which has suppressed the natural peak.



Typical Feeder 24hr Load Profile

Demand is highest in the morning and again in the evening. Similarly this demand will vary during the year depending on seasonal effects. In Northpower's case the highest demand occurs in winter. Unless some form of load control is in place to manage the peak demand (either supply side or demand side) all network components supplying the load are required to have sufficient capacity to meet the highest peak demand.

Northpower's ripple injection load control equipment (controlling hot-water load) is currently used to manage peak demand at Transpower Grid Exit Point level. It is not possible at this stage to manage peak loadings at a specific zone substations or feeder level and for most parts of the network the peak load is approximately coincidental across the network.

6.3.2 Recording and Analysing Network Loading

Northpower records network loading via the SCADA system in terms of current and power at the following levels:

- GXP
- Subtransmission feeder
- Zone substation transformer
- Zone substation feeder

This information is recorded in OSI PI historian.

Loading data is also available from tariff metering associated with large customer loads. At the distribution transformer and LV feeder level, selected large transformers (200kVA and above) in the Whangarei City area are equipped with maximum demand indication to capture peak loading. For all other distribution transformers and LV feeders, peak loading is estimated based on summated premise kWh data as well as the number of connections where the load is predominantly residential or rural.

When analysing current or historical network demand data for the purpose of establishing trends, there are a number of factors which can distort the data, such as:

- Seasonal effects e.g. wet/dry summer, cold/warm winter.
- The system may have been configured differently for a shutdown, fault event or permanent change to the normal supply configuration.
- The use of load control on switching off and restoration of controlled load.
- Economic cycles slowing or accelerating demand.

6.3.3 Load Forecasting Methodology

Northpower has traditionally relied heavily on a number of variables to generate the load forecast:

- Historical growth trends.
- Knowledge of the area.
- Degree of growth saturation of developed areas.
- Notification of reasonably definite potential new load.
- Notified planned increases in existing commercial and industrial load.
- Information obtained from district council plans.
- Future economic outlook.

We recognise the need to develop and employ a more sophisticated load forecasting methodology which also takes cognisance of potential future developments:

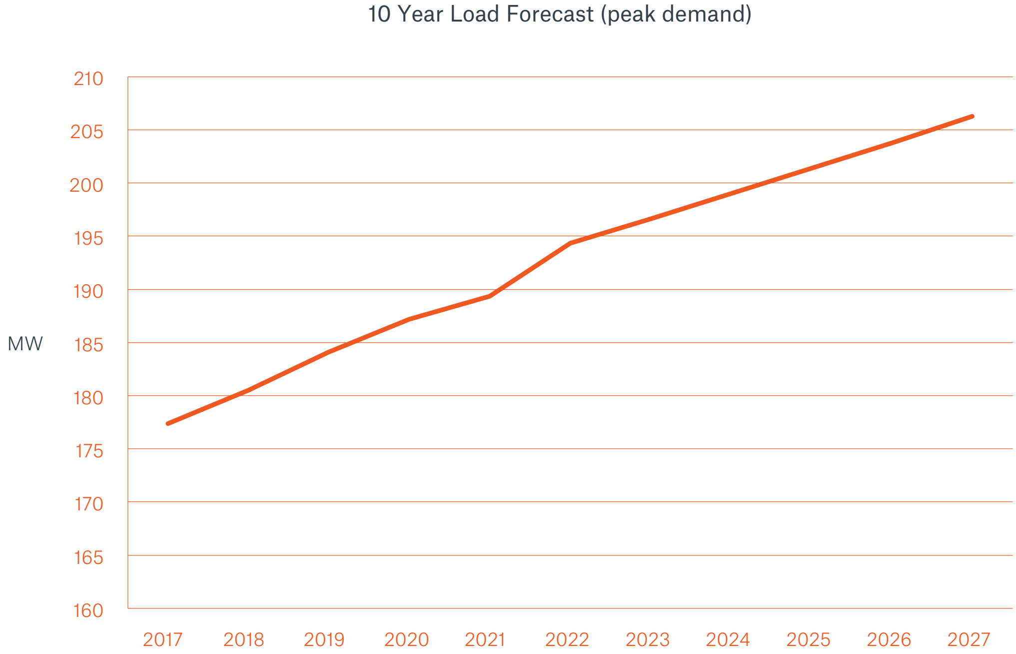
- Availability and affordability of grid power.
- Electric vehicles.
- Distributed generation.
- Demand side management (including SMART metering and time-of-use tariffs).
- Climate control systems.
- New major commercial and industrial loads.

Northpower's current demand growth comprises relatively low growth in domestic and commercial connections overlaid by some new industrial projects, as well as upgrade projects initiated by existing large commercial and industrial customers.

The demand growth averaged across the entire network is expected to be approximately 1.5% per annum for the 10 year forecast period. This figure, however, disguises the extremes of growth expected at local levels which can range from nil (or even negative) up to about 5% per annum in high growth areas. The estimated annual growth rates are based both on historical trends and an examination of present and expected future activity at feeder and zone substation level. The forecast includes anticipated step-load increases.

Section 6 - Network Development Plan

Northpower's network peak load forecast (allowing for output from the embedded generators at Wairua and Bream Bay and domestic solar PV) is shown in the graph below. The trend assumes continued use of water heating load control plant. Without load control the magnitude of the load would be approximately 10MW to 15MW higher. The peak demand (with generation) on the network is expected to increase from the present 177MW to around 206MW during the next 10 years, barring any developments with respect to major new loads or embedded generation. Peak demand on the network currently occurs in winter but peak demand in summer is increasing due to the emergence of increasing climate control and refrigeration load. The reason for the increase in 2022 is due to a possible increase in load from New Zealand Refinery.



Network Load Forecast 2017-2026

The detailed load forecast at GXP and zone substation level is set out in the table below. This forecast is supported in the following section which summarises present loading and expected growth activity at zone substation level. Some other considerations are given in the notes to the table below.

NORTHPOWER 10 YEAR PEAK LOAD FORECAST	0	1	2	3	4	5	6	7	8	9	10	Notes
(MW instantaneous)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Kensington	**63.9**	**64.9**	**65.5**	**66.5**	**67.5**	**68.6**	**69.6**	**70.7**	**71.8**	**72.9**	**74.1**	
Alexander Street 11kV	15.0	15.2	14.9	15.0	15.2	15.4	15.5	15.7	15.8	16.0	16.1	Load transfer to Maunu
Hikurangi 11kV	6.2	6.3	6.5	6.6	6.2	6.3	6.5	6.6	6.7	6.8	7.0	Load transfer to Helena Bay
Helena Bay 11kV [planned 2021]					1.0	1.0	1.0	1.0	1.0	1.1	1.1	Planned new substation
Kamo 11kV	11.3	11.6	11.9	12.2	12.5	12.8	13.1	13.4	13.8	14.1	14.5	
Ngunguru 11kV	3.3	3.4	3.4	3.5	3.6	3.6	3.7	3.8	3.9	3.9	4.0	
Onerahi 11kV	8.1	8.2	8.3	8.3	8.4	8.5	8.6	8.7	8.8	8.9	8.9	
Parua Bay 11kV	3.3	3.4	3.4	3.5	3.6	3.6	3.7	3.8	3.9	3.9	4.0	
Tikipunga 11kV	15.4	15.6	15.9	16.1	16.3	16.6	16.8	17.1	17.3	17.6	17.9	
Kauri [Industry 1] 33kV	7.7	7.8	7.9	7.9	8.0	8.1	8.2	8.3	8.3	8.4	8.5	
Bream Bay (no TP generation)	**53.9**	**55.1**	**55.4**	**56.7**	**57.0**	**60.3**	**60.6**	**61.0**	**61.4**	**61.8**	**62.1**	
Bream Bay [industry 2] 33kV	4.6	4.6	4.7	4.7	4.8	4.8	4.9	4.9	5.0	5.0	5.1	
Bream Bay [industry 3] 33kV	40.1	41.0	41.0	42.0	42.0	45.0	45.0	45.0	45.0	45.0	45.0	Provisional step load increases
Bream Bay 11kV	4.4	4.5	4.7	4.8	5.0	5.1	5.3	5.4	5.6	5.7	5.9	
Ruakaka 11kV	6.8	6.9	7.1	7.2	7.4	7.5	7.7	4.9	5.0	5.1	5.2	Load transfer to Waipu
Waipu 11kV [planned 2024]								3.0	3.1	3.1	3.2	Planned new substation
Maungatapere (no WPS generation)	**42.7**	**43.4**	**45.7**	**46.2**	**46.6**	**47.1**	**47.6**	**48.1**	**48.6**	**49.1**	**49.6**	
Maungatapere [industry 4] 33kV	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	
Maungatapere [industry 5] 33kV	13.6	14.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	Provisional step load increase
Maungatapere 11kV	7.1	7.2	6.0	6.1	6.1	6.2	6.2	6.3	6.4	6.4	6.5	Load transfer to Maunu
Kioreroa 11kV	11.1	12.3	12.5	12.8	13.1	13.3	13.6	13.9	14.1	14.4	14.7	Load transfer from Whangarei
Poroti 11kV	3.0	3.0	3.1	3.1	3.1	3.2	3.2	3.2	3.2	3.3	3.3	
Maunu 11kV [planned 2019]			2.5	2.6	2.7	2.7	2.8	2.9	3.0	3.1	3.2	Planned new substation
Whangarei South 11kV	12.0	11.1	10.2	10.3	10.4	10.5	10.6	10.7	10.8	10.9	11.0	Load transfer to Kioreroa/Maunu
Dargaville	**12.0**	**12.2**	**12.4**	**12.5**	**12.7**	**12.9**	**13.1**	**13.3**	**13.5**	**13.7**	**13.9**	
Dargaville 11kV	12.0	12.2	12.4	12.5	12.7	12.9	13.1	13.3	13.5	13.7	13.9	
Maungaturoto	**18.5**	**18.8**	**19.1**	**19.4**	**19.7**	**20.0**	**20.4**	**20.7**	**21.1**	**21.4**	**21.8**	
Maungaturoto 11kV	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.8	
Maungaturoto [industry 6] 11kV	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	
Ruawai 11kV	3.0	3.0	3.1	3.1	3.1	3.2	3.2	3.2	3.2	3.3	3.3	
Kaiwaka 11kV	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.3	2.4	2.4	
Mangawhai 11kV	7.2	7.4	7.6	7.9	8.1	8.3	8.6	8.9	9.1	9.4	9.7	
Mareretu 11kV	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.1	3.2	3.2	3.2	
Network ADMD (no generation)	**181.0**	**184.1**	**187.7**	**190.8**	**193.0**	**198.0**	**200.2**	**202.6**	**205.0**	**207.4**	**209.9**	Average increase: 1.5% pa
Generation (at TOSP)	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	
Wairua PS (Maungatapere GXP) 33kV	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	-3.6	Assumed station output at TOSP
Trustpower PS (Bream Bay GXP) 11kV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Assumed station output at TOSP
Network ADMD (with generation)	**177.4**	**180.5**	**184.1**	**187.2**	**189.4**	**194.4**	**196.6**	**199.0**	**201.4**	**203.8**	**206.3**	Average increase: 1.5% pa

Substation 10YR Load Forecast (MW Peak)

Notes to the load forecast table

1. Kensington and Maungatapere 110/33kV transformer loading is managed by transferring load (Kioreroa, Whangarei South and Alexander Street substations) between these two stations as required.
2. Northpower's 5MW Wairua hydro power station output (run of river) is dependent on rainfall and a 9MW diesel generator plant at Bream Bay is operated by a retailer as a peaking plant. The output of these plants is therefore unpredictable and may or may not reduce network peak loading.

6.3.4 Network Development Options

Northpower's guiding principle is to ensure that the target service levels are met at the lowest lifecycle cost. Accordingly, Northpower evaluates the following approaches to meeting service levels:

- Do nothing.
- Construct a new asset.
- Modify one or more features of an existing asset.
- Retrofit advanced technology that will allow greater operating ranges.
- Reconfigure assets.
- Install distributed generation.
- Influence customers demand for levels of service.

We have an approved equipment list that is managed by our Service delivery team. The approved equipment list is focused on ensuring standardised equipment is used whenever possible in our engineering design process. During the design process for network upgrades or new assets engineers always seek to minimise network losses by determining the optimal voltages and current carrying capacity of assets. This is done by loss and calculations and load flow simulations for various options.

The table below is a summary of network development options that Northpower may use to resolve constraints:

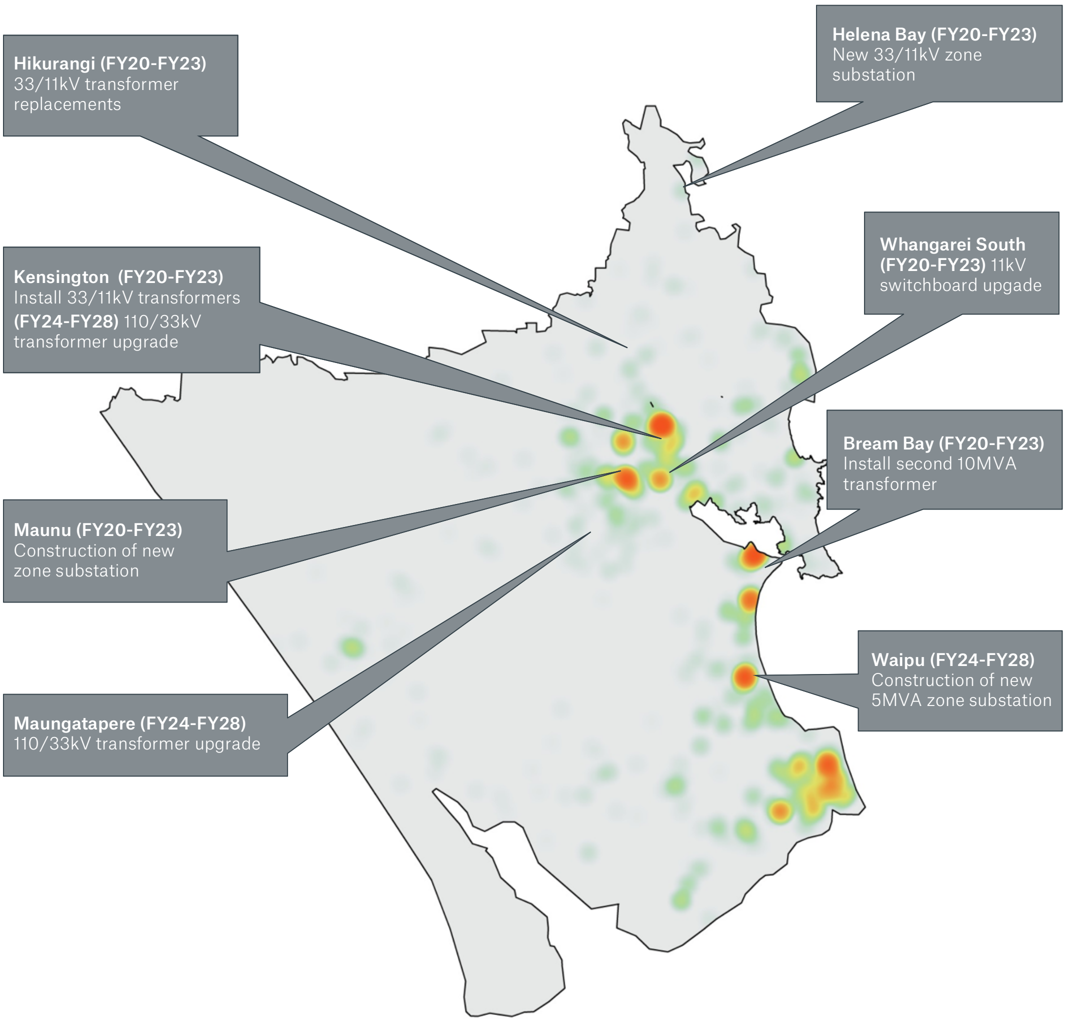
Network Development Options		
Constraint	Network Options	Non-network options
Voltage	Upgrade conductor	Install generator (peak load)
	Upgrade voltage	Promote demand side management
	Install voltage regulator	Distributed generation
	Install capacitor	Install grid storage battery
	Reconfigure feeder	
	Construct new feeder	
Capacity	Upgrade conductor	Install generator (peak load)
	Install forced cooling	Promote demand side management
	Improve power factor	Promote distributed generation
	Improve thermal resistivity	
	Increase line clearance	
	Upgrade voltage	
	Duplicate asset	
Security	Duplicate asset	Utilise mobile generator
	Install switches	
	Construct new feeder	
	Construct new zone substation	
	Ensure strategic spares available	
Reliability	Install reclosers/sectionalisers	Utilise mobile generator
	Install switches	
	Increase preventative maintenance	
	Install earth fault neutraliser	
	Reconfigure feeder	
	Construct new feeder	
	Construct new zone substation	

Northpower uses a range of decision making tools such as NPV analysis, payback period and risk assessment to determine which option will give the lowest lifecycle cost. The degree to which these decision tools are applied depends on the level of expenditure and significance involved. For example, recurring decisions made at the operational level of the business will typically use a pre-defined decision tool that considers a few simple parameters and identifies one of a few possible options as being optimal. In contrast, non-recurring decisions made at the executive level of the business may consider wide ranging and complex data and may use several decision tools to identify an optimal option from among a large number of possible options.

6.3.5 Zone Substation Loading and Load Growth Expectations

Several large industrial loads are supplied at 33kV at Bream Bay (2 customers), Maungatapere (2 customers), Kauri (1 customer) and Maungaturoto (1 customer) substations with the present and expected future peak demand values for these loads given in the load forecast on page 8.

Below is a map showing the areas of highest load growth, in orange, and the main projects planned to meet the projected load requirements.



At Bream Bay, the District Council has designated large areas of land for development and there is also the possibility of a deep water port being established at Marsden Point. In the medium to long term the load at Bream Bay could increase substantially.

In the Dargaville area there is potential for large scale forestry development with associated wood processing that could in the longer term lead to significant load growth.

Some growth is expected off the Hikurangi substation associated with the development of holiday homes and lifestyle blocks.

The Kamo substation is supplying medium growth in the development of residential areas and lifestyle blocks and this is expected to continue for the next 5 to 10 years.

Whangarei City is expected to grow out towards the west and substantial residential load growth is expected on the Maungatapere substation in the medium term. A new substation at Maunu will take some load off Maungatapere when commissioned.

Details of customer numbers, transformer capacities, peak loads and feeder maps for each zone substation are provided in Appendix B.

6.3.5.1 Subtransmission

The subtransmission circuits and zone substations form the backbone of our network. The most significant constraints to supply (both in terms of the number of customers potentially affected and the cost of overcoming the constraint) arise at zone substations and on the subtransmission network feeding them. Constraints at this level are normally a result of equipment current ratings (load as well as fault) rather than voltage and significant components are:

- Transformers.
- Circuit breakers and isolators.
- Busbars and jumpers.
- Cables and conductors.

Constraints on the subtransmission network over the next 10 years relate to subtransmission cable or line circuits and substation transformers.

Subtransmission cable/line circuit constraints anticipated over the next 10 years are referenced to the continued provision of N-1 capacity to key substations. They cover the 33kV supply from Kensington to Kamo substations and the 33kV supply to Kioreroa substation. Provision has been made in the 10 year Capex programme for projects to remove these constraints.

The table below shows anticipated substation transformer capacity constraints (for both N and N-1 requirements) and planned resolutions during the next 10 years (refer to the 10 year Capex program):

Substation	Voltage	Transformer	MD(MW)		N Constraint	N-1 Constraint	Backstop	Planned Resolution
	KV	MVA	2017	2027				
Alexander Street	33/11	2x 7.5/15	15.0	16.1	None	Trfr. rating	Whangarei South, Tikipunga, Kioreroa, Onerahi	Load transfer
Bream Bay (1)	33/11	1x 7.5/10	4.4	5.9	None	No supply	Ruakaka, Trustpower peaker plant	Install 2nd trfr.
Bream Bay (2) Transpower GXP	220/33	2x50/100	53.9	62.1	None	None	None	N/A
Dargaville	50/11	2x7.5/15	12.0	13.9	None	None	Maungatapere, Ruawai	N/A
Hikurangi	33/11	2x5	6.2	7.0	None	Trfr. rating	Kamo, Ngunguru	Transformer upgrade.
Kaiwaka	33/11	1x5	2.0	2.4	None	No supply	Mangaturoto, Mangawhai	Install 2nd trfr.
Kamo	33/11	2x 7.5/15	11.3	14.5	None	None	Hikurangi, Tikipunga, Poroti	N/A
Kensington	10/33	2x50	63.9	74.1	None	Trfr. rating	Maungatapere	Transformer upgrade.
Kioreroa	33/11	2x15/20	11.1	14.7	None	None	Whangarei South, Alexander Street	N/A
Mangawhai	33/11	2x5	7.2	9.7	None	Trfr. rating	Kaiwaka, Ruakaka	Strategic spare trfr.
Mareretu	33/11	1x5	2.8	3.2	None	No supply	Maungaturoto, Ruawai, Maungatapere	Install 2nd trfr.
Maungatapere (1) Transpower GXP	110/50	2x25	12.0	13.9	None	None	Ruawai, Maungatapere	N/A
Maungatapere (2) Transpower GXP	110/33	2x30	42.7	49.6	None	Trfr. rating	Kensington	Transformer upgrade.
Maungatapere (3)	33/11	2x5	7.1	6.5	None	Trfr. rating	Poroti, Dargaville, Mareretu, Kamo and Kioreroa, (Maunu)	Transformer upgrade.
Maungaturoto (1) Transpower GXP	110/33	2x20	18.5	21.8	None	SG rating	None	Transpower assets
Maungaturoto (2)	33/11	2x7.5	7.0	7.3	None	Trfr. rating	Kaiwaka, Mareretu	N/A

Substation	Voltage	Transformer	MD(MW)		N Constraint	N-1 Constraint	Backstop	Planned Resolution
	KV	MVA	2017	2027				
Ngunguru	33/11	1x3.75	3.3	4.0	Trfr. rating	No supply	Tikipunga, Hikurangi	Trfr. upgrade
Onerahi	33/11	2x 7.5	8.1	8.9	None	Trfr. rating	Parua Bay, Alexander Street, Tikipunga	Trfr. upgrade
Parua Bay	33/11	1x3.75	3.3	4.0	Trfr. rating	No supply	Onerahi, Tikipunga	Install 2nd trfr.
Poroti	33/11	1x5	3.0	3.3	None	No supply	Maungatapere, Kamo	Strategic spare trfr.
Chip Mill	33/11	1x3.75	2.2	2.2	None	No supply	None	Strategic spare trfr.
Ruakaka	33/11	2x10	6.8	5.2	None	None	Bream Bay, Mangawhai, Maungatapere (Waipu)	N/A
Ruawai	33/11	1x5	3.0	3.3	None	No supply	Dargaville, Mareretu	Install 2nd trfr.
Tikipunga	33/11	2x20	15.4	17.9	None	None	Alexander Street, Kamo, Onerahi	N/A
Whangarei South	33/11	2x10	12.0	11.0	None	Trfr. rating	Alexander Street, Kioreroa, (Maunu)	Load transfer

6.3.5.2 Distribution

A number of 11kV rural distribution feeders are expected to become voltage constrained within the planning period. Some feeders will become constrained due to load current or number of connected premises (in terms of number of customers affected after a feeder fault).

Each constrained feeder is unique in terms of length, conductor size, number of customers, load distribution and load characteristics. A number of solutions are available to rectify these constraints such as:

- Shunt connected capacitor banks (voltage and current)
- Voltage regulators (voltage)
- Conductor upgrade (current and voltage)
- Feeder reconfiguration (voltage, current and number of customers)
- Voltage upgrade (voltage and current)
- Distributed generation - diesel generator or PV stored energy (voltage and current)
- Zone substation (voltage, current and number of customers

The following 11kV feeders have been identified as possibly requiring constraint resolution within the planning period subject to actual load growth experienced:

Substation	Feeder	Constraint	Resolution
Alexander Street	Western Hills Drive	voltage, customer numbers	Maunu substation
Bream Bay	Marsden South	voltage and customer numbers	new feeder
Dargaville	North	voltage regulator capacity	200A regulator
Dargaville	Te Koporu	voltage	switched capacitors
Dargaville	Tangowahine	voltage	switched capacitors
Hikurangi	Jordan Valley	voltage	switched capacitors
Hikurangi	Whakapara	voltage and customer numbers	Helena Bay Substation
Hikurangi	Swamp North	voltage	switched capacitors

Substation	Feeder	Constraint	Resolution
Kioreroa	Toe Toe Road	voltage	reconfiguration
Mangawhai	Moir Point	voltage	reconfiguration
Maungatapere	Maunu	voltage and customer numbers	Maunu substation
Poroti	Titoki	voltage	conductor upgrade
Ruakaka	Marsden Point	customer numbers	reconfiguration
Ruakaka	Waipu	voltage	voltage regulator/Waipu Substation
Ruawai	Tangaihi	voltage	switched capacitors
Tikipunga	Whau Valley	customer numbers	reconfiguration
Tikipunga	Tikipunga Hill	customer numbers	switched capacitors
Tikipunga	Kiripaka Road	customer numbers	reconfiguration
Whangarei South	Otaika	customer numbers	Maunu substation
Whangarei South	Okara Drive	current	reconfiguration

6.3.6 Network Capacity Constraints

As part of the planning process, Northpower identifies what network constraints are under both system normal conditions and fault conditions or when the plant is temporarily out of service for maintenance.

Resolution of constraints usually involves upgrading of existing equipment but in some cases network reconfiguration of new assets is also required. In the case of N-1 capacity constraints (where there is one level of redundancy), decisions on what action to take will be based on risk and required levels of security. Temporary load shedding may be considered an acceptable solution in some cases, especially where the cost of resolving the constraint is excessive.

Thermal constraints can sometimes be resolved more cost effectively by means of cooling (fans for power transformers), improving ground thermal resistivity for underground cables or resagging of overhead line conductors to resolve ground clearance issues. Voltage constraints can be resolved by increasing conductor size, installing voltage regulators, improving the power factor using capacitor banks, changing to a higher voltage level or constructing new assets.

Northpower utilises power system modelling and thermal rating software in conjunction with load forecast data to identify future capacity constraints on the network. Load flow studies are carried out for both system normal power flows and for contingency situations. The results of these studies are used to optimise capacity utilisation and delay investment in new assets until they are absolutely necessary. Where a future capacity constraint is identified the software is used to model and evaluate alternative options available to resolve the constraint.

6.4 Distribution Management System

Although continued support is available to maintain and develop the SCADA, Northpower are planning to deploy an Advanced Distribution Management System (ADMS) which could involve the replacement of the PowerTG SCADA. An ADMS would include an outage management system that will integrate with the GIS. The proposed investments have the potential to reduce outage times and provide an improved service to customers. The implementation of an outage management system is part of Northpower's strategic plan.

A review of the ongoing serviceability and functionality of the GIS is planned as part of the deployment of an ADMS that includes an outage management system. Northpower is deploying an extension of the GIS to enable field based GIS that will be synchronised with the master GIS in 2018.

6.5 Telecommunications

Northpower has a number of enhancements planned for its telecommunications networks:

- Migration of SCADA fibre connections from a UFB service to a private dark fibre solution, although still delivered over Northpower Fibre's network;
- The establishment of a new voice repeater at Horokaka to improve RT coverage in the northwest of Northpower's distribution area;
- Upgrade radio repeater sites to allow for the connection of mobile generators in the event of an extended power outage and improve remote monitoring of facilities power quality, temperature and humidity;
- Upgrade the existing RT system dispatch console, currently used to link RT channels, to provide for additional redundancy; and
- Develop a telecommunication network strategy to support the requirements of advanced distribution automation, demand response initiatives including intelligent energy appliances (EVs, Battery Storage and PV's) and the migration to a digital RT network.

6.6 Distributed Generation Policy

Northpower's policy on the connection of distributed generation follows the requirements set out in Part 6 of the Electricity Industry Participation Code 2010. Northpower's website includes guidelines on connection requirements, consultation and approval.

Northpower recognises the value of distributed generation in the following ways:

- Reduction of peak demand at Transpower GXP's;
- Reducing the effect of existing network constraints;
- Deferring or even avoiding investment in additional network capacity;
- Contributing to supply security;
- Making better use of local primary energy resources thereby avoiding line losses; and
- Avoiding the environmental impact associated with large scale power generation.

Distributed generation can, however, have the following undesirable effects:

- Increased fault levels, requiring protection and switchgear upgrades;
- Uncontrolled voltage levels;
- Increased line losses where surplus energy is being exported through a network constraint.
- Stranding of assets or at least part of an asset's capacity;
- Potential for back-feeding into the network with inherent safety implications;
- The introduction of harmonic currents; and
- Upgrading of line capacity where the generation exceeds the capacity of existing lines.

Notwithstanding the need to address these potential effects, Northpower actively encourages the development of distributed generation and will ensure that the network responds as required, for the benefit of both the generator and Northpower. The key requirements for those wishing to connect distributed generation to the network are covered in the following sections.

6.6.1 Connection Terms and Conditions

Connection terms and conditions are set out in accordance with the Electricity Industry Act 2010.

6.6.2 Safety Standards

A party connecting distributed generation must comply with any and all Northpower safety requirements, as well as all electrical industry codes and regulations. Northpower requirements are based on AS/NZS4777 for small scale generation.

Northpower reserves the right to physically disconnect any distributed generation that does not comply with such requirements.

6.6.3 Connection Inquiries and Application Procedure

Information about the application procedure for potential connection of distributed generation (including relevant forms and required standards) is available on the Northpower website.

The applications are handled in a similar manner to processes currently employed to manage existing applications for power supply received from customers.

6.6.4 Distributed Generation and Development Planning

As at the end of December 2017, there were 649 small scale (mostly solar PV) distributed generation connections on the Northpower network. Total installed capacity is around 3.0MW with the average installation output being approximately 3.7kW. While distributed generation represents a low proportion of demand and as yet does not incorporate battery storage, the growth of solar PV has not yet had a material impact on the network or affected the development plan.

Solar PV generation without battery storage has the potential to increase voltage levels to beyond acceptable limits on 400/230V networks as maximum output occurs during sunlight hours, when loading on these networks is generally low. For this reason the number of connections and total installed capacity per distribution transformer will need to be limited to avoid expenditure on voltage regulating equipment.

Distributed generation is considered in the long term planning process, and operating PV connections are monitored. As trends develop, data will be used to understand the impact on changing network demand. Northpower also carries out this evaluation with other technologies such as heat pumps and air-conditioners. Increased installation of this type of load has changed some loading trends within the network.

Overall, Northpower recognises the potential for distributed generation to avoid capital expenditure required to increase capacity for peak loading.

6.7 Emerging Technologies

6.7.1 Introduction

The reducing cost of renewable generation alternatives, the availability of electric vehicles, reduced household consumption, a move to time-of-use pricing or cost reflective pricing by retailers and an increasing awareness of choices customers have available will effect changes on our network operations. There are new sources of network information available to support improved monitoring and control. Outlined below is an assessment of the impact of how these changes could affect Northpower's Network.

6.7.2 Smart Meter Information

The Industry is nearing the end of the replacement of legacy electricity meters with smart meters, and there is a wealth of information that should become available to the EDBs for network management purposes. Specifically smart metering information can be used to:

- monitor voltage excursions leading to identifying damaged neutrals, loose or poor corrections or incorrect transformer tap settings;
- reduce customer fault call outs by remotely interrogating the meter to determine whether the fault is in the customer or distribution network;
- identify supply loss through the last gasp functionality that sends a message to the network when supply to the ICP is lost and using this information fault crews can be proactively dispatched without waiting for a customer call resulting in a reduced SAIDI;
- reduce the need for fault crews to travel to take readings when power is restored remotely;
- improving network operating during both planned and unplanned outages by, for example, managing line back-feeding;
- verify the quality of supply as the smart meters log, at approximately 10 second intervals, voltage, current, power, power factor and harmonics which can be used to efficiently process Low Voltage Complaints;
- improving asset investment decision making by using the temporal facet of transformer/line loading information to complement the traditional Diversity Maximum Demand and Maximum Demand Indicators that generally leads to less conservative investment in new assets;
- improve phase balancing on transformers as most distributors do not have good records of what phases single phase supplies are connected to;
- identify where there has been solar installations connected without network approvals, and to
- expedite revenue assurance investigations.

The Industry is currently debating non-revenue smart data ownership, there is potential for the distribution industry to lower cost to serve and improve the customer experience. Northpower will advocate obtaining this metering information and making investment decisions anticipating that it will become available within the next 2 years.

6.7.3 Network Sensors

In addition to smart meters, there are two areas that Northpower intends to continue to investigate, namely transformer monitoring and line fault indicators to provide improved network monitoring and management. Distribution transformer monitoring using smart metering technology would enable improved network control and load management. Line fault indicators can enable fast location of faults leading to shorter restoration times and reduced SAIDI minutes. Northpower will have a programme in place within the next 2 years providing improved network monitoring.

6.7.4 Intelligent Appliances

There is a growing trend by appliance manufacturers to make their appliances smart capable by providing internet and in particular cellular connectivity. The potential benefit for Northpower is to shift residential appliance usage out of daily peaks through price signalling. This will require collaboration between the retail and distribution sectors of the Industry to ensure the price signals are passed to smart appliances.

6.7.5 Battery Storage

The battery storage market in New Zealand is still in its infancy. Recent commercial battery storage installations with capacity less than 1MW and greater than 10kW, include: Vector's 1MW/2.4MWh Tesla Powerpack energy storage system at Glen Innes substation and 250kW battery at Dominion Salt at Blenheim, Alpine Energy's 36kW/142kWh EMC lithium ion battery and Counties Power 250kW unit installed in Tuakau that will be trialled in collaboration with Genesis Energy. Genesis Energy is also partnering with Powerco to trial services linked to emerging technologies including battery storage with communities in the Wairarapa. Wellington Electricity, Wellington City Council and Contact Energy are trialling residential solar and battery storage to assess the benefits of a virtual power plant in the community.

In a recent Transpower discussion document, battery storage in New Zealand, it was concluded that grid-connected batteries would not become economic before 2022 however distribution-connected or community scale batteries are expected to be economic from 2020.

Vector recently announced that it had access to mPrest, a software solution that will enable, amongst other things, the aggregation and control of residential PV battery and electric vehicle (EV) storage, with elements of control residing with the battery owner.

Applications for commercial size battery storage include:

- Distribution network voltage support for locations with supply constraints;
- Participation in Transpower's demand response programmes including participation in the electricity reserves market, including primary (6s/FIR) and secondary (60s/SIR) instantaneous reserves and for the North Island reserve costs are between $3 and $6 per MWh;
- Remote area power supplies that involve PV and/or wind generation for storage of excess energy produced and for the stabilisation of the microgrid; and
- Energy arbitrage with respect to spot prices. The Transpower study calculated that for the upper North Island the value at peak times could be between $25 and $22 per MWh.

Whilst there are no immediate plans for Northpower to invest in large scale battery technology, the company will actively investigate the use of virtual power plants using battery storage owned by others in the area with a view to reducing peak load requirements. One option under consideration is the development of hybrid remote power generation, as a means of avoiding uneconomic remote network renewals.

6.7.6 Photovoltaic

The growth in residential photovoltaic (PV) presents a number of changes to the electricity distribution industry. Adverse effects can arise from more complex network management resulting from multiple points of supply and a loss of revenue that does not correspond with an equivalent reduction in costs.

To assess the likely impact of PV in Northland, it is necessary to understand the scale of solar market and whether growth patterns might change over time. As mentioned above at the end of December 2017, there were 649 residential PV ICPs connected to the Northpower Network. The number of connections has grown steadily at approximately 100 per year, but does not appear to be growing exponentially.

At current PV growth rates there will be little impact on the Network, it will require a significant change in market conditions to see a significant increase in the rate of growth of PV. One tipping point would be the lifetime cost of solar dropping below the cost of buying power from the grid over an equivalent period. Battery storage allows for the better use of the power generated, especially if pricing is time-based, however batteries add to the cost of an installation.

In their report on new technologies, Concept Consulting publicised the results of modelling of the Net Present Value for solar. To analyse the potential financial attractiveness of installing solar PV, the data for ~1,000 locations was evaluated against a range of retail electricity prices. Based on their assumptions (i.e. panel prices to fall at 7% per annum, inverter prices to fall at 3% per annum, and installation costs to fall at 3.5% per annum) the conclusions were that PV would become viable for about half the locations by 2026 and for all by 2036, assuming that retail tariff structures continue unchanged.

There are several commercial scale solar installations elsewhere in New Zealand, including Sylvia Park Mall (350kW) and Tarewa Mega Centre (240kW), that are grid connected.

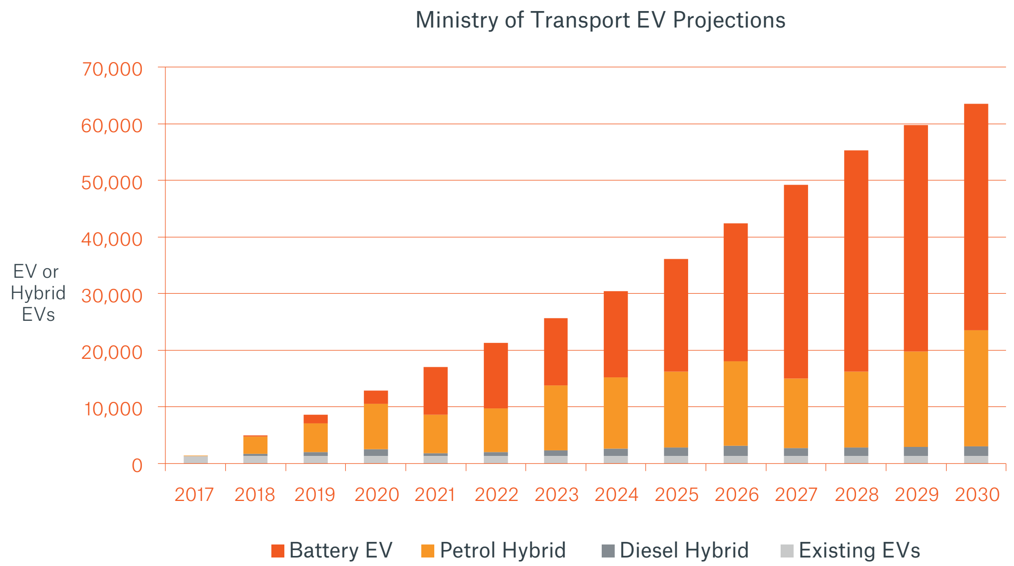
We will continue to support the installation of PV in the region, however Northpower plans no PV investments of its own. PV provides little benefit to the Network during winter months but high penetrations of PV would create summer reverse power flows that may require congestion management policies to manage this (particularly on the low voltage networks).

6.7.7 Electric Vehicles

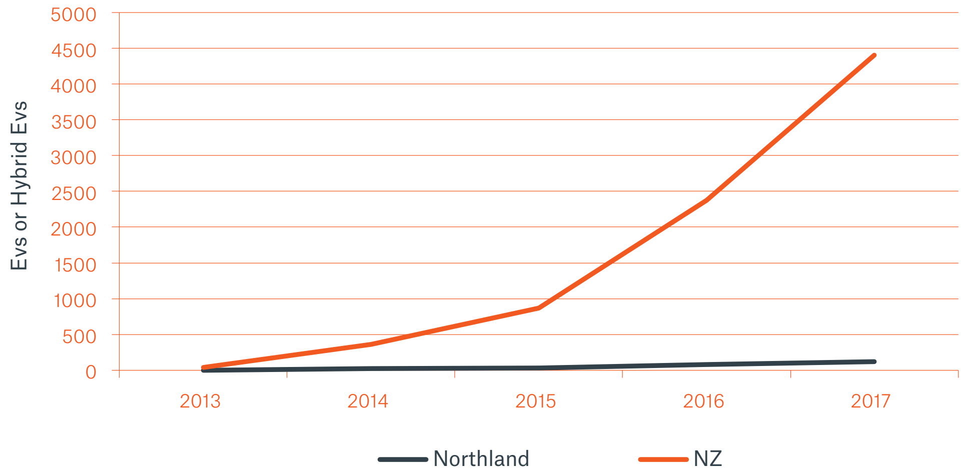
The potential impact of EVs is wide reaching. Real or perceived benefits to the public, the relative price compared to combustion engine vehicles, environmental benefits, and potentially Government incentives will drive vehicle uptake. These factors will largely be beyond the control of Northpower, and affected by international trends.

An EV is more expensive to purchase but cheaper to run. A rapid charge in New Zealand currently costs about $7.00 to provide around 100km of motoring. The purchase cost of EVs is trending down and with battery range increasing this cost saving will increase. A study by B Nykvist and M Nilsson, Nature Climate Change 2015, suggested that electric vehicles could achieve price parity with their equivalent internal combustion engine vehicle by 2020.

The Ministry of Transport is projecting that New Zealand will have some 60,000 EVs or hybrid EVs by 2030 as shown in the following graph. The growth of EV’s in New Zealand has been doubling and is continuing to double each year.



Data from NZTA show that Northland has 118 (3%) of the country's EV fleet out of a National total of 4,404 as at August 2017 (there are approximately 3.5 million vehicles in New Zealand in total). However the Northland EV uptake is not following national trends, as shown below.



In the short term it is not expected that there will be a significant EV load impact on the Northpower network. The impact, when it comes, will likely coincide with the evening peak as EV owners return home and plug in. In Norway, where there are approximately 100,000 EVs, 96% of EV owners charge their vehicles at home (Norwegian EV Association Survey 2015). Pricing signals will likely shift charging demand outside of the network peak periods.

New Zealand experience shows that early EV adopters tended to have higher daily commutes than overseas countries and it is likely that the average daily commute (includes shopping, taking children to school etc) to be around 50 km with electrical consumption of around 9 kWh (close to 50% of a typical Northland home).

Rapid charging stations can impact the electrical network through the injection of unwanted harmonics. However it is unlikely that in the near future charging stations will have a significant loading impact on the Northpower HV distribution network, to the point of triggering any capacity upgrade.

6.7.8 Remote Area Power Supplies

There are few areas that could be considered as a candidate for disconnection from the Network and supply using a remote area supply. Most remote loads are farms and lodges and if extraordinary maintenance requirements occur to these sites, Northpower will consider alternative supplies in collaboration with the customers. When considering alternatives to the Network supply the company would look to use an already developed solution such as the "BasePower" developed by Powerco for this purpose.

There are some areas of the network, and particularly at holiday times, where mobile standby generators could reinforce the supply. Northpower will investigate the technical and commercial viability of such schemes.

6.8 Non Network Solutions

Where increases in demand for key service level parameters (capacity, reliability and security of supply) are identified, Northpower considers both non-network and traditional network methods of meeting that increase in demand. The preference is for non-network methods (due to long term asset stranding risks, capital cost, resource consents etc.) provided that they are sustainable in the long term and that the cost comparison of options is based on lifecycle costs.

Non-network options for meeting these increased demands may include:

- Incentives for customers to not increase their demand through such means as interruptible or off-peak tariffs;
- Power factor recording or installation of half-hour metering to ensure customer compliance with power factor requirements;
- Technological solutions e.g. motor starting methods, switched capacitors, voltage regulators, line drop compensation (transformer tap changers);
- Load shifting or rearranging existing assets to optimise plant usage;
- Installation of distributed generation.;
- Customer education; or
- Promoting energy conservation practices;
- Minimisation of electrical losses in lines, cables and transformers.

Northpower is also actively engaged in the area of identifying and promoting any non-network incentives or solutions, such as:

- Monitoring and recording of electrical load information at HV feeder level using the SCADA system. This information coupled with network modelling software allows Northpower to optimise the electrical configuration of the HV distribution network;
- Employing a full time customer advisor, promoting safe and efficient use of electricity and appliances. This includes having a presence at local field days and home shows. Northpower also uses this consumer interaction to gain feedback on its performance from the customer's perspective;
- Participation in energy saving programmes such as the nationwide eco-bulb implementation of compact fluorescent lamps (CFL's);
- Keeping a watching brief on developments in the field of emerging technologies related to electrical energy and distribution technology;
- Providing guidance and support to customers considering and investigating privately owned distributed generation options; or
- Engaging with third party organisations investigating or planning renewable energy generation schemes.

All significant investment decisions are subject to an assessment of alternative options during project initiation including, where applicable, any new technology options. Options are ranked depending on life cycle costs/benefits and also taking into account local factors and stakeholder considerations.

6.9 Work Programmes

6.9.1 Significant projects currently underway or planned to start within the next year (FY19)

11kV O/H line conductor replacement	Replacement of EOL HDBC and corroding ACSR conductor	**$1,600,000**
Multiyear project to replace old 7/.064 copper conductor and corroding ACSR conductor (including associated cross arms and insulators) based on sample conductor test results		
Timely replacement of at risk conductor to maintain and also improve current levels of network reliability		
Alternatives considered: replacement on breakage – high risk with respect to safety and performance		
Whangarei South-Kioreroa 33kV T reconfiguration (stage 2)	Complete second 33kV T by upgrading and extending existing out of service No.2 33kV line	**$700,000**
Required to increase security of supply to Kioreroa substation (from Maungatapere GXP)		
Alternative options: do nothing or rely on proposed peaker plant at Kioreroa if commissioned.		
Whakapara 11kV feeder express line extension	Extend 33kV express line (11kV operation) back to Hikurangi substation	**$750,000**
Required to extend the existing section of express line (no distribution transformers) which is insulated to 33kV but operated at 11kV from its present starting point back to Hikurangi substation to enable operation as a true express line from the substation to the 11kV voltage regulator at Helena Bay. This extension is required to improve feeder performance.		
Alternatives considered: interim measures to improve performance were implemented in 2012 comprising of the installation of additional 11kV automatic sectionalisers and auto reclose function on the feeder circuit breaker.		

6.9.2 Significant projects planned to start within the next 4 years (FY20-FY23)

Kensington 33/11kV Substation	Install 33/11kV transformers at the existing substation site	**$3,500,000**
To meet the expected load growth of Central Whangarei.		
Alternative: Increase the capacity of the existing 33kV circuits out of Kensington or additional 33kV circuits		
Kaiwaka 11kV switchboard upgrade	Replacement of EOL switchgear	**$1,400,000**
Required to ensure personnel safety and plant reliability.		
Alternative options: continued operation (high risk)		
Hikurangi 11kV switchboard upgrade	Replacement of EOL indoor switchgear	**$1,400.000**
Required to ensure personnel safety and plant reliability.		
Alternative options: continued operation (high risk)		
Whangarei South 11kV switchboard upgrade	Replace EOL indoor switchgear	**$1,800,000**
Required to ensure personnel safety and plant reliability.		
Alternative options: continued operation (high risk)		
Ruawai 11kV switchboard upgrade	Replacement of EOL indoor switchgear	**$1,400.000**
Required to ensure personnel safety and plant reliability.		
Alternative options: continued operation (high risk)		
Helena Bay substation	New 33/11kV zone substation	**$2,500,000**
Required to increase power transfer capacity to the Helena Bay, Oakura and Bland Bay coastal areas. As this express line will already be insulated to 33kV (refer express line extension project), the project will involve installation of a 33kV line bay at Hikurangi substation and 33/11kV step-down transformer at Helena Bay.		
Alternative options: upgrade feeder to 22kV operation/distributed generation		
Hikurangi 33/11kV transformer replacements	Replace EOL transformers	**$1,600,000**
Replace 2 x 5MVA transformers with 2 x 10MVA or similar sized units		
Alternative options: none		
Maunu 33/11kV substation	New zone substation	**$3,210,000**
Required to strengthen the 11kV network in the growing residential area between Whangarei South and Maungatapere substations. Will also offload Alexander Street, Whangarei South and Maungatapere stations		
Alternative options: interim 11kV network strengthening/reconfiguration		
Poroti 11kV switchboard upgrade	Replace EOL indoor switchgear	**$1,296,000**
Required to ensure personnel safety and plant reliability.		
Ngunguru 11kV switchboard upgrade	Replace EOL indoor switchgear	**$1,345,000**
Required to ensure personnel safety and plant reliability.		
Ruawai 33/11kV transformer replacement	2nd Transformer for security of supply	**$600,00**
Required to ensure continuity of supply		
Maungaturoto 33/11kV transformer replacements	Replace EOL transformer	**$1,400,000**
Required to ensure continuity of supply		
Bream Bay 2nd transformer	Install second 10MVA transformer	**$1,800,000**
Required to increase substation capacity to meet load growth and provide N-1 capacity to improve security of supply and facilitate outages for plant maintenance (possibility of utilising Trust Power 9MW peaker plant connected to Bream Bay 11kV bus for this purpose to be investigated).		

6.9.3 Significant projects planned to start within the next 10 years (FY24-FY28)

Ngunguru transformer upgrade	2nd transformer for security of supply	**$300,000**
Replace existing 3.75MVA transformer with 5MVA unit (ex service) to increase substation security		
Waipu 33/11kV substation	New zone substation	**$3,300,000**
Construction of new 5MVA zone substation, 33kV line and feeder to strengthen the 11kV network in the Waipu area and provide capacity for anticipated load growth		
Ngunguru 11kV switchboard upgrade	Replace EOL indoor switchgear	**$1,345,000**
Required to ensure personnel safety and plant reliability.		
Poroti 33/11kV transformer replacement	Replace EOL transformer	**$512,000**
Required to ensure continuity of supply		
Maungaturoto 11kV switchboard upgrade	Replace EOL indoor switchgear	**$1,209,000**
Required to ensure personnel safety and plant reliability.		
Maungaturoto 33/11kV transformer replacements	Replace EOL transformer	**$1,400,000**
Required to ensure continuity of supply		
Maungatapere 110/33kV transformer upgrade	Replace 2x30MVA EOL transformers	**$3,850,000**
Replace EOL transformers with larger units to maintain n-1 capacity (possible use of 50MVA transformers ex. Kensington		
Kensington 110/33kV transformer upgrade	Replace 2x50MVA transformers with larger units	**$5,323,000**
Replace existing 50MVA transformers with larger units to provide increased capacity and continued n-1 security of supply to the greater Whangarei City area		
3rd 33 kV Circuit Kensington - Kamo	Increase sub-transmission capacity	**$3,900,000**
The load growth is likely to require more capacity on the circuits to the northern part of the Whangarei sub-transmission Network		
Alternatives: Increase the capacity of the two existing circuits		
Marеretu 11 kV switchboard Upgrade	Replace EOL indoor switchgear	**$2,000,000**
Required to ensure continuity of supply		
Ruawai 2nd transformer	Install second transformer	**$600,000**
To provide N-1 capacity to improve security of supply, load growth means that an alternative means of supply via the 11kV network is less effective as a back-up option.		
Alternative: back up diesel generation		
Kaiwaka 2nd transformer	Install second transformer	**$600,000**
To provide N-1 capacity to improve security of supply, load growth means that an alternative means of supply via the 11kV network is less effective as a back-up option.		
Alternative: back up diesel generation		
Marеretu 2nd transformer	Install second transformer	**$600,000**
To provide N-1 capacity to improve security of supply, load growth means that an alternative means of supply via the 11kV network is less effective as a back-up option.		
Alternative: back up diesel generation		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Section 7: Expenditure Forecasts

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Expenditure Forecasts - Section 7

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Section 7 - Expenditure Forecasts

This section outlines Northpower's forecast operational and capital expenditure for the 10 year period FY19 to FY28. Forecast operational expenditure averages $19 million per annum over the 10 year period and forecast capital expenditure averages $20 million per annum over the 10 year period. Expenditures presented in this section are in real 2017 dollars. An inflation rate of 2% has been used in the nominal expenditure figures provided in the disclosure schedules in Appendix C.

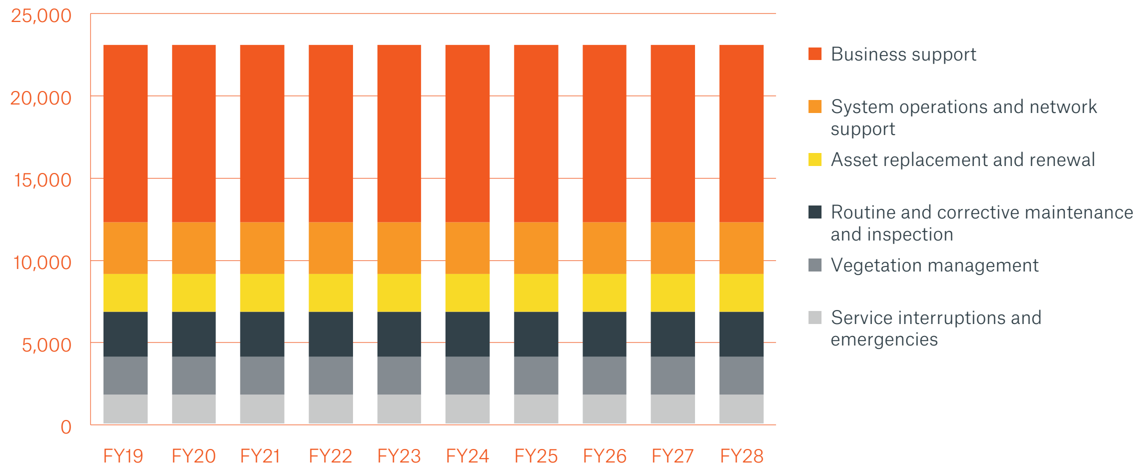
7.1 Operational Expenditure

Operational expenditure has as its basis the network operational activities outlined in section 4 (Lifecycle Asset Management) and is comprised of the following components:

- Routine and corrective maintenance and inspections (preventative maintenance)
- Asset replacement and renewal (follow up work on defects identified from routine maintenance)
- Vegetation management (preventative and follow up work relating to vegetation control)
- Service interruptions and emergencies (fault related work)
- System operations and network support (network operating overheads)
- Business support (corporate allocations and other overheads)

The forecast expenditure allocations are presented in graphical and tabular form below.

EDB 10 Year Opex Plan (2017 $000)



NORTHPOWER EDB 10 YEAR OPEX PLAN (2017 $000)	1	2	3	4	5	6	7	8	9	10
CATEGORY	**FY19**	**FY20**	**FY21**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**
Service interruptions and emergencies	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777
Vegetation management	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300
Routine and corrective maintenance and inspection	2,740	2,740	2,740	2,740	2,740	2,740	2,740	2,740	2,740	2,740
Asset replacement and renewal	2,306	2,306	2,306	2,306	2,306	2,306	2,306	2,306	2,306	2,306
Total Network Opex	**9,123**	**9,123**	**9,123**	**9,123**	**9,123**	**9,123**	**9,123**	**9,123**	**9,123**	**9,123**
System operations and network support	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145
Business support	10,836	10,836	10,836	10,836	10,836	10,836	10,836	10,836	10,836	10,836
Total Non-network Opex	**13,981**	**13,981**	**13,981**	**13,981**	**13,981**	**13,981**	**13,981**	**13,981**	**13,981**	**13,981**
Total Operational Expenditure	**23,104**	**23,104**	**23,104**	**23,104**	**23,104**	**23,104**	**23,104**	**23,104**	**23,104**	**23,104**

7.2 Capital Expenditure

Capital expenditure has as its basis the activities outlined in section 6 (Network Development Plan) as well as end of life asset replacement and is comprised of the following components:

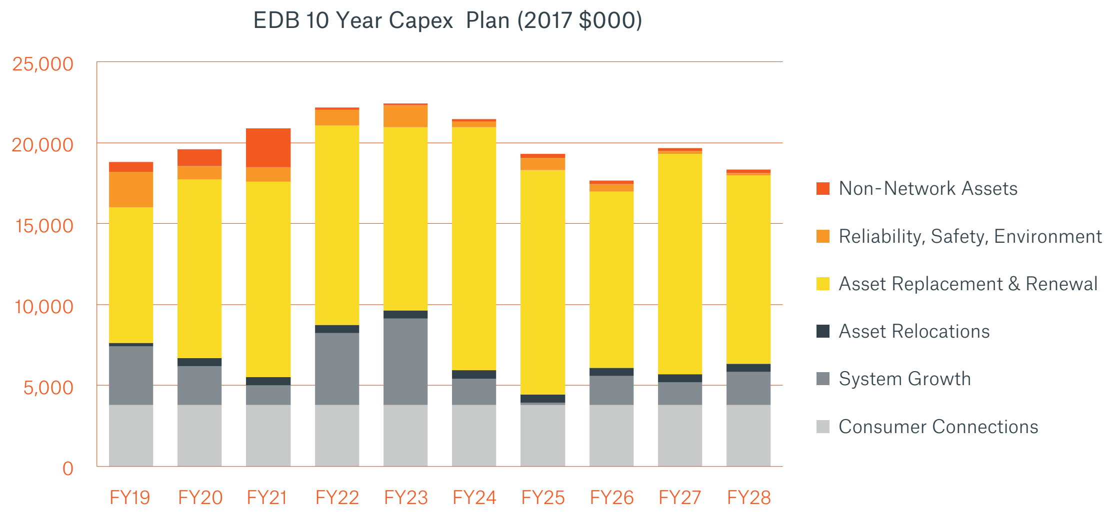
- Customer connection (new connections and supply upgrades)
- System growth (substation and line capacity)
- Asset relocation (line re-routes or overhead to underground conversion)
- Reliability, safety and environment (network performance and compliance)
- Asset replacement and renewal (defective, end of life or technological obsolescence)
- Non-network (operational, systems, engineering, research and development)

Projects (and associated high level cost estimates) listed in the development plan below are requirements as foreseen at this point in time. The further out a project appears on the planning horizon, the more likely it is that it could change with time as better or new information becomes available or unforeseen developments arise necessitating changes to the plan in the annual review.

The forecast percentage of total expenditure per category for the 10 year period FY19 to FY28 is given in the following table. As can be seen, the majority of the planned expenditure is on asset replacement due to the large number of aging assets on the network.

Capex Category	10 year expenditure (%)
Customer connection	18.9
System Growth	11.9
Asset Relocations	2.4
Asset Replacement & Renewal	60.0
Reliability, Safety, Environment	4.1
Non-Network Assets	2.6

The forecast annual expenditure allocations and 10 year development plan are presented in graphical and tabular form below.



NORTHPOWER EDB 10 YEAR CAPEX PLAN ($000) constant prices			1	2	3	4	5	6	7	8	9	10
WS	PROJECT TITLE	EXPENDITURE CATEGORY	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
6108	Transformer Acquisition Cost	Consumer Connections	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040
6109	Transformer Credits from Upgrades	Consumer Connections	-130	-130	-130	-130	-130	-130	-130	-130	-130	-130
6463	Ripple relay purchases	Consumer Connections	85	85	85	85	85	85	85	85	85	85
6107	Capital contributions (Customer)	Consumer Connections	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
6106	Capital contributions (Network)	Consumer Connections	300	300	300	300	300	300	300	300	300	300
	Total	Consumer Connections	3,795	3,795	3,795	3,795	3,795	3,795	3,795	3,795	3,795	3,795
6198	Power Factor Improvement	System Growth	80	0		108	0	0	0	117	0	0
6449	Power Factor Monitoring 11kV Feeders	System Growth	78	80	82	0	0	0	0	0	0	0
6401	Minor capital expenditure (system growth)	System Growth	75	75	75	75	75	75	75	75	75	75
6430	Distribution Transformer & LV Feeder Optimisation	System Growth	50	50	50	50	50	50	50	50	50	50
6461	Maunu Zone Substation	System Growth	1,310	1,900	0	0	0	0	0	0	0	0
6479	Waipu Zone Substation	System Growth	0	0	0	0	2,000	1,300	0	0	0	0
6480	Bream Bay Second 10MVA Transformer	System Growth	0	0	0	600	1,200	0	0	0	0	0
6481	Bream Bay New 11kV Feeder	System Growth	350	0	0	0	0	0	0	0	0	0
6603	Onerahi transformer upgrade (2x15MVA)	System Growth	1,200	0	0	0	0	0	0	0	0	0
6489	Kensington-Kamo Third Circuit	System Growth	0	0	0	0	0	0	0	1,000	1,000	1,900
6492	Helena Bay substation	System Growth	0	0	1,000	1,500	0	0	0	0	0	0
6595	Distribution feeder voltage support	System Growth	150	0	0	190	0	200	0	0	250	0
6551	Land Purchases (future substations Waipu, Helena Bay)	System Growth	0	300	0	400	0	0	0	500	0	0
6573	EV Charging Stations	System Growth	20	0	0	25	0	0	0	30	0	0
6611	Maungatapere transformer upgrade (ex Onerahi)	System Growth	300	0	0	0	0	0	0	0	0	0
6612	Kensington substation 33/11kV transformer	System Growth	0	0	0	1,500	2,000	0	0	0	0	0
	Total	System Growth	3,613	2,405	1,207	4,448	5,325	1,625	125	1,772	1,375	2,025
6402	Minor capital expenditure (relocation)	Asset Relocations	55	55	55	55	55	55	55	55	55	55
6540	Roading works asset relocations	Asset Relocations	50	50	50	50	50	50	50	50	50	50
6613	Overhead to underground conversion	Asset Relocations	0	250	250	250	250	250	250	250	250	250
6614	Ground mounting of 2/4 pole distribution transformers	Asset Relocations	100	150	150	150	150	150	150	150	150	150
	Total	Asset Relocations	205	505	505	505	505	505	505	505	505	505

Section 7 - Expenditure Forecasts

NORTHPOWER EDB 10 YEAR CAPEX PLAN ($000) constant prices			1	2	3	4	5	6	7	8	9	10
WS	PROJECT TITLE	EXPENDITURE CATEGORY	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
6274	RTU Replacements (Zone substations)	Asset Replacement & Renewal	150	150	0	0	0	0	150	150	50	0
6596	Remote switch RTU and comms replacements	Asset Replacement & Renewal	0	0	0	0	60	60	60	60	0	0
6598	Ripple injection plant replacements	Asset Replacement & Renewal	0	0	100	100	100	100	0	0	0	0
6599	Battery bank and battery charger upgrades	Asset Replacement & Renewal	50	0	50	0	50	0	50	0	50	0
6393	Power transformer refurbishment	Asset Replacement & Renewal	0	0	0	0	110	0	0	0	0	125
6601	Microwave radio terminal (Airmux) link replacements	Asset Replacement & Renewal	0	100	0	0	0	0	0	0	0	0
6531	Ahikiwi Voltage regulator replacement	Asset Replacement & Renewal	0	250	0	0	0	0	0	0	0	0
6604	Helena Bay voltage regulator replacement	Asset Replacement & Renewal	0	0	0	0	0	0	0	0	0	0
6396	Protection Relay Upgrades	Asset Replacement & Renewal	100	100	100	100	120	120	130	130	130	140
6397	33kV CT and VT replacements	Asset Replacement & Renewal	0	80	0	80	0	90	0	90	0	100
6494	Ngunguru transformer upgrade to 5MVA	Asset Replacement & Renewal	150	500	0	0	0	0	0	0	0	0
6483	Parua Bay transformer upgrade to 5MVA	Asset Replacement & Renewal	0	0	250	200	0	0	0	0	0	0
6501	Kaiwaka 11kV Switchboard replacement	Asset Replacement & Renewal	0	0	900	500	0	0	0	0	0	0
6502	Ruawai 11kV Switchboard replacement	Asset Replacement & Renewal	0	0	0	900	500	0	0	0	0	0
6503	Hikurangi 11kV Switchboard replacement	Asset Replacement & Renewal	0	900	500	0	0	0	0	0	0	0
6504	Whangarei South 11kV Switchboard replacement	Asset Replacement & Renewal	700	1,100	0	0	0	0	0	0	0	0
6505	Ngunguru 11kV Switchboard replacement	Asset Replacement & Renewal	0	0	0	1,045	300	0	0	0	0	0
6506	Poroti 11kV Switchboard replacement	Asset Replacement & Renewal	0	0	1,296	0	0	0	0	0	0	0
6507	Tap Changer Controller Upgrades	Asset Replacement & Renewal	0	60	0	0	60	0	0	60	0	0
6510	Maungatapere 110/33kV Transformer replacement	Asset Replacement & Renewal	0	0	0	0	0	0	0	1,925	1,925	0
6512	Kensington 110/33kV Transformer replacement	Asset Replacement & Renewal	0	0	0	0	0	2,693	2,630	0	0	0
6522	Abbey System Comms Upgrade	Asset Replacement & Renewal	90	0	0	0	0	0	0	0	0	0
6600	SCADA system hardware and software replacements	Asset Replacement & Renewal	60	0	0	0	300	0	0	120	0	0
6529	Maungaturoto 11kV Switchboard replacement	Asset Replacement & Renewal	0	0	0	0	0	0	1,209	0	0	0
6530	Whangarei Hospital 11kV Switchboard replacement	Asset Replacement & Renewal	300	0	0	0	0	0	0	0	0	0
6513	GXP ION meter upgrades	Asset Replacement & Renewal	0	0	0	0	0	0	0	0	0	0
6597	Security systems replacements	Asset Replacement & Renewal	0	0	0	0	0	75	75	75	75	0
6532	Chip Mill Transformer Replacement	Asset Replacement & Renewal	0	0	0	0	0	450	0	0	0	0
6533	Hikurangi Transformer replacements	Asset Replacement & Renewal	0	900	700	0	0	0	0	0	0	0
6534	Poroti Transformer Replacement	Asset Replacement & Renewal	0	0	0	0	0	512	0	0	0	0
6605	Ruakaka T2 replacement	Asset Replacement & Renewal	0	0	0	0	0	0	0	0	575	0
6606	Whangarei South transformer replacements	Asset Replacement & Renewal	0	0	0	0	0	0	0	0	600	400
6536	Maungaturoto Transformer Replacements	Asset Replacement & Renewal	0	0	0	0	700	700	0	0	0	0
6586	Recloser replacements	Asset Replacement & Renewal	0	0	65	0	65	0	65	0	65	0
6587	Long & Crawford GMS replacement	Asset Replacement & Renewal	100	100	100	100	100	100	100	0	100	100
6588	Recloser controller upgrades	Asset Replacement & Renewal	0	10	0	0	10	0	0	0	10	0

NORTHPOWER EDB 10 YEAR CAPEX PLAN ($000) constant prices			1	2	3	4	5	6	7	8	9	10
WS	PROJECT TITLE	EXPENDITURE CATEGORY	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
6583	Communications System Upgrades	Asset Replacement & Renewal	125	0	0	100	0	0	0	100	0	0
6615	Marеretu 11kV switchboard replacement	Asset Replacement & Renewal	0	0	0	0	0	1,000	1,000	0	0	0
6616	RT Network DMR Tier II upgrade	Asset Replacement & Renewal	0	150	150	0	0	0	0	0	0	0
6617	Analogue UHF point to point link digital upgrade	Asset Replacement & Renewal	30	0	0	0	0	0	0	0	0	0
6618	Kensington substation 33kV switchboard replacement	Asset Replacement & Renewal	0	0	750	2,250	0	0	0	0	0	0
6620	Distribution substation LV panel upgrades	Asset Replacement & Renewal	35	35	35	35	35	35	35	35	35	35
6621	Network strategic spares	Asset Replacement & Renewal	50	0	0	55	50	0	60	0	0	65
6622	Pole EOL replacements	Asset Replacement & Renewal	200	200	200	300	300	500	500	500	500	500
6623	Subtransmission line conductor EOL replacement	Asset Replacement & Renewal	500	500	500	500	500	500	600	700	800	1,000
6624	Distribution line conductor EOL replacement	Asset Replacement & Renewal	900	1,000	1,100	1,100	1,100	1,100	1,300	1,300	1,300	1,300
6625	Low voltage line conductor EOL replacement	Asset Replacement & Renewal	200	200	200	200	200	200	200	250	250	250
6626	Overhead switch EOL replacement	Asset Replacement & Renewal	50	50	50	60	60	60	70	70	70	80
6627	Low voltage service connection EOL replacements	Asset Replacement & Renewal	50	50	60	60	70	70	80	80	80	80
6628	Distribution transformer EOL replacements	Asset Replacement & Renewal	100	100	100	100	130	130	150	150	150	200
6629	Subtransmission oil cable EOL replacements	Asset Replacement & Renewal	0	0	0	0	1,500	1,500	0	0	1,500	1,500
6630	Distribution cable EOL replacements	Asset Replacement & Renewal	10	20	20	30	30	30	40	40	50	50
6631	Low voltage cable EOL replacements	Asset Replacement & Renewal	10	20	20	30	30	30	40	40	50	50
6632	Ripple relay EOL replacements	Asset Replacement & Renewal	10	20	20	30	30	40	40	40	50	50
6633	33kV Circuit Breaker EOL replacement	Asset Replacement & Renewal	0	0	0	0	0	100	0	0	0	110
6634	Zone substation buildings EOL upgrades	Asset Replacement & Renewal	0	0	400	0	0	0	430	0	0	450
6635	Zone substation outdoor switch EOL replacements	Asset Replacement & Renewal	0	0	0	0	50	0	0	0	60	0
6636	Zone substation outdoor structure EOL replacements	Asset Replacement & Renewal	0	0	0	0	100	0	0	0	110	0
6637	Capacitor bank EOL replacements	Asset Replacement & Renewal	0	0	0	15	0	0	20	0	0	25
6638	Minor Capital expenditure (asset replacement & renewal)	Asset Replacement & Renewal	75	75	75	75	75	75	75	75	75	75
	Subtotal (Projects)		4,045	6,670	7,741	7,965	6,735	10,270	9,109	5,990	8,660	6,685
9490	Zone substations	Asset Replacement & Renewal	10	10	10	10	10	10	10	10	10	10
9490	Buildings and grounds	Asset Replacement & Renewal	5	5	5	5	5	5	5	5	5	5
9490	Secondary systems	Asset Replacement & Renewal	95	95	95	100	100	100	100	100	100	100
9490	Overhead structures	Asset Replacement & Renewal	3,200	3,200	3,200	3,200	3,400	3,500	3,500	3,600	3,600	3,600
9490	Overhead conductor	Asset Replacement & Renewal	200	200	200	200	225	225	225	225	225	225
9490	Cables	Asset Replacement & Renewal	220	220	220	220	220	220	220	220	220	220
9490	Distribution transformers	Asset Replacement & Renewal	250	250	250	250	250	300	300	350	400	400
9490	Distribution switchgear	Asset Replacement & Renewal	75	75	75	75	100	100	100	100	100	100
9490	Compensators	Asset Replacement & Renewal	10	10	10	10	10	10	10	10	10	10
9490	Distribution earthing	Asset Replacement & Renewal	290	290	290	290	290	290	290	290	290	290
	Subtotal (Follow up maintenance)		4,355	4,356	4,356	4,360	4,611	4,761	4,760	4,911	4,961	4,960
	Total	Asset Replacement & Renewal	8,400	11,026	12,097	12,325	11,346	15,031	13,869	10,901	13,621	11,645

NORTHPOWER EDB 10 YEAR CAPEX PLAN ($000) constant prices			1	2	3	4	5	6	7	8	9	10
WS	PROJECT TITLE	EXPENDITURE CATEGORY	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
6348	New Reclosers	Reliability, Safety, Environment	45	0	45	0	0	50	0	0	55	0
6472	Whangarei South 33kV T - Stage 2	Reliability, Safety, Environment	700	0	0	0	0	0	0	0	0	0
6400	Whangarei City additional 11kV RMU's	Reliability, Safety, Environment	50	0	0	50	0	0	0	56	0	0
6581	Provision for fibre	Reliability, Safety, Environment	60	60	60	50	50	50	50	50	50	50
6370	Zone Substations Risk Mitigation	Reliability, Safety, Environment	100	100	150	0	0	0	0	0	0	0
6374	Zone Substations Security Improvement	Reliability, Safety, Environment	65	0	0	0	0	75	0	0	0	0
6404	Comms for remote control of motorised switches	Reliability, Safety, Environment	175	0	0	0	0	0	0	0	0	0
6425	11kV feeder backstopping improvements	Reliability, Safety, Environment	0	80	0	0	85	0	0	90	0	0
6607	Distribution feeder auto-reclosing	Reliability, Safety, Environment	25	0	0	0	0	0	0	0	0	0
6434	DSUB MDI Meters (CBD)	Reliability, Safety, Environment	65	65	65	0	0	0	0	0	0	0
6435	Minor capital expenditure (reliability, safety, environment)	Reliability, Safety, Environment	100	100	100	100	100	100	100	100	100	100
6447	AC/DC Panel Upgrades	Reliability, Safety, Environment	50	50	0	0	0	0	0	0	0	0
6497	Whakapara Feeder Express Line to Hikurangi	Reliability, Safety, Environment	250	200	300	0	0	0	0	0	0	0
6519	Fault Passage Indicators	Reliability, Safety, Environment	75	0	0	0	0	0	0	0	0	0
6537	Maungaturoto 33kV Circuit Separation	Reliability, Safety, Environment	258	0	0	0	0	0	0	0	0	0
6560	Communications Network Security Improvements	Reliability, Safety, Environment	0	0	0	50	0	0	0	60	0	0
6565	Zone Substation Neutral Earthing Resistors	Reliability, Safety, Environment	125	125	125	0	100	0	0	105	0	0
6567	Busbar Arc Flash Protection	Reliability, Safety, Environment	50	50	0	0	0	0	0	0	0	0
6591	SCADA comms transfer to dark fibre	Reliability, Safety, Environment	0	0	0	0	0	0	0	0	0	0
6592	Remote station SCADA monitoring	Reliability, Safety, Environment	0	0	0	0	0	0	0	0	0	0
6639	SMART Distribution system (load monitoring)	Reliability, Safety, Environment	0	0	50	100	100	100	0	0	0	0
6640	Ruawai Transformer T2 (new purchase)	Reliability, Safety, Environment	0	0	0	600	0	0	0	0	0	0
6641	Kaiwaka Transformer T2 (new purchase)	Reliability, Safety, Environment	0	0	0	0	600	0	0	0	0	0
6642	Ngunguru Transformer T2 (ex Hikurangi)	Reliability, Safety, Environment	0	0	0	0	300	0	0	0	0	0
6643	Mareretu Transformer T2 (new purchase)	Reliability, Safety, Environment	0	0	0	0	0	0	600	0	0	0
	Total	Reliability, Safety, Environment	2,193	830	895	950	1,335	375	750	461	205	150

NORTHPOWER EDB 10 YEAR CAPEX PLAN ($000) constant prices			1	2	3	4	5	6	7	8	9	10
WS	PROJECT TITLE	EXPENDITURE CATEGORY	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
6443	Network strategic spare store	Non-Network Assets	50	0	0	0	0	0	40	0	0	0
6546	Research and Development (component testing)	Non-Network Assets	30	30	30	30	30	30	50	50	50	80
6569	Aerial Imagery (GIS)	Non-Network Assets	0	0	0	40	0	0	0	50	0	0
6572	Engineering hardware/Software	Non-Network Assets	0	0	50	0	0	0	55	0	0	0
6574	UAV Asset Inspection Platform	Non-Network Assets	30	0	0	0	0	0	0	0	0	16
6577	University Project Collaboration	Non-Network Assets	16	16	16	16	16	16	16	16	16	16
6590	Research and Development (new technology)	Non-Network Assets	50	50	50	50	50	60	70	80	85	90
6571	AMS (WASP replacement and CBRM software)	Non-Network Assets	300	500	400	0	0	0	0	0	0	0
6525	ADMS (Advanced Distribution Management System)	Non-Network Assets	50	300	1,700	0	0	0	0	0	0	0
6644	Minor capital expenditure (non-network assets)	Non-Network Assets	25	25	25	25	25	25	25	25	25	5
6645	Low voltage network operational management system	Non-Network Assets	50	100	100	0	0	0	0	0	0	0
	Total	Non-Network Assets	601	1,021	2,371	161	121	131	256	221	176	207
	Total EDB		18,807	19,582	20,870	22,184	22,427	21,462	19,300	17,655	19,677	18,328


Northpower

Section 8:
Capacity to Deliver

Northpower

Capacity to Deliver - Section 8

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Section 8: Capacity to Deliver

8.1 Overview

Northpower commits to delivering on the following core objectives:

- Customer Service levels – meeting the consumer's needs and expectations, and being responsive to the changing demands on the network;
- Network Development – planning for growth and delivering on the Capex programme;
- Lifecycle Asset Management Plan – optimising expenditure while delivering on the preventative and follow-up maintenance programmes, and managing asset condition; and
- Network Performance – Targets met for reliability and power quality.

To ensure the delivery of objectives Northpower regularly reviews the resources required.
These resources include:

- Finance – funding and cash flows
- Systems – information and management system and process
- People – skills, staffing levels and access to external personnel resources

8.2 Finance

As part of the asset maintenance, replacement and growth asset management processes, Northpower ensures there is sufficient funding to implement the planned work. Northpower's Network business is funded from revenues received from consumer accounts via the Retailers who trade on the Northpower Electricity Network. Our regular updates throughout the financial year enables us to match the necessary funding to provide service levels, including capacity, reliability, security and quality of supply to customers with the work required to achieve these levels.

Northpower ensures it has sufficient funding to meet the AMP expenditure and investment requirements through its annual planning process, including 10 year forecasting models, cashflow forecasts, and a robust Treasury Policy. For funding of new assets (i.e. beyond the immediate financial year), Northpower considers the following:

- Funding from revenue within the year concerned
- Funding from after-tax earnings retained from previous years
- Debt funding using existing and/or new debt facilities (which has a cost and is subject to interest cover ratios)

8.3 Asset Information Management Systems

In order to deliver on our investment programmes we have initiated specific initiatives to help focus on our delivery and streamline work flow processes. Our asset management processes will be reset during 2018, including maintenance management and works planning. This will lead to an improved asset management regime, with intent to align with and potentially certify to ISO 55000.

The current EAM (WASP) asset management system is under review for validity towards the business future state of a more condition based approach. WASP does allow condition based measurements however this feature has not been fully utilised in the past and the functionality WASP offers is not particularly suitable. The work order transaction history is of concern due to either (but not limited to) many work orders not being recorded in the system or multiple jobs being recorded under the one work order. This makes it difficult to rely on this history to make asset management decisions, such as early replacement. The review will lead to a decision to procure and install a new asset management system in the 2019 financial year.

Through the improvement of asset information and analytics, our investment and maintenance profile will ensure improved efficiency in programme scheduling and delivery.

Our inspection programmes are being enhanced, and we now employ (in addition to visual inspection services):

- Drone technology to inspect high and poorly observable zone substation plant, and in future remote distribution lines (aerial zone substation inspections are currently in place); and
- Routine Foresight acoustic testing of all distribution line and plant for electrical discharges.

8.4 Asset Management People

Maintenance strategy was previously managed by the delivery team (Contracts) of Northpower; this is now managed by a dedicated Asset Management team who set out the strategy, budget and work approval. The change will drive delivery of maintenance services, and address any routines that are in backlog.

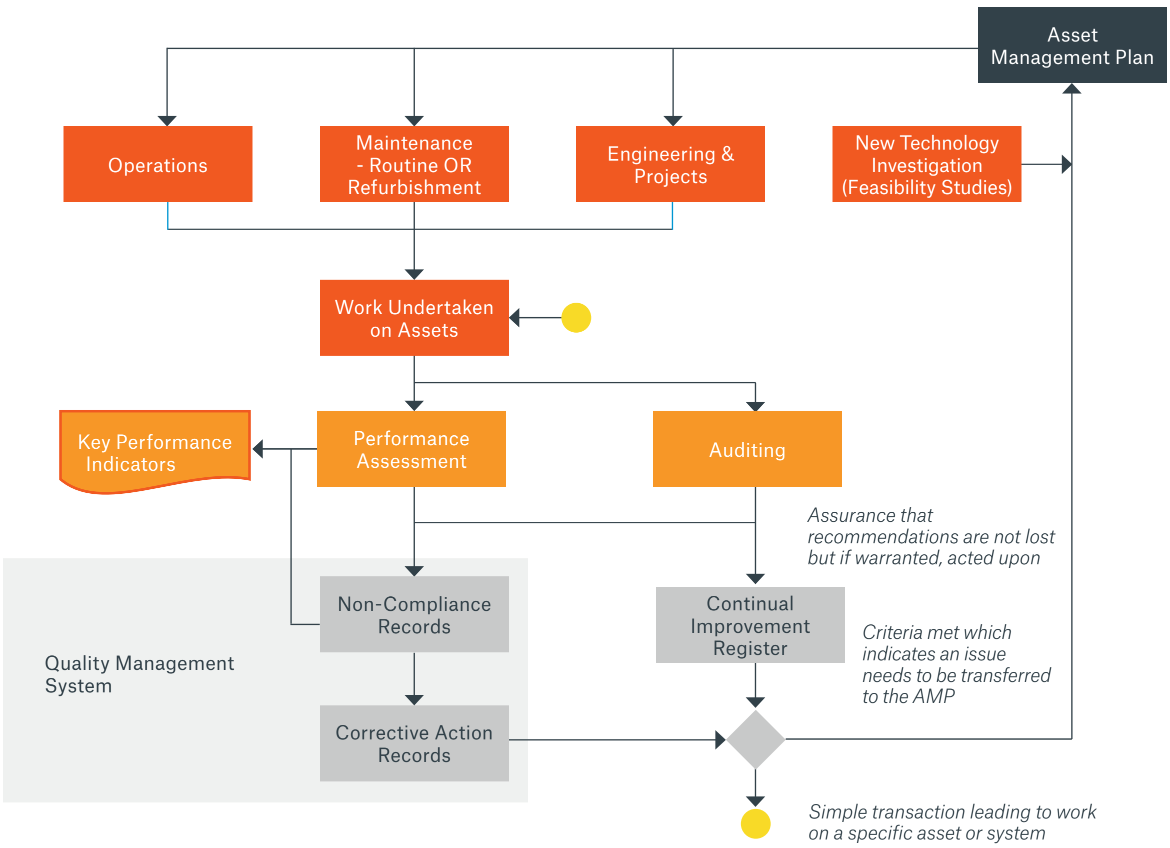
The relationship with our principal contractor, Northpower Contracting, and other contractors that provide services to the Network, has strengthened over the years, and plans are in place to better define the respective responsibilities of the field service and engineering teams.

A robust Service Level Agreement is in place with Northpower Contracting, supported by a series of KPI's to ensure good performance and manage delivery to time and budget.

Northpower has a comprehensive training programme in place for staff, it includes awareness training on Northpower policies, procedures and standards. Staff development also includes attendance at industry conferences and participation in EDB working groups. Staff are encouraged to gain formal qualifications that are related to their roles. In addition to ongoing Health and Safety training, field staff are regularly tested for competency to work on specific network assets. Registers record training and competencies, where additional training is identified this is managed through the People and Capability Group.

8.5 Improvement Programmes

Northpower will continue to follow a path of continuous improvement, as shown in the following diagram, which will help us meet the asset management objectives. Outcomes include efficiency gains and improved ability to deliver projects on time and to budget. The following flow chart depicts our continual improvement process in relation to asset management.



Continual Improvement in Asset Management

We have a number of improvement programmes underway, to ensure continued capacity to deliver, these include:

- Digital customer engagement – better use of digital technologies to communicate to customers, particularly around power outage notification;
- Increased staff resources – additional and new asset management roles in planning, design, project delivery and asset maintenance;
- New Asset Management System – migrate from the existing maintenance management system to a new and improved asset management system, including a reset of our approach; and
- Improved asset information gathering from the field and better data analytics.

Northpower has responded to the planned increase in asset investment through an increase in resourcing and ensuring the right mix of capabilities is available. Plans to increase internal resourcing include increasing our resources in the area of planning, design, maintenance strategy, and project management.

Key focus areas include:

- Lifting our project management and governance processes to enable us to deliver work programmes;
- Managing work programmes to optimise design and procurement processes;
- Improving our network demand and dynamic load modelling; and
- Reviewing our asset inspection programme to provide better asset condition information.


Northpower

Section 9:
Risk Management

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Risk Management - Section 9

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Section 9: Risk Management

9.1 Introduction

Risk management forms an integral part of Northpower's overall business philosophy. The company's business objectives are managed and achieved through the application of sound and thorough risk management practices.

9.2 Risk Management Policy

Risk is represented as a threat or uncertainty that impacts on our ability to achieve Northpower's goals and objectives and is integrally linked to Northpower's business plan and strategy. Risk is defined in terms of a combination of the impact and likelihood of an event occurring.

Risk management is a process that manages the uncertainty of events that materially impact on Northpower's ability to achieve its goals and objectives. Risk management involves the process of risk assessment and recording through to developing treatments and controls to mitigate the impact of the risks. Northpower is committed to proactively and consistently managing risk in order to:

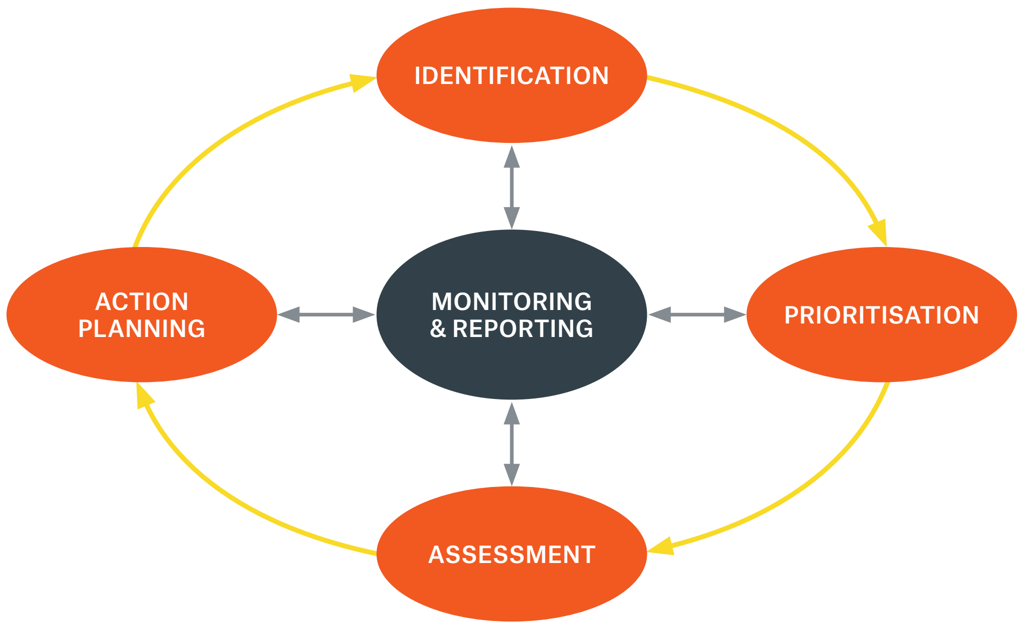
- enhance and protect Northpower's value by delivering on its commitments and meeting stakeholders' expectations;
- allow Northpower to pursue opportunities in an informed way and aligned with the Board's risk appetite; and
- ensure a safe and secure environment for Northpower people (employees and contractors), partners and customers.

Risk management will be carried out generally in accordance with the following standards:

- AS/NZS 7901:2014 Electricity and Gas Industries – Safety Management Systems for Public Safety
- AS/NZS 3931:1998 Risk Analysis of Technological Systems - Application Guide
- AS/NZS ISO 31000:2009 Risk Management – Principles and Guidelines.

9.3 Risk Management Framework

Northpower has developed its Risk Management Framework based on the principles and framework of AS/NZS ISO 31000:2009. The framework is represented by the following model.



Risk Management Framework Model

9.3.1 Risk Governance

Northpower maintains a risk register and regularly evaluates, ranks, and reassesses its risks. Risk analysis (which involves consideration of both likelihood and consequence) is undertaken across the business units and recorded in the risk registers. The registers are structured to list the risks and include assessed current risk levels. The outputs from the risk analysis are used to set priorities for risk action plans.

Northpower applies a risk assessment to both its network operations, and in the development of its projects.

The risk registers are controlled documents, located centrally and the following Northpower documents outline processes to enable management of targeted risks and hazards:

SMS-030 Hazard Management Flow Chart

SMS-031 Manage Hazards Procedure

SMS-032 Operational Risk Group – Composition, Role and Responsibility

SMS-033 Procedure for Categorisation of Risks/Hazards

SMS-034 Procedure for Review of Operational Hazards

SMS-035 Procedure for Data Entry into Operational Hazard Register

9.3.2 Electricity Network Risk Management

Evaluation of Electricity Network risks begins with a regular review of the risks involved in building, operating, and maintaining the electricity network. Activities include reviewing risks in the risk register, updating risks that have changed, and adding newly identified risks. Mitigations and controls are identified, and where necessary are implemented through action plans. The key network risks are reviewed at least twice annually and circulated to the Northpower Board.

Northpower's staff, contractors and sub-contractors are tested for competencies, to be authorised to work on the network. Inductions and "tail-gate" sessions ensure field staff manage health and safety risk when working on the assets. Operational policies and formalised permitting and switching processes manage risk of asset damage and injury.

Northpower has a holistic approach to risk management, acknowledging that as part of its risk management context, community wide risk management is necessary to ensure a safe, robust and resilient electricity network. Northpower also participates in industry initiatives to access learnings from peers.

Network risk action plans, via projects or initiatives, implement treatments and controls to reduce the risk to within acceptable levels. The majority of network projects are identified and justified based on the risk reduction potential they offer.

9.3.3 Project Risk Management

During project delivery, the project management framework covers the process of project risk management as a key control mechanism to assure the benefits of project delivery. Whilst having a knowledge base of known, generic risks, the project manager is encouraged to review each job uniquely to assess and then manage risk. For larger projects the project specific risks are reviewed more frequently.

Safety-in-design practices manage project risks however more essentially mitigate ongoing operational risks. One example is the inclusion of firewalls in new zone substations to control risks to staff and the public in the unlikely event of a transformer explosion. During the design stage project safety is ensured by managing site layout to enable safer access during construction. Northpower actively utilises safety-in-design practices on all major projects.

9.3.4 Risk Evaluation Methodology

The risk evaluation methodology for Northpower business risks is provided in the Risk Management Framework.

Networks operate a tailored adaptation of this framework that is specific to the Network's context.

The following section describes the methodology for risk evaluation.

All risks have their risk levels (scores) evaluated in the above manner and are then entered into the Network risk register, which can be sorted, ranked and displayed according to various criteria. When ranked according to residual risk level, this ranking is used to prioritise Network risks and allocate money, resources and management effort to reduce risks to within target levels. Priority is given to mitigation of risks with a high risk rating, or risks that can achieve significant risk reductions for minimal effort. Generally a watching brief is maintained over low risks, considered to be within Northpower's risk appetite. Existing controls that have been identified to reduce raw risk scores to within acceptable levels are audited and tested internally on a regular and critical basis, to ensure that the controls are still in place and are effective.

The risk assessment includes the following steps:

1. Ensure each risk is well defined in terms of its description, categorisation, clear cause/event, clear consequence/effect, and context.
2. Assess the likelihood (chosen from categories 1 – 5, each objectively based on a probability)
3. Determine the consequence (choose from categories 1 – 5, based on the worst impact against all consequence categories)
4. Determine the risk (product of consequence x likelihood)
5. Identify actions that can be taken to reduce risk levels, focussing more on the higher risk levels
6. Determine the priority of actions to be taken, with owners (based on risk levels and the cost/benefit of the actions)

Likelihood					
Almost Certain (5) Within 1 year	Moderate (5)	High (10)	Extreme (15)	Extreme (20)	Extreme (25)
Likely (4) 1 in 2-5 years	Moderate (4)	High (8)	High (12)	Extreme (16)	Extreme (20)
Possible (3) 1 in 5-10 years	Low (3)	Moderate (6)	High (9)	High (12)	Extreme (15)
Unlikely (2) 1 in 10-50 years	Low (2)	Moderate (4)	Moderate (6)	High (8)	High (10)
Rare (1) 1 in 50 years or more	Low (1)	Low (2)	Low (3)	Moderate (4)	Moderate (5)
	Low 1	**Minor** 2	**Moderate** 3	**Major** 4	**Catastrophic** 5

Consequences

Risk Treatment

All risks, once identified and assessed, are considered for treatment by actions taken to reduce the consequences and/or likelihood. Since resources, funding and management effort is not unlimited, these responses will need to be prioritised across the entire risk register according to the ranking of residual risk levels as well as consideration of the costs/benefits of the various responses. The treatment of risks will create plans, actions and projects and, when completed, should reduce the residual risk levels to within target levels. This reduction should be tested to ensure the full benefit of the risk treatments is being realised.

The effectiveness of risk treatments are monitored by the Asset Management Group, and issues escalated for action to the Network's senior Management Team where required.

Risks with a score level of Extreme are reported to and monitored by Northpower's Chief Executive and the Executive Leadership Team. The table below summarises the response to assessed scores for identified risks.

Risk Score	Response
Extreme	Immediate escalation/notification to executive, urgent action to reduce risk
High	Action to reduce risk in short term, monitor existing controls for effectiveness
Moderate	Reduce risk via cost effective measures, monitor existing controls for effectiveness
Low	Monitor existing controls for effectiveness

9.4 Risk Management Process

This Asset Management Plan focuses on risks to the successful operation and management of Northpower's electricity distribution business and associated assets.

Northpower has a companywide commitment to reduce safety risks. Assessment of safety factors and risks is routinely considered in every activity including asset management functions.

The major physical risks (and associated mitigations/solutions) to Northpower's network are summarised in the sections below.

9.4.1 Key Business Risks

Northpower collates and review risks on a twice-yearly basis for the Network The key risks on the register include the following asset related risks:

Risk Title	Definition
Unsafe Network asset causes injury to staff or public	If we do not identify and remedy unsafe assets we may injure the staff or the public
Injury to member of the public due to poor or inadequate public safety protection, information or education.	If we do not protect, inform or educate the public they may seriously injure themselves
Contractor injury/fatality due to failure to follow safe working practices.	If we do not monitor health and safety behaviours and ensure our contractors adopt safe working practices, we may have a fatality on the network.

Risk Management Process – Key risk from Network Business Unit register

9.4.2 Asset Risks – Faults and Outages

The risk of equipment failure is assessed regularly and is a key rationale in setting strategy and budgets. Northpower draws upon records of incidents, inspections, experience and national and international practice to determine the risk associated with assets and asset types and has put in place mitigations for these risks.

Key Physical Risks to Assets

Risk loss/fault/event	Likelihood	Impact	Consequential Damage Risk	Solutions / Mitigations in place
Loss of Continuity of Supply from Transpower or Generators causes major and lengthy disruption to customers	Unlikely	Major	Severe reduction in supply capacity for hours, weeks or months over entire network	Load management Customer information and management Relationship management with Transpower and Generators
Loss of 33/11kV transformer at 'n' security substation causes outages	Unlikely	Moderate	Loss of supply for up to several hours	Restore supply via 11kV network Install spare or replacement from another substation Temporary generator connection
Loss of 33/11kV transformer at n-1 security substation causes outages	Unlikely	Minor	Loss of supply for up to several hours	Reduce load on remaining transformer (if necessary). Temporary backfeed support on 11kV

Risk loss/fault/event	Likelihood	Impact	Consequential Damage Risk	Solutions / Mitigations in place
Damage to 11kV switchboard in Zone Substation causes outages	Very Unlikely	Moderate	Up to 24 hours loss of supply for some customers	Isolate faulty section or repair. Transfer load to alternative source (e.g. back-feed or generator
Overhead Line section failure causes outages	Almost Certain	Insignificant	Unlikely to cause major damage to other assets	Isolate faulty section or repair. Transfer load to alternative source (e.g. back-feed or generator)
Cable section failure causes outages	Very Likely	Insignificant	Unlikely to cause damage to other assets	Isolate faulty section or repair. Transfer load to alternative source (e.g. back-feed or generator)
Individual Circuit Breaker failure causes outages	Possible	Insignificant	Catastrophic failure could damage other assets, for indoor switchboards some damage can be expected	Maintenance regimes, design (protection/housing) and equipment standards for breakers
33kV Outdoor Bus failure causes outages	Unlikely	Major	Catastrophic failure could damage other assets	Assess and repair as soon as possible. Design and install substation risk mitigations eg walls and containment
Indoor switchboard failure causes outages	Very Unlikely	Major	Catastrophic failure could damage other assets including the building	Assess and repair as soon as possible. Design and install substation risk mitigations eg walls and containment
SCADA system failure causes outages	Unlikely	Minor	Major failure will result in loss of monitoring and control	Redundancy and backup on key components (including software)
Earthquake causes network damage leading to widespread outages	Rare	Major	*Note 1*	Mitigate by upgrade and specific design for major equipment. Repair damage as soon as possible
Storm causes network damage leading to widespread outages	Likely	Moderate	*Note 1*	Mitigate by tree maintenance and line design Repair damage as soon as possible
Flood causes network damage leading to widespread outages	Unlikely	Moderate	*Note 1*	Repair damage as soon as possible using response procedures
Tsunami causes network damage leading to widespread outages	Rare	Major	Transmission supply at Bream Bay is at risk and could cause systemic outages	Repair damage as soon as possible using response procedures
Pandemic impacts network operations leading to widespread outages	Very Unlikely	Minor	Asset Management Capability	Use corporate contingency procedure
Serious harm incident caused by failure of safety performance of NP assets and/or staff	Very Unlikely	Moderate	Costly damage to plant or property or other assets Reputation impacts Liability	Quality design Strict safety specifications Safety orientated decision making Safe work practices Preventative Maintenance Schedules Follow up Maintenance Fault Response Asset Renewal/Replacement Program

Note 1: Contingent upon the severity of the event, restoration will depend on accessibility to sites of damage and the extent of damage to the overall network. Typically, even for a natural disaster, the vast majority of customers can be restored within 1 to 2 days.

9.4.3 Asset Risk Identification / Event Mechanism Tables

The following table provides a list of potential risks for each of the major distribution asset categories grouped under risk categories of Electric Shock, Physical, Flash / Explosion and Environmental.

Distribution Asset	Electrical Shock	Physical	Flash/Explosion	Environmental
Poles Structures and fittings	Pole becomes conductive. Pole/ fitting failure allows conductor to fall. Cables running up poles damaged or unprotected Ability to climb pole or structure near pole allowing access to live conductors.	Structural failure 3rd party contact e.g. car v pole. Excavating near pole Loose or disconnected guy	Failure causes fire	
Overhead lines and cables	Contact with live conductor e.g. mobile plant, boats, high loads, recreation, construction activities, structures etc. Trees growing or falling on lines Unauthorised tree trimming by lines Contact between HV and LV conductors. Conductor clearances, drop and failure (to ground and other structures)	Contact with live conductor e.g. mobile plant, aircraft, boats, high loads, construction activities etc. Conductor Drop. Perceived EMF risk.	Failure or clashing causes fire	
Underground cables	Contact with live conductors. Broken neutrals. Inadequate depth or protection Excavating near cables	Cable location incorrectly recorded in GIS Inaccurate cable location on site		Oil leak (oil cables only)
Distribution pillars	Contact with live conductors or metal components. Excavating near pillar	3rd party contact e.g. car v pillar.	Equipment failure causes fire	
Pole mounted transformer	Contact with live conductors. Site becomes alive (includes EPR risk)	Perceived EMF risk.	Internal fault that creates an explosive rupture of tank and or oil fire starts.	Oil leak.
Ground mounted transformer	Contact with live conductors. Tank becomes alive (includes EPR risk)	3rd party contact e.g. car v transformer Perceived EMF risk.	Internal fault that creates an explosive rupture of tank and or oil fire starts.	Oil leak.
Pole mounted switchgear			Flash-over ("open" ABS type)	SF6 Leak
Ground mounted switchgear	Contact with live conductors. Tanks become alive (includes EPR risk)	3rd party contact e.g. car v switchgear.	Internal fault that creates an explosive rupture of tank and or oil fire starts.	Oil leak (oil type) SF6 leak.
Electric Vehicle Chargers		3rd party contact e.g. car	Equipment failure causes fire	

Distribution Asset	Electrical Shock	Physical	Flash/Explosion	Environmental
Distributed Generation	Non-compliant or unauthorised DG does not shut down during network outage Electric shock risk	Overvoltage damage to appliances		
Revenue Metering	Contact with live conductors	3rd party contact (e.g. meter reader)	Equipment failure causes fire	
Design		Poles, lines, cables and equipment positioned in hazardous locations	Underrated or inappropriate conductors or equipment	Oil containment insufficient to contain spill
Construction	Phase and neutral crossed Conductor clearances inadequate	Open excavations eg trench, jointing pits, pole holes		
Asset Management	Reticulation not identified or inspected Generator feedback Unauthorised connections Inadequately secured sites and equipment		Voltage unbalanced or outside limits and earth fault, leakage or over currents	

Key Hazards with Physical Distribution Assets

Zone Substation	Electrical Shock	Physical	Flash/Explosion	Environmental
Site	Earth potential rise (EPR)	Perceived EMF risk.	Flying debris, spread of fire.	Noise, radio interference.
Outdoor yard (including switchgear)	Contact with live conductors, EPR of yard fence & other exposed metal.	Perceived EMF risk.	Arc flash, flying debris, spread of fire.	Noise, radio interference, SF6 (contained in some CB's)
Indoor switchgear and control systems	Contact with live conductors. EPR of exposed metal.	Perceived EMF risk.	Arc flash, explosive force.	SF6 (contained in some CB's)
Ripple Plants	Contact with live conductors or metal components.		Flying debris	(all capacitors are non PCB type)
Outdoor transformers	Contact with live conductors. Site becomes alive (includes EPR risk)	Perceived EMF risk.	Internal fault that creates an explosive rupture of tank and or oil fire starts. Flying debris (busing & surge arrestors)	Oil leak. Transformer noise.
Indoor Transformers	Contact with live conductors. Site becomes alive (includes EPR risk)	Perceived EMF risk.	Internal fault that creates an explosive rupture of tank and or oil fire starts. Flying debris (busing & surge arrestors)	Oil leak but contain within the building Ventilation noise.

Key Hazards with Physical Substation Assets

To prevent and mitigate the identified asset risks, Northpower starts with good design principles. Installed assets are inspected regularly and undergo a structured preventative maintenance programme to monitor condition and hazard risk. Additionally, from a process perspective, each physical job by a service provider starts with a risk identification step to ensure that countermeasures to the risk are identified and implemented.

9.4.4 Environmental Risk

Northpower's Environmental Management Plan defines the policies, procedures, organization and responsibilities that in total create the Environmental Management System (EMS) for Northpower

The EMS is designed for compliance and certification to the international standard ISO14001:2004 Environmental Management System. It is integrated with other major systems:

- ISO9001:2008. Quality Management System,
- AS/NZS 7901;2008 Electricity and Gas Industries – Safety Management Systems

Northpower's EMS aims to maximise the positive impacts and minimise the negative impacts that Northpower's activities, products or services may have upon human health and the environment and to ensure compliance with the relevant environmental legislation.

Northpower aims to demonstrate leadership and continual improvement in environmental management. In all activities, Northpower will seek to identify, monitor and improve the impact on the environment. To this end, Northpower will:

- Aim to achieve a level of performance which complies with the Resource Management Act 1991 and all statutory requirements and conditions of consents relating to environmental matters.
- Continually improve our performance as measured by our environmental objectives and their associated targets.
- Prevent pollution, and commit to re-use, recovery and recycling as opposed to disposal.
- Identify, implement and promote ways to improve efficient use of resources, including energy and water.
- Incorporate environmental performance standards into contracts and service level agreements for suppliers and contractors who meet the same high environmental standards imposed on Northpower.
- Plan to adopt a structured environmental management system using the ISO 14001 standard. This system will be the means by which, environmental objectives and targets, are set and reviewed.
- Include environmental considerations in all business planning, including options to reduce or eliminate adverse effects on the environment resulting from Northpower's activities.

In a similar vein to our safety procedures, environmental risks are reviewed at the start of a project or site works and prevention/mitigation measures are established. Environmental effects/consequences taken into consideration in the process include some or all of the following:

- Contamination via Oil Spill
- Contamination via Chemical Spill
- Contamination via Pollution of Waterways or Sea – sediment, slurry, other contaminant
- Contamination via Air Pollution
- Visual Pollution
- Damage to Protected Tree/Area
- Damage to Trees/Vegetation
- Damage to Other Utilities, e.g. water, gas
- Damage to Other People's Property
- Noise
- Dust
- Fire
- Landslip and/or Erosion
- EMF

9.5 Emergency Response and Contingency Plans

Northpower manages exposure to two emergency-related consequences, namely safety impacts and outage impacts. Safety impacts are managed according to safety response procedures that have been mentioned previously.

Northpower's business continuity framework covers the response to outage impacts.

Northpower Business Continuity Framework

Focus		People	Infrastructure	Plans
Storm Response Accident Response Building Evacuation	Emergency Response	• Emergency team structures • Clearly understood roles • Appropriate nominations • Alternatives for key roles • External parties integration • Rehearsed /trained / tested	• Emergency operations • Onsite • Local off site • Remote off sites • Supporting resources • Communications systems • Tested	• Roles clearly defined • Emergency plans • Key scenario coverage • Action checklist for roles • Contact numbers • Reference information • Chart, plans, maps
Executive leadership Business disruption Manage consequences Co-ordinate response Lifelines response	Crisis Management	• Executive team structures • Clearly understood roles • Appropriate nominations • Alternatives for key roles • External parties integration • Rehearsed /trained / tested	• Management command Centres • Onsite • Local off site • Remote off sites • Supporting resources • Communications systems • Tested	• Roles clearly defined • Key scenario crisis plan • Civil defence lifelines plan • Action sheets / call trees • Reference information • Command Centre Kit
Core business Core support functions Recovery focus Lifelines response Contractors	Business Recovery	• B.U. team structures • Clearly understood roles • Appropriate nominations • Alternatives for key roles • External parties integration • Rehearsed /trained / tested	• Back up facilities • Plant & equipment • Vehicles & spares • Communications • Access to systems • Documents & records • Live tested	• Roles clearly defined • Recovery plans for key BU's • Recovery strategy overview • Action checklist for roles • Reference information
IT systems Scada Radio Telephony Security/CCTV	Technology Recovery	• IT team structures • Clearly understood support • Backup and support for roles • Clear recovery strategies • Rehearsed	• END USER • Meets BU needs • Fall back site • CENTRAL • Backup site tested • Logistics tested	• Roles clearly defined • Recovery strategy overview • Constraints and priorities • Action checklist / call trees • Reference available

Business Continuity Framework

Northpower has developed emergency response plans that lay out emergency responses to a range of emergency events.

Northpower's guiding principle is to firstly avoid injury or loss of life, secondly to avoid property damage, and thirdly to restore electricity supply in an order that may give priority to certain classes of customers such as medical facilities.

A Corporate Business Continuity Plan has been developed to provide executive and senior management level corporate response to contingencies (including establishing an Incident Management Team). The Emergency Response team has operational responsibility during contingent events, and reports to the Incident Management Team. The Emergency Response Team prepares for contingencies that cover three broad scenarios:

- Loss of significant assets
- Natural disasters and large scale events
- Loss of supply due to failure of the Transpower Grid

9.5.1 Contingencies for Loss of Major Assets

Every event is different and affects different assets. For example, loss of supply at a zone substation could be caused by a single fault on an N security sub-transmission line or a fire. Northpower has addressed this by creating generic contingency plans for individual assets, balancing investment cost against the impact of non-supply to various customers.

Electricity supply interruption risks are managed through ensuring adequate capacity in the assets to deliver peak power flows under emergency and normal conditions. This leads to redundancy/duplication of supply, depending on whether the additional costs of outage to a large customer base outweigh the cost of investment. Security categories are:

- N Security - a system that, following the loss of a single power system element, is unable to accommodate the full load.
- N-1 Security - a system that, following the loss of a single power system element, is still able to accommodate the full load.
- Switched N-1 security – a system that, following the loss of a single power system element results in a relatively short outage while alternate supplies are connected (such as switching to a back-up high voltage feeder).

The following table notes Northpower's network contingency measures that are targeted for support of the network power flows in the event of asset failure.

Asset Type	Target Network Contingencies	Other Mitigation Measures
Overhead Line	Circuits with N-1 or N-1 switchable security: use the remaining circuit while the line is repaired Circuits with N security: back-feed as many customers as possible through alternative feeds. Use portable generation to support distribution back-feed for sustained outages	Large stocks of basic line hardware components are held for general use, e.g. poles, conductors, cross arms etc. Have own 500KVA mobile generator and access to other large generators.
Cable	Circuits with N-1 or N-1 switchable security: use the remaining circuit whilst the line is repaired. Circuits with N security: back-feed as many customers as possible through alternate feeds. Use portable generation to support distribution back-feed for sustained outages	Strategic stocks of cables. Have own 500KVA mobile generator and access to other large generators. Access to specialist cable repair staff in Auckland.
Transformers	Substation with N-1 or N-1 switchable security: supply on remaining transformer whilst faulted transformer in repaired or replaced.	Have strategic spares for components such as bushings. Have stocks of transformers.
Individual Circuit Breaker	Most zone substations can supply load with an individual feeder CB out of service. Incomer CB of N-1 or N-1 switchable security: run on remaining incomer until CB is returned to service or replaced. Incomer CB of N security substation: back-feed as many customers as possible through alternate feeds. , until CB is returned to service or replaced. Use portable generator to support distribution back-feed, for sustained outages	Many of the indoor CB's are "rackable"", in some cases can take a CB from a less critical location. Have strategic spares of most type of CBs, so simple defects can often be fixed relatively easily.
33kV Outdoor Bus	Substations with N-1 or N-1 switchable security have a bus section switch. Supply can be restored by opening this switch and re-livening the un-faulted section. Substations with N security option will vary depending on the situation: some faults can be isolated by switches and supply restored by the use of the bypass switch. Back-feed as many customers as possible through alternate feeds until repairs have been effected. Use portable generator to support distribution back-feed, for sustained outages	Have stocks of insulators, copper bus-bar & conductor etc.

Asset Type	Target Network Contingencies	Other Mitigation Measures
Indoor switch	Substation with bus couplers, open coupler and re-liven un-faulted section of bus: for 11kV switchboards, some configuration (by switching) of the HV distribution network will be required. For switchboards without bus couplers: back-feed as many customers as possible through alternate feeds. In the worst case, may have to cut faulty section away. Use portable generation to support distribution back-feed for sustained outages.	Have some stocks of bushing & CTs for the more critical switchboards. For Bream Bay, 33kV switchboard have complete spare cubicles & CBs.
SCADA system	Northpower has the capability to manually operate substations on site. Note loss of SCADA will not cause any interruption to supply. The communication network is configured in an N-1 configuration, ensuring all key trunk communication circuits have back-up. Northpower does operate “Translay” protection using pilot wires. In the event of pilot wire failure steps can be taken are to disable “Translay” protection & restore supply, all circuits with “Translay” protection have back-up protection scheme.	Have a large range of the RTUs, radio system & communication cables. Have a least one means of communication that is independent from the communications used by SCADA. In the process of removing protection using “copper” pilot cables.
Control Room	A back up control room, fitted for SCADA services, is provided at an alternate location. Duplicate servers are provided at an alternate location.	Man critical substations. Utilise radio and cell phone communications.

Asset Contingencies

Northpower operates both indoor and outdoor switchyards at its zone substations. Both arrangements have bus coupling circuit breakers to facilitate load transfer, in addition to the ability to isolate individual circuit breakers. All Northpower’s 11kV switchgear is of the indoor type, some with and some without bus coupling circuit breakers.

9.5.2 Responding to Natural Disasters and Large Scale Events

Northpower has a number of additional planning tools and processes available to aid recovery in significant events. These include:

- Switching plans to restore power to areas affected by large scale outages
- Processes and procedures to manage operations and field staff involved in the event
- Guidelines to aid prioritisation of network restoration
- Policy and mutual agreement to provide assistance to and receive assistance from other networks.
- Storm Management Plan.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LEATHER PROTECTORS

Appendix A: Glossary of Terms

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Glossary of Terms - Appendix A

Appendix A - Glossary of Terms

A	Ampere
AAAC	All Aluminium Alloy Conductor
AAC	All Aluminum Conductor
ABS	Air Break Switch
AC	Alternating Current
ACSR	Aluminium Conductor Steel Reinforced
ADMS	Advanced Distribution Management System
AMMAT	Asset Management Maturity
AMP	Asset Management Plan
AMS	Asset Management System
BC	Bus Coupler
BIL	Basic Insulation Level
BU	Business Unit
CAIDI	Customer Average Interruption Duration Index
CAPEX	Capital Expenditure
CB	Circuit Breaker
CBD	Central Business District
CCTV	Closed Circuit Television
CE	Chief Executive
CT	Current Transformer
DC	Direct Current
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DSL	Digital Subscriber Line
E/F	Earth Fault
E/S	Earth Switch
EAM	Enterprise Asset Management
EBIT	Earnings before Interest and Tax
EDB	Electricity Distribution Business
ELB	Electricity Lines Business
ELEC	Electronic
EMF	Electromagnetic Field
EOL	End Of Life
EPR	Earth Potential Rise
FY	Financial Year
GAAP	Generally Accepted Accounting Principles
GFN	Ground Fault Neutraliser
GIS	Geographical Information System
GM	Ground Mounted
GM	General Manager
GPS	Global Positioning System
GWh	Gigawatt Hour
GXP	Grid Exit Point
HDBC	Hard Drawn Bare Copper
HR	Human Resources
HSQE	Health Safety Quality Environment
HV	High Voltage, greater than 1kV
ICP	Installation Control Point
ICCP	Inter-Control Centre Communications Protocol
IED	Intelligent Electronic Devices
IP	Internet Protocol
km	Kilometer
KPI	Key Performance Indicator
kV	Kilovolt
kVA	Kilovolt Ampere
kVAr	Kilovolt Ampere (reactive)
kW	Kilowatt

Glossary of Terms - Appendix A

kWh	Kilowatt Hour
LTI	Lost Time Injury
LV	LV Low Voltage, less than 1kV
MD	Maximum Demand
MDI	Maximum Demand Indication
MVA	Megavolt Ampere
MW	Megawatt
NEPT	Northpower Electric Power Trust
NER	Neutral Earthing Resistor
NPV	Net Present Value
O/C	Overcurrent
ODV	Optimised Deprival Value
OH	Overhead
OHUG	Overhead to Underground
OLTC	On Load Tap Changer
OPEX	Operational Expenditure
PCB	Polychlorinated Biphenyl
PDC	Polarisation Depolarisation Current
PILC	Paper Insulated Lead Covered
PM	Project Manager
PV	Photovoltaic
RAB	Regulatory Asset Base
RC	Replacement Cost
RMA	Resource Management Act
RMU	Ring Main Unit
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Duration Index
SCADA	Supervisory Control and Data Acquisition
SF6	Sulphur Hexafluoride
SFE	Sanction for Expenditure
STAT	Static
SVL	Sheath Voltage Limiter
SWER	Single Wire Earth Return
TRFR	Transformer
UAV	Unmanned Aerial Vehicle
UG	Underground
UHF	Ultra High Frequency
UPS	Uninterrupted Power Supply
V	Volt
VAC	Vacuum
VHF	Very High Frequency
VOIP	Voice Over Internet Protocol
VT	Voltage Transformer
WASP	Works, Assets, Solutions and People
XLPE	Cross linked Polyethylene


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Appendix B: Substations Data and Feeder Maps

Northpower

Substations Data and Feeder Maps - Appendix B

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Appendix B - Substations Data and Feeder Maps

Bream Bay Zone Substation

Zone Substation	Bream Bay		
Transformer 1 (MVA)	7.5/10		
Peak load (MW)	4.6		
ICP's connected (No.)	1201		
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**
Marsden South	1107	11	1193
Port Feeder	1110	11	8

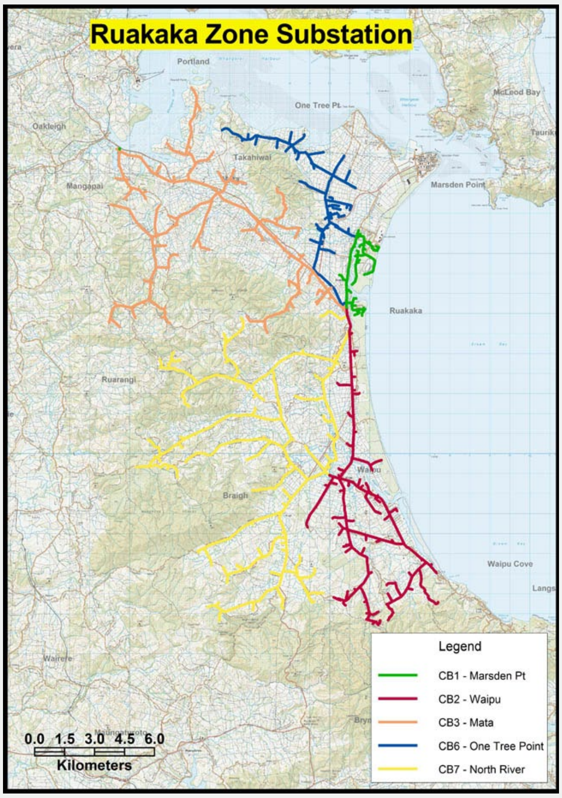
Bream Bay Geographic Feeder Layout

This substation supplies a mixture of industrial, commercial and residential load. The potential for growth in the surrounding area is very high, with the District Council designating large areas of land for heavy industry, service industry and residential development. The present 11kV load is relatively small but is expected to increase substantially in the medium to long term due to the development of the deep-water port at Marsden Point, a newly established marina in the One Tree Point area and other growth potential noted above.

Although it is possible to back feed part of the 11kV load from Ruakaka substation, in the event of a contingency on the single 10MVA 33/11kV transformer, installation of a second transformer is planned in future (FY23) to increase security of supply as the load grows. The need for and timing of a second transformer will need to take into consideration the recent commissioning of a 10MW peaker generation plant (connected to the station's 11kV bus) by an energy company as this plant could be used for backstopping purposes but at a relatively high cost. An additional 11kV feeder is also planned in future (2019) to offload one of the feeders and also improve feeder backstopping capability.

Ruakaka Zone Substation

Zone Substation	Ruakaka		
Transformer 1 (MVA)	10		
Transformer 2 (MVA)	10		
Peak load (MW)	6.8		
ICP's connected (No.)	3647		
Feeder Name	CB	Voltage (kV)	ICP's (No.)
Marsden Pt	1	11	1274
Waipu	2	11	924
Mata	3	11	404
One Tree Point	6	11	262
North River	7	11	783



Ruakaka Geographic Feeder Layout

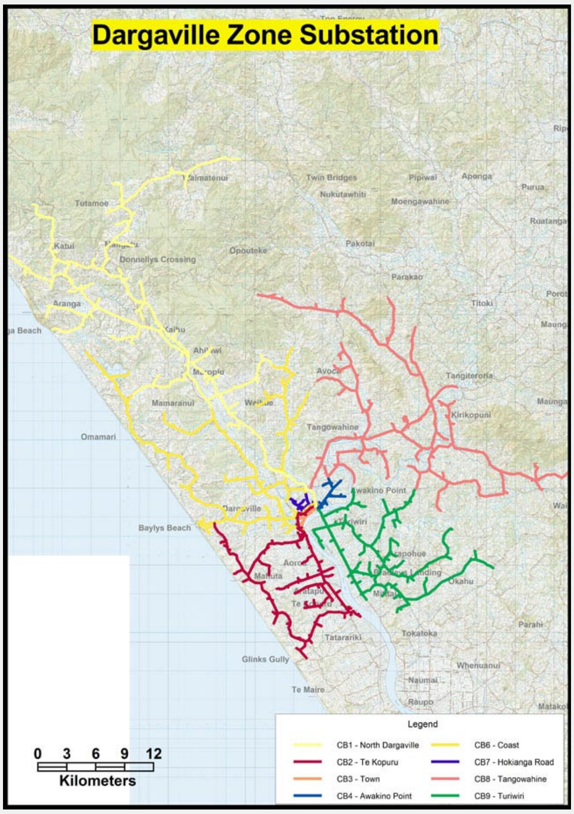
This substation is centred on Ruakaka Township and also feeds the surrounding rural dairying area, Waipu Township and the south-east coast holiday resort area. The rural area is becoming more lifestyle in nature and significant subdivision activity and growth which is expected to be high in future.

Ruakaka substation was recently upgraded to 2 x 10MVA 33/11kV transformers and the old 11kV oil circuit breaker switchboard was replaced with modern gas insulated switchgear in 2008. The new switchboard incorporates a spare feeder for the anticipated future growth. A voltage regulator was installed on the Waipu feeder in 2016 to support the growing load on this feeder. A future zone substation in the Waipu area is planned (2023/24) when it is expected that the load will exceed the capacity of the regulator.

Appendix B - Substations Data and Feeder Maps

Dargaville Zone Substation

Zone Substation	Dargaville		
Transformer 1 (MVA)	15		
Transformer 2 (MVA)	15		
Peak load (MW)	12.0		
ICP's connected (No.)	5758		
Feeder Name	CB	Voltage (kV)	ICP's (No.)
North Dargaville	1	11	597
Te Kopuru	2	11	918
Town Dargaville	3	11	891
Awakino Point	4	11	359
Coast	6	11	896
Hokianga Rd	7	11	1014
Tangowahine	8	11	579
Turiwiri	9	11	504



Dargaville Geographic Feeder Layout

A major reconfiguration of the 11kV feeders at this station was completed in 2015 in order to remove a double circuit line running through the town and optimise feeder loading.

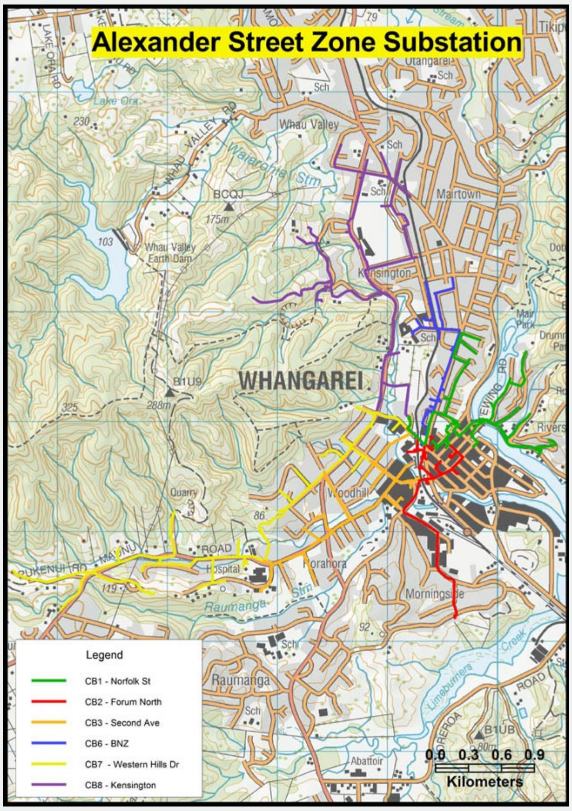
This substation supplies a large rural area (mainly dairy farming) centred on Dargaville Town. The meatworks on the outskirts of the town and a sawmill to the north form the only significant industrial loads. Load growth has historically been very low, although there is a small amount of seasonal growth due to subdivision activity along the coast west of Dargaville Town.

The mostly likely sector for significant load growth in the future is forestry as the large plantations to the north of Dargaville mature. The growth in the medium to longer term is expected to be low.

Substations Data and Feeder Maps - Appendix B

Alexander Street Zone Substation

Zone Substation	Alexander Street		
Transformer 1 (MVA)	7.5/15		
Transformer 2 (MVA)	7.5/15		
Peak load (MW)	15.0		
ICP's connected (No.)	4605		
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**
Norfolk St	1	11	837
Forum North	2	11	404
Second Ave	3	11	1002
Bank of NZ	6	11	460
Western Hills Dr	7	11	1170
Kensington	8	11	732



Alexander Street Geographic Feeder Layout

This substation supplies the Whangarei City CBD and the central residential areas. The substation is supplied directly from Kensington GXP.

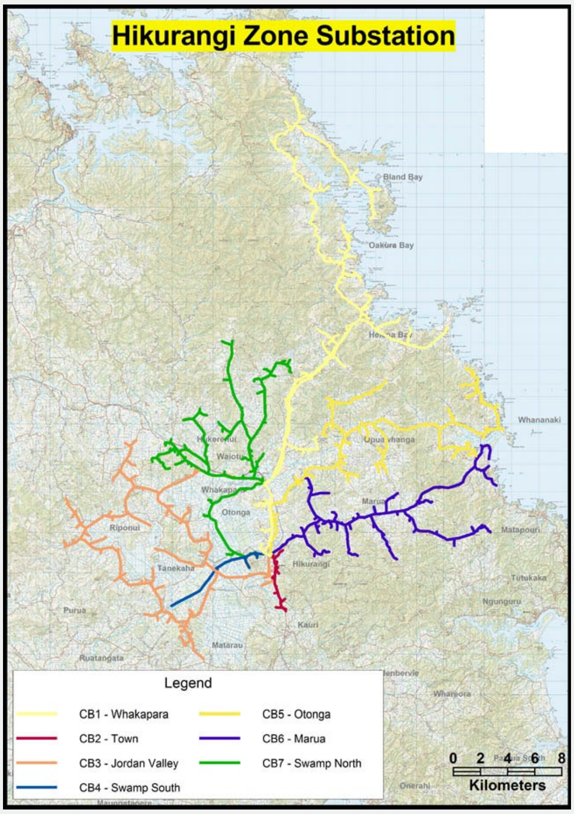
The long term load growth in the area is expected to be moderate as the CBD area is almost fully developed. Business expansion taking place in Whangarei tends to be outside the current CBD area and a number of businesses have also relocated away from the central commercial area.

Some residential load will be transferred from this station to the planned new substation in Maunu in future, thus delaying the need to upgrade the transformers for some time. Alexander Street substation is an important backstop for any contingency at Whangarei South or Tikipunga substations.

Appendix B - Substations Data and Feeder Maps

Hikurangi Zone Substation

Zone Substation	Hikurangi		
Transformer 1 (MVA)	5		
Transformer 2 (MVA)	5		
Peak load (MW)	6.2		
ICP's connected (No.)	3242		
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**
Whakapara	1	11	1023
Town Hikurangi	2	11	516
Jordan Valley	3	11	449
Swamp South	4	11	22
Otonga	5	11	546
Marua	6	11	298
Swamp North	7	11	388



Hikurangi Geographic Feeder Layout

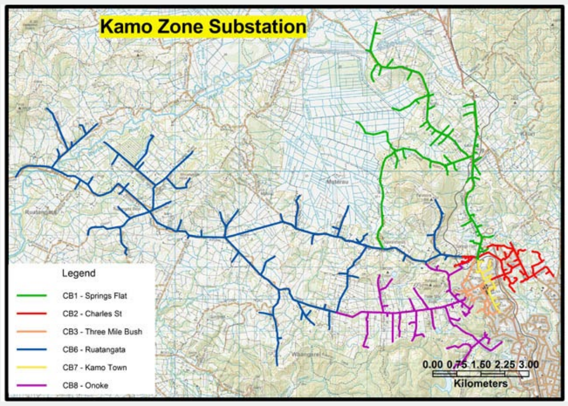
The mainly dairy farming rural load surrounding the Hikurangi Township dominates the substation, although there is also some industrial load in the Town. The substation also supplies a large flood-pumping scheme in the Hikurangi swamp area (occasional operation) as well as the coastal resort areas along the east coast as far north as Bland Bay.

The most likely prospect for growth is lifestyle section and holiday resort development in the scenic east coast area and Hikurangi Town itself could see development in future as an overflow from Whangarei. To date most of the coastal growth has been south of Whangarei and, to a lesser extent, in the Tutukaka area. As these areas become more populated it is expected that the demand for coastal properties north of Whangarei will increase.

Load growth in the short to medium term is likely to be moderate but could increase in the longer term in association with growth in Whangarei. Northpower has plans in place to upgrade and strengthen the 11kV network feeding the Helena Bay, Oakura and Bland Bay areas but actual upgrade expenditure will only be incurred when the capacity of the existing network needs to be increased (currently planned for FY22). The 2 x 5MVA 33/11kV transformers are planned to be replaced with 2 x 10MVA units in 2020/21.

Kamo Zone Substation

Zone Substation	Kamo		
Transformer 1 (MVA)	7.5/15		
Transformer 2 (MVA)	7.5/15		
Peak load (MW)	11.3		
ICP's connected (No.)	5204		
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**
Springs Flat	1	11	609
Charles St	2	11	1299
Three Mile Bush	3	11	867
Ruatangata	6	11	684
Kamo Town	7	11	625
Onoke	8	11	1120



Kamo Geographic Feeder Layout

Located on the northern boundary of Whangarei City, this substation supplies a mixture of industrial, commercial, residential and rural load.

The industrial and commercial load is small, with the main growth occurring in the residential segment through a high number of lifestyle blocks and new residential developments. This trend is likely to continue with planned development to the west, and a relatively high growth rate can be expected over the next 5-10 years. Associated moderate commercial and light industrial load growth is also expected.

The 15MVA firm capacity at Kamo substation is adequate for the medium to long term. The 11kV switchboard upgrade was completed in 2011 and a new 11kV feeder was commissioned in 2015 to offload the Three Mile Bush feeder and reconfigure two other feeders to allow for load growth.

Appendix B - Substations Data and Feeder Maps

Ngunguru Zone Substation

Zone Substation	Ngunguru		
Transformer 1 (MVA)	3.75		
Transformer 2 (MVA)			
Peak load (MW)	3.3		
ICP's connected (No.)	1956		
Feeder Name	CB	Voltage (kV)	ICP's (No.)
Tutukaka Block	1	11	608
Kaiatea	4	11	650
Matapouri	5	11	698
Tutukaka Block	1	11	608

Ngunguru Geographic Feeder Layout

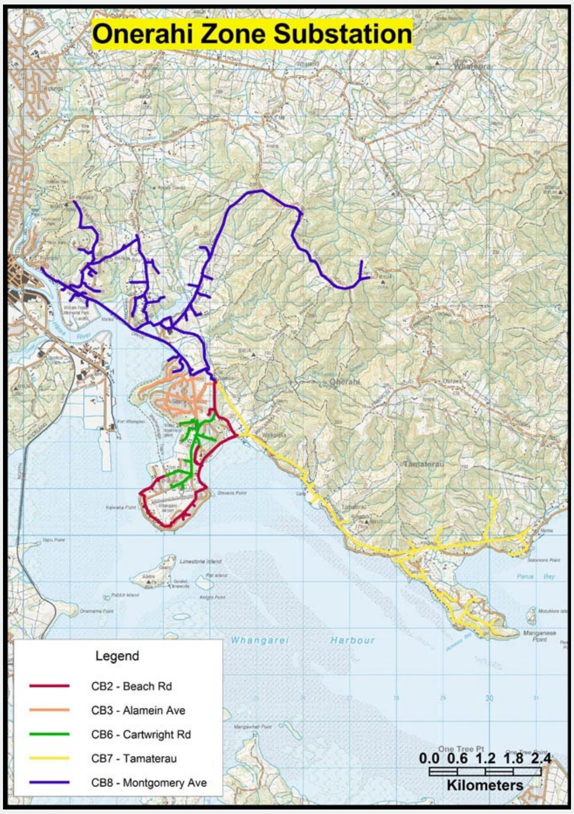
This substation supplies Ngunguru Township and the coastal area to the north-east of Whangarei. The area has a mix of residential, rural and lifestyle load and the demand peaks during holiday periods. Potential new holiday resort type developments centred on Tutukaka, Matapouri and Ngunguru itself could increase demand on the substation significantly in the future.

The 3.75MVA transformer will be upgraded to 5MVA in the 2019/20 financial year to accommodate the anticipated increase in load and the aging 11kV switchboard is planned for replacement in FY23. Provision has also been made in the 10 year plan to install a second transformer in FY23 to improve security of supply.

Substations Data and Feeder Maps - Appendix B

Onerahi Zone Substation

Zone Substation	Onerahi		
Transformer 1 (MVA)	7.5		
Transformer 2 (MVA)	7.5		
Peak load (MW)	8.1		
ICP's connected (No.)	3946		
Feeder Name	CB	Voltage (kV)	ICP's (No.)
Beach Road	2	11	629
Alamein Ave	3	11	989
Cartwright Rd	6	11	790
Tamaterau	7	11	524
Montgomery Ave	8	11	1014



Onerahi Geographic Feeder Layout

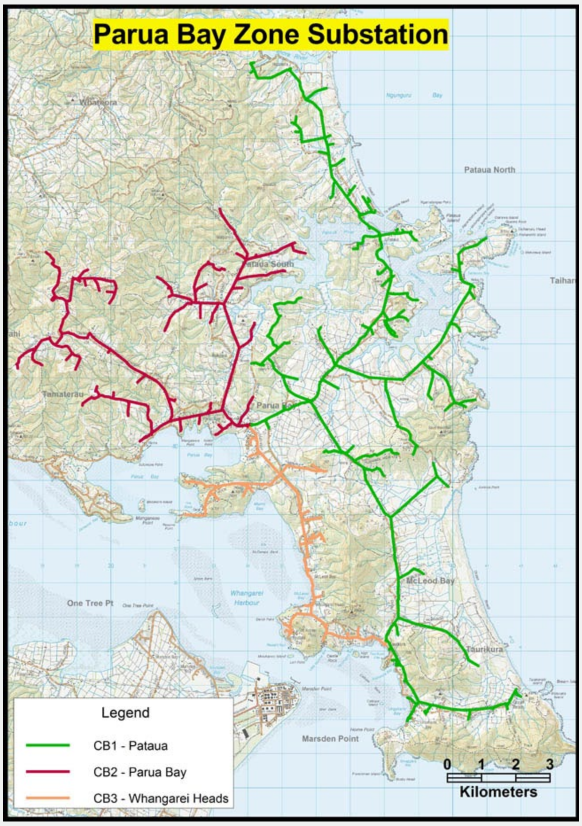
This substation supplies the suburb of Onerahi (mainly residential with some commercial load) but the 11kV network also stretches out to the residential areas of Tamaterau, Manganese Point and part of Riverside. There is a moderate amount of residential development in the area fed from this substation and this is expected to continue.

The 11kV switchboard at Onerahi substation was upgraded in 2010 and two 11kV feeders were reconfigured in 2015 to offload the Montgomery Road feeder. It is planned to replace the 2 x 7.5MVA 33/11 kV transformer in 2019 to provide more long term capacity and redeploy elsewhere within the Network. This will form the start of a programme to provide more capacity and to replace some of the oldest 33/11kV transformers in the network.

Appendix B - Substations Data and Feeder Maps

Parua Bay Zone Substation

Zone Substation	Parua Bay		
Transformer 1 (MVA)	3.75		
Peak load (MW)	3.3		
ICP's connected (No.)	2093		
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**
Pataua	1	11	853
Parua Bay	2	11	515
Whangarei Heads	3	11	724
Parua Bay Local Service	9833	11	1



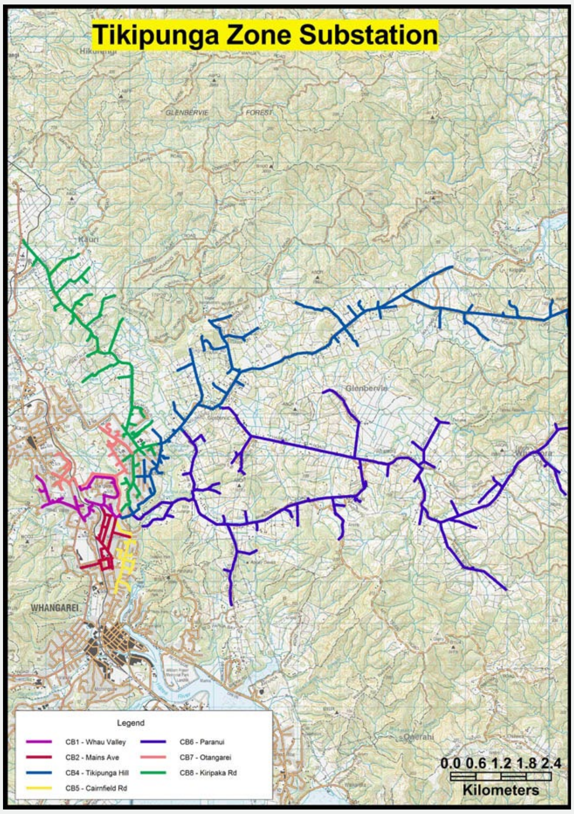
Parua Bay Geographic Feeder Layout

This substation supplies the Parua Bay, McLeod's Bay, Whangarei Heads and Pataua areas comprising of mainly residential type load. Load growth has been fairly low during the past 5 years, but there is potential for significant development. This substation was commissioned early in 2007 utilising one of the refurbished 3.75MVA transformers relocated from the Hikurangi zone substation. This transformer is planned to be replaced with a 5MVA unit in FY22 as it reaches end of life. The new transformer will have enough capacity to meet growth for the foreseeable future. A strategic spare transformer held in the second transformer bay will remain until it is no longer needed. This transformer is also near end of life due to age.

Substations Data and Feeder Maps - Appendix B

Tikipunga Zone Substation

Zone Substation	Tikipunga		
Transformer 1 (MVA)	20		
Transformer 2 (MVA)	20		
Peak load (MW)	15.4		
ICP's connected (No.)	7144		
Feeder Name	CB	Voltage (kV)	ICP's (No.)
Whau Valley	1	11	1257
Mains Ave	2	11	849
Tikipunga Hill	4	11	968
Cairnfield Rd	5	11	1182
Paranui	6	11	600
Otangarei	7	11	926
Kiripaka Rd	8	11	1362



Tikipunga Geographic Feeder Layout

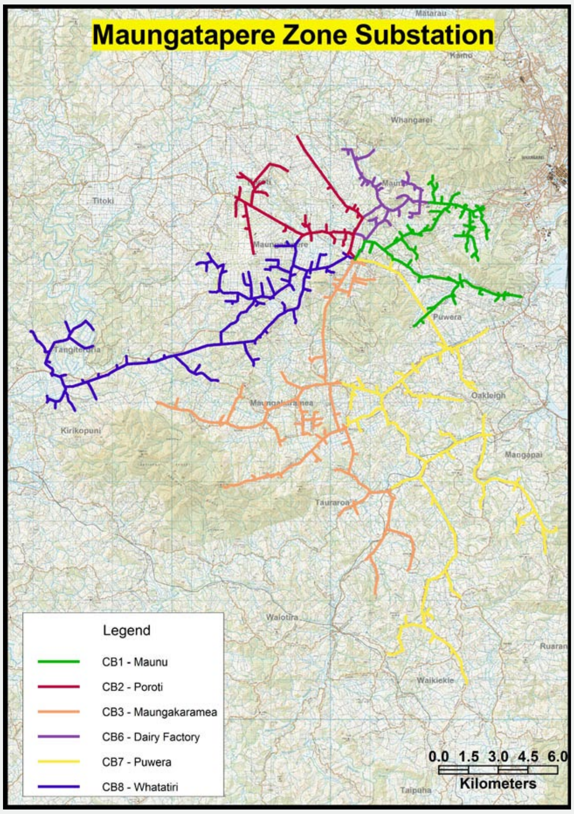
This is Northpower's largest zone substation based on number of premises connected. Feeders supply the residential areas to the north of the CBD as well as the rural area to the north-east of Whangarei, which includes a fairly large sawmill load. The substation load peaks in winter due to heating load. Load growth is moderate, driven mainly by residential growth in the Kensington and Tikipunga suburbs due to urban 'in-fill', but development is expected to continue in the area to the north and east of the substation.

The old 11kV oil switchgear at this station was replaced with modern gas insulated switchgear in 2008 and the transformers were upgraded to 2 x 20MVA units in 2009. Some changes were recently made to feeder configurations resulting in the transfer of some load from Kamo substation to Tikipunga substation.

Appendix B - Substations Data and Feeder Maps

Maungatapere Zone Substation

Zone Substation	Maungatapere		
Transformer 1 (MVA)	5		
Transformer 2 (MVA)	5		
Peak load (MW)	7.1		
ICP's connected (No.)	3297		
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**
Maunu	1	11	954
Poroti	2	11	363
Maungakaramea	3	11	574
Maungatapere - Dairy Factory	6	11	415
Puwera	7	11	405
Whatatiri	8	11	586



Maungatapere Geographic Feeder Layout

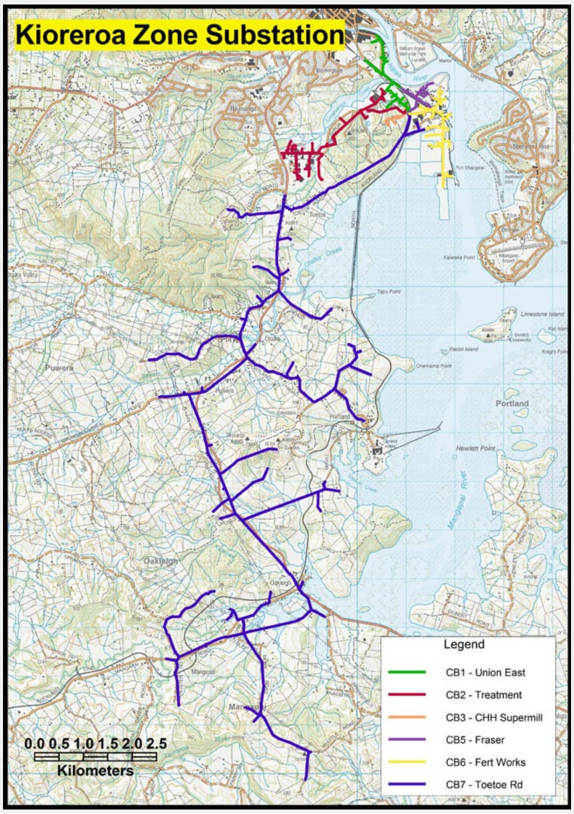
The substation supplies a predominantly rural area (dairy and fruit farming) around Maungatapere village which includes Maungakaramea, Poroti, Tangiteroria, Puwera and Mangapai. One of the feeders also supplies part of the Maunu residential area to the west of Whangarei City. There is a significant amount of lifestyle type development in the rural areas and this trend is expected to continue in future.

A large amount of upmarket subdivision activity is expected in the Maunu area pending economic upturn as Whangarei City spreads westward. This is expected to result in substantial residential load growth in the medium to long term. Some load was transferred to Kioreroa substation in 2010 in order to maintain N-1 security (it is also possible to backfeed some of the Maungatapere load via the 11kV network from Poroti substation in the event of a contingency).

Some feeder reconfiguration work is planned for 2018 in order to provide additional capacity in the Maunu area as an interim measure until the planned new zone Maunu substation is constructed (planned for 2019/20). Maunu substation will relieve Maungatapere substation of some load and delay the need to upgrade the 2 x 5MVA transformers. Maungatapere substation is planned to receive the two ex. Onerahi 7.5MVA 33/11kV transformers giving the substation the capacity required for the foreseeable future.

Kioreroa Zone Substation

Zone Substation	Kioreroa		
Transformer 1 (MVA)	15/20		
Transformer 2 (MVA)	15/20		
Peak load (MW)	11.1		
ICP's connected (No.)	1028		
Feeder Name	CB	Voltage (kV)	ICP's (No.)
Union East	1	11	63
Treatment	2	11	202
CHH Supermill	3	11	1
Fraser	5	11	78
Fert. Works	6	11	84
ToeToe Rd	7	11	600



Kioreroa Geographic Feeder Layout

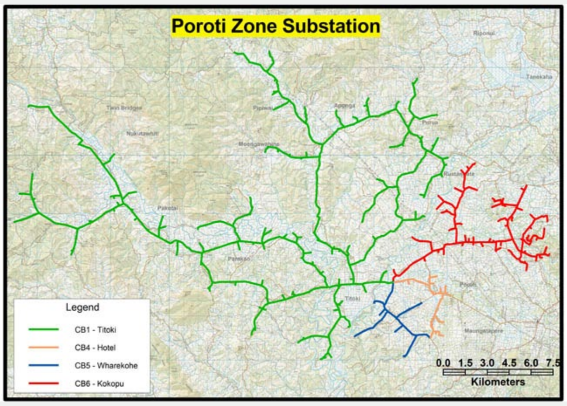
The area supplied by this substation is dominated by heavy industry with associated light industry and commercial loads. The Portland area to the south of Whangarei is also supplied from this substation and includes some rural load. Load growth has been high in the past due to the expansion of some industries but has been marginal in recent years. The development of the deep-water port at Marsden Point will see a continuation of the downsizing of the existing port activities resulting in a substantial amount of land being available for the establishment of new industries to the south-west of the substation. Significant load growth can be expected if development of this area proceeds.

The 2 x 10 MVA transformers at this station were upgraded to 2 x 15/20 MVA in early 2006 in anticipation of the expected future load growth as well as to facilitate the upgrading of the transformers at 3 other zone substations. Some rural load south of Whangarei was transferred to this station from Maungatapere substation in 2010 in order to offload the transformers at the latter station. An additional 11kV feeder was commissioned in 2014 to offload Whangarei South substation and optimise feeder loadings.

Appendix B - Substations Data and Feeder Maps

Poroti Zone Substation

Zone Substation	Poroti		
Transformer 1 (MVA)	5		
Peak load (MW)	3.0		
ICP's connected (No.)	1295		
Feeder Name	CB	Voltage (kV)	ICP's (No.)
Titoki	1	11	744
Hotel	4	11	110
Wharekohe	5	11	71
Kokopu	6	11	370



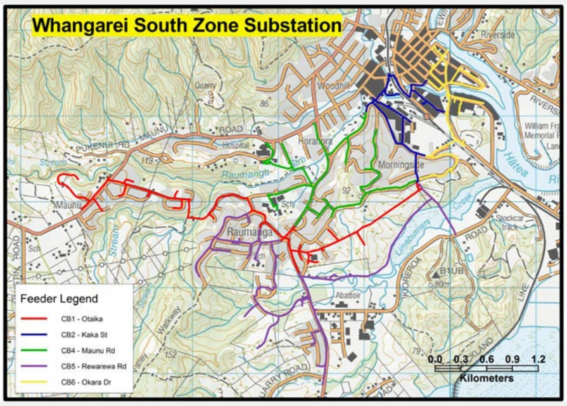
Poroti Geographic Feeder Layout

This substation supplies a predominantly rural region with no significant urban centres other than Titoki village. The substation covers a large area with a relatively small total load. Load growth is low with no signs of development, future growth is also expected to be low. Poroti substation was built in 1990 to provide capacity for a large irrigation scheme proposed for the area. The scheme never developed as planned but some dairy farms in the Titoki area later installed irrigation schemes.

The load is seasonal and weather dependent. Residential and lifestyle growth is relatively low and any significant growth is more likely to come from additional irrigation schemes. The 5MVA transformer capacity at the substation is considered adequate for the medium term. A ground fault neutraliser was commissioned at Poroti substation in 2010 as a pilot project in order to evaluate the effectiveness of this technology and switched capacitors are employed on the Titoki feeder for voltage regulation purposes. The transformer and 11kV switchboard are planned to be replaced between 2020 and 2022 due to their age.

Whangarei South Zone Substation

Zone Substation	Whangarei South		
Transformer 1 (MVA)	10		
Transformer 2 (MVA)	10		
Peak load (MW)	12.0		
ICP's connected (No.)	3773		
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**
Otaika	1	11	977
Kaka St	2	11	474
Maunu Road	4	11	898
Rewa Rewa Rd	5	11	885
Okara Drive	6	11	539



Whangarei South Geographic Feeder Layout

This substation is situated to the south of Whangarei central business district and supplies a mixture of residential, commercial and light industrial load. Two major customers are supplied from Whangarei South, Whangarei Hospital and Northland Polytechnic. The transformers at this station were upgraded to 2 x 10MVA in 2006. The peak load exceeds the transformer n-1 capacity however, due to the close proximity of Alexander Street and Kioreroa substations, it is possible to transfer load in the event of a contingency. These transformers are planned to be replaced in 2027/28 due to age.

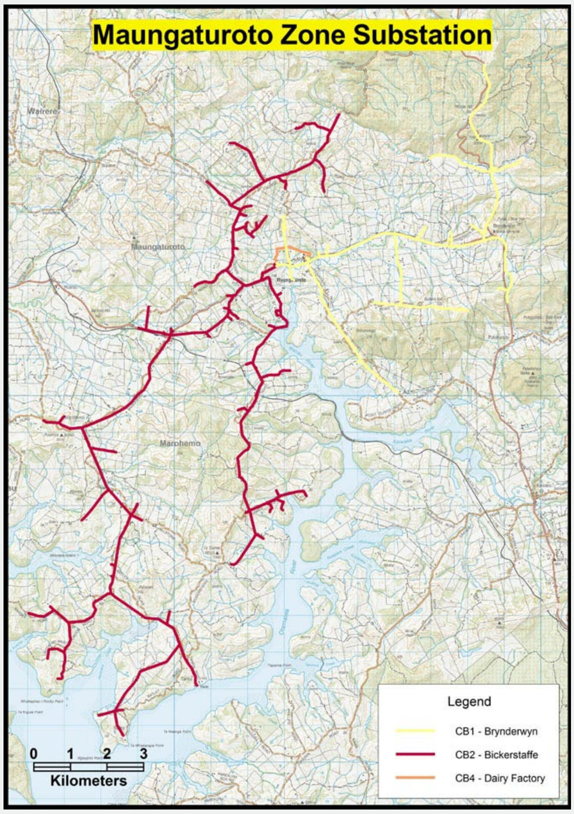
The planned Maunu zone substation will result in the transfer of some residential load lying to the west of Whangarei South. This will free up capacity to accommodate anticipated new load to the south as well as some marginal growth of existing load. The commissioning of a new feeder at Kioreroa substation in 2014 allowed some load to be transferred to that substation.

The 11kV switchgear is planned for replacement in 2019/20 due to age.

Appendix B - Substations Data and Feeder Maps

Maungaturoto Zone Substation

Zone Substation	Maungaturoto		
Transformer 1 (MVA)	7.5		
Transformer 2 (MVA)	7.5		
Peak load (MW)	6.1		
ICP's connected (No.)	896		
Feeder Name	CB	Voltage (kV)	ICP's (No.)
Brynderwyn	1	11	183
Bickerstaff	2	11	711
Maungaturoto - Dairy Factory	4	11	2



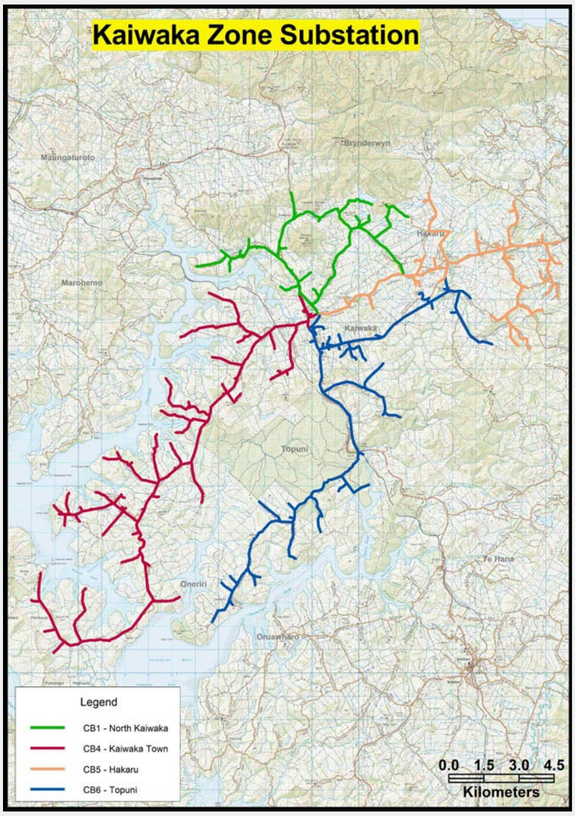
Maungaturoto Geographic Feeder Layout

The load on this substation is dominated by the local dairy factory, which accounts for approximately 75% of the substation's maximum demand. The dairy factory load is not expected to increase in the short to medium term. The remainder of the load comprises of the Maungaturoto township and large surrounding rural area in which the load is predominantly dairy farming. Maungaturoto substation is an important backstop for Kaiwaka and Mareretu single transformer substations.

The growth in the township and surrounding area is low and the future load growth potential is mainly driven by the possible expansion of the Dairy Factory, in the longer term. The 2 x 5MVA transformers at this station were replaced with 7.5MVA units in 2006 and the 10 year plan makes provision for upgrading the 11kV switchboard in 2025 and replacing the transformers in 2023/24 for age reasons.

Kaiwaka Zone Substation

Zone Substation	Kaiwaka		
Transformer 1 (MVA)	5		
Peak load (MW)	2.0		
ICP's connected (No.)	1468		
Feeder Name	CB	Voltage (kV)	ICP's (No.)
North Kaiwaka	1	11	188
Kaiwaka Town	4	11	419
Hakaru	5	11	406
Topuni	6	11	455



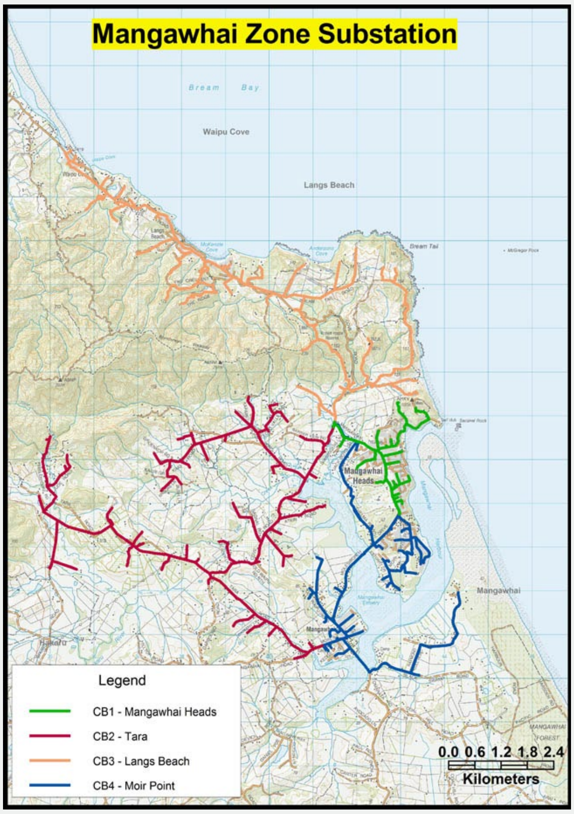
Kaiwaka Geographic Feeder Layout

This substation supplies Kaiwaka Township and surrounding rural area, which is predominantly dairy farming. There is however an increasing amount of lifestyle block development and the expectation is that the demand for lifestyle properties will continue or even increase due to the proximity to Auckland and the development in the Oneriri and Topuni (Kaipara harbour) area. The 11kV switchboard is planned to be replaced in FY22 and provision has been made in the 10 year plan to install a second 5MVA transformer in FY23 to improve security of supply and a second 5 MVA transformer is planned to be added for reliability in 2023.

Appendix B - Substations Data and Feeder Maps

Mangawhai Zone Substation

Zone Substation	Mangawhai		
Transformer 1 (MVA)	5		
Transformer 2 (MVA)	5		
Peak load (MW)	7.2		
ICP's connected (No.)	3898		
Feeder Name	CB	Voltage (kV)	ICP's (No.)
Mangawhai Heads	1	11	1241
Tara	2	11	573
Langs Beach	3	11	632
Moir Point	4	11	1452



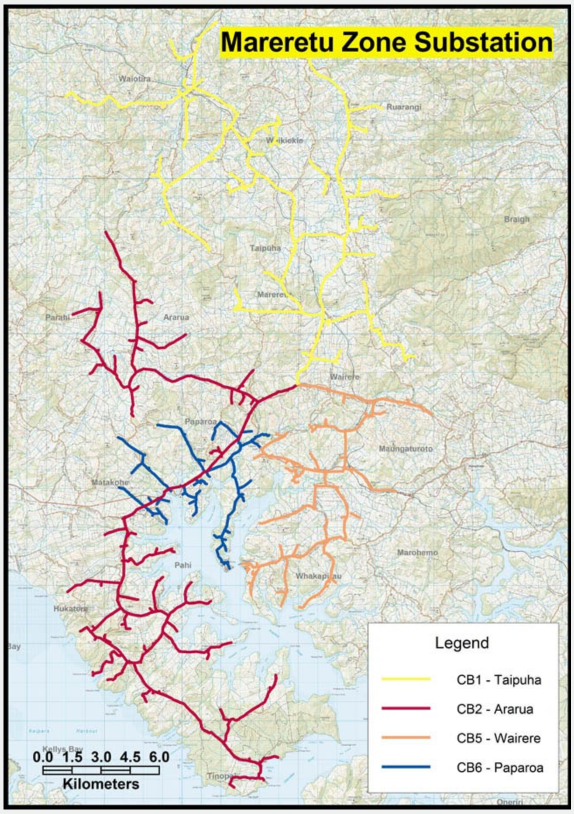
Mangawhai Geographic Feeder Layout

The load on this substation comprises mainly of coastal residential with holiday homes and rural lifestyle dominating. Some commercial connections are present and there is also some dairy farming in the Tara area. The urban areas include Mangawhai Heads, Mangawhai Village, Lang's Cove and Waipu Cove. The substation load is characterised by high peak demands during holiday periods. The load has grown at a very high rate in the past but has reduced significantly in recent years. Further growth is expected in the future due to Mangawhai's proximity to Auckland.

A second 5MVA transformer was commissioned at this station at the end of 2009 for both capacity and security of supply reasons and the Moir Point feeder was recently extended by means of a cable link in order to offload the Mangawhai Heads feeder as well as providing feeder backstopping capability.

Mareretu Zone Substation

Zone Substation	Mareretu		
Transformer 1 (MVA)	5		
Peak load (MW)	2.8		
ICP's connected (No.)	1963		
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**
Taipuha	1	11	438
Ararua	2	11	602
Wairere	5	11	376
Paparoa	6	11	547



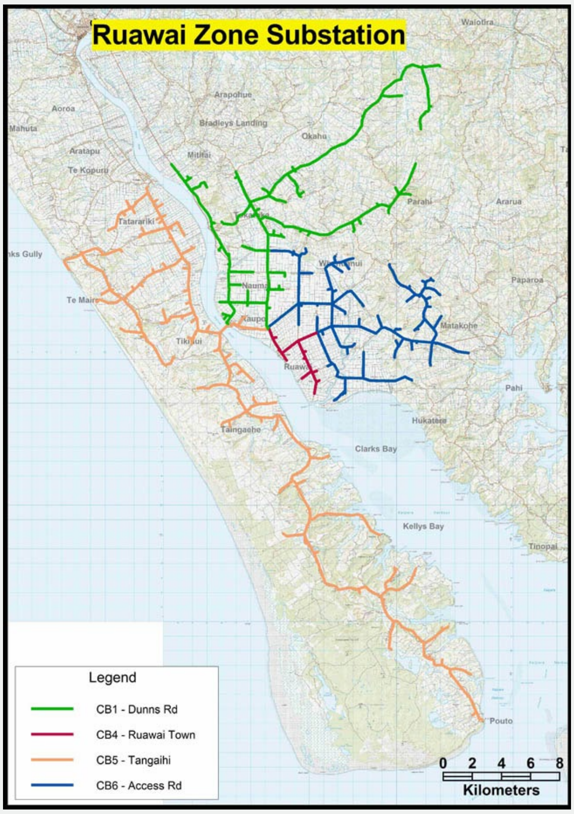
Mareretu Geographic Feeder Layout

The load on this substation is predominantly rural dairy farming with no significant urban centres other than Paparoa Village. The substation supplies a large area, although the total load is relatively small. Load growth is low with no sign of significant development in the short to medium term, with growth expected to remain fairly low. There is however significant potential for lifestyle type development in the Matakohe and Tinopai peninsula areas. The 11kV switchgear is planned to be replaced in 2024/25 for age reasons and provision has been made in the 10 year plan to install a second 5MVA transformer in FY25 to improve security of supply.

Appendix B - Substations Data and Feeder Maps

Ruawai Zone Substation

Zone Substation	Ruawai		
Transformer 1 (MVA)	5		
Peak load (MW)	3.0		
ICP's connected (No.)	1670		
Feeder Name	CB	Voltage (kV)	ICP's (No.)
Dunns Rd	1	11	366
Ruawai Town	4	11	328
Tangaihi	5	11	645
Access Rd	6	11	331



Ruawai Geographic Feeder Layout

This substation supplies Ruawai Town with demand dominated by the surrounding rural dairy farming area. Growth is low and this trend is expected to continue for the short to medium term.

Some load was transferred from the Dargaville area in 2015 which resulted in a fairly significant increase in substation peak load. The 11kV switchboard is planned to be replaced in FY23 for age reasons and provision has been made in the 10 year plan to install a second 5MVA transformer in FY22 to improve security of supply.


Northpower

Appendix C: Disclosure Schedules

Northpower

Disclosure Schedules - Appendix C

Table of Contents

COMMERCE COMMISSION NEW ZEALAND

EDB Information Disclosure Requirements

Information Templates for Schedules 11a–13

Company Name	Northpower Ltd
Disclosure Date	31 March 2018
AMP Planning Period Start Date (first day)	1 April 2018

Templates for Schedules 11a–13 (Asset Management Plan)

Template Version 4.1. Prepared 24 March 2015

Schedule 11a: Report On Forecast Capital Expenditure

Company Name: **Northpower Ltd**
AMP Planning Period: **1 April 2018 – 31 March 2028**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
9	**11a(i): Expenditure on Assets Forecast**		$000 (in nominal dollars)										
10		Consumer connection	2,772	3,795	3,981	4,061	4,140	4,224	4,311	4,395	4,482	4,573	4,664
11		System growth	578	3,613	2,523	1,291	4,853	5,927	1,846	145	2,093	1,657	2,489
12		Asset replacement and renewal	8,277	8,400	11,566	12,944	13,447	12,628	17,075	16,060	12,874	16,413	14,312
13		Asset relocations	204	205	530	540	551	562	574	585	596	609	621
14		Reliability, safety and environment:											
15		Quality of supply	776	1,320	294	423	818	1,208	170	695	172	66	-
16		Legislative and regulatory	350	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	2,198	873	577	535	218	278	256	174	372	181	184
18		**Total reliability, safety and environment**	3,324	2,193	871	958	1,036	1,486	426	869	544	247	184
19		**Expenditure on network assets**	15,155	18,206	19,470	19,794	24,027	24,826	24,232	22,053	20,589	23,499	22,270
20		Expenditure on non-network assets	235	601	1,071	2,537	176	135	149	296	261	212	255
21		**Expenditure on assets**	15,390	18,807	20,541	22,331	24,203	24,961	24,381	22,350	20,850	23,711	22,525
22													
23	plus	Cost of financing	67	94	102	110	145	157	128	114	118	125	125
24	less	Value of capital contributions	1,900	2,500	2,550	2,601	2,653	2,706	2,760	2,815	2,872	2,929	2,988
25	plus	Value of vested assets	281	-	-	-	-	-	-	-	-	-	-
26													
27		**Capital expenditure forecast**	13,838	16,401	18,093	19,840	21,695	22,411	21,748	19,648	18,096	20,907	19,662
28													
29		Assets commissioned	12,731	15,089	16,645	18,253	19,960	20,618	20,008	18,076	16,648	19,234	18,089
30			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31		for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
32			$000 (in constant prices)										
33		Consumer connection	2,718	3,795	3,795	3,795	3,795	3,795	3,795	3,795	3,795	3,795	3,795
34		System growth	568	3,613	2,405	1,207	4,448	5,325	1,625	125	1,772	1,375	2,025
35		Asset replacement and renewal	7,995	8,400	11,026	12,097	12,325	11,346	15,031	13,869	10,901	13,621	11,645
36		Asset relocations	200	205	505	505	505	505	505	505	505	505	505
37		Reliability, safety and environment:											
38		Quality of supply	761	1,320	280	395	750	1,085	150	600	146	55	-
39		Legislative and regulatory	343	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	1,963	873	550	500	200	250	225	150	315	150	150
41		**Total reliability, safety and environment**	3,067	2,193	830	895	950	1,335	375	750	461	205	150
42		**Expenditure on network assets**	14,548	18,206	18,561	18,499	22,023	22,306	21,331	19,044	17,434	19,501	18,120
43		Expenditure on non-network assets	235	601	1,021	2,371	161	121	131	256	221	176	207
44		**Expenditure on assets**	14,783	18,807	19,582	20,870	22,184	22,427	21,462	19,300	17,655	19,677	18,328
45													
46	**Subcomponents of expenditure on assets (where known)**												
47		Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
48		Overhead to underground conversion	-	-	250	250	250	250	250	250	250	250	250
49		Research and development	75	80	80	80	80	80	90	120	130	135	170

Company Name	Northpower Ltd
AMP Planning Period	1 April 2018 – 31 March 2028

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
50												
52	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
53	**Difference between nominal and constant price forecasts**	$000										
54	Consumer connection	54	-	186	266	345	429	516	600	687	778	869
55	System growth	10	-	118	84	405	602	221	20	321	282	464
56	Asset replacement and renewal	282	-	540	847	1,122	1,282	2,044	2,191	1,973	2,792	2,667
57	Asset relocations	4	-	25	35	46	57	69	80	91	104	116
58	Reliability, safety and environment:											
59	Quality of supply	15	-	14	28	68	123	20	95	26	11	-
60	Legislative and regulatory	7	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	235	-	27	35	18	28	31	24	57	31	34
62	**Total reliability, safety and environment**	257	-	41	63	86	151	51	119	83	42	34
63	**Expenditure on network assets**	607	-	909	1,295	2,004	2,521	2,901	3,009	3,155	3,998	4,150
64	Expenditure on non-network assets	-	-	50	166	15	14	18	40	40	36	47
65	**Expenditure on assets**	607	-	959	1,461	2,019	2,534	2,919	3,049	3,195	4,034	4,197
66												

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
67	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
68	**11a(ii): Consumer Connection**						
69	*Consumer types defined by EDB**	$000 (in constant prices)					
70	Transformer Acquisition Cost	2,718	1,040	1,040	1,040	1,040	1,040
71	Transformer Credits from Upgrades	-	(130)	(130)	(130)	(130)	(130)
72	Ripple relay purchases	-	85	85	85	85	85
73	Capital contributions (Customer)	-	2,500	2,500	2,500	2,500	2,500
74	Capital contributions (Network)	-	300	300	300	300	300
75	**include additional rows if needed*						
76	**Consumer connection expenditure**	2,718	3,795	3,795	3,795	3,795	3,795
77	*less* Capital contributions funding consumer connection	1,863	2,500	2,500	2,500	2,500	2,500
78	**Consumer connection less capital contributions**	855	1,295	1,295	1,295	1,295	1,295
79	**11a(iii): System Growth**						
80	Subtransmission	-	-	-	-	-	-
81	Zone substations	417	2,810	2,200	1,000	4,000	5,200
82	Distribution and LV lines	74	150	-	-	190	-
83	Distribution and LV cables	-	350	-	-	-	-
84	Distribution substations and transformers	57	50	50	50	50	50
85	Distribution switchgear	-	-	-	-	-	-
86	Other network assets	20	253	155	157	208	75
87	**System growth expenditure**	568	3,613	2,405	1,207	4,448	5,325
88	*less* Capital contributions funding system growth	-	-	-	-	-	-
89	**System growth less capital contributions**	568	3,613	2,405	1,207	4,448	5,325
90							

Company Name	Northpower Ltd
AMP Planning Period	1 April 2018 – 31 March 2028

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92		for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
93	**11a(iv): Asset Replacement and Renewal**		$000 (in constant prices)					
94		Subtransmission	441	500	500	500	500	2,000
95		Zone substations	900	1,165	3,805	5,062	5,190	2,106
96		Distribution and LV lines	5,340	4,750	5,100	4,960	5,060	5,355
97		Distribution and LV cables	209	240	260	260	280	280
98		Distribution substations and transformers	408	385	385	385	385	415
99		Distribution switchgear	305	525	235	290	235	335
100		Other network assets	392	835	740	640	675	855
101		**Asset replacement and renewal expenditure**	7,995	8,400	11,026	12,097	12,325	11,346
102	*less*	Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
103		**Asset replacement and renewal less capital contributions**	7,995	8,400	11,026	12,097	12,325	11,346
104								

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106		for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
107	**11a(v):Asset Relocations**							
108		*Project or programme**	$000 (in constant prices)					
109		Minor capital expenditure (relocation)	53	55	55	55	55	55
110		Dargaville ripple plant relocation	49	-	-	-	-	-
111		Roading works asset relocations	98	50	50	50	50	50
112		Overhead to underground conversion	-	-	250	250	250	250
113		Ground mounting of 2/4 pole distribution transformers	-	100	150	150	150	150
114		**include additional rows if needed*						
115		All other project or programmes - asset relocations	-	-	-	-	-	-
116		**Asset relocations expenditure**	200	205	505	505	505	505
117	*less*	Capital contributions funding asset relocations	-	-	-	-	-	-
118		**Asset relocations less capital contributions**	200	205	505	505	505	505
119								

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121		for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
122	**11a(vi):Quality of Supply**							
123		*Project or programme**	$000 (in constant prices)					
124		New Reclosers	-	45	-	45	-	-
125		Whangarei South 33kV T - Stage 2	-	700	-	-	-	-
126		Whangarei City additional 11kV RMU's	-	50	-	-	50	-
127		Comms for remote control of motorised switches	98	175	-	-	-	-
		Maungaturoto TP-NP fibre	88	-	-	-	-	-
128		11kV feeder backstopping improvements	74	-	80	-	-	85
		Distribution feeder auto-reclosing	-	25	-	-	-	-
		Whakapara Feeder Express Line to Hikurangi	44	250	200	300	-	-
		Fault Passage Indicators	245	75	-	-	-	-
		Chipmill RTU and Comms	16	-	-	-	-	-
		Mareretu substation 33kV switch upgrades	147	-	-	-	-	-
		KEN-TIK 33kV cables protection upgrade	49	-	-	-	-	-
		SMART Distribution system (load monitoring)	-	-	-	50	100	100
		Ruawai Transformer T2 (new purchase)	-	-	-	-	600	-
		Kaiwaka Transformer T2 (new purchase)	-	-	-	-	-	600
		Ngunguru Transformer T2 (ex Hikurangi)	-	-	-	-	-	300
130		All other projects or programmes - quality of supply	-	-	-	-	-	-
131		**Quality of supply expenditure**	761	1,320	280	395	750	1,085
132	*less*	Capital contributions funding quality of supply	-	-	-	-	-	-
133		**Quality of supply less capital contributions**	761	1,320	280	395	750	1,085
134								

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2018 – 31 March 2028**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
135			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
136		for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
137	**11a(vii): Legislative and Regulatory**							
138	*Project or programme**		**$000 (in constant prices)**					
139	Zone Substations Risk Mitigation		343	-	-	-	-	-
145	All other projects or programmes - legislative and regulatory		-	-	-	-	-	-
146	**Legislative and regulatory expenditure**		343	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory		-	-	-	-	-	-
148	**Legislative and regulatory less capital contributions**		343	-	-	-	-	-
149								
150			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
		for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
151	**11a(viii): Other Reliability, Safety and Environment**							
152	*Project or programme**		**$000 (in constant prices)**					
154	Provision for fibre		98	60	60	60	50	50
155	Maungatapere-Dargaville Fibre (Network share)		1,176	-	-	-	-	-
156	Zone Substations Risk Mitigation		-	100	100	150	-	-
	Zone Substations Security Improvement		61	65	-	-	-	-
	DSUB MDI Meters (CBD)		64	65	65	65	-	-
	Minor capital expenditure (reliability, safety, environment)		147	100	100	100	100	100
	AC/DC Panel Upgrades		98	50	50	-	-	-
	Replace VHF Analog with Digital (Mobile Radio)		147	-	-	-	-	-
	Maungaturoto 33kV Circuit Separation		-	258	-	-	-	-
	Communications Network Security Improvements		34	-	-	-	50	-
	Zone Substation Neutral Earthing Resistors		-	125	125	125	-	100
	Busbar Arc Flash Protection		50	50	50	-	-	-
	SCADA comms transfer to dark fibre		39	-	-	-	-	-
157	Remote station SCADA monitoring		49	-	-	-	-	-
159	All other projects or programmes - other reliability, safety and environment		-	-	-	-	-	-
160	**Other reliability, safety and environment expenditure**		1,963	873	550	500	200	250
161	*less* Capital contributions funding other reliability, safety and environment		-	-	-	-	-	-
162	**Other reliability, safety and environment less capital contributions**		1,963	873	550	500	200	250
163								
164			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
165		for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
166	**11a(ix): Non-Network Assets**							
167	**Routine expenditure**							
168	*Project or programme**		**$000 (in constant prices)**					
170	Research and Development (component testing)		74	30	30	30	30	30
171	Aerial Imagery (GIS)		-	-	-	-	40	-
172	Engineering hardware/Software		49	-	-	50	-	-
	University Project Collaboration		15	16	16	16	16	16
	Research and Development (new technology)		-	50	50	50	50	50
	Vehicles		43	-	-	-	-	-
	Minor capital expenditure (non-network assets)		-	25	25	25	25	25
175	All other projects or programmes - routine expenditure		-	-	-	-	-	-
176	**Routine expenditure**		181	121	121	171	161	121
177	**Atypical expenditure**							
178	*Project or programme**							
179	Network strategic spare store		25	50	-	-	-	-
180	UAV Asset Inspection Platform		29	30	-	-	-	-
181	AMS (WASP replacement and CBRM software)		-	300	500	400	-	-
182	ADMS (Advanced Distribution Management System)		-	50	300	1,700	-	-
183	Low voltage network operational management system		-	50	100	100	-	-
185	All other projects or programmes - atypical expenditure		-	-	-	-	-	-
186	**Atypical expenditure**		54	480	900	2,200	-	-
187								
188	**Expenditure on non-network assets**		235	601	1,021	2,371	161	121

Schedule 11b: Report On Forecast Operational Expenditure

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2018 – 31 March 2028**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,169	1,777	1,864	1,901	1,938	1,978	2,018	2,057	2,098	2,141	2,184
11	Vegetation management	2,150	2,300	2,413	2,461	2,509	2,560	2,613	2,663	2,716	2,772	2,827
12	Routine and corrective maintenance and inspection	2,167	2,740	2,874	2,932	2,989	3,050	3,113	3,173	3,236	3,302	3,368
13	Asset replacement and renewal	1,943	2,306	2,419	2,467	2,516	2,566	2,619	2,670	2,723	2,779	2,834
14	**Network Opex**	7,429	9,123	9,570	9,761	9,953	10,154	10,363	10,564	10,774	10,993	11,212
15	System operations and network support	2,544	3,145	3,299	3,366	3,432	3,501	3,573	3,642	3,715	3,790	3,866
16	Business support	5,263	10,836	11,367	11,595	11,822	12,060	12,310	12,548	12,797	13,057	13,317
17	**Non-network opex**	7,807	13,981	14,666	14,960	15,254	15,561	15,883	16,190	16,512	16,848	17,183
18	**Operational expenditure**	15,236	23,104	24,236	24,721	25,206	25,715	26,246	26,754	27,286	27,840	28,395
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,169	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777
23	Vegetation management	2,150	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300
24	Routine and corrective maintenance and inspection	2,167	2,740	2,740	2,740	2,740	2,740	2,740	2,740	2,740	2,740	2,740
25	Asset replacement and renewal	1,943	2,306	2,306	2,306	2,306	2,306	2,306	2,306	2,306	2,306	2,306
26	**Network Opex**	7,429	9,123	9,123	9,123	9,123	9,123	9,123	9,123	9,123	9,123	9,123
27	System operations and network support	2,544	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145
28	Business support	5,263	10,836	10,836	10,836	10,836	10,836	10,836	10,836	10,836	10,836	10,836
29	**Non-network opex**	7,807	13,981	13,981	13,981	13,981	13,981	13,981	13,981	13,981	13,981	13,981
30	**Operational expenditure**	15,236	23,104	23,104	23,104	23,104	23,104	23,104	23,104	23,104	23,104	23,104
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses	-	-	-	-	-	-	-	-	-	-	-
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	-	-	-	-	-	-	-	-	-	-	-
36	Insurance	-	-	-	-	-	-	-	-	-	-	-
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	87	124	162	201	242	281	322	364	407
43	Vegetation management	-	-	113	161	209	260	313	363	416	472	527
44	Routine and corrective maintenance and inspection	-	-	134	192	249	310	373	433	496	562	627
45	Asset replacement and renewal	-	-	113	161	210	261	314	364	417	473	528
46	**Network Opex**	-	-	447	639	830	1,031	1,241	1,441	1,651	1,870	2,089
47	System operations and network support	-	-	154	220	286	355	428	497	569	645	720
48	Business support	-	-	531	759	986	1,224	1,474	1,712	1,961	2,221	2,481
49	**Non-network opex**	-	-	685	979	1,272	1,580	1,901	2,209	2,531	2,866	3,202
50	**Operational expenditure**	-	-	1,132	1,617	2,102	2,611	3,142	3,650	4,182	4,736	5,291

Schedule 12a: Report On Asset Condition

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2018 – 31 March 2028**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref						Asset condition at start of planning period (percentage of units by grade)						
7–9	**Voltage**	**Asset category**	**Asset class**		**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	52781	No.	1.00%	2.00%	68.00%	29.00%	-	2	2.40%
11	All	Overhead Line	Wood poles	1467	No.	11.00%	6.00%	56.00%	27.00%	-	2	17.00%
12	All	Overhead Line	Other pole types	104	No.	26.00%	18.00%	51.00%	5.00%	-	2	28.80%
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	293.3	km	13.00%	12.00%	74.00%	1.00%	-	2	13.60%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	28.1	km	-	-	100.00%	-	-	2	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	10.3	km	-	-	41.00%	59.00%	-	2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	8.5	km	-	-	100.00%	-	-	2	25.00%
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	0	km	-	-	-	-	-	N/A	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	3	km	-	-	100.00%	-	-	2	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	0.2	km	-	-	50.00%	50.00%	-	2	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	0	km	-	-	-	-	-	N/A	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	0	km	-	-	-	-	-	N/A	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	0	km	-	-	-	-	-	N/A	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	0.5	km	-	-	100.00%	-	-	2	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	20	No.	-	5.00%	80.00%	15.00%	-	2	5.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	1	No.	-	-	100.00%	-	-	2	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	30	No.	-	-	73.00%	27.00%	-	2	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	59	No.	2.00%	3.00%	80.00%	15.00%	-	2	5.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	11	No.	-	-	18.00%	82.00%	-	2	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	172	No.	-	-	87.00%	13.00%	-	2	-
30	HV	Zone substation switchgear	33kV RMU	4	No.	-	-	100.00%	-	-	2	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	0	No.	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	20	No.	-	-	100.00%	-	-	2	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	145	No.	11.00%	1.00%	40.00%	48.00%	-	2	30.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	0	No.	-	-	-	-	-	N/A	-

sch ref						Asset condition at start of planning period (percentage of units by grade)						
35–38	**Voltage**	**Asset category**	**Asset class**		**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2018 – 31 March 2028**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref												
39	HV	Zone Substation Transformer	Zone Substation Transformers	39	No.	-	5.00%	69.00%	26.00%	-	2	10.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	3499.1	km	2.00%	2.00%	77.00%	19.00%	-	2	2.90%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	0	km	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	0	km	-	-	-	-	-	N/A	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	225	km	1.00%	-	51.00%	48.00%	-	2	0.70%
44	HV	Distribution Cable	Distribution UG PILC	38.7	km	-	-	93.00%	7.00%	-	2	1.00%
45	HV	Distribution Cable	Distribution Submarine Cable	1.5	km	-	-	100.00%	-	-	2	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	29	No.	-	-	31.00%	69.00%	-	2	10.00%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	0	No.	-	-	-	-	-	N/A	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	8277	No.	3.00%	1.00%	52.00%	44.00%	-	2	3.90%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	30	No.	17.00%	20.00%	63.00%	-	-	2	45.00%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	193	No.	-	-	54.00%	46.00%	-	2	7.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	5842	No.	7.00%	3.00%	55.00%	35.00%	-	2	7.70%
52	HV	Distribution Transformer	Ground Mounted Transformer	1367	No.	2.00%	4.00%	54.00%	40.00%	-	2	1.80%
53	HV	Distribution Transformer	Voltage regulators	10	No.	-	-	40.00%	60.00%	-	2	10.00%
54	HV	Distribution Substations	Ground Mounted Substation Housing	118	No.	13.00%	5.00%	71.00%	11.00%	-	2	12.70%
55	LV	LV Line	LV OH Conductor	1191.8	km	1.00%	1.00%	75.00%	23.00%	-	2	1.50%
56	LV	LV Cable	LV UG Cable	681.9	km	-	-	36.00%	64.00%	-	2	0.10%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	398.5	km	9.00%	2.00%	73.00%	16.00%	-	2	9.40%
58	LV	Connections	OH/UG consumer service connections	57000	No.	-	-	84.00%	16.00%	-	2	7.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	357	No.	-	-	60.00%	40.00%	-	2	15.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	1	Lot	-	100.00%	-	-	-	2	100.00%
61	All	Capacitor Banks	Capacitors including controls	29	No.	-	-	31.00%	69.00%	-	2	5.00%
62	All	Load Control	Centralised plant	6	Lot	33.00%	33.00%	34.00%	-	-	2	41.70%
63	All	Load Control	Relays	34768	No.	26.00%	9.00%	54.00%	11.00%	-	2	28.80%
64	All	Civils	Cable Tunnels	0	km	-	-	-	-	-	N/A	-

Company Name: **Northpower Ltd**

AMP Planning Period: **1 April 2018 – 31 March 2028**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Alexander Street	15	15	N-1	5	97%	15	103%	No constraint within +5 years	Load transfer
10	Bream Bay	4	-	N	2	-	10	51%	No constraint within +5 years	
11	Dargaville	12	15	N-1	3	80%	15	86%	No constraint within +5 years	
12	Hikurangi	6	5	N-1	2	124%	10	63%	No constraint within +5 years	
13	Kaiwaka	2	-	N	2	-	5	44%	No constraint within +5 years	
14	Kamo	11	15	N-1	3	75%	15	85%	No constraint within +5 years	
15	Kioreroa	11	20	N-1	2	56%	20	67%	No constraint within +5 years	
16	Mangawhai	7	5	N-1	2	144%	5	166%	Transformer	Backfeed + mobile generation + load control (holiday load)
17	Mareretu	3	-	N	2	-	-	-	Other	(single transformer) Backfeed + mobile generation + load control
18	Maungatapere	7	5	N-1	3	142%	8	78%	No constraint within +5 years	
19	Maungaturoto	6	8	N-1	2	81%	8	78%	No constraint within +5 years	
20	Ngunguru	3	-	N	2	-	5	72%	No constraint within +5 years	
21	Onerahi	8	8	N-1	2	108%	15	57%	No constraint within +5 years	
22	Parua Bay	3	-	N	2	-	-	-	Other	(single transformer) Backfeed + mobile generation + load control
23	Poroti	3	-	N	3	-	-	-	Other	(single transformer) Backfeed + mobile generation + load control
24	Ruakaka	7	10	N-1	2	68%	10	75%	No constraint within +5 years	
25	Ruawai	3	-	N	2	-	5	64%	No constraint within +5 years	Single transformer substation - backfeed via distribution network
26	Tikipunga	15	20	N-1	4	77%	20	83%	No constraint within +5 years	
27	Whangarei South	12	10	N-1	4	120%	10	105%	No constraint within +5 years	Load transfer
28						-				

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Schedule 12c: Report On Forecast Network Demand

Company Name	Northpower Ltd
AMP Planning Period	1 April 2018 – 31 March 2028

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref								
7	**12c(i): Consumer Connections**							
8	*Number of ICPs connected in year by consumer type*				**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
11	*Consumer types defined by EDB**							
12	Very large industrial		-	-	-	-	-	-
13	Commercial and Industrial (demand based ND9)		1	1	1	1	1	1
14	Mass market		969	988	1,008	1,028	1,049	1,070
17	**Connections total**		970	989	1,009	1,029	1,050	1,071
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		150	200	250	300	300	300
21	Capacity of distributed generation installed in year (MVA)		1	1	1	1	1	1
22	**12c(ii) System Demand**							
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)**	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
25	GXP demand		170	173	177	180	182	187
26	*plus* Distributed generation output at HV and above		4	4	4	4	4	4
27	**Maximum coincident system demand**		174	177	180	183	185	190
28	*less* Net transfers to (from) other EDBs at HV and above							
29	**Demand on system for supply to consumers' connection points**		174	177	180	183	185	190
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		1,095	1,117	1,141	1,165	1,189	1,213
32	*less* Electricity exports to GXPs		-	-	-	-	-	
33	*plus* Electricity supplied from distributed generation		22	22	22	22	22	22
34	*less* Net electricity supplied to (from) other EDBs		-	-	-	-	-	
35	**Electricity entering system for supply to ICPs**		1,117	1,139	1,163	1,187	1,211	1,235
36	*less* Total energy delivered to ICPs		1,071	1,092	1,114	1,137	1,159	1,182
37	**Losses**		46	47	49	50	52	53
38								
39	**Load factor**		73%	74%	74%	74%	75%	74%
40	**Loss ratio**		4.1%	4.1%	4.2%	4.2%	4.3%	4.3%

Schedule 12d: Report Forecast Interruptions And Duration

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2018 – 31 March 2028**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	85.0	95.0	100.0	100.0	100.0	100.0
12	Class C (unplanned interruptions on the network)	90.0	90.0	90.0	90.0	90.0	90.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.24	0.27	0.30	0.30	0.30	0.30
15	Class C (unplanned interruptions on the network)	2.00	2.00	2.00	2.00	2.00	2.00

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2018 – 31 March 2028**
Asset Management Standard Applied	**PAS55/ISO55000**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score 2018	Score 2016	Evidence—Summary	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	1	1	Northpower PAS-55 Gap Analysis Review August 2008 by Maunsell Ltd. External asset management review conducted August 2017 by WSP, identifying gaps and opportunities. Draft policy in place.	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	3	AMP section 2. Company-wide values, common management systems certified to ISO 9001 and ISO 14001	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	3	AMP section 2. Purpose specifically refers to lifecycle and planning management asset information including age and condition. Refer statement of corporate intent. "Life Cycle Asset Management Plan" is covered in the AMP section 6 . A project is underway tp ensure access to timely and accurate data, for making more informed life cycle decisions.	Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	3	AMP section 6. Process for assessing asset condition documented (Knowledge Central). Largely uses age to to determine remaining life for most classes of assets, but a project is underway to enhance our ability to capture asset condition.	The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Company Name	Northpower Ltd
AMP Planning Period	1 April 2018 – 31 March 2028
Asset Management Standard Applied	PAS55/ISO55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	Northpower Ltd
AMP Planning Period	1 April 2018 – 31 March 2028
Asset Management Standard Applied	PAS55/ISO55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score 2018	Score 2016	Evidence—Summary	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	2	The AMP is available on the corporate intranet and is part of the suite of documents that form the quality management system. The AMP is made available to staff and to the general public via Northpower's website or alternatively a copy can be obtained at Northpower's head office. monthly project overview meetings evaluates delivery to plan.	Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	3	Roles are defined in section 2 of the AMP. Process and manual owners are defined in the management system. Northpower is strengthening its asset management capabilities, and business structure. This includes recestablishment of new asset management roles over the last year.	The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3	3	There is a formal service level agreement (SLA) in place with principal contractor. Montly reporting on progress to the plans. Supplier arrangements are in place for key equipment and materials. Competitive commercial processes relating to procurement are well established. Smarter systems relating to electronic data capture, data management and information systems have been implemented and continue to be developed.	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	3	Storm plan is documented in the Operations manual and risk management process is outlined in section 9 of the AMP. Corporate plans include pandemic situations and Northpower is an active member of the Northland Lifelines group and is active in the regional CDEM group. Northpower has a dedicated strategic spare store and a process for managing these. Disaster recovery plans for some events need updating, Northpower is in the midst of a Business Continuity Plan update and development, which will be completed later in 2017, and feed into the storm plan.	Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score 2018	Score 2016	Evidence—Summary	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	3	Section 2 in the AMP outlines structure and responibilities. Senior staff have performance objectives to meet which are reviewed annually. Asset management capabilities have been under review, ensuring clearly defined responsibilities, new position descriptions are in place. Engineering involvement in national organisations.	In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	2	Statement of corporate intent and strategic plans. Solution team established, supporting processes and systems being defined through the recent completion of the Functional Interface that defines business unit accountabilities. The need for some additional resources have been identified and recruitment has taken place to fill new roles.	Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	2	Senior management have communicated a desire to align asset management practice with ISO55000 (project has been scoped and initiated). A Programme Director has established project governance and delivery mechanisms, this adds more focus on completing capex projects on time and on budget.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	3	Compliance ensured by service level agreement (SLA) for field work. The SLA includes responsibilities between the network/contracts/asset management groups and KPI's to ensure performance. Decision-making regarding what activities are to be carried out resides with Network, the asset management engineering team is responsible for delivering to programme.	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score 2018	Score 2016	Evidence—Summary	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	1	Department managers indentify long term human resource requirements. Succession plans include the recruitment and appointment of young graduate engineers. Staff resources are being scaled up to reflect work load. External reviews of Northpower's asset management capabilities have been carried out, identifying gaps in resourcing. Structure changes and recruitment are in progress.	There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	2	Regular visits to distribution companies enables a sharing of expertise and link to other suppliers. There are annual performance reviews, including performance measure reviews. Asset management staff are actively involved in industry bodies such as the Electricity Networks Association & EEA.	Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2	2	Professional engineers are encouraged to attend relevant courses or seminars relating to technology and asset management. Staff new to the industry are assisted with their development by exposure to engineering projects and related tasks under the guidance of senior staff.	A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score 2018	Score 2016	Evidence—Summary	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	3	Publication and availability of the AMP on Northpower website, customer newsletters, meetings with Northpower Trust, simplified annual reports mailed to customers, Contractor given access to asset information and reports. Technical and operational standards are available to contractors (e g policy on ownership of asset).	Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	3	Section 2 in the AMP outlines asset management systems and processes. Standard asset management practices are outlined in the Network standards manual available on the intranet.	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3	3	Data requirements are decsribed at a high level in section 2 of the AMP. Data rules relating to asset representation are defined in the Network Standards Manual. The GIS and WASP asset management system have data rules defined the the configuration of the asset.	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	3	Staff are in place whose role it is to maintain asset management information systems and ensure data quality is maintained and improved. Data quality is continuously improved by way of ongoing field capture and data analysis.	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score 2018	Score 2016	Evidence—Summary	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	2	Strategic plans as well as business plans include information technology requirements. General managers (ELT) meet monthly to discuss information technology and human resource issues. Asset management issues and initiatives are reported orally at the leadership metings each wek.The management team (ELT) decide on priorities in terms of Information technology resources. There is however a weakness in the operational reporting system which is primarily for reporting fault statistics, not asset management. The ability to monitor the financial status of capex projects and work activity is currently unsatisfactory, a Programme Director posision has been established and filled, and project oversight and	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	3	Section 9 in the AMP outlines risk identification and mitigation policies. The corporate division monitors key risks across the business. An audited saftey managent system (SMS) in accordance with NZS 7901 is in place. ISO 9001 ISO 14001 also identify risks. A separate electricity network risk register is maintained.	Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	2	The board of directors is strongly averse to exposure to public harm and staff health and safety risk and priority is given to funding risk mitigation in these areas. Training and competency requirements are identified by departmental and area managers. The output from the risk assessment for Directors is "high" level to determine the adequancy of resources, training and comptency needs. Safety by design application sees project risks managed (for example ensuring plant spacing at a substation meets safety requirements). Engineers still need formal training in "safety by design" to align with the recently released EEA good practice guide.	Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	3	A senior manager is tasked with coordination responsibility for mapping compliance and ensures that requirements are communicated to the responsible person(s). In house legal counsel. A compliance register is in place. The AMP is also reviewed by several senior managers and also an external consultant before presentatation to the board of directors.	In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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		Asset Management Standard Applied	PAS55/ISO55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score 2018	Score 2016	Evidence—Summary	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	3	The AMP feeds into Opex and Capex budgets (section 7 in the AMP). Approved budgets feed directly into Contracting program of works which is governed by the SLA. Network standards are in place for design, approved equipment, commissioning etc. The draft asset policy ensures targeted programmes are developed in the budgeting cycle.	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3	3	There is a defined process for assessing work that is carried out on Network assets. Monthly progress reports are required to be submiited by the contractor and a relationship meeting takes place between Network and Contracting once a month. Regular meetings with Contracting and Supply Chain take place to review new products, equipment and material and resolve issues with existing.	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	2	Regular reliability reports and incident monitoring. Debriefs are held following significant weather events and other incidents. Plans are in place to move to asset health or condition assessment in place of just noting defects. Geospatial data on fautls is now in place. Resourcing is being addressed withthe recent appointment of a Maintenance Strategy Manager. This should remove our issue with lack of resources to look at in detail all assets and components indivually about	Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	2	Responsibility is in general outlined in the objectives and duties of the relevant staff. A company wide reporting system (NPSAFE) is in place to report and follow up on incidents and is used for all types of non-conformity, not just safety aspects. The system can be deployed to cover a wider business area.	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score 2018	Score 2016	Evidence—Summary	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	4	4	Northpower is compliant with IS 9001, which sets the standards for correction processes and investigations. External reviews by experts have been conducted, to facilitate structural and capability enhancement. Have commenced an asset works management and maitnenace process review that will align Northpower to ISO55000.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	4	4	Northpower's corrective action processes have been audited as complying with IS 9001. Our Health and Safety policies and practices provide for incident investigations and reporting on asset conditions and risks.	Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3	3	Continual improvement is a core element of ISO 9001. Significant project business cases/sanctions for expenditure require NPV analysis in support of the business case. Safety in Design principles enables learnings to be tranbsferred into other projects.	Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	4	4	This is done by way of key supplier communications, participation in the industry EEA, attendance of industry conferences, forums and trade displays by key personnel and having dedicated development staff. Key staff participate in industry working groups and there is a strong relationship with Auckland and Canterbury Universities with respect to research and development. Northpower lacks a controlled test environment to test new equipment and components for withstand under envirnomental conditions e.g. corrosion and exposure to UV. Testing takes place "in the field".	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 14a: Mandatory Explanatory Notes on Forecast Information

Electricity Distribution Information Disclosure Determination 2012 – (consolidated in 2015)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure

The difference between nominal and constant prices is based on application of an escalation factor, using economic forecasts provided by the New Zealand Institute of Economic Research.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

The difference between nominal and constant prices is based on application of an escalation factor, using economic forecasts provided by the New Zealand Institute of Economic Research.

Schedule 17: Certification for Year-beginning Disclosures

(Asset Management Plan and Forecast Information)

Electricity Distribution Services Information Disclosure Determination 2012 as consolidated in 2015
Clause 2.9.1

We, Phil Hutchings & David Ballard, being directors of Northpower Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Northpower Limited prepared for the purposes of clauses 2.6.1, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Northpower Limited's corporate vision and strategy and are documented in retained records.

Director

Date: 28/03/18

Director

Date: 28/03/18

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