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I. Executive Summary

I.1. Introduction

The objective of this Asset Management Plan (AMP) is to outline the various asset management strategy techniques used to manage the assets of Horizon Energy Distribution Limited “Horizon Energy” for “the Company” and to ensure that appropriate investment is made to provide for the sustainable and reliable operation of the network.

This AMP describes the asset management and network development strategies through to the year 2024. This AMP reflects a move by Horizon Energy to align with asset management practices consistent with British Standard PAS 55¹, and the document and supporting systems are being revised to reflect this. As signalled last year the Company continues its transition its AMP to meet the requirements of the PAS 55 requirements.

This AMP represents the views and plans of Horizon Energy as at the date of the report. Due to the process for the continuous review of network priorities, proposed projects, and the operational work described in this asset management plan, Horizon Energy gives no assurances that any individual project or work proposed in the plan will be implemented as described in this AMP.

It is particularly pertinent that this version of the plan includes two scenarios when considering future expenditure. The primary scenario is similar to previous versions of the Plan in that no financial provision for the purchase of the Transmission Assets east of Edgumbe is included. The option to purchase has long featured in Horizon Energy’s plans as they would more logically integrate with local lines business infrastructure than Transpower. Unfortunately the risks arising from the regulatory regime have precluded commitment to the acquisition of assets previously. However, close to the date for publishing the AMP the Company has advanced its thinking on the acquisition of the East Coast Assets, which, if approved, by the Board will fall outside the AMP disclosure timelines. The timing disconnect between the Company’s internal decision making process and the Commerce Commissions request for information has lead Horizon Energy to include the East Coast Asset purchase as a second scenario in its associated financial forecasts.

I.2. Key Achievements 2013-14

This year has seen the Company continue its substantial four year investment in reliability with \$3.9 million spent on 164 separate projects since the reliability project initiative began in 2010. The project is now 75% complete.

The financial and job management package MS Dynamics NAV went live in December 2011 and is now providing substantially improved intercompany financial management information, reporting and job control management.

An increased focus on vegetation management has helped to achieve a significant reduction of outages caused by tree interference or contact with low lines during the previous period. Further initiatives are being implemented to make improvements in this area with the creation of a dedicated vegetation control management role.

¹ Note:

PAS 55 is a British Standard (Publicly Available Specification) that provides objectivity across 28 aspects of good asset management, from lifecycle strategy to everyday maintenance (cost/risk/performance). It enables the integration of all aspects of the asset lifecycle: from the first recognition of a need to design, acquisition, construction, commissioning, utilisation or operation, maintenance, renewal, modification and/or ultimate disposal. It is a standard promoted in the Electricity Distribution Information Disclosure Determination 2012 issued by the Commerce Commission in October 2012.

Planning for new substation developments at Gateway and Opotiki have continued, with detailed estimates and preliminary concept designs completed. Negotiations with affected parties are on-going for both projects.

Significant projects completed include:

- East Bank substation protection system upgrade;
- Kopeopeo substation transformer T2 replacement;
- Conversion of Galatea zone substation to an indoor 11kV switchboard;
- Procurement of a 1MVA generator for capacity reinforcement and emergency supply;
- GIS system implementation.

The contracting arm Horizon has been re-branded as Horizon Services Limited (HSL).

1.3. Major Projects 2014-17

Major projects in planning for the next three years are:

2014-16	Gateway 33kV switching station
2015-16	2 nd 1MVA network support generator
2016-17	New 33kV line into Aniwhenua
2014-17	Opotiki substation development
2015-16	Plains T1 transformer replacement
2015-16	Waiotahi substation circuit breaker replacements with indoor units
2016-17	Kope 33kV indoor conversion

1.4. Levels of Service

The network delivered 525 GWH of energy to 24,675 customers during 2012-13, a decrease in delivered energy from the previous year of 1.7%. This is the second year in a row with reducing demand, a 1.3% reduction was recorded the previous year, and is in direct contrast to the weighted average network zone substation peak demand, which increased by 1.2% in 2012-13.

SAIDI and SAIFI performance for 2012-13 was 191.6 and 2.3 respectively, both higher than the previous year. The SAIDI value was above the Company internal target of 145 SAIDI minutes.

Three separate faults exceeded 10 SAIDI minutes, and two at 9 SAIDI minutes. These high impact faults are further expanded on in section 4.3.

The reliability improvement projects are showing an average reduction of 30% in SAIDI minutes for the feeders that have been completed, despite a 4% increase in the number of faults.

The targets to be achieved over the coming year, 2014-15 for both planned and unplanned interruptions on the Horizon Energy network are:

	Planned	Unplanned
SAIDI	20	125
SAIFI	0.14	1.6
CAIDI	140	78

1.5. Asset Utilisation Summary

Coincident network demand increased by 3.5% over the previous year. Non-coincident demand increased by 4.6%. This is in contrast to the delivered total energy which reduced by 1.3%.

The peak demand growth in 2012-13 for each of the zone substations is shown in Table 1.1.

Zone Substation Peak Demand 2012-13		
Zone Sub	MVA	Predicted Growth
East Bank	6.4	1.4%
Galatea	4.8	0.4%
Kaingaroa	2.4	0.0%
Kawerau *	19.0	1.6%
Kopeopeo	15.5	2.1%
Ohope	4.6	1.0%
Plains	6.2	1.5%
Station Road	8.4	0.3%
Te Kaha *	2.1	0.0%
Waiotahi *	9.4	1.5%

* Transpower Assets

Note 1- Kaingaroa and Te Kaha substations recorded negative growth

Table 1.1 - Zone Substation Demand 2012-13

Known network constraint issues are:

- Kawerau town feeders are heavily loaded to 50% of the feeder rating at peak, with substantial de-rating applied to the cables due to soil conditions;
- Kawerau Onepu feeder has been scheduled to be split into two feeders due to load issues when embedded generation is off;
- Notwithstanding the ownership of Transpower assets within the Opotiki region, the network and 11kV distribution system around Opotiki requires further investment due to load growth and quality of supply issues. Preliminary plans to build a new zone substation at Opotiki are scheduled from 2014 through to 2018 and planning is proceeding on this basis;
- Major 11kV conductor upgrade projects intended to provide inter-connectivity between Station Road and Kope continued in 2013. The work completed so far has enabled Kope substation to be totally shut down for essential maintenance work during low load periods;
- The development of the Gateway substation at 33kV is being progressed in conjunction with a major industrial customer. This project is scheduled to enter the implementation phase during 2014;
- As a result of the failure of one of the supply transformers at the Nova Generation Station, the Galatea system is being supplied from Edgecumbe via the Snake Hill circuit (since 2009), instead of the preferred supply from Aniwhenua. This causes a lower level of reliability, higher system losses, and lower system spare capacity. The Nova Energy transformer was returned to service mid 2013;
- A review of the proposal to purchase the transmission assets east of Edgecumbe in 2017, (the Edgecumbe to Waiotahi 110kV line, Waiotahi and Te Kaha substations, and the 50kV Waiotahi-Te Kaha line) was carried out in 2013-14 and has resulted in the Horizon Energy Board continuing to monitor opportunities to procure these assets; and
- A study of load flows and projected demand within the Whakatane region has identified that a CBD based zone substation would have more benefit than an 11kV substation previously proposed at Mill Road, being closer to the load centre, allowing displacement of load driven feeder cable upgrade projects, and supported by the existing Kopeopeo substation.

1.6. Financial Summary

During 2013-14 Horizon Energy plans to spend around \$2.5 million on maintenance and \$9 million on capital works. The total expenditure uplift through to 2016 reflects the capital expenditure on zone substation construction and large power transformer replacements. The financial budgets are described in further detail in section 8.7.

NB

The financial forecasts in this AMP differ from previous versions in that the CAPEX and OPEX forecasts now have inter-company margins removed.

Figure 1.1a shows the projected expenditure by maintenance and capital categories for the ten year planning period. Note that it includes expenditure funded by capital contributions.

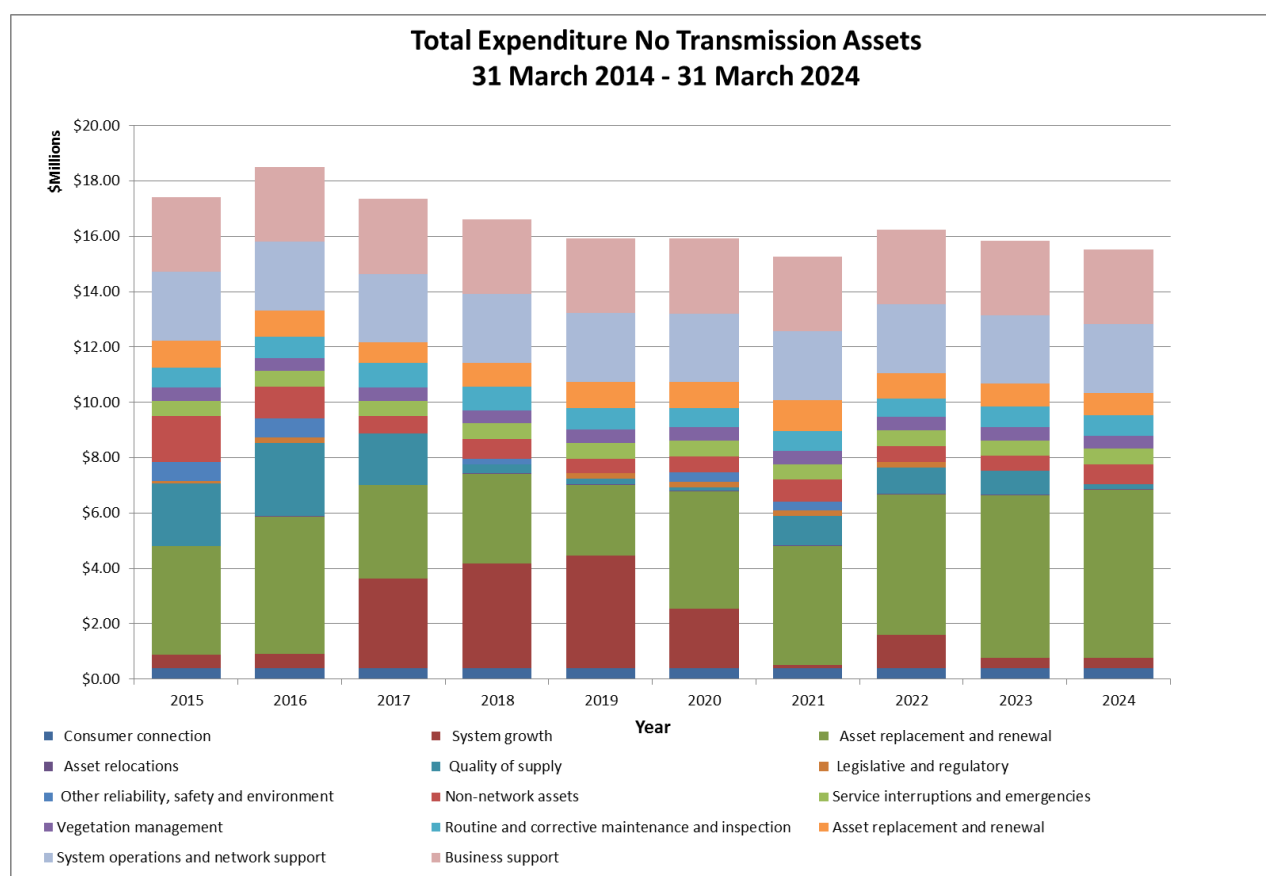


Figure 1.1a - 10 Year Projected Expenditure

- There has been an increase in planned expenditure during the latter years of the planning period compared to previous plans. This increase in expenditure is a result of:
 - Improved knowledge of the assets.
 - More forward planning for age and condition based replacement projects.
 - There are more defined projects included in the forward plan that are based on specific asset replacement or refurbishment and less reliance on generic asset type replacement projects.
 - For practical and cost efficiency reasons the plan is subject to some smoothing to accommodate available resources.
- The maintenance forecast varies year by year. This is caused by:
 - Routine maintenance of certain assets being time based, with different assets having between one to five yearly routine overhaul or maintenance periods.

- The effects of the different maintenance cycles combining to give a variable amount each year.
- Significant maintenance costs associated with particular types of asset refurbishment. For example, up to 20% of the line upgrade or refurbishment will be expensed as maintenance not capital. These values are included in the overall maintenance predictions.
- Increasing asset replacement and renewal expenditure for the next two years driven by Plains substation TI replacement.

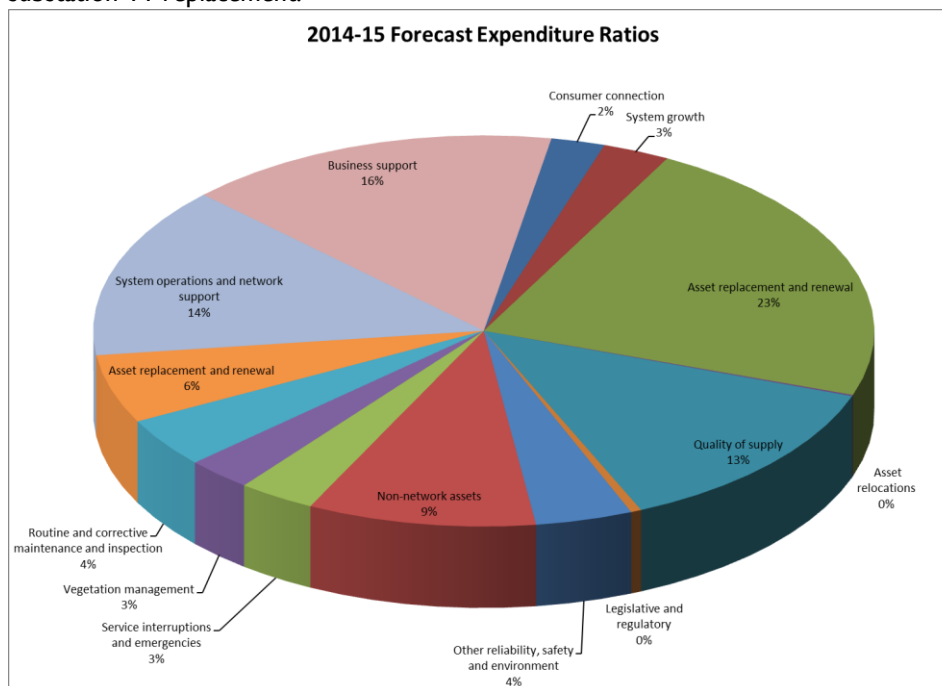


Figure 1.2 - 2013-14 Expenditure Classification Ratios

The projected expenditure by classification is shown in Figure 1.2. Section 8, the Financial Summary Section, provides background on the assumptions and uncertainties around these projections.

1.7. Financial Summary (Scenario 2 - East Coast Asset Purchase)

During March 2014 the Commerce Commission requested information relating to the transfer of assets from Transpower to Distribution Lines businesses. Horizon Energy is considering the purchase of the Transpower assets east of Edgecumbe, being 110kV line, 50kV line, Waiotahi GXP and Te Kaha GXP. The Board will consider a recommendation from management relating to the purchase early in the new financial year which, if approved, will result in the assets being purchased within the 2015-2020 pricing period. In the interest of disclosure and to ensure that Commerce Commission has regard to the Company's plans in its forthcoming price reset process, the following expenditure charts are included to inform interested parties.

Figure 1.3 shows the projected expenditure by maintenance and capital categories for the ten year planning period if the purchase takes place in 2017 the earliest practical date.

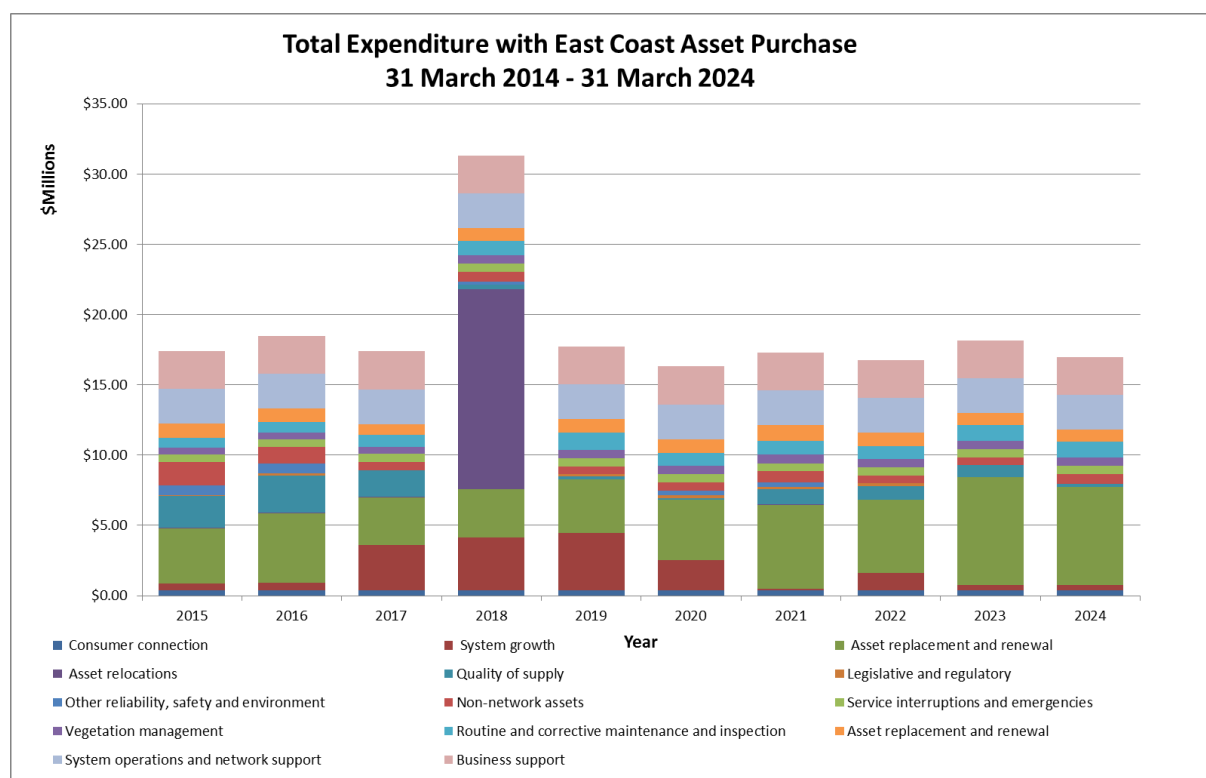


Figure 1.3 - 10 Year Projected Expenditure

In this scenario, the CAPEX is increased by \$6M above the purchase price because of the asset replacement that is expected to be required with in the forecast period.

OPEX is budgeted to increase by \$3M largely due to increased switchgear, vegetation and access route maintenance.

1.8. Risk Management

The Company continues to proactively manage public and worker safety, as well as network risks. We are improving safety and quality systems by working towards and achieving national standards based certification in key areas. This process is described in detail in Section 7, Risk Management. Target levels of service are detailed in Section 4.4.

1.9. Improvement Plan

This plan has been updated to reflect the progress made by improving asset management practices. A large number of the improvements identified are dependent on continuing the implementation and refinement of the Information System Review (ISR) group of projects, which started in 2011. Section 9, Improvement Plans, summarises the plans in place to continually improve and refine the planning processes.

The key improvements planned for 2013/2014 include:

- Continuation of the integration of the GIS, job management and financial systems and development of reporting systems;
- Implementation of a project to automate regulatory reporting processes;
- Continued improvement to service delivery systems through the development and refinement of unit rates, benchmarking, KPI's and more focus on stakeholder engagement and service level agreements; and

- More work on implementing and refining systems to better position the company for PAS55 accreditation.

I.10. Safety

Horizon Energy has achieved and will maintain accreditation for NZS 7901:2008 Safety Management Systems for Public Safety and AS/NZS 4801: Safety Management Systems.

I.11. Electricity Distribution Information Disclosure Determination 2012

The Commerce Commission published the Electricity Distribution Information Disclosure Determination 2012 in October 2012.

Section 2.6 of the Electricity Distribution Information Disclosure Determination 2012 sets out the required disclosures relating to the AMP and forecast information.

Horizon Energy has elected to complete the templates provided by the Commerce Commission contained in the reports under subclause 2.6.5(1) within Appendix A2 and (under sections 2.6.5(1) (a) and (b)) Appendix A3 of this AMP. Appendix A2 reflects the forecasts for the Company without the purchase of any transmission assets from Transpower. The schedules in Appendix A3 show the expenditure forecast for the scenario where Horizon Energy purchases the transmission assets east of the Edgumbe GXP.

Horizon Energy has included the templates for completeness but they do not constitute public disclosure which is not required under subclause 2.6.5(5) prior to 31 August 2014

2. Background and Objectives

2.1. Overview

This Asset Management Plan is based on the framework of previous plans but is undergoing a shift in emphasis to the asset management principles embodied in the British Standard Institute's PAS 55.

A substantial number of the asset management practices advocated under PAS 55 are currently being employed by the Company and are included in this document. Other information is included to meet the requirements of the Commerce Commission's determinations. Just as importantly the document provides a convenient repository for information referenced by staff and contractors.

This Asset Management Plan is written in accordance with section 2.6 of the Electricity Distribution Information Disclosure Determination 2012 published by the Commerce Commission in October 2012. For completeness, the information contained in each of the reports required under subclause 2.6.5(1) of the Electricity Distribution Information Disclosure Determination 2012 has been provided in Appendix A2.

The Asset Management Plan is intended to be a working document that drives the Company's capital and maintenance planning processes, and provides information to all stakeholders of the forward planning objectives and the justifications for the budgets. It is a living, working document.

2.2. Plan Structure

The structure of this plan is as follows:

Section 1	Executive Summary. Provides an overview of the salient points within the document.
Section 2	Purpose of the AMP, corporate vision, stakeholders and target audiences.
Section 3	Geographical area covered and high level summaries of assets covered under the AMP.
Section 4	Service levels, targets, including performance summaries, analysis of faults and outages.
Section 5	Network planning principles and detailed description of network assets in a parent child relationship. Includes utilisation data to feeder level and identifies any constraints and projects against particular assets.
Section 6	Asset lifecycle management planning; covers asset renewals and refurbishment policies, asset lifecycle replacement and policies that are driving these programs, and asset replacement projects.
Section 7	Summarises the risk policies and programs to minimise risk to the network and Company.
Section 8	Expenditure forecasts and reconciliations. Describes development of budgets and financial forecasts.
Section 9	Improvement Plan. Details improvement initiatives to improve AMP practices and reporting.

Table 2.1 – Plan Structure

To improve usability, this AMP is structured to try to minimise data repetition. Summary data will be carried between sections but this is minimised where possible. All information pertaining to an asset or group of assets is kept in the same Section so that all data and information is readily accessible.

2.3. Company Background

The Horizon Energy electrical network is the result of a merger between the Bay of Plenty Electric Power Board and the Whakatane District Council Municipal Electricity Department that occurred in 1989. These two organisations first started the reticulation of the Eastern Bay of Plenty in the mid to late 1920's. During the early to mid-1990's Government initiatives resulted in this Power Board being restructured as a publicly listed integrated electrical lines/supply company (Bay of Plenty Electricity Ltd).

The action undertaken in accordance with the 1998 Electricity Industry Reform Bill, which required the separation of lines and supply businesses, resulted in the lines business selling its generation and supply business (and name), and re-branding itself as Horizon Energy Distribution. The generation and supply business so formed was Bay of Plenty Electricity Ltd, recently re-branded as Nova Energy.

Now the network distributes electricity to over 25,500 customers from four Grid exit points. Its assets include 33kV sub transmission, 11kV distribution and 400V reticulation with a total depreciated replacement value as at 31 March 2012 of \$98.2 million.

The Company is a publicly listed company which includes a number of subsidiaries. The Eastern Bay Energy Trust holds 77.4% of the shareholding on behalf of the consumers connected to the Company's network.

2.4. Asset Management Policy and Corporate Vision

The Asset Management Policy drives the asset management system, and is a means of communication for Executive Management to communicate to Managers, employees and stakeholders the intentions of the Company regarding asset management. It is directly aligned to the Company's Strategic Plan and reflects the corporate Vision and Mission statements.

The following definition guides Horizon in the generation of this plan:

Asset management is maintaining a desired level of service for what you want your assets to provide at the lowest life cycle cost. Lowest life cycle cost refers to the best appropriate cost for rehabilitating, repairing or replacing an asset. Asset management is implemented through an **Asset Management Policy** and includes a written **Asset Management Plan**.

The policy statement below is core to the asset planning principles outlined in this document:

"To manage the electricity supply network assets in a safe manner that provides an appropriate, cost effective level of service for existing and future customers, and to ensure that value is created for all stakeholders within the confines of the regulated framework".

Horizon Energy's asset management process and core purpose is guided by its vision for the future. This vision forms part of the Strategic Plan which is reviewed annually by the Board.

Horizon Energy's **Vision** is to be a:

Nationally recognised infrastructure services provider that generates long term value for our shareholders.

The Vision is supported by the **Mission Statement**:

To be the service provider of choice in all market segments that we operate in.

The Horizon Energy Network business unit has as its component of the Mission Statement.

To provide a safe, efficient, sustainable and reliable electricity network service to the Eastern Bay of Plenty that supports growth.

The AMP is a key document that considers the past and predicted performance of the assets along with the processes that are undertaken for their replacement and maintenance. From this on-going monitoring, specific actions and targets are set out to ensure the assets meet the desired outcomes as stated in the Vision and Mission statements.

2.5. Objectives of the Asset Management Policy

The Asset Management Policy determines the framework for the Asset Management Plan, whilst also ensuring other Company and stakeholder drivers and policies are recognised in its development and implementation.

In summary, the Asset Management Policy complies with the PAS 55 Guidelines in that it:

- a) Is consistent with the strategic plan;
- b) Is appropriate with the nature and scale of the Company's assets and operations;
- c) Is consistent with other Company policies;
- d) Is compliant with the Company risk management policies;
- e) Provides the framework for best practice management of assets using an Asset Management Plan as the key driver of asset management practices and policies;
- f) Is designed to achieve compliance relevant legislation;
- g) Has due regard to health and safety, and sustainability;
- h) Provides for a continual improvement in asset management practices;
- i) Is documented, implemented and maintained;
- j) Is able to be communicated to all relevant stakeholders and service providers; and
- k) Can be reviewed so that it remains relevant and consistent with the Strategic Plan.

Expanding on the Asset Management Policy summary points, the following subsections define the requirements and guidelines for developing and managing the Asset Management Plan from the Policy.

a) Strategic Plan

The Asset Management Plan shall be written using Horizon Energy's Strategic Plan as an integral guide to decision making and policy, and will reflect the Corporate Vision and Mission Statements.

The strategic goals related to the Network business include:

- Achieve prescribed customer service levels;
- Maximise the value of the network assets for the owners;
- Ensure legislative compliance;
- Continue to improve staff and public safety; and
- Ensure compliant and improving environmental practice.

The Strategic Plan is reviewed annually by the Board.

b) Scale of the Company's Operations

The Company owns a large quantity of infrastructure assets spread over a large geographical area. Asset management planning shall consider maximising the lifecycle of assets whilst considering the operational requirements, risks, stakeholder requirements and operational costs involved in doing this. Annual budgets are derived out of the 10 year Asset Management Plan and are approved by the Board of Directors.

Horizon Energy is relatively small compared to other network companies and has a small engineering department and constrained budgets. Economy of scale and efficiencies are to be managed by using standard components, standard designs, and documented work practices and procedures wherever possible.

Asset lifecycle replacement shall be determined with consideration of:

- Age;
- Condition;
- Lifetime utilisation;
- Safety for the public, staff and network;
- Maintenance history;
- Operational risk; and
- Load.

c) Consistency of Policies

Policies relevant to asset management are defined in the Quality Manual and Network Standards, which defines policies and procedures around:

- Corporate policies and procedures;
- Network design standards;
- Network operation standards and procedures;
- Health and safety policy;
- Financial standard;
- Contracting standards;
- Personnel policies;
- Stores management; and
- Emergency procedures.

Where policies around network assets are not defined within these documents then the AMP will determine the maintenance and lifecycle requirements for individual assets; but in all cases the approved quality manual or network standards shall take precedence over any AMP determination if there is any conflict.

Various non-network sections of the Quality Manual are managed by the designated Manager.

Standards relevant to network assets are approved by the General Manager Network.

Where there is a discrepancy discovered in the documents then they shall be reviewed and amended to maintain consistency.

Wherever possible all works shall be designed and built to the relevant AS/NZS standard, or an IEC standard if an AS/NZS standard does not exist. Recommendations from professional or organisational bodies incorporated in New Zealand should be referred to and any recommendations made by them considered and approved prior to use. This includes, but is not limited to:

- Electricity Engineers Association (EEA);
- Institution of Professional Engineers New Zealand (IPENZ); and
- Electricity Networks Association (ENA).

d) Compliant with the Company Risk Management Policies

The risk management sections of the Quality Manual include, but are not limited to:

- Emergency Procedures;
- Health and Safety Manual;
- Risk Management Plan;
- Environmental Policy; and
- Disaster Recovery Plans.

There shall be no deviation from the risk management policies included in these standards. Any discrepancies must be brought to the attention of Management.

Risk management principles which consider due risks to the Company, public, and individuals shall be an integral part of the design process in engineering new works and in assessing the condition of existing assets.

All implementation of works and work practices shall comply with relevant health and safety policies.

e) Provides the frame work for best practice management of assets using an Asset Management Plan as the key driver of asset management practices and policies

The Asset Management Plan and associated forward works plan shall drive the annual capital and maintenance plan and budget, within the dimensions specified by the Board representing shareholders and other stake holders.

The Asset Management Plan will predict ahead for a minimum ten year rolling period.

Asset management practices shall follow the policies and practices defined in the British Standards Institute (BSI) **PAS55-1:2008 Part 1: Specification for the optimised management of physical assets.**

Best asset management practices include the following, and these considerations should be incorporated into all asset lifecycle and maintenance deliberations:

Assets critical to sustained performance:

- How critical the assets are to system operations;
- Conducting of failure analysis (root cause analysis, failure mode analysis);
- Determining the probability of failure and listing assets by failure type;
- Analysing failure and consequences;
- Using asset decay curves; and
- Reviewing and updating system's vulnerability assessment.

Minimum lifecycle costs:

- Moving from reactive maintenance to preventative maintenance;
- Knowing the costs and benefits of rehabilitation versus replacement;
- Looking at lifecycle costs, especially for critical assets;
- Deploying resources based on asset conditions;
- Analysing the causes of asset failure to develop specific response plans; and
- Asset nominal life is as defined in the 2004 ODV Handbook unless specified different in the AMP for specific classes of assets.

Sustainable levels of service:

- Analysing current and anticipated customer demand and satisfaction with the system;
- Understanding current and anticipated regulatory requirements;
- Writing and communicating a level of service "agreement" that describes the system's performance targets; and
- Using level of service standards to track system performance over time.

Prioritisation for operational expenditure and asset replacement works shall be based on the impact to the network and number of customers or load affected if the asset should fail in service. Industry standard measurements (SAIDI, SAIFI) shall be used to determine the relative performance of assets and network enhancements. Other considerations shall include public safety, environmental and consistency with strategic plans.

f) Designed to achieve compliance with relevant legislation

The Asset Management Plan and all works shall take into account the following legislative requirements and subsequent amendments:

- (a) Electricity Act 1992;
- (b) Electricity Distribution Information Disclosure Determination 2012;
- (c) Electricity Industry Act 2010;
- (d) Electricity (Safety) Regulations 2010;
- (e) Energy Companies Act 1992;
- (f) Electricity Industry Reform Act 1998;
- (g) Resource Management Act 1991;
- (h) Building Act 2004;
- (i) Environment Act 1986;
- (j) Health & Safety in Employment Act 1992;
- (k) Health and Safety in Employment Regulations 1999;
- (l) Electricity (Hazards from Trees) Regulations 2003;
- (m) Commerce Act 1986;
- (n) Commerce Act (Electricity Distribution Thresholds) Notice 2004; and

Local legislation and by-law issues by the following territorial authorities:

- (a) Bay of Plenty Regional Council;
- (b) Whakatane District Council;
- (c) Kawerau District Council; and
- (d) Opotiki District Council.

The requirements of these bodies are included in:

- Policy Statements;
- Land Management Plans; and
- Coastal Environmental Plans and District Plans.

Other organisations that have requirements that must be adhered to are:

- New Zealand Transport Agency (NZTA) as stated in its State Highway Plan;
- Transpower; and
- Telecommunication companies.

g) Has due regard to health and safety, and sustainability

- The AMP shall not be in conflict with any Company health and safety policy;
- The AMP document provides a long term management plan; although the document itself does not have direct responsibility for the implementation of health and safety practices, the implementation of asset management planning, as works derived from the AMP, does;
- Health and safety shall be an integral part of all implementation works planning and shall be incorporated in all aspects of the works. The health and safety policy will be managed by a designated person;
- Budgets derived from the AMP 10 year plan are for works. Departmental budgets must additionally allow for health and safety practices, including training, staff retention and recruitment, safety equipment, inspections, safe work practices, public safety, certification, etc.;
- Company health and safety policies describe the responsibilities and the requirements of staff and contractors to work in a safe and healthy environment; and

- Environmental considerations and public impact are to be considered in all works. These shall be:
 - Visual interference;
 - Disturbance to domestic services and other utility assets;
 - Reinstatement of work sites;
 - Minimising operating noise including machinery;
 - Emission of unnecessary fumes and pollutants;
 - Minimising contamination risk by oil, fuel or other contaminants;
 - Engineering assessments reflect the life cycle impact of the various alternatives;
 - Optimise the useful life of its assets;
 - Minimising the likelihood of property damage;
 - Noise;
 - Public safety;
 - End of life policies.

h) Provides for a continual improvement in asset management practices

The guiding principles for asset management improvements are:

- The AMP is a living document and will be continuously updated, and archived by the end of every year;
- Works will be added to the long term 10 year works plan throughout the year;
- All works prices will be at current costs and refreshed annually;
- There will be a person responsible for maintaining and managing the asset plan documentation and data up-dates;
- Network standards will be reviewed and amended on an as-required basis ensuring new technologies, practices and equipment will have network standards established to ensure consistency of design and work practices;
- The asset management practices and plan will be assessed regularly for asset management maturity to PAS55 and to the criteria defined by the Electricity Distribution Information Disclosure Determination 2012. Areas showing a low maturity are to be prioritised for improvement;
- Regular, generally not more than three yearly, assessments of network and stakeholder requirements;
- The Asset Management practices which drive improvements include:
 - Setting of forward service levels and retrospective measurement against these;
 - Comparison of actual expenditure against budgets at high level and at project level;
 - Regular reporting to Management and Board on variance to budgets and non-compliance issues;
 - The review of complaints by public;
 - The review of satisfaction level of stakeholders.

To facilitate consistency of reporting between the AMP and regulatory reporting, the following principles will apply:

- Interconnection of asset management and financial management systems shall be streamlined to provide traceable and repeatable reporting between years;
- Reports shall be developed using a change control process to facilitate any required changes directly linked to regulatory reporting;
- Sufficient data categories shall be built into any reporting system to enable regulatory reporting to be carried out with minimum manual data manipulation;
- Where reporting assumptions are made these must be clearly stated; and
- The Asset Management plan data and regulatory reporting data will be the same, if not; the reasons for discrepancies are to be noted.

i) Is able to be communicated to all relevant stakeholders and service providers

The AMP will be published annually on the Company internet and intranet and will be provided in printed form to:

- Any person who requests a copy.

j) Can be reviewed so that it remains relevant and consistent with the Strategic Plan

Reviews of the AMP and 10 year works plan shall occur on regular basis:

- Works reviews are on a continuous basis;
- Annual load and asset data updates August;
- Policies and works reviews by Network during the year;
- Draft works plan issued to contracting and finance for review and budgeting by November;
- Issue draft budgets to Management and Contractor– January;
- Issue to Board – February;
- Approval by Board – March; and
- Publish 1 April each year.

2.6. Corporate Strategic Plan

In conjunction with the Board, the Chief Executive is responsible for the preparation of the Company's Strategic Plan and review activities. The Strategic Plan shall:

- Be reviewed and adopted by the Board annually. The review shall be completed three months prior to the end of the financial year;
- Have a five-year focus;
- Include a staff resource plan covering staff numbers and skills;
- Include objectives for achievement of the plan with responsibilities and achievement dates; and
- Be presented to, reviewed and accepted by the Board.

The Strategic Plan looks at many areas of the existing and potential business activities. The strategic goals related to the Network business include:

- Achieve prescribed customer service levels;
- Maximise the value of the network assets for the owners;
- Ensure legislative compliance;
- Continue to improve staff and public safety; and
- Ensure compliant and improving environmental practices.

To achieve those goals the Company strives to achieve industry best practice through the following:

- Optimising system reliability and the quality of supply as required by consumers;
- Providing an effective 24 hour service;
- Optimising the network configuration to ensure the system fully utilises its available capacity and operates in the most efficient manner;
- Managing the system load profile;
- Meet changing customer requirements;
- Providing a service in an equitable manner;
- Ensuring the system is installed and maintained in a manner that removes or mitigates any safety hazard to the general public and its staff;
- Ensure all contractors undertaking works on the network are skilled and competent in the activity they are to perform; and
- Select technology and designs considering the life cycle economic and environmental costs.

The following definitions affect the need, priority and scope of asset management practices summarised as:

(a) Shareholder Wealth

Shareholder wealth is enhanced when corporate objectives are met and stakeholders' targets are achieved. This requires an AMP that is continually up-dated to meet new and improved targets.

(b) Customer Service

At present Horizon Energy's direct customers are the retailers that sell electricity to consumers connected to the Horizon Energy network, and major customers that have Connection Agreements with the Company.

Through this relationship with the retailers, Horizon Energy has a prime responsibility to the electricity end-user, as indirect customers, for the performance and reliability of the network.

(c) Network Expansion

Horizon Energy has a goal of meeting the on-going and future needs of network users at the most efficient economic cost.

AMP planning provides clear justification for forward work programs and provides the ability to level out funding demands and account for changes in asset service potential.

The network must have the capability to meet the demands of existing consumers, and the ability to be augmented as required to meet the needs of increased demand and new consumers.

(d) Safety

Horizon Energy's objective is to achieve high standards of health and safety through the prevention of accidents and the promotion of health and welfare.

Horizon Energy states in its safety policy that it will:

- Support and nurture a culture that promotes employee wellness and raises health and safety awareness;
- Adopt and maintain management systems designed to support continuous performance improvement;
- Furnish necessary information, training and support and provide a healthy and safe working environment;
- Ensure commitment from employees and all levels of management;
- Require our business partners to meet the same health and safety standards.

In conjunction with the above, Horizon Energy maintains a safety management system to safeguard members of the public and property by providing:

- Preparation, implementation and review of policies, procedures and guidelines relevant to the safe design and management of the network assets; and
- Control of the safety and integrity of those assets and the minimisation of the potential for, and consequences of failure.

The Company's occupational health and safety policies and procedures are comprehensive and are documented in Horizon Energy's Quality system.

In recognition of the commitment and importance of this objective, the Company has a Health and Safety Manager, who along with line managers ensures, that the Company, its staff and its contractors comply with health and safety requirements and industry best practice at all times.

Horizon Energy achieved certification under AS/NZS 4801 Occupational Health and Safety Management and NZS 7901 Safety Management System for Public Safety certification in 2012 and maintains certification.

(e) Economic Efficiency (Pricing)

End use customers and electricity retailers have an interest in ensuring that Horizon Energy conveys electricity at the price-quality level expected by consumers. The AMP supports economic efficiency by:

- Providing a basis for monitoring asset performance and utilisation, taking into account pricing;
- Enabling asset managers to anticipate, plan, and prioritise asset maintenance and renewal expenditure;
- Plan funding of asset maintenance and renewal;
- Quantifying any environmental effects;
- Extending the life of an asset by optimising maintenance programs and demand management;
- Ensuring that customer consultation is undertaken and their expectations are considered in all planning undertaken; and
- Relating the investment on reliability to the type and number of customers being supplied.

(f) Environmental

Horizon Energy encourages its staff, customers and suppliers to interact with the environment in a responsible manner for the sustainable benefit of the community. Environmental requirements for works are set out in Horizon Energy's standards.

Horizon Energy is working towards Environmental certification under NZS 1400.

Horizon Energy strives to implement its policies and procedures such that the Company adheres to the principles contained within the Resource Management Act 1991. Notifiable works are carried out after receiving consent from the relevant District and/or Regional Council.

All work undertaken by Horizon Energy includes consideration for environmental effects:

- Visual interference;
- Disturbance to domestic services and other utility assets;
- Reinstatement of work sites;
- Minimising operating noise including machinery;
- Emission of unnecessary fumes and pollutants;
- Minimising contamination risk by oil, fuel or other contaminants;
- Engineering assessments reflect the life cycle impact of the various alternatives;
- Optimise the useful life of its assets; and
- Minimising the likelihood of property damage.

2.7. Period Covered

This plan provides a long-term indication of AMP requirements and specific work programs over the 10 year planning period from 1 April 2014 to 31 March 2024.

This plan is based on recorded levels of service, current available information and the experience and knowledge of Horizon Energy staff and key contractors/consultants. The plan does not commit the Company to any specific project or work mentioned in the plan and Horizon Energy may change the plan at any time to reflect changing needs or new information.

2.8. AMP Plan Approval

This plan was approved by the Horizon Energy Board of Directors on 25 March 2014.

2.9. Stakeholders

2.9.1. Stakeholder Interest Identification

Balancing stakeholder needs and interests drives the strategic planning process. Key stakeholders methods used to identify their interests are presented over four pages in Table 2.2.

2.9.2. Accommodation of Interests

Stakeholder's interests are considered within Horizon Energy's asset management practices. The desire to provide a reliable electricity supply is common to all stakeholders but must be undertaken in a manner that ensures a price / quality trade off that matches the stakeholder's expectation.

2.9.3. Conflict Resolution

The framework that Horizon Energy uses in resolving conflict considers the following factors:

- Safe and reliable electricity supply;
- Legal compliance;
- Cost effectiveness;
- Fairness and equitable solution to all parties; and
- Regulatory requirement.

Specific issues of conflict are expected to be resolved directly between the Company and the other party by a complaints investigation process and negotiation.

Should there not be a satisfactory resolution either party may refer the dispute to the Electricity and Gas Complaints Commission.

Common examples of conflict between the network owner and other parties that are mostly resolved through negotiation are:

- The public expectations on the undergrounding of urban overhead lines, and the lack of public understanding on the financial drivers of such projects;
- Vegetation control, especially around trees of significant interest to the public; and
- Private land easement issues.

Stakeholders

Stakeholder	Method of Identifying Stakeholder Interests	Key Interests	Accommodation into AMP Process
Customers (end user and retailers)	<ul style="list-style-type: none"> Customer satisfaction surveys Use of System Agreements with retailers 	<p>Electricity end-users require the product purchased to be delivered consistently and to meet the level of price versus quality that they desire. In particular they have concerns with regard to the level of charges made by Horizon Energy, the network performance and response to network development requirements.</p> <p>Network Users are mainly electricity retail companies who have a Network Use of System Agreement with Horizon Energy for the transportation of electrical energy that they are selling to end-use customers.</p>	<ul style="list-style-type: none"> Adequacy - security and capacity, refer to Section 4, Level of Service (LOS) Reliability – frequency and duration of supply interruptions, refer to Section 4, LOS Growth – requests for additions or alterations to the network, refer to Section 5, Asset Utilisation Supply quality – refer to Section 4, LOS
Customers (Major direct connect agreements)	<ul style="list-style-type: none"> Direct customer meetings and feedback 	<p>Major consumers in the network area have individual agreements for the provision of their connection to the nearest GXP. These companies have a specific interest that the network performance and quality of supply will deliver electricity in accordance with their Distribution Services or Connection Agreements to ensure they are able to meet their operation requirements.</p>	<ul style="list-style-type: none"> Quality of supply and capacity, Sections 4 and 5 Lifecycle management planning for direct connect assets, refer to Section 6 Load growth management, refer to Section 5
Economic Regulator (Commerce Commission)	<ul style="list-style-type: none"> Submissions Relationship meetings Industry forums 	<ul style="list-style-type: none"> Statutory obligations Economic efficiency Conformity/Compliance Delivery of Plan 	<ul style="list-style-type: none"> Asset investment – refer to Section 6, Lifecycle Management Plan Operating cost – refer to Section 9, Financial Summary Network Performance and quality of supply, refer to Section 4, LOS Structure of the AMP document

Stakeholder	Method of Identifying Stakeholder Interests	Key Interests	Accommodation into AMP Process
Industry regulators (Commerce Commission, Ministry of Business Innovation and Employment, Electricity Authority, Ministry for the Environment, Department of Labour)	<ul style="list-style-type: none"> • Submissions • Relationship meetings • Industry forums 	<ul style="list-style-type: none"> • Statutory obligations • Economic efficiency • Environmentally and safe service • Safety of staff and the public • Staff welfare 	<ul style="list-style-type: none"> • As above • Environmental management – refer to Section 8, Risk Management • Safety – refer to Section 8, Risk Management
District and Regional Councils	<ul style="list-style-type: none"> • Coordination meetings • Planning awareness • Submissions • Relationship meetings • Membership of strategy groups 	Four District Councils are stakeholders in the Company and have an interest in the Company's performance and in particular assets that are installed in the public domain and in the conversion of overhead lines to underground cables. These are the Whakatane, Opotiki, Kawerau and Rotorua District Councils.	<ul style="list-style-type: none"> • Asset investment – undergrounding of overhead lines, refer to Section 6, Lifecycle Management Plan • Emergency response – refer to Section 8, risk management • Environmental management – refer to Section 8, Risk Management
Shareholders and lenders	<ul style="list-style-type: none"> • Relationship meetings • Shareholder briefing (AGM) • NZX regulations • Annual Report 	Horizon Energy is a publicly listed Company on the NZ Stock Exchange. The Eastern Bay Energy Trust holds approximately 77% of the issued shares. A key shareholder interest is the maximisation of Company value and the return of an appropriate dividend through the efficient and effective operation of the Company. The banks have an interest in the security of any debt incurred.	<ul style="list-style-type: none"> • Return on investment – refer to Section 9, Financial Summary • Good service for customers - refer to Section 4, Levels of Service • Prudent investment practices
Other stakeholders (Transpower and Embedded generators)	<ul style="list-style-type: none"> • Regular communications at planning and operational levels 	<p>Transpower have an interest in the maintenance and growth of their business, the impact on the quality of supply to other customers and their relationship as portrayed to the end user of energy. Both companies have significant mutual interest in each other's future development plans.</p> <p>They are also interested in the revenue they receive from Horizon Energy.</p> <p>Embedded generators have an interest in the on-going performance of the transmission corridor through which they get their energy to the market.</p>	<ul style="list-style-type: none"> • Maintenance management – refer to Section 6, Lifecycle Management Plan • Growth planning, Asset Utilisation, and Development Planning – refer to Section 5 Network Planning • Long term financial forecasts – refer to Section 9, Financial Summary

Stakeholder	Method of Identifying Stakeholder Interests	Key Interests	Accommodation into AMP Process
Contractors	<ul style="list-style-type: none"> Contract Procurement framework 	Horizon Energy engages contractors for much of its fieldwork and also some of its administrative requirements. Contractors have a stakeholder involvement in the Company as a source of income (and a measure of their efficiency reflected by Horizon Energy's performance). Contractors also have an interest in work continuity, a safe work environment and a good contractual relationship.	<ul style="list-style-type: none"> Workflow – refer to Section 6, Lifecycle Management Plan Safety – Risk Management including auditing, refer to Section 8, Risk Management
Board of Directors	<ul style="list-style-type: none"> Monthly Board meetings Regular meetings with senior management 	The Board of Directors have a specific interest in the Company's performance related to its statutory obligations and their responsibilities as the governing body of the Company on behalf of the shareholders. Not the least of these is the Company's planned investment profile.	<ul style="list-style-type: none"> Financial performance – refer to Section 9, Financial Expenditure Summary – refer Section 9 Risk Management and good governance – refer to Section 8, Risk Management Corporate KPI's - refer to Section 4, LOS
Staff	<ul style="list-style-type: none"> Performance appraisals Internal communications Allocation of responsibilities 	Staff implements the Company's AMP and policies to maximise utilisation and the best performance of the Company assets. They are interested in the successful achievement of network performance targets and in meeting the requirements of network users. Staff also have an interest in the safety, profitability, longevity and reputation of the Company. Accountability for financial performance is clearly defined and allocated to those senior managers best able to manage the outcome. Delegated authorities for expenditure are similarly well defined and provide for appropriate levels of expenditure beyond which detailed business cases are required prior to any financial commitment being entered into.	<ul style="list-style-type: none"> Health and Safety - refer to Section 7, Risk Management Professional work environment - refer to Section 7, Risk Management Good business culture - refer to Section 7, Risk Management

Stakeholder	Method of Identifying Stakeholder Interests	Key Interests	Accommodation into AMP Process
Landowners and the General Public	<ul style="list-style-type: none"> • Meetings with Landowners prior to the installation or planned maintenance of assets • Vegetation Control Programmes • Asset inspection programmes • Feedback through local Authorities 	<ul style="list-style-type: none"> • The integrity of their property rights • The mitigation or removal of hazards • Safety of the assets • Environmental degradation 	<ul style="list-style-type: none"> • Maintenance management – refer to Section 6, Lifecycle Management Plan • Growth planning, Asset Utilisation, and Development Planning – refer to Section 5 Network Planning • Safety – Risk Management including auditing, refer to Section 8, Risk Management

Table 2.2 – Stakeholder Interest Identification

2.10. Asset Management Responsibilities

2.10.1. Governance and Board Reporting

Horizon Energy is a publicly listed Company governed by a Board of Directors and managed by an Executive Management Team. The following sets out the Governance and management reporting relationships.

2.10.2. Accountabilities and Responsibilities

Horizon Energy's hierarchal management model for defining asset management responsibilities and relationships is presented in Figure 2.1.

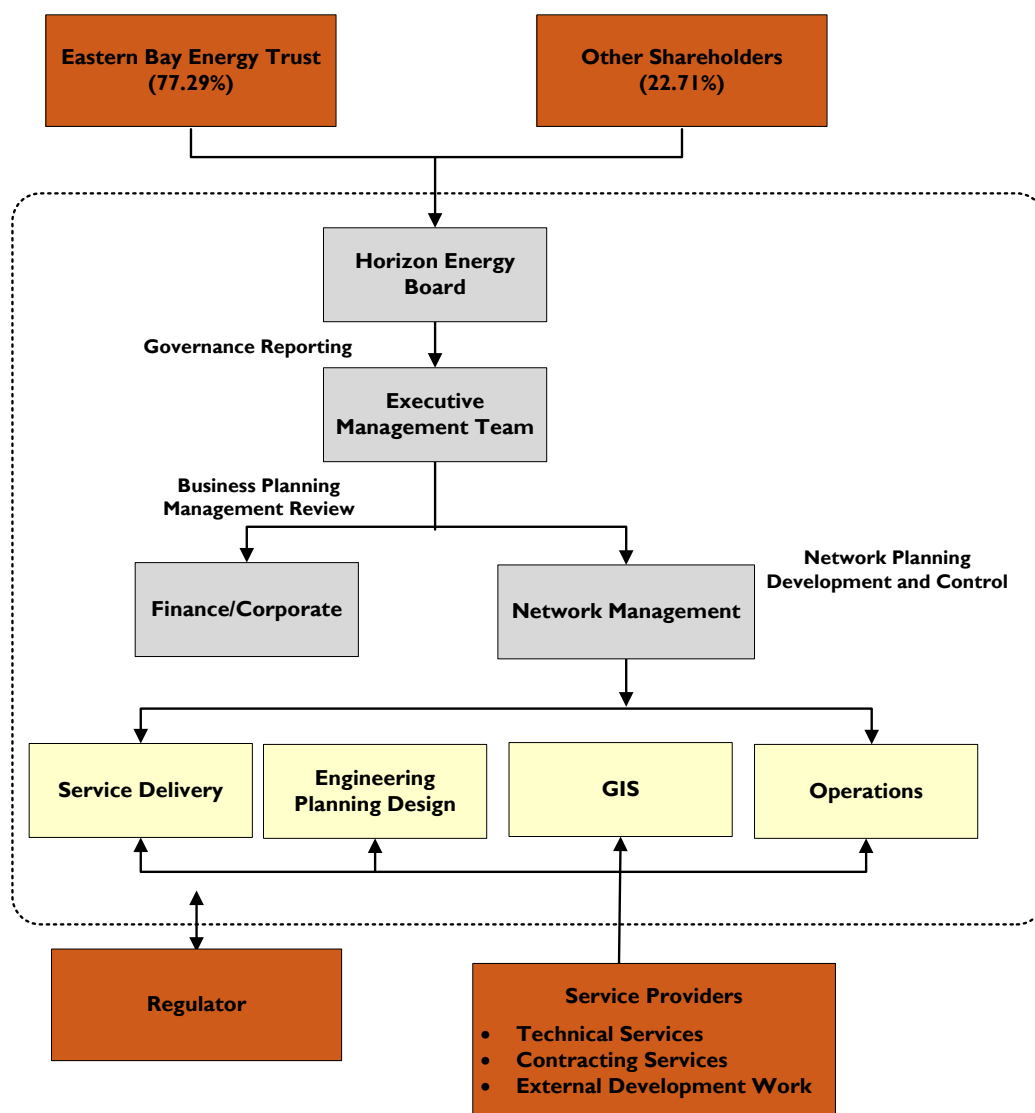


Figure 2.1 - Asset Management Responsibilities at Horizon Energy

A summary of the parties identified above and their relationship towards managing the assets follows:

Horizon Energy Board

The Board is responsible for the overall corporate governance of Horizon Energy and are responsible to all shareholders for their actions.

The governance role of the Board includes the setting of the Company's strategic direction. The Directors meet at least ten times a year and more often if required to undertake specific consideration or to attend committee meetings. As an example, the Audit Committee meets formally three times a year and as required.

The Board reviews and approves the following asset management processes and plans:

- Strategic Plan;
- The Asset Management Plan document;
- Annual operating and capital expenditure forecasts;
- Delegated operating and financial authorities for the Executive Management Team;
- Major projects;
- Risk Management Plan;
- Interim and Annual Reports; and
- Disclosure documents.

The Board approves any purchase expenditure >\$100,000.

Executive Management Team

The Executive Management Team has the responsibility for the day to day management of Horizon Energy, delivering the AMP, and for achieving the operational objectives.

The regular reporting to the Board includes the following:

- Top ten identified risks from the Audit Committee and any new risks identified;
- Annual Strategic Plan objectives;
- Annual Budgets (directly linked to AMP);
- Actual financial performance against budget;
- Business unit operational reports;
- Monthly reports presenting the monthly KPI's including SAIDI and SAIFI;
- Major project approval as required;
- Major project progress and report against annual budgets;
- Compliance and safety reports; and
- Corporate reporting - NZX reports and human resources.

This Team is led by the Chief Executive Officer and consists of:

Chief Executive Officer

- Responsible for all non-governance management of the Company, its assets and the service that is supplied to its customers and other stakeholders; and
- Responsible for delivering the AMP and for achieving the operational objectives.

Chief Financial Officer/Company Secretary

- Provides financial services and business information in support of all Company operations;
- Ensures that adequate financial resources are available; and
- Also co-ordinates the risk management review process.

General Manager Contracting

- Manages the subsidiary company that provides the vast majority of the field services.

Group People and Performance Manager

- Responsible for ensuring the safety and wellbeing of staff in conjunction with line managers and also the provision and monitoring of training, standards and certifications; and
- Compliance of Standards, EGCC, Risk Mitigation.

General Manager Commercial

- The Group Commercial and Regulatory Manager provides performance analysis and guidance for the Network and other business areas and has a major role in the development of regulatory submissions; and
- Responsible for regulatory reporting requirements.

General Manager Network

- Executive Manager is responsible for all network operations including:
 - Service delivery;
 - Operations;
 - Planning;
 - GIS and asset information systems;
 - Resourcing and planning; and
 - Capital plan.

Network Team

This group is led by the General Manager Network and consists of the following specific roles:

Asset Manager

- Responsible for the long term planning;
- Responsible for standard setting; and
- Responsible for condition assessment and data analysis.

Operations Manager

- Responsible for management of the operations control centre;
- Responsible for the safe and efficient day to day operations of the Network;
- Management and co-ordination of planned outages;
- Liaison with energy suppliers and customers; and
- Control of switching required to manage the network.

Service Delivery Manager

- Implementation of the capital and operational maintenance plans;
- Customer driven works; and
- Application of the network standards and designs.

Control Room Operators

- Manage the processes installed to monitor and control network operating systems;
- Provide operational network related services and the customer connection data; and
- Provide a network support base 24 hours a day, 7 days a week.

Engineering Staff

- Planning and supervising maintenance activities;
- Identifying and managing threats to supply integrity;
- Providing engineering and project management services for network works; and
- Processing of new connections for supply.

Planning and Design Engineer

- Primary responsibility for producing and maintaining the asset management plan;
- Manages long term (10 year) plan;
- Assessment of the performance of the network system; and
- Development of projects that will enhance performance, address issues of poor supply, quality or cater for growth.

Draughting/GIS Manager

- Management of the asset records, drawings, and geographical information services in support of network operational, planning and financial objectives.

Service Providers

A number of specialist providers are used to implement the works.

Horizon Services Limited

Horizon Services Limited is the contracting division of Horizon Energy.

- Horizon Services Limited undertakes the majority of Horizon Energy's capital and maintenance works;
- Is a wholly owned subsidiary of Horizon Energy; and
- Preferred supplier of construction, operations and maintenance services.

Other Sub Contractors

Specialised contractors are engaged to support the network when these specialised skills are either not available or are over extended:

- Specialised technical services – communications and protection systems;
- Engineering design services and project management;
- SCADA support;
- IT services; and
- Directional drilling.

Horizon Energy maintains direct relationships with SCADA and IT providers, engineering service providers and other non-network service providers.

2.10.3. Field Operations

Field service operations provide the support to manage and maintain the network, and to provide response to faults and emergencies, assess asset condition, and undertake the network maintenance and capital works.

Horizon Services Limited (HSL) is a wholly owned contracting company which operates the following work teams, established to support the network:

Technical Services	Technician level support for substation protection and maintenance Radio communications support Cable jointing
Electrical Services	Electricians for network and non-network (private) support Street lighting servicing Data cabling Air conditioning
Line Construction and Maintenance	Line maintenance Line construction, network and private Faults response
Live Line Services	Specialist crew that are able to perform 11kV and 33kV line work whilst the line is still energised

Project Management and Estimating	Provision of project management, supervision, quantity surveying and estimating skills
Asset Inspection	Dedicated asset inspectors surveying and assessing asset condition and estimated remaining life for all network assets
Logistics	Dedicated specialist network warehouse service including spares management and procurement services
Vegetation Control	Skilled Arborists providing vegetation management and tree trimming services
Fault Response	Fault response for all network faults

To be able to deliver on the plan detailed in this AMP there are a number of different strategies and plans either in place or under development intended to streamline and improve the planning and delivery of works.

Horizon Energy provides the following field operations:

- Operation control;
- Engineering services;
- Design and project management; and
- Network management.

HSL provide the following field operations:

- Fault response;
- Routine maintenance operations;
- Defect remedial works;
- Implementation of the capital works plan;
- Customer liaison for works and connections;
- Disconnections;
- Management of spare parts and consumables;
- Asset condition assessment;
- Live line services; and
- Asset replacement and renewals.

The existing field operations model is based around utilising HSL as a first call service provider. Where neither HSL nor Horizon Energy have the skill sets or specialised equipment required, or undertaking the works would overload the capability of either to successfully deliver the service required, external specialised contractors and consultants are engaged to complete work. Services that are outsourced to a number of different suppliers are:

- Specialised services for SCADA and communications systems;
- Detailed or specialised design engineering, protection systems, earthing design, detailed engineering and draughting services;
- Thermal vision, partial discharge, and tan–delta cable testing;
- Specialised substation maintenance and construction work;
- Protection design, programming and testing;
- Specialised audits and compliance monitoring;
- Non-destructive testing of assets;
- Oil testing;
- Roadside safety and traffic management;
- Specialised construction works; and
- Civil works.

Methods of improving service delivery to customers and to the network are continuously being reviewed by the respective managers and service providers, and as further opportunities to improve services are implemented, costs, efficiency and customer satisfaction should increase.

Improvements being implemented or considered are:

- Greater use of unit rate form of contracts;
- Competitive fixed price tender process for certain works;
- Single bid fixed price works;
- Design and build contracts;
- More use of sub-contract models to better define responsibilities; and
- Formalising supplier / contractor relationships with the implementation of service level agreements.

2.11. Asset Management Documentation, Controls and Review Processes

Various sources of data are used in managing the network and in the planning process. Due to the various input sources, multiple non-integrated data storage systems, and the historical practice of capturing electronic data input from field updated forms, this data has varying levels of accuracy. The data sources currently used and the levels of confidence in the data that they contain is summarised below in Table 2.3, Asset Data Sources:

Item Description	Record Type	Record Location/Software	Data Confidence	System Management	Planned Improvements
Overhead Lines	Plans/GIS	Oracle DB /GIS	High	GIS team	Integration into Intergraph
Zone Substation Wiring	Plans	Drawing Office	Medium	GIS Team	Drawing verification project
Streetlight Connections	Database/GIS	Oracle DB /GIS	Medium	GIS Team	Link to Councils' Data
11kV Switchgear	Database/GIS	Oracle DB /GIS	High	GIS Team	Link Maintenance Records
11/0.4 kV Transformers	Database/GIS	Oracle DB /GIS	High	GIS Team	Link Maintenance Records
Overhead Distribution Equipment and Poles	Database/GIS	Oracle DB /GIS	High	GIS Team	Link Maintenance Records
Distribution Substations	Database/GIS	Oracle DB /GIS	High	GIS Team	Link Maintenance Records
Zone Substation Transformers	Card System/ Database	Engineering Office and Contractor Records plus some on SQL Server	High	GIS Team	Link Maintenance Records
Zone Substation Protection Relays	Card System/ Database	Engineering Office and Contractor Records plus some on SQL Server	Medium/High	Planning Engineer	Centralised records management system
Zone Substation Switchgear and Field Circuit Breakers	Card System/ Database	Engineering Office and Contractor Records plus some on SQL Server	High	GIS Team	Centralised records management system
Zone Substation Maintenance Records	Log Book and Card System	Individual Zone Substations and Maintenance Contractor	Low	Contractor	Integration into asset management system
Underground Cables Sizes and Cable Type	Plans /GIS	Oracle DB /GIS	Medium	GIS Team	Sizes and type verified as required for projects or works
11kV Underground Cables Location	GIS	Oracle DB /GIS	Medium/High	GIS Team	Locations verified prior to any work undertaken. There is no plan to improve this asset detail for existing installed assets
400V Underground Cables Location	GIS	Drawing Office and GIS terminals	Medium	GIS Team	Marked up as located Individually located for excavation requests. No data accuracy improvement planned
Transpower and Embedded Generation Demand Data	Spread sheets iHistorian SQL server	Accounts / SQL Server	High	Planning Engineer	

Item Description	Record Type	Record Location/Software	Data Confidence	System Management	Planned Improvements
SCADA Equipment	Database	SQL Server	High	Operations Manager	
SCADA Historian	Database	SQL Server	High	Operations Manager	
Applications for Supply	Database and paper record	SQL Server and manual filing system	High	Operations Manager	
Works Order and Purchase Order Database	Database	SQL Server	High	IT Team	Microsoft Dynamics Navision
Works Analysis against Regulatory Reporting Categories	Database from works NAV	Analysed by spread sheets and SQL reporting	Medium/High	Business Development Manager	Data rules applied at source entry reduces category choices. Linked to asset in new ISR system
Fault Logs	Database	SQL Server	High	Operations Manager	Audited process and system
Defects	Database	SQL Server	Medium	Operations Manager	To be integrated in to centralised storage system
Customer Connections (ICP)	Database	SQL Server	High	Operations Manager	ICP database and registry differ slightly, to be reconciled as part of ISR project
Works Plan	Spreadsheet	Server	High	Planning Engineer	Rolling updates, estimating databases

Table 2.3 - Asset Data Sources

The criteria of high, medium and low are used in assessing the level of confidence for the data as follows:

- High - the data is regarded as accurate and can be relied on with little or no verification, has a verification tag attached in GIS, has been marked as-built, or is collected electronically with little human intervention;
- Medium - historical records, GIS data with no verification tag, data that is manually collected with limited verification process or limited additional information. Data that should be verified prior to use; and
- Low - historical data that has been transferred manually between capture and storage systems with little verification. Manually recorded data that cannot be readily verified. Existing data that requires a level of research or verification before it can be reliably used.

The data used to compile this AMP is derived from many sources as summarised in Table 2.3. The source data is supplied by contractors and staff in either hard copy or electronic formats and is verified by the individual engineer responsible for the works prior to passing to the GIS Team for further validation and data entry.

2.11.1. Independent Review of Asset Management Practices

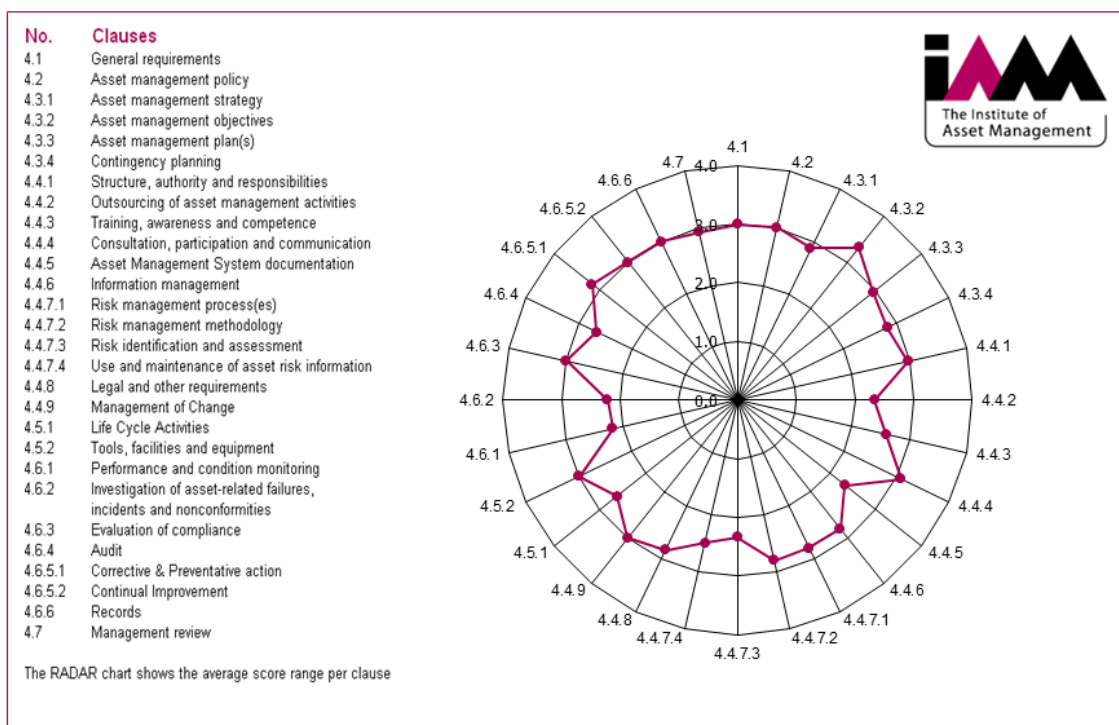
As part of Horizon Energy's desire to monitor and improve the asset management practices, external consultant AECOM was engaged during 2013 to undertake a review to determine Horizon Energy's readiness for assessment and potential accreditation to PAS55 / ISO55000 standard for asset management practices.

General Findings

The purpose of the review was to undertake a gap analysis of the current Horizon Energy Asset Management System to identify any necessary actions which will need to be undertaken to ensure alignment with and to achieve formal accreditation in accordance with PAS55.

To obtain PAS55 accreditation the requirement is to achieve a maturity level of above 2.5 in all 28 categories of the assessment. Horizon has set a goal of achieving above a level 3.0 in all 28 categories of the assessment.

The assessment results for the maturity level for asset management are shown in the diagram below and have been scored in a range from 2.2 to 3.3 out of 4. Of these scores 11 out of 28 (39.3%) achieve the level of 3 or above, with a list of evidence provided and associated scores summarised in the regulatory disclosures AMMAT self-assessment section in the appendices.



To obtain a level 3 and above for all 28 categories the following projects were recommended by the assessment consultant to be implemented.

- 1) Implement a Computerised Maintenance Management System (CMMS) to store the maintenance history, which includes a gap analysis of alignment with the Horizon Energy asset management requirements.
 - a) Resources: GIS Team, Operations Manager, General Manager Network and Contract Manager.
 - b) Timeframe: 18 months.
- 2) Implement an electronic data acquisition system (mobile field dispatch) and integrate with the CMMS. Include a gap analysis of alignment with the Horizon Energy asset management requirements.
 - a) Resources: GIS Team, Operations Manager, Network Manager and Contract Manager.
 - b) Timeframe: 9 months.
- 3) Implement as mandatory, the requirement for Hazard and Operability identification (HAZOP) as a part of the approval process for the design of new infrastructure.
 - a) Resources: Network Manager, and Contract Manager.
 - b) Timeframe: 3 months.
- 4) Further develop the contingency planning for responding to a larger selection of incidents and emergency situations through workshops with the O&M team and formally documented.
 - a) Resources: O&M Team, Operations Manager Network Manager, and Contract Manager.
 - b) Timeframe: 6 months.
- 5) Further develop the training matrix to include specific training for asset management activities, such as condition assessment, life cycle activities and costing analysis, asset acquisition and industry compliance.
 - a) Resources: O&M Team, Network Manager and Contract Manager.
 - b) Timeframe: 9 months.

- 6) Review, revision and approval of the policies and procedures that are in draft and awaiting approval.
 - a) Resources: Senior management, management and contractors.
 - b) Timeframe: 9 months.
- 7) Resolve the concern in Navision that delegated approvals can be bypassed.
 - a) Resources: Network Manager and Contract Manager.
 - b) Timeframe: 3 months.

Note that not all projects may be implemented fully in the suggested time frames, nor may they be required to be implemented in full to achieve accreditation, as to achieve PAS55 accreditation the average score is required to be 3 or better.

2.12. Asset Management Planning Processes

2.12.1. Relationship To Other Planning Documents

The AMP is a key part of the planning process linking with other plans including strategic plans, business plans, legislation and operational / maintenance policies. Interaction of the key process is shown in Figure 2.2.

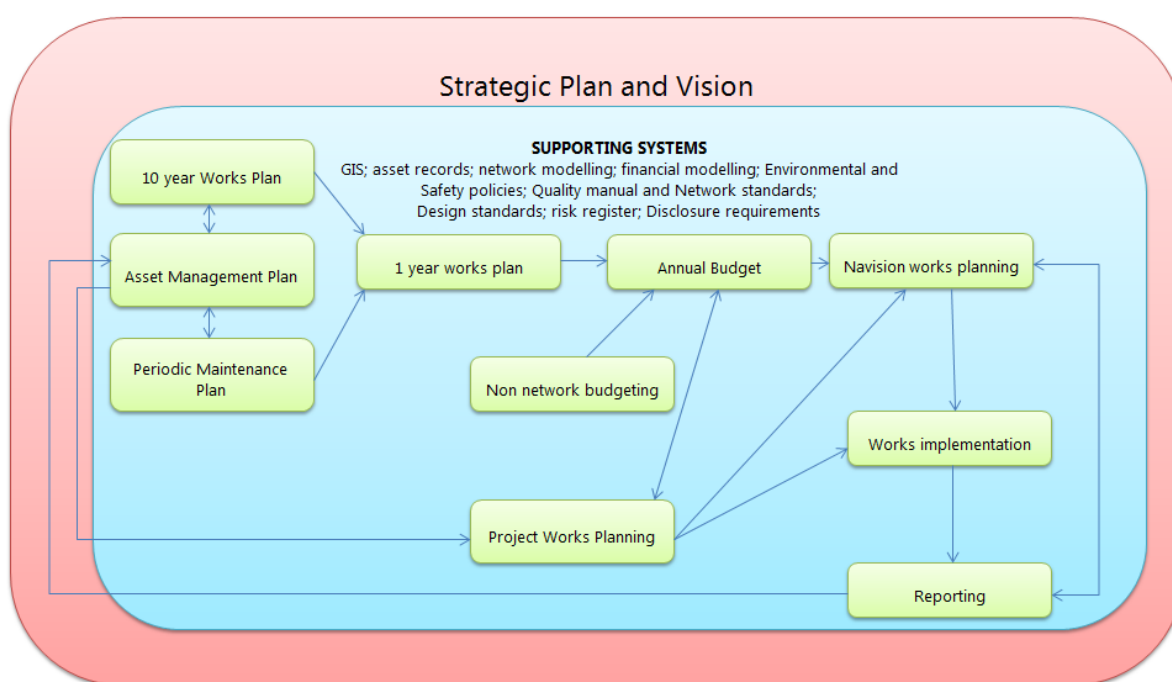


Figure 2.2 - Asset Management Planning Documentation Flow Process

The AMP is a key input into the corporate planning process. The interaction of the AMP with the other key plans and processes are summarised as follows:

Strategic Plan

- Five year focus and sets the key goals and objectives for the business; and
- Provides a corporate overview and guidance under which projects, manning levels, budgets and resources are made available.

Budgets

- Budgets are prepared based on the capital expenditure projections and the network maintenance and operations activities outlined in the AMP;
- The AMP reflects the reality of long term Company funding and predicted earnings; and
- The production of the two documents is an interactive process managed by the Executive and the Board. The budgets are updated annually.

Asset Planning Process

- Planning for growth renewals, third party development, maintenance and operations;
- Has a long term >10 year focus;
- Feeds into the strategic, capital and maintenance plans; and
- This process designs the projects summarised in the AMP.

Capital Plans

- Projects described by the AMP are collated into annual capital plans; and
- These projects are for network extensions, replacement of assets, additional assets to meet customer services or to improve service levels and quality of supply.

Maintenance Process

- Comprised of a mixture of preventative maintenance and reactive maintenance;
- Previous fault performance is a major driver of preventative maintenance schedules; and
- Managed such that the network system performance meets the service levels detailed in the AMP.

Operations Process

- Provides real time operation of the network;
- Manages reduction of losses and capacity utilisation;
- Outage and performance information is gathered for planning and reporting purposes; and
- This process endeavours to ensure that the target levels of performance as detailed in the AMP are met.

2.12.2. AMP Delivery

A practical asset management plan only has benefit if it has a realistic chance of delivering the outcomes and objectives projected. The structure of the planning and approval process around this AMP ensures a high level of confidence that the plan can be delivered as intended. By following the work and approval flow process described in section 2.5 ensures that there is buy in from Senior Management, Board, functional managers, and users at an early stage. The process of driving the annual works plan and annual budgets from the AMP 10 year plan provides a direct linkage from the 10 year plan through to the annual budget setting processes, and then to the implementation phase. The document flow relationships shown in the above section 1.12.1 shows how the 10 year plan drives the annual budgets, and timing of the various stages of information distribution and approvals is covered in section 2.5, paragraph J, with the approval process starting six months before the start of the financial year, and preliminary works programs being reviewed prior to finalising budgets. This process has been used in this format since 2010 and is now an accepted and integral part of the annual plan and budgeting process.

During the review process in developing the plan, considerations such as the ability of contractors to deliver, the needs of the network, lead times, high level and detailed budgets, stakeholders requirements, and the cash flow requirements of the business are all taken into account. These decision points are detailed throughout this document.

3. Assets Covered

3.1. Network Area

The geographical area supplied by Horizon Energy is shown in Figure 3.1. The Horizon Energy sub-transmission network is summarised as:

- Four Transpower grid exit point (GXP) substations;
- Bay of Plenty Energy owned Aniwhenua power station;
- Six 11kV zone substations;
- Three of the Transpower GXP substations provide supply directly to 11kV distribution; and
- Forty-two 11kV feeders.

Figure 3.1, shows the layout of Horizon Energy's sub-transmission Network along with the Transpower 110kV and 5kV lines that supply the eastern parts of the area. The total service area covered is approximately 8,400km² and over 25,500 customers in the area bounded north of Whangaparaoa Bay Te Kaha, Pikowai, and Lake Rotoma to Ruatahuna.

There are four separate GXP supplied distribution areas - Edgecumbe, Kawerau, Te Kaha, and Waiotahi, and an Edgecumbe GXP embedded generation direct connection at Aniwhenua power station, in the Galatea region.



Figure 3.1 – Horizon Energy Network Area Sub-transmission
* Transpower owned and operated.

Areas supplied by each GXP

Transpower Edgecumbe, GXP

- Whakatane District region including Whakatane urban, Edgecumbe urban, and surrounding regions;
- Edgecumbe is supplied by three 220kV circuits (one from Kawerau, two from Tarukenga near Rotorua) and two 110kV lines (one from Kawerau and one from Owhata in Tauranga);
- Edgecumbe supplies the Waiotahi GXP at 110kV, which then supplies Te Kaha GXP at 50kV, with each of these circuits being single radial feeds.

Transpower Kawerau GXP

- Directly connected at 110kV to the hydro generating stations at Matahina and Aniwhenua, and to the geothermal powered Mighty River Power Kawerau generator;
- The GXP is connected with 220kV circuits to Edgecumbe and Ohakuri;
- This generation capability is sufficient to make the Eastern Bay of Plenty almost self-sufficient for electrical energy. Although Aniwhenua is listed above as a GXP, it is physically connected to Horizon Energy assets and is treated commercially as being embedded within the Edgecumbe GXP supply area. Matahina is likewise considered embedded within the Edgecumbe GXP.

Transpower Waiotahi and Transpower Te Kaha

- Supplied from single circuit feeders and as such have N security at 110kV to Waiotahi and 50kV to Te Kaha.

Waiotahi, Te Kaha, and Kawerau have Transpower owned 11kV assets that distribute directly into the Horizon Energy network, rather than through a Horizon Energy zone substation. Refer to Table 5.17 for summaries of each GXP.

3.2. Zone Substations Summary

A list of zone substation and feeders supplied by each GXP as at 31 March 2013, identifying the zone substations, feeders, number of customer connection points (ICP) and dominant load type is shown in Table 3.1. Galatea and Kaingaroa substations are fed from Aniwhenua when supply is available but are part of the Edgecumbe GXP load.

GXP Substation	Number of Connections	Dominant Load Type
GXP Edgecumbe (Aniwhenua)	1728	
Galatea	1540	
Galatea	214	Rural
Jolly Road	253	Rural
Minginui	292	Rural & Urban
Murupara	780	Urban
Kaingaroa	188	
Dunn Road	185	Urban
Kaingaroa Mill	3	Industry
GXP Edgecumbe	14538	
East bank	1135	
Thornton	353	Urban
West Bank	780	Rural
Kope	5390	
King St	1121	Urban
Rex Morpeth	840	Urban
Strand North	1127	Urban
Strand South	904	Urban
Victoria	1398	Urban

GXP Substation	Number of Connections	Dominant Load Type
Ohope	2053	
Harbour	992	Rural & Urban
Pohutukawa	1061	Urban
Plains	2623	
Awaiti	539	Rural
Awakeri	443	Rural
Manawahe	762	Rural
Te Teko	878	Rural
Station Road	3336	
Angle Road	451	Rural
City South	466	Urban
Mokoroa	621	Urban
Piripai	695	Rural & Urban
Ruatoki	649	Rural
Taneatua	454	Rural
WBM	1	
Whakatane Board Mill (1)	1	Industry
GXP Kawerau	3009	
Kawerau (2)	3009	
Kawerau	1686	Urban
Onepu	63	Rural
Paper	39	Industry
Plateau	1220	Urban
Pulp (3)	1	Industry
GXP Te Kaha	1039	
Te Kaha (2)	1039	
Te Kaha	415	Rural
Waihau Bay	624	Rural
GXP Waiotahi	4291	
Waiotahi (2)	4291	
Factory	1127	Rural
Hospital	1346	Rural & Urban
Opotiki	964	Rural & Urban
Waimana	853	Rural

Table 3.1 – Horizon Energy Zone Substation Summary

Notes:

- (1) Direct connect Edgecumbe GXP to customer, Whakatane Mill Ltd
 (2) Transpower owned 11kV distribution assets. GXP and zone substation are combined assets
 (3) Direct connect Kawerau GXP customer, SCA Hygiene

3.3. Zone Substation Load Characteristics

Table 3.2 summarises the peak load data for each zone substation for the year 1 April 2012 to 31 March 2013.

Zone Substation	Peak Demand (MVA)	Av 100 peak periods (MVA)	Peak Period
Eastbank	6.4	5.9	Winter
Galatea	4.8	4.27	Summer
Kaingaroa	2.4	2.3	Winter
Kawerau (GXP)	19.0	17.2	All year
Kope	15.5	12.7	Winter
Ohope	4.6	3.93	Winter
Plains	6.2	5.3	Summer
Station Road	8.4	8.2	Winter
Te Kaha (GXP)	2.1	1.3	Summer
Waiotahi (GXP)	9.4	8.5	Winter
Edgumbe GXP	61.6	53	Winter

Table 3.2 – Zone Substation Load Summary as at 31 March 2013

Note: Edgumbe GXP load included Galatea region load during 2009-13 due to Galatea load being supplied by Edgumbe after the failure of BOPE's Aniwhenua TI in 2009. See Section 5.5 for more detail.

3.4. Major Customers

Major customers are defined as customers with a demand load that exceeds 1MW. These customers are summarised in Table 3.3 below:

Customer	Business	Connection	Load	Comments
Whakatane Mill Ltd	Packaging board manufacture	Edgumbe GXP	25 MVA	Two dedicated 33kV feeders
Fonterra	Milk Products	Plains and East Bank zone substation	8 MVA	Connection to both East Bank and Plains substation. Embedded generation reduces peak demand with normal operation being energy export from the site. Horizon Energy owns all dedicated distribution assets on the factory site
SCA Hygiene	Tissue Products	Kawerau, Pulp feeder	9.5MVA	Dedicated single feeder with 100% backup from second feeder
Sequal Lumber	Sawn Timber Production	Kawerau, Paper feeder	2 MVA	Horizon Energy owns dedicated distribution assets on the mill site
Norske Skog	Oxidation Ponds	Kawerau, Onepu feeder	2.5 MVA	Supply to effluent treatment site with Horizon assets on site
BOPE	Generation	Kawerau, Onepu feeder	5 MVA	TG1 and TG2 geothermal generation plant
BOPE and Trustpower	Generation	Matahina and Aniwhenua power stations	N/A	Notionally embedded generation within Edgumbe GXP supply area. Direct connect to Transpower
Carter Holt Harvey	Timber Mill	Kawerau, Onepu feeder	3.5 MVA	Normally on one 11kV cable
Timberlands	Wood Products	Kaingaroa	2 MVA	Low security supply

Table 3.3 – Major Customer Summary

3.5. Embedded Generation

Embedded generation is generation that is connected to the distribution network, as opposed to being connected to Transpower. There are a number of generation sites embedded within the Horizon Energy network that are connected either directly to the distribution network or to customers' load. These are summarised below:

Generator	Owner	Connection	Capacity
Co-generation	Fonterra	Connected to site loads and to Plains substation	2x5 MW = 10MW
Geothermal TGI, TG2	Nova Energy	Onepu Feeder, Kawerau	5 MW
Hydro	Nova Energy	Aniwhenua Barrage compensation flow generator connected to the Galatea feeder, Galatea	100 kW
Steam Turbine	Whakatane Mill	On site - currently not operational	2x2.5 MVA
Mini Hydro		Braemar Road, Awaiti feeder, Plains	400kW

The policy for new generator connections is available from the Horizon Energy website. <http://www.horizonenergy.net.nz/customers/distributed-private-generation>.

Every application for generation connection is assessed individually to ascertain:

- The connection arrangement meets legal requirements;
- The impact the generation may have on the network and other connected customers;
- Any constraints that the connection may cause to the ability to deliver acceptable quality to other customers;
- Any restraints that may need to be put in place to facilitate the connection;
- Applications for generation connections below 10kW are processed according to regulatory requirements; and
- Safety within the network.

While Horizon Energy is not actively engaged in the development of distributed generation projects in its own right, Horizon Energy does support the development of distributed generation within its service area by:

- Facilitating network connections for independent power providers to exploit local energy sources; and
- Discussing on-site co-generation or demand management schemes with large industrial customers as an option for managing load peak demand.

There has been very little distributed generation development within the network area recently.

Non-Embedded Generation

Generation within the network region that is not embedded within the Horizon Energy distribution network:

- 70MW Matahina Hydro Station, although a physical connection to Transpower Kawerau, is treated commercially as being notionally embedded within the Edgecumbe supply area;*
- 24MW Aniwhenua Hydro Station is also treated the same way although has both a network connection at 33kV and a Transpower connection at 110kV;*
- 100MW Mighty River Power, Kawerau, has a Transpower Kawerau direct connection at 110kV; and
- 10 MW KA24 generator at Kawerau is embedded into the Norske Skog Mill site.

*Both Matahina and Aniwhenua have been subject to a Notionally Embedded Agreement that expires 31 March 2014. A Prudent Discount Agreement with Transpower is expected to replace it.

3.6. Other Horizon Energy Generation Assets

Two truck-mounted 300kVA mobile generator units are available to help manage planned and unplanned outages. A small trailer mounted mobile 300kVA substation has been configured for use with the generator units when a connection is required directly onto the 11kV network system.

One 1MVA transportable generator set and transformer procured in 2013 is used to support outages, as well as voltage support and peak load lopping. The unit is planned to be located within the Waiotahi network but can be transported elsewhere if required.

3.7. Assets that are not covered by this AMP

Assets owned and maintained by Horizon Energy that are not covered under the policies outlined in this plan include:

- Land and buildings, other than substation land and buildings;
- Vehicles;
- Furniture and fittings;
- Corporate computers and software;
- Other sundry assets; and
- Non-regulated subsidiary companies.

3.8. Summary of Assets

3.8.1. Asset Summary List

Assets ages as reported in the 2013 information disclosure reporting is included in Appendix A2.

With a replacement asset valuation of \$204M, asset replacements per annum need to be around \$3.9M. Average planned expenditure per year over the next 10 years on direct asset replacement and renewals is \$3.9M. There will be additional asset replacements or retirements occurring as work in other classes of expenditure occur.

A detailed summary of the total number of major system assets as at 31 March 2012 is shown in Table 3.4.

Asset Description	Quantity	Unit
33kV lines	174	Kilometres
33kV cables	4	Kilometres
11kV single wire earth return circuits (SWER)	63	Kilometres
11kV lines	1,456	Kilometres
11kV cables	186	Kilometres
400V lines	226	Kilometres
400V cables	261	Kilometres
Zone substations	8	Ea
Zone substation power transformers	13	Ea
Distribution substations	3,301	Ea

Asset Description	Quantity	Unit
Zone substation switchgear (11kV)	67	Ea
Pole top circuit breakers and automated switches	70	Ea
Ring main units (11kV)	153	Ea
Air break switches (11kV)	448	Ea
Fuses and links (11kV)	4,341	Ea
Pillar boxes 400V	438	Ea
Service pillar boxes	5,950	Ea
Load control ripple injection plants	4	Ea
Voltage regulators	1	Ea

Table 3.4 - Asset Summary, 31 March 2012

Overhead circuits “length by terrain type” in Table 3.5, gives a summary of the lengths of lines that are installed in each of the different terrain areas.

Overhead line by terrain	Length (km)
Urban	229
Rural	1038
Remote	164
Rugged	391
Remote and Rugged	96
Total Overhead Length	1919

Table 3.5 - Overhead Circuit Asset Summary

3.8.2. Distribution Assets

The distribution system assets of Horizon Energy are summarised in detail in Sections 5 and 6.

4. Service Levels

4.1. Introduction

The levels of service (LOS) defined in this Section are used to:

- Inform stakeholders, in particular customers, of the proposed type and level of service to be offered;
- Identify strategies to deliver required service levels;
- Measure the effectiveness of actions undertaken in accordance with this and past AMP's; and
- Demonstrate compliance with regulatory requirements.

Definition of Customers

Commercially, Horizon Energy's customers are the users of the network, being retailers and direct supply customers.

The service that is supplied is for the 'customer', particularly in the assessment of price/value trade off. When the term 'customer' is used throughout this document it is intended to refer to the end user of the energy.

The drivers behind service level expectations are generally based on:

- Network capability:
 - The type of network (overhead versus underground), the environment the overhead line is exposed to (e.g. vegetation, coastal, geothermal), its locality (e.g. rural, remote) and its ability to be configured to provide alternate supply routes are all primary drivers for the number of faults a customer can expect to experience and the time it will take to restore supply.
- Customer Expectations:
 - Information gained directly or from current and potential electricity customers and retailers, on expected quality and price of services offered.
- Regulatory Requirements:
 - Environmental standards, Regulations and Acts that impact on the way assets are managed (i.e. resource consents, electricity regulations, and health and safety legislation). These requirements set the mandatory minimum level of service that must be provided.
- Strategic and Corporate Goals:
 - Provide guidelines for the scope of current and future services offered, the manner of service delivery and define specific levels of service which the organisation wishes to achieve over and above the legislative requirement.

Target levels of service fall into two categories:

1. **Technical** (asset/product) related measures, which define the outputs the stakeholder receives in terms of:

- | | |
|--------------------------|-------------------------------|
| • Safety | • Capacity |
| • Quality | • Environmental impacts |
| • Quantity | • Cost / Affordability |
| • Availability | • Maintainability |
| • Legislative compliance | • Reliability and performance |

2. **Functional** (process related) measures, which can be measured by customer satisfaction surveys, and define how the customer perceives the service in terms of:

- | | |
|------------------|--|
| • Tangibles | • Empathy (understanding, attention) |
| • Responsiveness | • Assurance (knowledge, trust, confidence) |
| • Courtesy | |

4.2. Customers Research and Expectations

Horizon Energy's obligations to customers are stated in the Standard Terms and Conditions of Connection, Use of System Agreement and in specific agreements relating to a small number of major end users. The Standard Terms and Conditions set the minimum expectations of users of the network for the distribution of electrical energy.

Expectations of the electricity end-users are recognised and contained in their agreements with Horizon Energy which cover:

- Service standards/performance measures;
- Options for service delivery; and
- Payment options.

A network company must have a clear understanding of the needs and wants of its customers. To this end Horizon Energy has a program of targeted liaison and gathering feedback from interested groups in order to better assess the needs of customers related to their business or private requirements.

Apart from what is received from major direct supply customers, feedback that has been obtained to date is not specific enough to be able to develop targeted capital works programs that address the particular needs of individual customers and/or specific locations. Feedback tends to be of a more generic nature which reflects the broad customer base.

Horizon Energy understands quality from an end user or consumer perspective as:

- Availability of continuous power;
- Voltage consistency within regulated limits;
- Quick response to restore power following an unplanned outage;
- Consideration in the scheduling of planned outages of the network; and
- A network system designed to meet the capacity and energy needs of the customer.

The results of the communications indicate that customers are generally satisfied with the price and quality trade-off that Horizon Energy provides. This is evident in a number of ways:

- Survey respondents were generally satisfied with current quality levels;
- Urban survey respondents are more satisfied than rural;
- No general support from customers for improvements in quality levels (associated with a higher price); and
- No queries on disclosed information including the Asset Management Plan and pricing schedules.

Horizon Energy continually interacts with customers with respect to price and quality of the services provided. The latest review involved a detailed phone survey covering the various regions of the network along with different customer types. This has allowed a review of services and the comparison of customer views in the differing parts of the network.

Table 4.1 provides a summary of the three main processes employed by Horizon Energy in relation to customer consultation:

Process	(i) Properly Advise	(ii) Consult	(iii) Consider	(iv) Action
Consumer Surveys	A detailed phone survey was undertaken in 2012 which, among other things, requested information relating to the price and quality of services provided.	<p>Consumers were consulted about price and quality they require by:</p> <ul style="list-style-type: none"> • Requesting consideration of price-quality trade-offs. • Following up on requests for further information. 	Results of the customer surveys were aggregated, analysed and considered by Senior Management.	<p>The analysis of the results has been incorporated into the AMP by:</p> <ul style="list-style-type: none"> • Consideration of customer consultation results, historical and forecast quality and financial data. • Other actions including sponsorships.
Direct Consultation	<p>Horizon Energy advises customers or representatives by providing information directly to:</p> <ul style="list-style-type: none"> • New customers. • Large industrial customers. • Consumer advocacy bodies. • Target groups associated with specific supply assets. 	<p>Customer quality and price requirements were consulted directly with:</p> <ul style="list-style-type: none"> • New customers. • Large customers annually or more regularly. • Customer advocacy groups. • Retailers with respect to initially establishing and renewing UoSA. 	<p>Customer views were considered when:</p> <ul style="list-style-type: none"> • Developing new connection agreements. • Undertaking annual pricing or changing connection agreements. • Considering applicability of customers to the Low Fixed Charge Domestic option. 	<p>Customer views were taken into account through:</p> <ul style="list-style-type: none"> • Agreement on new or changed connections. • Agreement on price and quality matters.
Information Disclosure	<p>Horizon Energy publishes price and quality information via its website, newspapers and retailers:</p> <ul style="list-style-type: none"> • Tariff disclosures. • Pricing Methodology. • Information Disclosure. • Use of System Agreements (UoSA). • Standard Terms and Conditions. 	Horizon Energy engages with customers directly on any aspect of information disclosure. However this rarely occurs.	<p>Horizon Energy will consider any feedback on information disclosures from customers.</p> <p>Horizon Energy engages in and considers best practice reviews undertaken on information disclosure and reporting requirements.</p>	<p>Horizon Energy will action any appropriate feedback on information disclosures from customers.</p> <p>Horizon Energy incorporates appropriate best practice recommendations into information disclosure and reporting requirements.</p>

Table 4.1 - Customer Consultation

4.2.1. Customer Engagement and Price Quality Trade off Research

- Horizon Energy last carried out customer research among its customer groups with respect to service levels and price quality trade off in 2012;
- A total of 500 respondents were surveyed by phone using an independent market research company;
- Customers were selected from among Horizon Energy's main customer groupings; residential, commercial and rural, with the sample distributed across Horizon Energy's network;
- Comparisons were made with the earlier survey results; and
- This research follows similar methodologies used by other lines companies and has proven to be an effective barometer of customer satisfaction and opinion.

4.2.2. Overall Satisfaction

- In 2012 overall levels of satisfaction among customers were consistent at around 73% across all urban and rural customer groups; and
- This means that 73% of all customers stated they were either satisfied or very satisfied with the service of their electricity lines company.

4.2.3. Network Performance Perceptions

Respondents were asked to indicate whether they perceived that the quality of their power had improved, stayed the same or declined over the past 12 months.

Overall customers indicate that they believed their power had either stayed the same or improved. Reasons for improvement included a decline in frequent short power cuts, shorter outages and less flickering lights.

4.2.4. Importance of Network Service Deliverables

As presented in Figure 4.1 below, across all customer groups, customers rated price/keep costs down (as the highest priority) followed by reliability/no power cuts and a quick response/fix cuts quickly (43.8%) in the event of a fault.

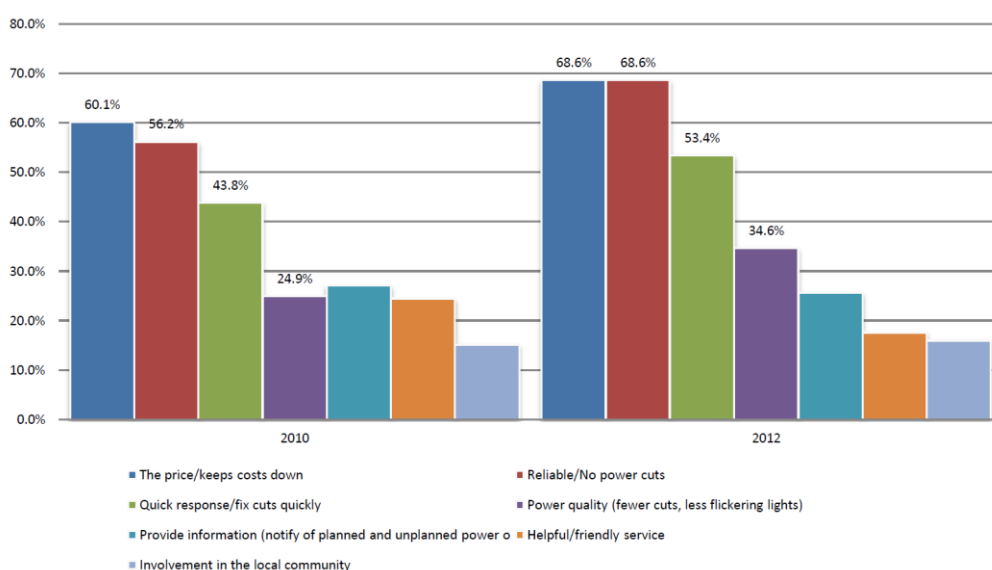


Figure 4.1 - 2012 overall importance of network deliverables - all customers

4.2.5. Rating of Network Service Deliverables

Customers were asked to rate how Horizon Energy performed across a series of lines company deliverables as follows:

- Overall customer service;
- How quickly power is restored;
- Speed of response;
- Attitude of fault staff;
- Number of times power goes off;
- Notifying of planned shutdowns;
- Easy to get hold of to report faults;
- Keeping power fluctuations to a minimum; and
- Length of time power is off.

A 10 point scale was used where 1 = poor performance and 10 = excellent performance. Across all customers Horizon Energy has achieved a satisfactory/good level of performance across all deliverables scoring between 7.5 and 8 for all categories.

4.2.6. Price Quality Trade-off

In terms of price quality trade-off, customers were asked to state whether they were prepared to pay more for an improvement in the quality and reliability of their power supply; a choice of \$100, \$150 or \$200 per annum was offered along with the option of replying that any increase would be too much. Across all customer groups, most respondents (93%) indicated that any increase to improve reliability would be too much (see Figure 4.2a).

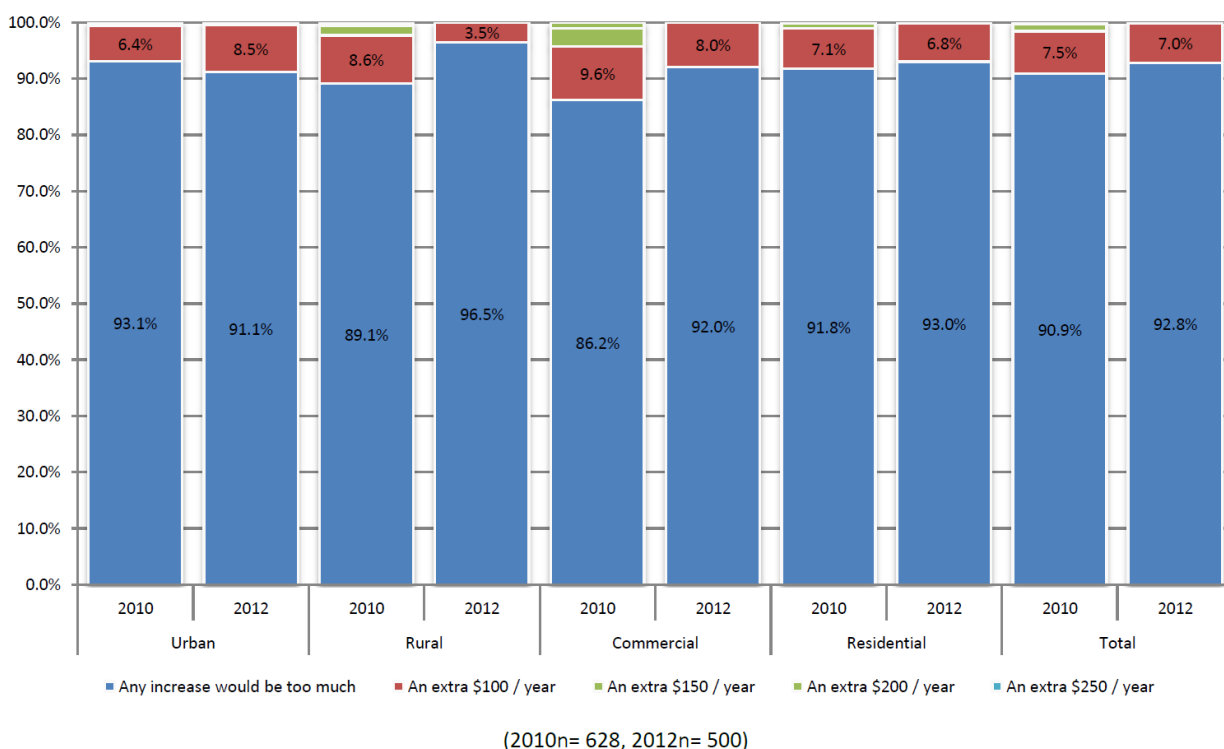
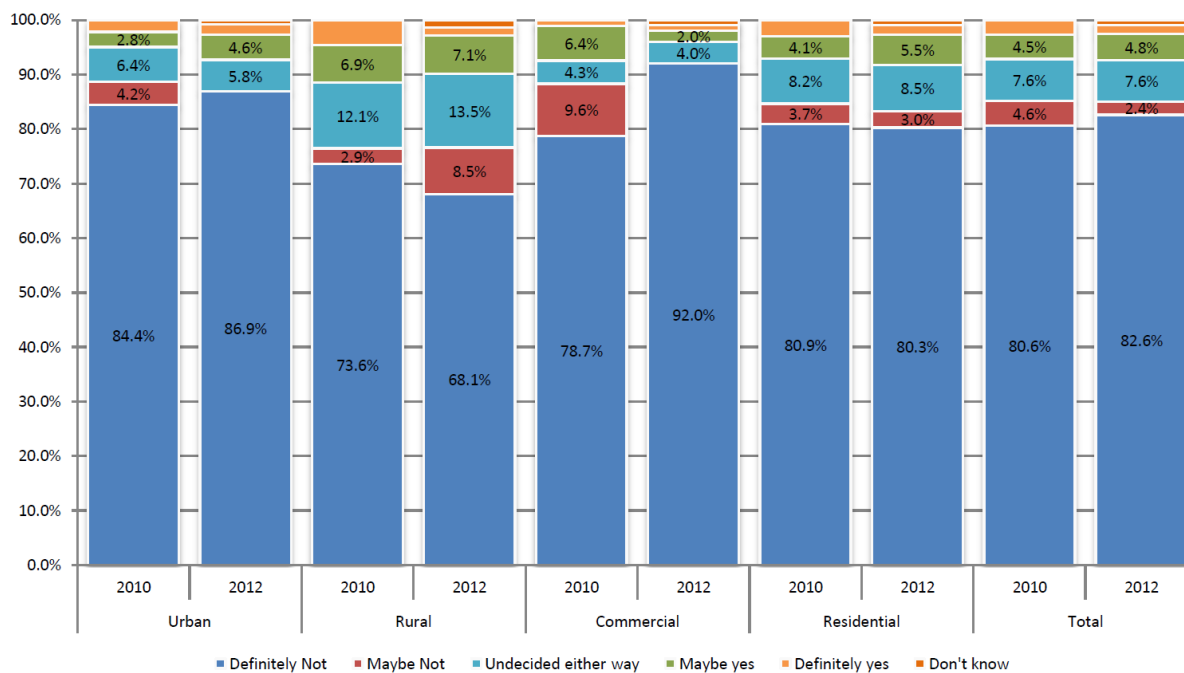


Figure 4.2a - Willing to pay more



(2010n= 628, 2012n= 500)

Figure 4.2b - Reduced quality for reduction

In addition to the above, customers were also asked whether they would be prepared to accept a trade-off in the quality of their power in exchange for a reduction in their lines charges. 83% of customers stated this would NOT be acceptable (see Figure 4.2b).

It can be seen from the above that there is a general acceptance of the price/quality and performance level of the Horizon Energy network system and as a result no specific asset enhancement projects have been initiated solely on the outcome from these surveys.

4.2.7. Shareholder Customer Expectations

There are a number of initiatives currently underway or planned that are related to the network service levels noted above. The service deliverables and associated initiatives are detailed below.

4.2.8. Reliability

Horizon Energy is undertaking a series of reliability projects initially targeting rural feeders that, although they will not prevent outages, will reduce the number of customers affected by those outages and also reduce the time required to restore supply. A 30 per cent reduction in unplanned outage driven SAIDI minutes can be shown across the feeders already completed. Greater detail is provided on these initiatives and the next round of scheduled feeders in Section 5.

4.2.9. Response

In addition to, and complementing the reliability projects, a major project is well underway to enhance the communication systems used between field devices and the master station. This is having a direct impact on the reliability of the network through the gathering of field information from remote devices which allows the identification of the area affected, location and cause of the fault. Improved asset labelling, carried out during the asset data capture programme completed in 2011, will also allow members of the public to identify and report equipment that has been damaged.

4.2.10. Notification of Planned and Unplanned Power Outages

A complete review of standards, both construction and operational, has been undertaken. From this the notification requirements will be reinforced to better guide the actions of the staff that are responsible for these tasks. It is anticipated an outage management system will be in place to improve management of planned and unplanned outages after 2014 that includes a web based customer outage portal.

4.2.11. Power Quality (fewer cuts, less flickering lights)

Planning and power system analysis tools are being used to a greater extent in the assessment of the network to better cater for interference contributors. Statutory requirements will be met and where complaints are received they will be investigated and addressed on a case by case basis.

4.2.12. Helpful / Friendly Service

A new customer charter has been developed. This charter provides a commitment from Horizon Energy to ensure that it performs to the highest standard in the undertaking of activities that impact on its customers. Performance guarantees cover:

- Processing an Application for Service;
- Processing an Application for transport of a high load through the network;
- Disconnection for safety;
- Customer complaints;
- Dispensation to work near lines;
- Switching requests;
- Retailer notification for planned outages; and
- ICP creation.

Horizon Energy is a committed member of the Electricity and Gas Complaints Commission and is supportive of its goals.

4.2.13. Involvement in the Local Community

Horizon Energy has a strong commitment to making a positive difference in the community in which it operates. The Company is active in the local community through targeted sponsorships where it can be identified that tangible benefits result.

4.3. Current Levels of Service

4.3.1. Prudent Investment

Accountability for financial performance is clearly defined and allocated to those Senior Managers best able to manage the outcome.

Delegated authorities for expenditure are similarly well defined and provide for appropriate levels of expenditure beyond which detailed business cases are required prior to any financial commitment.

A high standard of reporting is provided to the Board of Directors monthly and to other stakeholders in the form of the Company's Annual and Interim Reports.

The financial performance of the Company impacts directly on the return to shareholders. This must be managed in consideration to legislation that monitors (restricts) the level of return on assets employed to levels considered appropriate for a distribution lines business by the regulator.

Continued effort is being made to optimise the financial burdens and benefits to shareholders and customers within the constraints of the regulated environment. This is reflected in both the tariff options available and the rates applied to those options.

4.3.2. *Physical Performance*

Actual network performance is compared, typically on a monthly basis, with developed targets for each performance measure.

The performance against target for each reporting category is reviewed and carefully analysed. This is done yearly for most targets as part of the DPP Compliance review. Others, like SAIDI and SAIFI reporting are undertaken monthly for staff, Management and the Company Directors. Trends are evaluated and action taken as appropriate.

Where a trend develops that indicates a need for concern, the following steps are undertaken:

1. Any mitigating factors are analysed and in some instances a “one off” event may well have distorted the results. Some events (such as a major flood event causing extensive damage to distribution circuits) are reported, and then an adjustment made as it is accepted that the infrastructure is not designed to withstand such an extreme event.
2. Next, analysis is undertaken to identify the root cause of the problem and actions put in place to reverse the trend.
3. Lastly the target is re-evaluated to ensure that it is realistic and that the original target considered all factors in the setting of that particular level.

All factors that affect the results are examined, including:

- Maintenance Policies;
- Capital Expenditure Policies;
- Internal and External Contractor Work Practices;
- Material Supply and Specification Review; and
- Design and Construction Standards.

Changes are then made as appropriate.

Analysis reviews are essential to ensure performance and practices are maintained at an optimal level. End of year results are important indicators of how the system performed against target.

4.3.3. *Reliability*

Historic network performance for both planned and unplanned shutdowns, are shown in the following graphs. The key indicators used are those adopted by the industry (and regulations) as standard for network companies and include:

- System Average Interruption Duration Index (SAIDI) (minutes / customer);
- System Average Interruption Frequency Index (SAIFI) (interruptions / customer); and
- Customer Average Interruption Duration Index (CAIDI) (minutes / interruption).

The data shown applies only to interruptions caused by failures or planned outages on the Horizon Energy network and does not include outages due to Transpower or generation sources. The latter is, however, captured and analysed as it is important in the assessment of impact on customers who don't differentiate between what part of the upstream supply network caused the outage.

The graphs shown below are for the Horizon Energy network performance as a whole from 2006 to 2013.

There were nine significant fault events during 2012-13 that contributed greater than 5 SAIDI minutes per event.

- Three cable faults affecting large customer numbers, Kawerau, Ohope, and Whakatane. The Whakatane event was an external party directional drilling contact- the other two were cable failures;
- One car accident;
- Two external party tree felling events;
- One insulator failure in an urban network;
- One overhead failure in Kawerau; and
- One line failure at Galatea.

The number of faults against different fault categories for the previous five years is summarised below. Vegetation is showing an increasing trend compared to earlier in the period and this has been addressed since 2011 with additional budgeted expenditure in vegetation control.

FAULT CAUSE	2008/09	2009/10	2010/11	2011/12	2012/13
3rd Party interference	17	15	23	29	21
Adverse Weather	11	9	6	7	19
Cause unknown	35	29	33	35	26
Defective Equipment	43	40	36	44	49
Human Error	1	1	2	3	2
Lightning	2	10	3		3
Loss Of Bulk Supply			1	2	1
Vegetation	7	5	26	18	17
Grand Total	116	110	130	138	138

The charts below show the SAIDI, SAIFI, and CAIDI performance over the previous eight years.

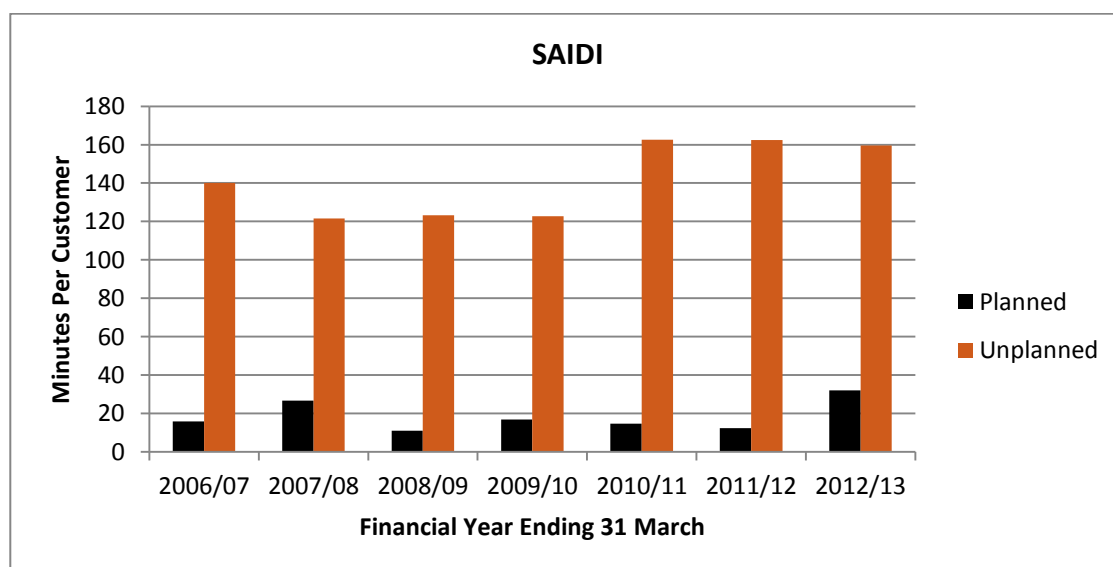


Figure 4.3 - SAIDI Performance 2006 to 2013

SAIDI is a measure of how long the average customer will be without power during a year. SAIDI is expected to improve as the effects of the reliability initiatives come on stream.

A project to trial self-healing networks has been proposed for the Plains region and is intended to assist improving the SAIDI and CAIDI results. Initial feasibility engineering for this project is planned for 2014-15.

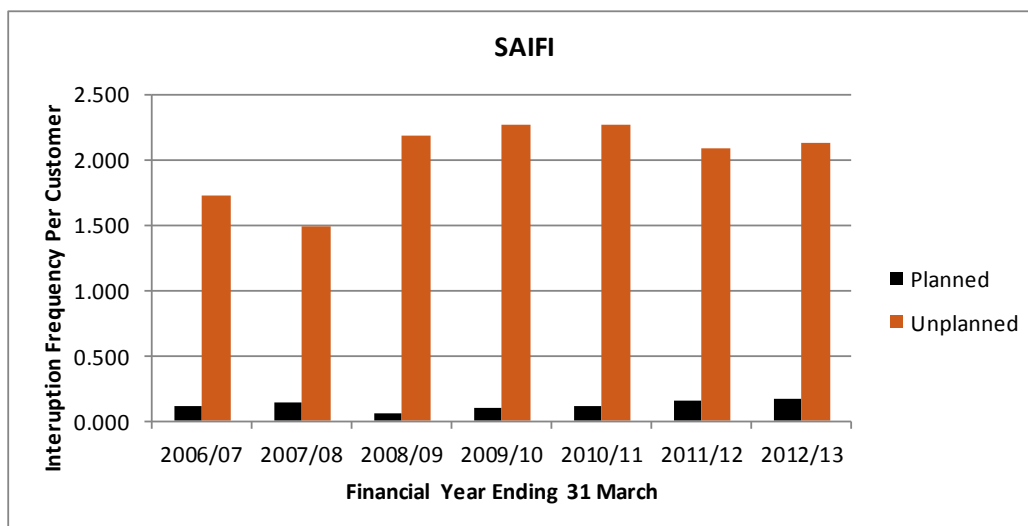


Figure 4.4 - SAIFI Performance 2006 to 2013

SAIFI is a measure of the number of times an average customer will suffer an interruption to their supply during a year.

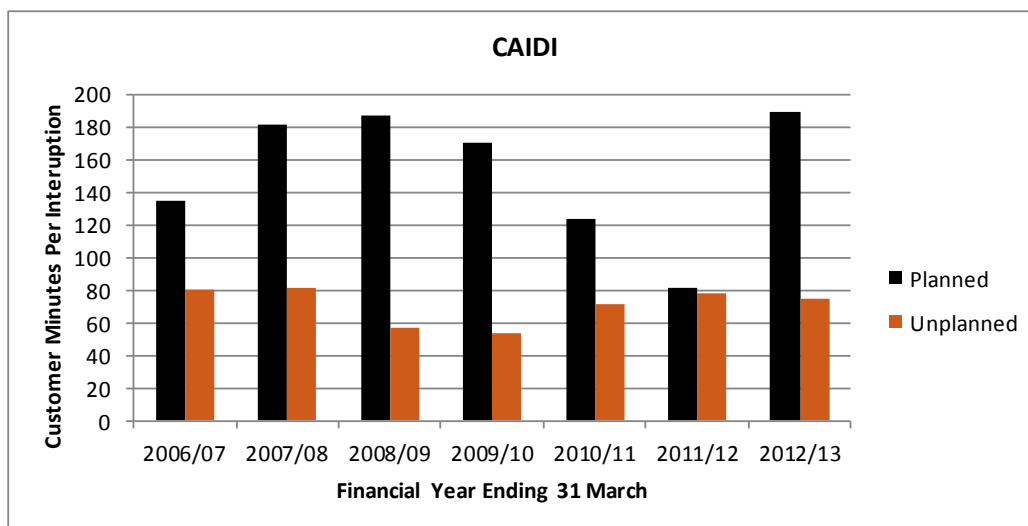


Figure 4.5 - CAIDI Performance 2006 to 2013

CAIDI is a measure of how long an interruption to supply will last on average.

The spike in 'Planned outages' in 2012-13 was an increase in outage durations due to the two 300KVA generators being out of service for a major refit.

The chart that follows plots SAIFI against the number of outages to give a measure of the number of outages a customer may expect. The reducing trend shown on the orange bar below shows the reduction in outage durations being incurred due to the increased sectionalising of rural feeders, with the installation of more line circuit breakers as part of the reliability projects program.

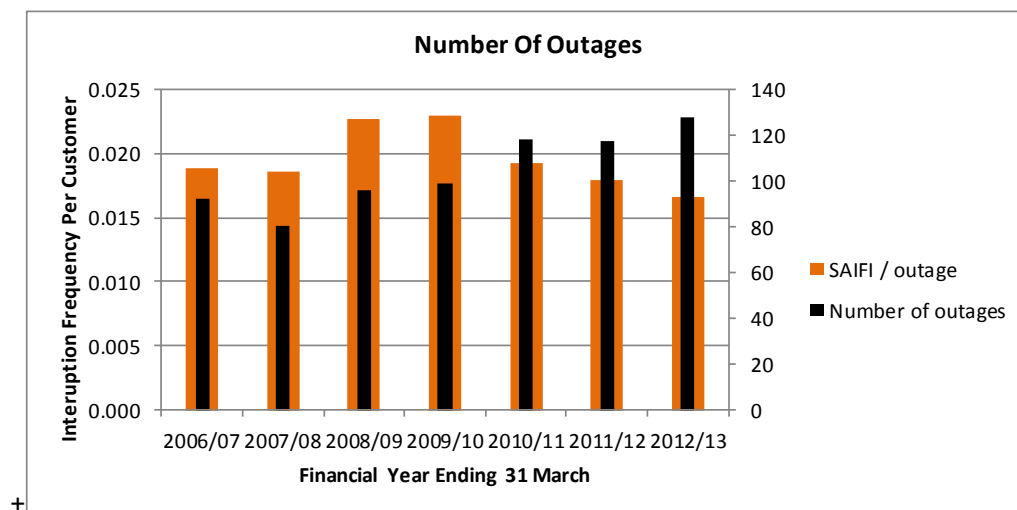


Figure 4.6 –Number of Outages

The group of reliability driven projects were planned following a reliability enhancement study in 2009 which included a detailed feeder analysis for all feeders during the financial years 2004 to 2009. The worst performing feeders became priority for planned installation of reliability projects over the following six years. These projects involve:

- The installation of additional circuit breakers and sectionalising circuit interrupters;
- Drop out sectionalisers and fuse saving circuit breakers;
- More fuse links; and
- Automated tie point switches.

The reliability improvement projects are showing an average reduction of 30% in SAIDI minutes for the feeders that have been completed, despite a 4% increase in the number of faults.

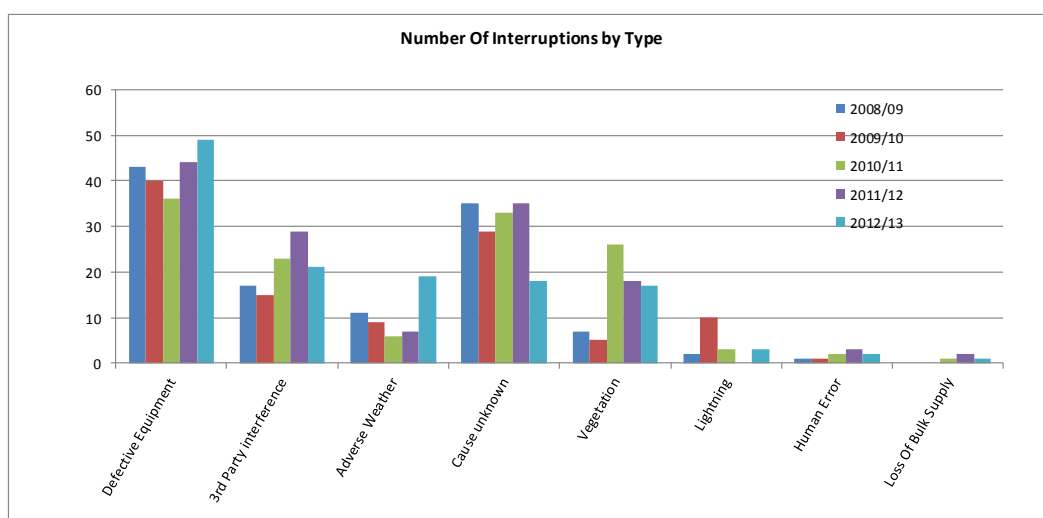


Figure 4.7 - Cause of Unplanned Interruptions Last Five Years

Interruptions by Type, Figure 4.7:

- “Defective equipment” faults still high. A large percentage (33%) are overhead conductor failures and insulator failures (30%), followed by DDO and failures;
- “Third Party interference” was vehicle accidents or trees which are outside of the vegetation managed zones which have been felled by other parties;
- Tree contacts have reduced as tree maintenance was increased in 2012; and
- “Unknown” includes auto reclose events which incur no lost time.

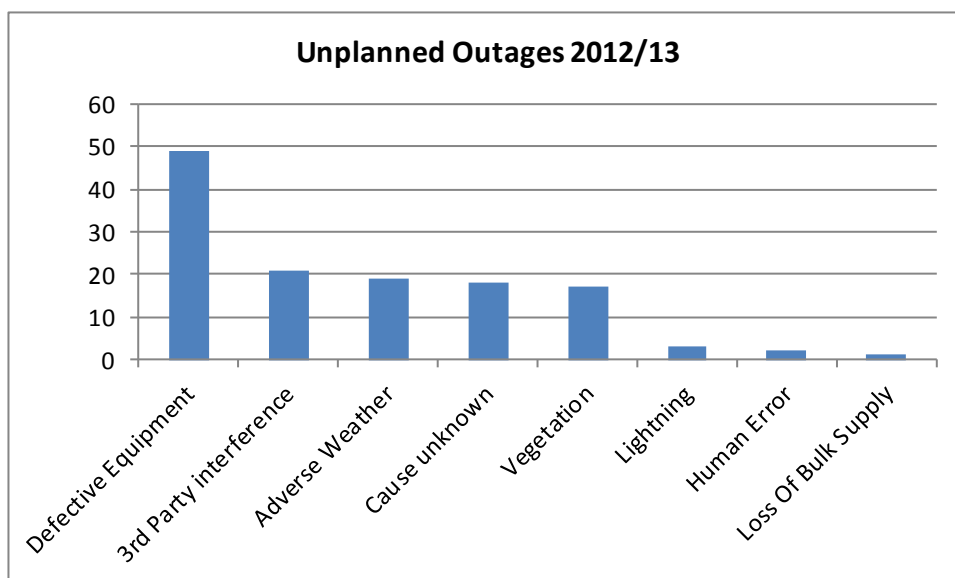


Figure 4.8 - Unplanned Outages Performance by Cause

Strategies in place to ensure that on-going improvements are made include:

- On-going replacement of low capacity conductor sections;
- Discontinued use of small diameter squirrel conductor except on private or dedicated spur lines;
- Increased partial discharge testing on ground mounted switchgear;
- Continued installation of automation equipment;
- Increased use of spur line fusing;
- Trialling of electronic devices that are designed to protect fuses from operating on momentary faults; and
- Trialling of self-healing networks in the Plains area.

Figure 4.9 below shows the number of unplanned 33kV interruptions:

- Te Rahu Feeder outages do not accrue outage time due to the two out of three N-2 redundancy inherent in the design of the Te Rahu substation;
- Snake Hill feeder faults cause a loss of supply to Galatea due to the continuing supply from Edgecumbe over rugged terrain, being supplied by a single feeder circuit instead of the normal supply from the Aniwhenua generator; and
- Ohope is affected by having a single sub-transmission feeder circuit that runs through rugged terrain.

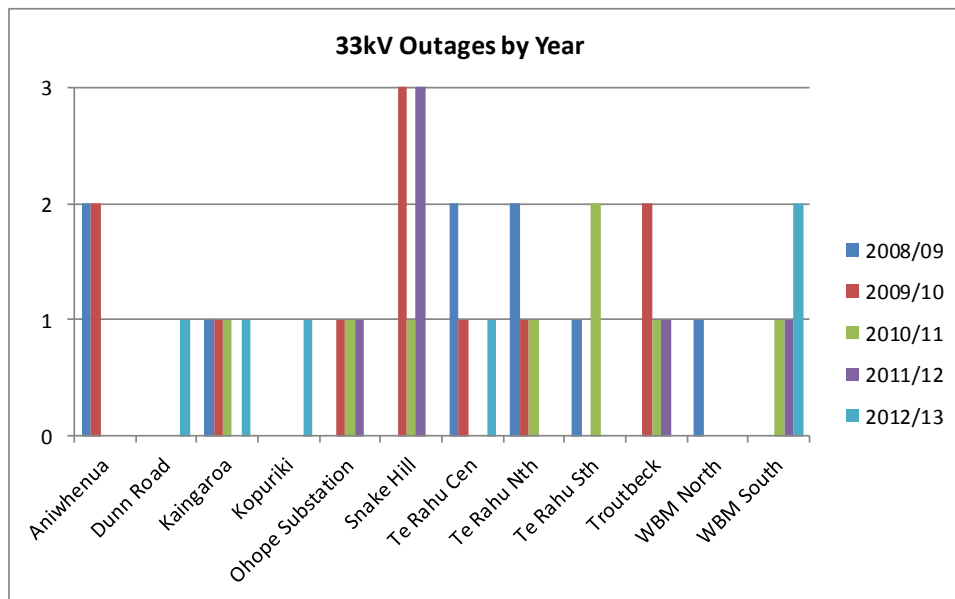


Figure 4.9 – 33kV Unplanned Interruptions

4.3.4. Feeder Performance

Figure 4.10 indicates the relative performance between feeders for the 2012-13 financial year.

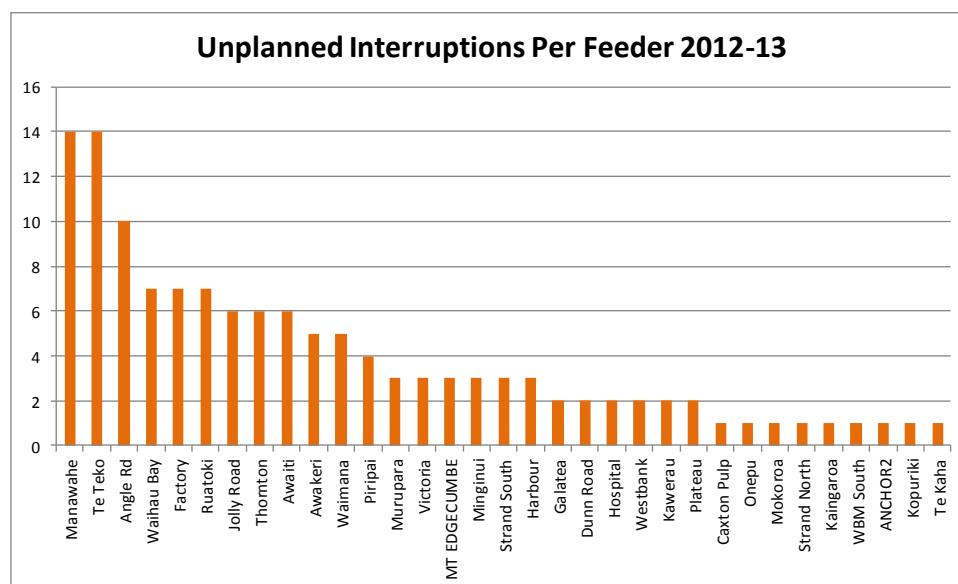


Figure 4.10 - Feeder Performance Ranking

A relative indication of the overall condition of a feeder in relation to others is to monitor the actual number of fault outages against distance. There is a correlation between faults, condition, and feeder length for rural feeders, so faults per 100km is also a measure used to assess performance. This is shown in Figure 4.11, Feeder Faults per 100km.

Note that the five feeders with the highest number of faults are relatively short feeders which affect their faults/100km ratio.

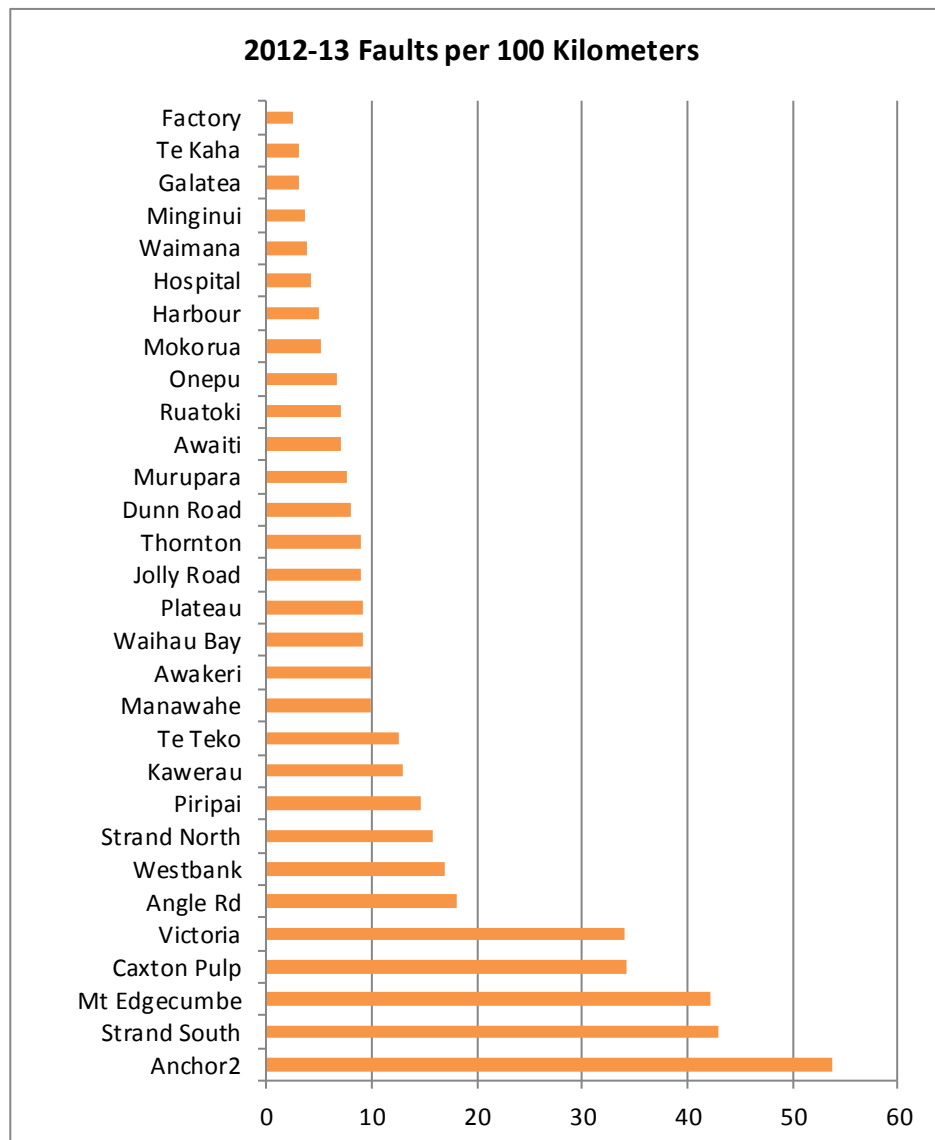


Figure 4.11 – Feeder Faults per 100km

The 33kV underground system is small and has performed well with zero unplanned interruptions since data has been captured.

Tree Contacts

There was a large increase in tree contact faults in 2010-11, as shown in Figure 4.12. A number of the faults were 'out of zone trees' that fell on lines during an abnormally wet 2010 spring season.

In recognition of this increasing trend Horizon Energy implemented an increase in vegetation expenditure for vegetation management for the 2012-13 year, which is showing some improvement.

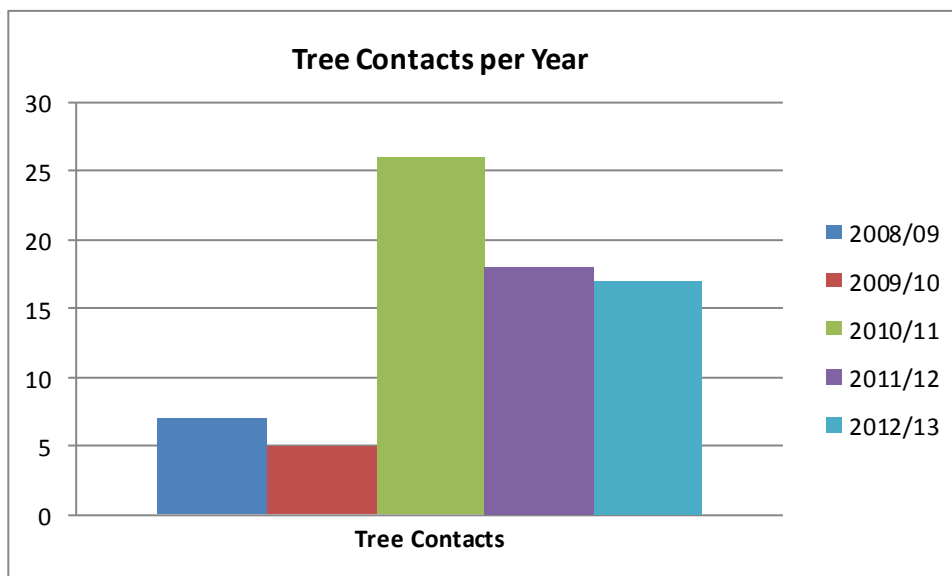


Figure 4.12 - Faults due to Vegetation

The vegetation faults are spread fairly evenly across the rural feeders with no feeder standing out as having significantly more faults than any of the other feeders.

4.3.5. Responsiveness

Fault Response

Horizon Energy does not operate a call centre and each consumer's respective energy retailer takes fault calls. Response to the fault is made by a contractor working for the retailer who will establish the problem. If the problem is found to be a network system fault, or if the fault has caused an outage on those parts of the system monitored by the SCADA system, then Horizon Energy operational staff will coordinate the response. In such a system, Horizon Energy may be unaware of a small loss of supply affecting only a few customers until the retailer reports it.

Where it is established that a problem exists on the network, contractors are despatched to respond to the problem. The contractor is authorised to work on both the Horizon Energy network and retailers equipment, and will undertake work for both parties. In some cases the problem may be found on the customer's property in which case the contractor will offer to undertake the repair, working directly for the customer.

Horizon Energy has engaged Call Care (a specialist call centre) to take calls from retailers and pass fault information onto the respective contractors operating on the network. This action was prompted due to the difficulty that retailers had in identifying the correct contractor for each part of the network in the Eastern Bay. The dominant retailer, being based in the Eastern Bay, still uses their own system for contractor dispatch.

In 2011/12 Horizon Energy's control room staffing was restructured to extend manning hours as part of an on-going process to streamline the handling of faults as well as providing improved worker safety monitoring. Lone worker considerations are important in the management of a safe work place which is driving greater monitoring and control by Horizon Energy's system control operators.

Notice of Pre-Planned Supply Interruption

Horizon Energy's target is to supply detail of any outage proposed to the retailer not less than five days prior to the event. This target is achieved unless, following negotiation with the customers affected, the notice period is changed. This may occur when the work is recognised as being urgent or where only a few customers may be affected and they can be informed with ease in advance of the outage.

Providing New Reticulation

Installation is by agreement with individual customers. Horizon Energy utilises information on the Horizon website which explains the lines company, contractor and customers' relationship and responsibilities. The information also contains links to the Standard Terms and Conditions of Connection and other details necessary for a trouble free connection to eventuate.

4.3.6. Quality of Supply

There are a number of enquiries per year with regard to voltage level of supply considered to be outside the regulatory requirement. The voltage divergence is initially investigated by control room staff in accordance with a procedure detailed within the Horizon Energy quality documents. This involves visual and physical system checks as well as the possible installation of a power quality data capture instrument.

Many of the initial investigations often show that supply is within the regulatory requirement at the point of supply and that the problem is due to inadequacies within the consumer's electrical installation. An increasing trend is being noticed in this occurrence due to a greater dependence on electricity and the use of equipment that highlights voltage divergence.

A good example of this is the use on many farms of UPS's to supply computers, the performance of which is displayed on the screen. As a result, customers are far more aware of dips and spikes in voltage than they would otherwise be. Where this is the case, the consumer is advised how the problem can be resolved and the enquiry is not recorded as a network voltage quality issue.

Where it is established that a network quality issue is present, this is passed to an Engineering staff member to investigate and correct. It is recorded on Horizon Energy's system as a valid voltage complaint that may result in the generation of a network upgrade project.

Whilst the frequency of problems experienced is low, the system is monitored on a regular basis. Increasing use is being made of instrumentation that is temporarily connected throughout the system in order to measure system parameters. The installation of modern pole top circuit breakers and switches, connected to SCADA, allows a greater volume of data to be collected from remote locations which provide a better understanding of the actual conditions at the pole top site. This data is used to verify system modelling which is used as a tool to check system quality parameters.

The configuration of the supply system is checked with each new application for connection to ensure an adequacy exists to provide a quality of supply to the proposed load.

The majority of investigations find that the complaint is due to either the customer's load growing in excess of the capability of their service system, or they have installed equipment that has a need for an increased quality of supply.

4.3.7. Environmental Standards

To date no environmental problems have been experienced. Good environmental performance is a key objective of Horizon Energy and close monitoring in this area is vital. During 2013-14 Horizon Energy intends to seek certification under ISO 14001 Environmental Management Systems.

Oil spill kits are available at all zone substation sites. Environmentally friendly synthetic oil has been specified for the new Kope T2 transformer and will be specified for all new zone substation transformers.

The photograph on the right is a typical layout as installed at the East Bank Road substation where an oil spill capture bund has been retro fitted to the pad. An oil separator has also been added to capture any oil that may become present in storm water due to a serious leak occurring.

Material containing asbestos is removed in the approved manner when found and all facilities are checked to ensure that environmental hazards are not present.



Horizon Energy has a number of SF6 circuit breakers or gas filled switches in known locations. SF6 has been identified as being a gas that is harmful to the ozone layer and as such must be managed in a responsible manner. Additionally, the product formed following arcing and a failure of the SF6 containment vessel is harmful and must be managed in a proper manner. A procedure is in place for the monitoring of these breakers and older circuit breakers that use SF6 as an arc quenching medium have been scheduled for replacement.

New primary 11kV switchgear has been specified as SF6 free.

4.4. Target Levels of Service

The service targets for 2012-13 for the overall network are scheduled in Table 4.2. This demonstrates that there are some service gaps with the current levels of service. The strategies or programmes to close these service gaps are also detailed.

Horizon Energy has set the target levels through a variety of methods and taking into consideration the impact that they may have on quality of supply, manning levels and cost. The goals are felt to be realistic and achievable whilst providing optimum safety and levels of service.

Future goals are influenced by past performance in meeting regulatory requirements and a desire to provide a safe service. Targets developed are the result of analysis and agreement among the AMP team. All goals are measured in either a formal or informal manner and where not achieved, performance improvement strategies are developed. Where goals are consistently met they are adjusted, where appropriate, to maintain incentives for improvement.

Performance measures and their justification are broadly categorised into the following areas:

Safety

Safety is paramount for both staff and the public. Horizon Energy has a responsibility to ensure that all of its equipment, systems and work places meet the highest of standards. Many of Horizon Energy's electrical assets are located in the public domain and contain hazards that can be fatal. The risks that cannot be eliminated are mitigated by design and by maintenance programmes. Horizon Energy holds AS/NZS 4801 certification for staff safety management systems and AS/NZS 7901 certification for public safety.

Quality	End use customers are becoming increasingly conscious of the characteristics of electricity supply that may impact on equipment they own or on their utilisation of energy.
Environmental Standards	Horizon Energy values a sustainable environment and will set targets that reflect the on-going management of all activities that affect the environment. Efficiency within the network is a key consideration and components are chosen that will have a low life time impact on the environment. Achieving ISO 14001 certification is part of that commitment.
Reliability	A key measure of supply quality, and a critical measure for regulatory compliance, is a progressive improvement in the reliability of supply offered to customers. A large component of the Company's resources goes into the management of this indicator.
Efficiency/Pricing	Horizon Energy is motivated to ensure that its efficiency measures are ranked highly within the distribution industry. These indicators also reflect to a degree how well the Company is operating its assets to meet the needs of its customers.
Responsiveness	Customers expect service in all areas of their dealings with Horizon Energy. The Company is keen to ensure that all processes and interaction with customers are handled in an appropriate, efficient and timely manner.
Financial	Customers expect a reasonably priced service, and shareholders expect a return on investment.

Table 4.2 identifies the service levels achieved against targets for the previous five years.

Key Service Criteria	Quality Characteristic	Target Level of Service	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Strategy or Programme to close Service Gaps
Safety	Safety of general public	Zero serious harm incidents	0	0	0	0	0	Health and safety systems continuous improvement program. All hazards within the control of Horizon Energy identified and controlled appropriately. Individual Project hazard and operability assessments (HAZOP) are undertaken for projects that are unique or uncommon for the network. Mandatory tailgate hazard briefings at all worksites. New programme to increase line clearances over state highways.
	Safety of employees and contractors	Zero serious harm incidents	0	1	1	1	1	Health and safety systems continuous improvement program. All hazards within the control of Horizon Energy identified and controlled appropriately. Individual Project hazard and operability assessments (HAZOP) are undertaken for projects that are unique or uncommon for the network. Mandatory tailgate hazard briefings at all worksites.
	Safety of network assets	All unsafe (red tag) conditions rectified within a three month term	N/A	N/A	N/A	Yes	Yes	Increase robustness and accuracy of defect system to ensure that priorities are met.

Key Service Criteria	Quality Characteristic	Target Level of Service	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Strategy or Programme to close Service Gaps
	Safety of network assets	Reduce the number of low road crossings over State Highways by 8 per annum (new 2012 - 13)	N/A	N/A	N/A	3	16	Use the GIS and recently captured asset data to identify and prioritise road crossings for removal or reconfiguration. Reduce hazards to public road users as crossing tend to sag over time.
Quality	Voltage	Less than five legitimate voltage complaints per year	0	0	0	0	1	Procedures being revised to improve reporting.
Environmental	PCBs	Zero problems	0	0	0	0	0	No PCB's in the network.
	SF6	Zero problems	0	0	0	0	0	Gas pressure readings taken at regular intervals and a register of SF6 devices and volume of SF6 gas is maintained.
	Transformer oil spills	Zero spills	0	0	0	0	0	Covered by specific projects for each facility as required, discussed in Section 5, Network Planning.
	Asbestos	Zero reports	None reported	None reported	None reported	None Reported	None Reported	No known asbestos within network assets.
Reliability	Faults per 100 circuit kilometres 11kV	5	5.76	5.4	6.91	6.82	7.25	Addressed with maintenance and renewal programmes in Sections 5 and 6.
	Faults per 100 circuit kilometres 33kV	2	4.01	6.19	2.8	2.8	3.45	As above.
	SAIDI	145 mins (class B & C)	122.24	123.02	162.67	174.62	191.6	Increased due to higher number of planned outages.
	SAIFI	1.8 (class B & C)	2.16	2.26	2.27	2.24	2.3	As above.

Key Service Criteria	Quality Characteristic	Target Level of Service	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Strategy or Programme to close Service Gaps
	CAIDI	81 mins (class B & C)	56.58	54.33	71.54	77.99	83.3	As above.
Service	Standard Application For Service (NCI)	five working days						There is currently no reporting on performance against these levels of service targets. These processes will be covered with business reporting in the IT systems upgrade projects during the 2012-13 financial year.
	Request for livening of new connection ready for supply	Not more than three working days						
	Planned shutdown advertised time off	0 minutes before advertised time						

Table 4.2 - Actual Performance and Identified Service Gaps

4.4.1. *Justification for Targets*

The targets presented in this AMP have been mainly based on historic performance and customer engagement. The customer surveys detailed earlier have indicated that both urban and rural customers are generally satisfied with the service provided with regard to availability and responding to outages. However, both urban and rural customers were not prepared to pay to improve the supply quality.

The analysis of the worst performing feeders provides another mechanism of validating consumer service levels since they reflect the network architecture.

The justification for the targets are summarised below.

4.4.1.1. *Safety*

Public and employee safety is paramount. Health and Safety legislation has very strong incentives for a company and individuals to provide a safe workplace and environment for employees and for members of the public. Horizon Energy takes all safety responsibilities very seriously, and any safety issue is dealt with promptly. Where equipment is identified as unsafe a replacement or minimisation process is instigated to remove or mitigate the hazard. Internal measures for the effectiveness of these programs are the monitoring of safety defects, red tag pole defects and the introduction or reinforcement of training programs.

Public and employee safety measures include traffic and worksite management, education, hazard identification, competencies management, and re-training schemes. Although Government regulation is not the primary driver for safety, the new requirement for lines businesses to comply with NZS 7901 is added justification to set and achieve public safety Key Performance Indicators.

Horizon Energy has an active Health and Safety Committee that meets and publishes a regular newsletter to drive and continually improve safety and wellbeing. Incidents, accidents and near miss reports are recorded and analysed. Any corrective actions required are added to the Corrective Action Register (CAR) for tracking.

The target of zero serious harm incidents for workers and the public is a measure of the effectiveness of these programs, and a measure of contractor lost time injuries (LTI) gauges the effectiveness of safety programs instigated by the contractor.

Because so much of its asset is overhead, Horizon Energy has identified road crossings as a public risk area that could be improved. It is not practical to remove the risk but Horizon has identified its large number of crossings as an area that improvements can be made and has decided to target state highways first.

4.4.1.2. *Quality*

Quality measures fall into many different categories. At present Horizon Energy is focusing on measurements for two key quality areas; customer complaints for voltage quality, and contractor performance with regards to customer satisfaction. Power system quality manifests itself in the following ways:

- Modern electrical equipment is more sensitive to power quality variations than equipment installed in the past. Many new load devices contain microprocessor-based controls and power electronic devices that are sensitive to many types of disturbances;
- The increasing emphasis on overall power system efficiency has resulted in a continued growth in the application of devices such as high-efficiency, adjustable-speed motor drives and shunt capacitors for power factor correction to reduce losses. This is resulting in increased harmonic levels on the power system and is of concern as to the impact this may have on the systems future capability;

- Increased awareness of power quality issues by the end users. Due to the increased use of electronic power quality devices by consumers, and the ability of these devices to inform of the actual power system characteristics, utility customers are becoming better informed about such issues as interruptions, sags, and switching transients, and are challenging the utilities to improve the quality of power delivered;

Voltage quality affects customers in the ways described above and Horizon Energy will work with customers to resolve voltage complaints.

Customer dissatisfaction with workmanship is often measured by the visual condition a worksite is left upon departure. When these concerns are brought to the attention of Horizon Energy they are passed on to the contactor to action and repair. A zero re-work target based on customer complaint is a measurable and achievable target.

4.4.1.3. *Environmental Standards*

The following broad targets have been set in this area:

- Certification under ISO 14001;
- Zero discharge of any pollutants into waterways, ground or ground water systems;
- Disposal of office and work place waste in an approved manner that will minimise adverse impacts on the environment;
- Manage all discharges to the atmosphere in a manner that ensures minimal impact on the environment;
- Monitor any adverse effects that may be created by the electrical network and work to ensure that the public understand these effects;
- Ensure that consideration is given to the aesthetic and acoustic impact that may be caused during the installation of network components;
- Maintain a prudent approach to electrical efficiency on the network while lobbying to have the regulatory environment recognise and reward lines company investment in reducing technical energy losses; and
- Noise containment or shielding when required meeting target noise levels.

Environmental measurements are easy to monitor and report against. There are legal responsibilities as well as customer expectations that the environment is correctly managed, as well as a social responsibility to be responsible for the environment.

4.4.1.4. *Reliability*

Comparative measures of reliability are SAIDI, SAIFI, and CAIDI. These are separated into two categories, planned and unplanned. Generally Horizon Energy has little control over the number of unplanned events that are influenced by weather or external events. The network operator can influence the reliability measurements by responsiveness to switching, repair time and restoration. Therefore measurements that address these three issues are a benchmark of how well the network and contractors can respond to faults.

Planned outages are totally within networks control. Proper planning to include all available works into an outage, meeting outage and restoration times, and adherence to these times, are a measure of efficient planning. There is a cost benefit to customers in the use of outages against using the more expensive live line work alternative to outages.

The measurements planned against these categories are an indication of how well the network is performing, both as a relative measure against other networks, as well as a measure of performance against preceding years.

The targets set for unplanned outages for SAIDI, SAIFI, and CAIDI are set below the regulatory compliance threshold set by the Commerce Commission for Horizon Energy and are based on past performance. Customers appear satisfied with the current level of service.

Target numbers have been set lower as the newly installed reliability equipment starts to be effective in reducing the effects of faults.

4.4.1.5. Responsiveness

The measures of responsiveness to customer services are self-explanatory, and provide an indication of how service focused the network is towards meeting the expectations of the new customer. These targets are both measurable and achievable, and are currently established targets although no measurement is made against the target. Once measurement systems are established, processes will be reviewed to enable better compliance to the targets if the targets are not achieved.

4.4.1.6. Loss Ratio

A number of networks include loss ratio as a service target. Horizon Energy has opted not to use loss ratio as a service measure as the network has little influence on the technical losses incurred within the distribution network, and as loads increase technical losses will invariably rise. Technical losses are considered within the design phase of development but are not normally the primary driver for equipment selection especially as the logical relationship between capital investment and cost savings resulting from electrical efficiency gains no longer exists in the current regulated environment.

4.4.2. Future Targets

Future service level targets are shown in Table 4.3 below:

Key Service Criteria	Measure	Target for the period of the AMP year start				
		2014	2015	2016	2017	2018
Safety	Number of public injuries on Horizon Energy facilities	0	0	0	0	0
Quality	Number of complaints for voltage or work quality	<5	<5	<5	<5	<5
Reliability	SAIDI	145	145	145	140	140
	SAIFI	1.74	1.74	1.74	1.74	1.74
	CAIDI	83	83	83	83	83
Restoration of Supply to Customers	Restore supply within three hours for urban customers	95%	95%	95%	96%	96%
	Restore supply within six hours for rural customers	95%	95%	95%	96%	96%
Customer Outage Impact	No more than two planned outages p.a. for urban customers	90%	90%	90%	92%	92%
	No more than two planned outages p.a. for rural customers	90%	90%	90%	92%	92%
Environmental	No environmental impact events	0	0	0	0	0

5. Network Planning

5.1. Introduction

This Section describes principles and practices used in network development planning. It includes the measurement and analysis methods used, assumptions made, and the sources and confidence levels of data used.

Assets are described in detail in the individual asset sections, along with load profiles, utilisation, operational constraints, development plans and restrictions that the various assets may have. Any changes in load type or profile are discussed and reasons for the changes explained. Works emanating from the studies of the various assets are further expanded throughout Section 5.

The planning process utilises a number of stages to plan and develop the network. The key inputs to the planning process are summarised in Figure 5.1.

Due to the continual review of proposed projects during the planning process, the priority for implementing individual projects proposed in this AMP may alter depending on the changing needs of the network and its customers.

5.2. Network planning principles

Network planning is a crucial process required to assess the impact future changes have on the network. These changes can be driven by load growth or reduction, equipment obsolescence, equipment age and condition based replacement, regulatory requirements, worker and public safety, stakeholder requirements, and desired improvements in service levels to better meet customer expectations.

Network development planning requires data and asset knowledge to be extracted from various sources, and analytical systems and procedures to ensure reliable data analysis.

In simple terms, project planning involves discovery or identification of the need for a proposed project; identifying alternatives, allocating costs and benefits; assessing the feasibility, providing detailed planning and design; and finally implementation.

This process is shown diagrammatically in Figure 5.1. The purpose of this Section of the AMP is to set out the inputs into the discovery phase, and the drivers that assist with the feasibility study and implementation phases.

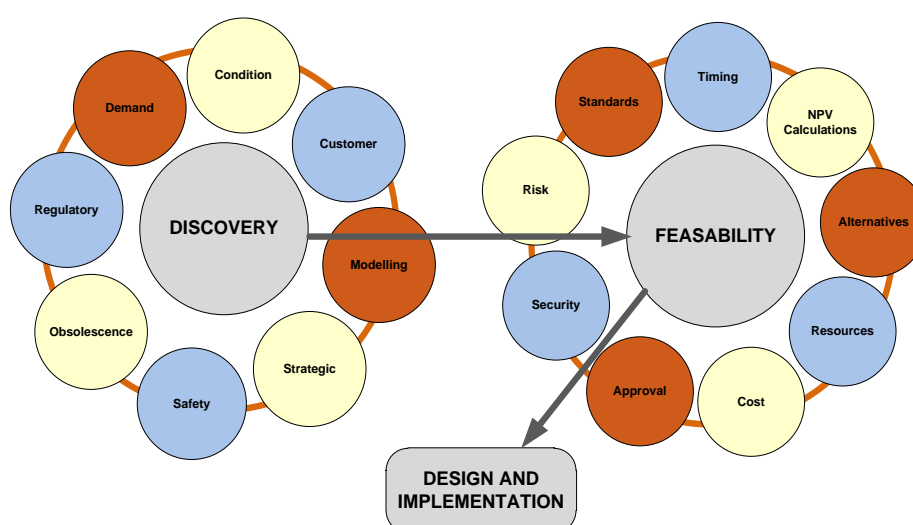


Figure 5.1 - Planning Inputs

5.2.1. Planning Criteria

Security of Supply Classification

In the same way as other electrical lines businesses, Horizon Energy classifies its zone substations on the basis of their ability to supply the current peak load without curtailment or interruption if one or more zone substation transformers installed at the existing zone substation are not operating.

Valid classification types are:

- N means that the current peak load may only be supplied without curtailment or interruption if all zone substation transformers are operating;
- N minus 1 (or N-1), means that the current peak load may be supplied without curtailment or interruption including if the largest zone substation transformer is not operating;
- N minus 2 (or N-2), means that the current peak load may be supplied without curtailment or interruption including if the largest 2 zone substation transformers are not operating;
- N minus 1 switched (or N-1 switched), means that the current peak load may be supplied following a brief interruption during which switching is carried out to re-establish supply following an unexpected outage of the largest zone substation transformer.

Network Security Criteria

Network security is the capability of the network to provide an alternative path of supply in the event of an item of equipment failing or being removed from service for maintenance. The level of network redundancy required is determined based on the load at risk, the predominant customer type supplied from the network and an appreciation of the value of lost supply to the customer. Target design security criteria are summarised in Tables 5.1.

Load / Customer Type	Planning Security Level
Fully redundant Zone substation 10 MVA or greater	L1
Zone substation pair (e.g. Plains and East Bank)	L2A or L2B
Major Industrial Customers (by agreement)	L1, L2A or L2B
Major Industrial Customers (standard terms of supply)	L3
Zone substation less than 10MVA	L3
High density commercial load	L3
Urban and rural areas with meshed networks	L4
Urban and rural areas with no meshing	L5

Level	Description
L1	Fully redundant alternative supply path that maintains supply without an outage
L2A	Ability to restore load by automated 'self-healing' SCADA controlled switching
L2B	Ability to restore load by manual SCADA controlled switching
L3	Outage that is restorable by alternative supply by manual switching within two hours
L4	Restoration within three hours, except for faulted segments
L5	Restoration after repair

Tables 5.1 - Security Criteria

As more projects are implemented that contain SCADA controlled switching devices, then the time for restoration will improve and more areas will be able to achieve a L2 level of security.

The above levels of security are guidelines for design undertaken across the network. By agreement with customers, higher levels of security can be provided if required.

Capacity Criteria

Assets are operated within their technical capacity allowing for acceptable levels of short term overload in contingency situations. Any short term overload is managed to ensure that this does not materially damage the asset or create a hazard. Network reinforcement or other management measures will generally be implemented prior to load exceeding 100% of the assets rated cyclic thermal or fault current capacity.

Asset Type	Overload Capacity
XLPE cable	110% for four hours, four times per year
Paper Lead cable	100% of rated capacity
Zone substation transformer	130% four hours @ 20° C
Distribution Transformer	130% two hours
Low voltage cables, PVC	100% of rated capacity

Table 5.2 - Overload Capacities

Transformer overloading is based on IEC 60354 standards. In emergency situations a higher level of overload may be allowable for cables on the understanding that the asset condition ageing may be accelerated.

Any asset that may be overloaded during reinforcement will be scheduled for upgrading.

5.2.2. Asset Building Blocks

All new assets are selected from the suite of standard network building blocks, unless otherwise required for specific technical or commercial reasons. Standard asset sizes are used wherever possible to minimise costs associated with procurement, design and lifecycle support. Horizon Energy's standard network building block elements are summarised below:

Tables 5.3a – 5.3e set out Horizon Energy's standard asset types.

(a) Distribution Transformers

Transformers are selected according to their connected load. Horizon Energy selects transformers for domestic installations based on a formula, defined in its construction standards, that considers the diversity that exists between increasing numbers of customers. Non domestic loads are engineered on a case by case basis. Using the design criteria for domestic loads, the table below details the maximum number of ICP's that would be connected to a particular size of transformer for a new installation.

Transformers	Number of Domestic ICP's
1000kVA Ground mount	Industrial use only
750kVA Ground mount	166
500kVA Ground mount	111
300kVA Ground mount	66
200kVA Ground mount	44
100kVA Ground mount or poletop	22
75kVA Ground mount or poletop	16
50kVA Ground mount or poletop	11
30kVA Ground mount or poletop	6
15kVA Ground mount or poletop	3

Table 5.3a - Distribution Transformers

(b) 33kV Feeders

Conductor Type	Size (sqmm)	Nominal Capacity (MVA)	Use
AAAC Krypton	158	24 MVA	All new circuits
ACSR Dog	103	17 MVA	Legacy conductor. Not used for new circuits
300 sqmm ² Al, XLPE Cable	300	Determined by defined conditions	Sub-transmission incomer cable to zone substations
185 sqmm ² Al, XLPE Cable	185	Determined by defined conditions	Sub-transmission incomer cable

Table 5.3b - 33kV Conductor Sizes

(c) 11kV Feeders

Conductor Type	Size (sqmm)	Nominal Capacity (MVA)	Use
Overhead Conductors			
AAAC Krypton	158	8 MVA	New high capacity feeder circuits
AAAC Iodine	124	6 MVA	Replacement for Dog and Wasp conductors
AAAC Fluorine	49.5	4 MVA	Replacement for Squirrel, Mink, Flounder, Ferret conductors
Legacy Overhead Conductors			
ACSR Dog	103	6 MVA	Main route Feeder circuits
ACSR Mink	62.2	4 MVA	Medium Capacity Feeder Circuits Legacy conductor
ACSR Ferret	41.8	3 MVA	Low capacity feeder circuits
ACSR Squirrel	20.7	2 MVA	Spur lines and private lines

Conductor Type	Size (sqmm)	Nominal Capacity (MVA)	Use
Cables			
300mm ² AL/XLPE Cable	300	7 MVA	Zone substation exit cables and feeder first sections
185mm ² AL/XLPE Cable	185	6 MVA	Feeder sections
95mm ² AL/XLPE Cable	95	4 MVA	Legacy cable. No longer used
35mm ² AL/XLPE Cable	35	2 MVA	Distribution Transformer supply cable

Table 5.3c – Distribution Conductor Sizes**(d) Earth Conductor**

Conductor Type	Nominal Fault Capacity 1 second rating (kA)
95mm ² Copper	10.5 kA
70mm ² Copper	7.7 kA
35mm ² Copper	3.9 kA

Table 5.3d - Earth Conductors with Ratings**(e) Switchgear**

Ring Main Units	Manufacturer
Field Ring Main Units	ABB Safelink or SD Units
Field Circuit breakers	Schneider RM6
Pole top CB	Cooper Power Nova
Automated Switch	Entec I5

Table 5.3e - Switchgear**5.2.3. Standard Designs**

Standard designs are used for:

- Overhead line structures;
- Ring main installations;
- Cable termination kits;
- Substation and protection designs; and
- Primary switchgear.

Due to the relatively small nature of the network standard designs are able to be implemented for most works. As designs evolve with experience, they are rolled out as updated revisions.

Network policy is to use, wherever possible, equipment that the rest of the industry is using. This is to leverage the experience and research capability of larger networks and suppliers, to gain the benefits of readily available equipment and supplier support.

5.2.4. Load Flow Measurement

Fundamental to understanding historical load performance and asset utilisation, and as the basis to predict growth, is the accurate measurement of demand and load flow. As a minimum, Horizon Energy has load current measurement at each zone substation for each feeder. Table 5.4 describes the load data measurements available at each zone substation.

With the transition of communications to industry standard protocol DNP over IP, the gradual replacement of obsolete protection relays with smart microprocessor based relays (IED relays), and the addition of modern poletop circuit breakers and switches into the network, additional data is becoming available to enable more accurate analysis of the load within the distribution network.

Measurement data from each zone substation is collected by SCADA and stored in a database. Horizon Energy has been archiving data into this database since 2005. All circuit breaker status information is returned to SCADA, but not all points are archived for historical collection.

Table 5.4 summarises by zone substation the metering data available for use in network development studies.

Substation	Measurements available	Source	Limitations/Class
East Bank	Bus voltage	Voltage Transformer	Class I
	Transformer MW	IED Relay	Relay 0.1%, Class P10 CT
	Feeder Amps	IED Relay	Relay 0.1%, Class P10 CT
Galatea	33kV Bus Voltage T1	Voltage Transformer	Class I
	33kV Bus Voltage T2	Voltage Transformer	Class I
	11kV Bus Voltage	Transducer	Class I
	Transformer MW	Transducer	1%
	Tap Position	Transducer	1%
	Feeder Amps	Single phase CT	Protection CT
	Load Control	Load control channels on/off times	SCADA time
Kaingaroa	33kV Voltage	Voltage Transformer	Class I
	11kV Voltage	Voltage Transformer	Class I
	Transformer MW	Transducer	1%
	Feeder Amps	Single phase CT	Protection Class CT's
Kawerau	11kV Bus Voltage	Voltage Transformer	Transpower supplied data
	Feeder Amps	IED relay	Transpower supplied data
	Feeder MW	IED relay	Transpower supplied data
Kope	33kV Bus Voltage	Voltage Transformer	Class I
	11kV Bus Voltage	Voltage Transformer	Class I
	Transformer Amps	IED Relay	Relay 0.1%, Class P10 CT
	Transformer MW	Relay 0.1%, Class P10 CT	Relay 0.1%, Class P10 CT
	Protection	Protection CT	IOP10
	Feeder Amps	IED Relay	Relay 0.1%, Class P10 CT

Substation	Measurements available	Source	Limitations/Class
Ohope	33kV Bus Voltage	Voltage Transformer	Class I
	11kV Bus Voltage	Voltage Transformer	Class I
	11kV Feeder Amps	Single phase CT	CT + Transducer
Plains	33kV Bus Voltage	IED relay	Class I
	11kV Bus Voltage	Voltage Transformer	Class I
	Transformer Amps	IED relay	Relay 0.1%, Class P10 CT
	Feeder Amps	IED relay	Relay 0.1%, Class P10 CT
	Feeder MW/MVAR	Voltage Transformer	Relay 0.7% – 6.5%
	Feeder distance to fault	IED relay	Indeterminate
	Load Control	Load control channels on/off times	SCADA time
Station Road	33kV Bus Voltage	IED relay	Class I
	11kV Bus Voltage	IED relay	0.2%
	Transformer Amps	IED relay	Relay 0.1%, Class 10P10 CT
	Feeder Amps	IED relay	Relay 0.1%, Class 10P10 CT
	Feeder MW/MVAR	Voltage Transformer	Relay 0.7% - 6.5%
	Feeder distance to fault	IED relay	Indeterminate
Waiotahi GXP	11kV Bus Voltage	Voltage Transformer	Transpower supplied data
	Transformer MW	Transducer	Transpower supplied data
	Feeder Amps	Single phase CT	CT + Transducer
	Load Control	Load control channels on/off times	SCADA time
Edgecumbe GXP	33kV Bus Voltage	IED Relay	Transpower supplied data
	33kV Feeder Amps		
Te Kaha GXP	Sub MW	Transducer	Transpower supplied data
Aniwhenua TGI, TG2, Matahina BOPE	110kV Voltage 33kV Bus Voltage Power MW	Various	BOPE supplied data from embedded generation sites

Table 5.4 - Metering Limitations

5.2.5. Network Modelling Methods

The network is modelled for load flow geographically using PSS SINCAL network modelling software. The application is capable of undertaking calculations for load flow analysis of conductor loading, voltage drop, substation loading, power transformer loads, and 33kV and 11kV network losses.

Network models have been developed for the 33kV Sub-transmission system as well as for all 11kV Distribution Feeders. There is no modelling at the 400V distribution level except for specialised installations for individual customers. Model accuracy and confidence is described in Table 5.5.

Model	Level of Uncertainty
33kV Sub-transmission system	<ul style="list-style-type: none"> • Low level of uncertainty; • Modelled results have been verified against source and destination metering data, manual calculations, and models on alternative modelling packages; • Transmission models from Edgecumbe to Waiotahi and Te Kaha correlate to modelling undertaken by Transpower; • Destination loads are well known due to actual metering data being available.
11kV Distribution	<p>Te Kaha, Waiotahi, Edgecumbe GXP models are believed to be reasonably accurate. Spot checks of modelled loads and voltage profiles at various sites have been within an acceptable tolerance of predictions. Uncertainties are introduced by:</p> <ul style="list-style-type: none"> • Different line build configurations to that modelled; • Errors in conductor size; • Data update lags; • Assumptions on load factors; • Loads not fitting average profile assumptions e.g. pump loads; • Phasing connection assumptions for single phase transformers; • Geographical placement errors; • Embedded generation and load equipment assumptions; • Unsure locations of large intermittent loads e.g. irrigation pumps; • Power factor variations from 0.95; • Harmonics are not modelled.
11kV Distribution Galatea	<ul style="list-style-type: none"> • High degree of uncertainty with the rural zones modelling; • Predominance of summer irrigation loads; • Lack of detailed knowledge of the placement of the irrigation pumps; • The addition of intelligent switching devices into the Galatea network will provide more accurate load data to allow the models to be checked.
Modelling Improvement Plans	<p>Plans to improve the accuracy of load flow modelling include:</p> <ul style="list-style-type: none"> • Automatic updating of variable data (lines, locations and transformers) from the GIS system; • Additional data from intelligent switching devices; • Review of Galatea system once additional metering data is obtained; • Additional user training; • Identification of specific load groups such as frost protection, irrigation and industry to enable tailored growth and utilisation patterns to be applied for these groups.

Table 5.5 – Model Accuracy

Protection configuration modelling is done using spreadsheets. Parameters modelled are over-current and earth fault elements. All calculations use standard IEC or ANSI equations. Non IEC equipment curves, fuse data, line constants and cable constants are pre-determined and applied using look up tables. Data is peer reviewed for accuracy.

All modelling systems are managed by the Planning team.

5.2.6. *Asset Condition Replacement*

Planning processes relating to asset replacement based on condition and/or age is covered in Section 6, Asset Lifecycle Management Planning.

5.3. Project Implementation

Project implementation is the process for progressing a project from concept to completion. Projects for a planning year are identified in the Annual Plan which in turn is derived from the Ten Year Plan. The annual plan is approved by the Board of Directors prior to each financial year. Projects are then further approved for expenditure according to the designated financial authorities and presentation of project justification and cost.

All projects are assigned a Project Manager who is responsible for managing the project implementation. For a small project the Project Manager may run the project from conception to completion. Larger projects are set up with a Project Manager and a project team selected to provide the skill sets required to engineer and implement the project. External resources are engaged when specialised skills are required or the work load capability of the available staff is exceeded.

5.3.1. *Long Term Planning*

Long term planning addresses projected network growth, strategic initiatives and obsolescence or condition based asset replacement. The outcomes of network and equipment analysis result in future projects being identified. These projects are included in the 10 year plan. As priorities alter, the plan alters, and projects are moved to suit the needs of the network and its customers. Projects are initially entered with high level budgets based on today's dollars. Budget estimates are developed at high level from past experience or unit rate prices.

The long term plan is approved by the Board of Directors as part of the AMP but is a guideline planning document only and will alter as network priorities alter.

As is the nature with predicting the future, the further ahead we look the less clarity there is. Horizon Energy's AMP is no different with the main planning trends being:

- An increased maintenance, asset replacement and refurbishment spend as assets continue to age;
- Increased capital spend to resolve network constraint issues and improve reliability; and
- Increased asset replacement spend as zone substation power transformers are replaced due to either age or capacity.

5.3.2. *Project Justification*

A project cannot proceed unless it passes a number of tests to determine if the expense is justified and warranted. Pre-feasibility checks are carried out at a high level by the Planning department to determine if the concept idea warrants further development. This process can be either informal or formal depending on the level of engineering applied to the pre-feasibility and the value of the proposed project. Projects are initiated by several different drivers summarised below:

- Public safety, staff or contractors;
- Providing capacity to meet demand;
- Customer initiated projects for new connections or capacity;
- Meeting reliability and security targets;
- Improving asset value;
- Improving operational efficiency; and
- Replacement of aged assets.

The basic principle applied to every project is to ask the question 'Why are we doing this project?' Major proposed projects will be accompanied by a project feasibility report or strategic plan that identifies:

- The project drivers and issues addressed;
- Key findings from engineering or planning studies;
- A summary of projects and alternative options considered;
- Possible non network options;
- Recommendations ranked in order of priority with reasons for selecting or rejecting various options;
- High level budgets and proposed cash flow;
- Risk assessment, including the risk of not doing the project; and
- Cost or benefit analysis of the main and alternative options.

Horizon Energy recognises that it has a limited engineering resource, so for major projects involving a significant cost, the feasibility study will either be outsourced to an external consultant, or completed in-house and reviewed externally. This ensures an independent check of the project concepts and draws on the experiences of industry specialists who have access to a larger pool of engineering resources and knowledge.

5.3.3. Project Priority

Prioritising a large number of projects is done using a points system. Projects are assessed using a series of yes/no answer questions and each answer is given a point value. The greater the number of points allocated to a project, the greater is the project priority.

Projects are allocated points according to the following criteria. Each project is further subjected to a capital approval process that considers the economic and technical benefits of each project on a stand-alone basis. The basic scorecard is shown in Table 5.6.

The questions are designed to be a yes/no answer. This is functionally more effective than using a graded number system (e.g. 1-5) which has a tendency for assessors to grade mostly in the midrange region (2-4). Weighting is determined by Management.

The final priority for work is based on financial approvals, the availability of resources, and the directions that the Board, Customers, or Shareholders may determine.

Priority Scorecard

Customer Focus	Score (Yes=1)	Weighting	Examples or assessment criteria
Is this a safety driven job?	0	2	Applies to jobs that are directly safety driven e.g. safety barriers, improved locking, improved earthing, etc. Does not apply to a project that may indirectly improve safety, e.g. a line that is upgraded, improved protection, etc. does not qualify.
Is this job required to comply with legal requirements?	0	2	Applies to jobs required for company/asset to be compliant, e.g. clearances or prevention of access to ground mounted equipment.
Installing the project provides an estimated potential saving in SAIDI greater than one minute?	0	1	If the existing equipment fails, estimate the SAIDI impact minutes lost. Number of customer's time off/total number of customers.

Is fault response time likely to be improved?	0	1	Any project that reduces the time to sectionalise or restore faults e.g. if automation is installed where previously there was no automation, or if a tie point is installed, this will be one.
Is a customer prepared to contribute some costs?	0	2	
Is SAIDI <0.5 minutes to install?	0	1	If installation SAIDI is too high then the cost of construction goes up which may alter the financial viability of a project.
Is there an improved public visual benefit over an existing installation?	0	1	Is it smaller, less obtrusive and more visually appealing for customers?
Business Focus	Score (Yes=1)	Weighting	Examples or assessment criteria
Is the project strategic or required to support another project?	0	1	Zone substation, tie feeder, communications link, SCADA, line to new substation, condition testing or monitoring, ZS transformer replacement, sub transmission upgrade etc. Any project that must be completed to support a subsequent project.
Is environmental risk reduced?	0	1	Oil containment, noise reduction, vehicle impact reduction, end of life environmental advantage.
Is risk to the sub transmission or 11kV distribution network reduced?	0	1	Applies to main feeder equipment; replacement of main feeder lines in poor condition, spur line fusing, undergrounding, etc.
Is the project technically complex?	0	1	Work that requires a higher level of engineering than 'normal' work; elevates priority to allow resources to be allocated earlier.
Does the project address multiple faults or has overall asset condition been assessed as poor?	0	1	Applies to a project that groups a series of defects or poor condition assets (does not apply to lifecycle replacement of end of life assets).
Does delaying the project by 1-2 years cause a problem?	0	1	Do we have to do it now or can it be delayed without consequence.
Is this a totally new asset?	0	1	Does this project increase the asset base of the company i.e. is NOT a replacement for existing equipment? (This gives some weighting to the non-replacement projects).
Asset replacement	Score (Yes=1)	Weighting	Examples or assessment criteria
Is an asset to be replaced > 90% of its EDB end of life age?	0	1	Elevates older assets in priority for works.

Will this project reduce direct maintenance costs?	0	1	Reduces routine maintenance cost e.g. non-oil enclosed switches have a reduced maintenance requirement compared to an oil filled switch; undergrounding of overhead lines reduces line maintenance costs.
Will operations costs be reduced?	0	1	Measurable operations costs; cost of travel, reduced operation time, less people to operate, reduced losses. Does not include un-measurable costs, possible savings in reduced faults, defects, etc.
Does the piece of equipment being replaced have a history of failure?	0	1	Targets individual pieces of equipment that has had a history of poor performance.
Is the equipment type prone to failure?	0	1	Targets particular equipment class (e.g. And elect series 1 RMU etc. that has a known class type fault.
Does the project address load, overload, or reinforcement constraints?	0	1	Conductor or transformer upgrades due to overloading or reinforcement requirements.

Table 5.6 – Priority Scorecard**5.3.4. Engineering**

Detailed engineering is worked on in-house for smaller projects and contracted out for large projects. Horizon Energy uses the following engineering tools and their various characteristics are listed in Table 5.7 below:

Tool	Description	Limitations
Standards	<ul style="list-style-type: none"> Network design and equipment standards 	<ul style="list-style-type: none"> Under continual review Managed as controlled documents
PSS Sincal	<ul style="list-style-type: none"> Network electrical load flow modelling software provides load flow analysis Protection modelling Load development modelling 	<ul style="list-style-type: none"> Requires skilled engineers to use effectively
Poles'n'Wires	<ul style="list-style-type: none"> Overhead line design tool 	<ul style="list-style-type: none"> Specialised skill set required to use effectively Non intuitive interface
Intergraph GTech	<ul style="list-style-type: none"> Geographical Information System 	<ul style="list-style-type: none"> System replaced in 2013
Autodesk AutoCAD	<ul style="list-style-type: none"> 2D/3D drawing package Industry standard 	<ul style="list-style-type: none"> Requires skilled users
Protection Design Spread sheets	<ul style="list-style-type: none"> Models protection curves Standard IEC calculations 	<ul style="list-style-type: none"> Limited in-built functionality

Table 5.7 – Engineering Design Tools**5.3.5. Non Network Development Options**

As part of the engineering process all projects need to consider the alternatives that non-network options may provide. Non-network development options are alternative solutions that do not require spending capital on the distribution network.

Table 5.8 summaries non-network options for load management. These solutions are generic and are discussed here separately to the individual area issues. Each load driven project, as it is engineered, will be assessed using the following discussions to see if any non-network solutions could be applicable.

Option	Advantages	Disadvantages
Demand Load Management Ripple Control	<p>Ideal solution for short term peaks. Emergency load shedding up to 5%. Assets already owned by network.</p> <p>Horizon Energy is actively studying this option</p>	<p>Not viable as a long term solution for overloading. Customer quality issues if used for long duration per day. Unable to control smaller regional sub areas e.g. a single subdivision, without new meters being installed network wide.</p>
Demand Load Management Smart Metering	<p>Customer empowered to make choices. Some controls can be made transparent to customer. Enables individual small areas to be shut off in emergencies. Ability to control smaller regional sub areas e.g. subdivision.</p> <p>Horizon Energy is actively studying this option</p>	<p>Requires all customer meters to be replaced. Requires peak load tariff structure or incentive for customers to manage load. Customer behaviour is not consistent. Consistent load reduction not available on short notice. Requires retailer buy-in as meters are (currently) owned by retailers, or a change in meter ownership policy. Requires communication to the meters. No infrastructure currently installed. Requires extensive IP communications infrastructure, probably wireless.</p>
Demand Load Management Customer Education	<p>No network cost for equipment. Empowers customers to make choices to manage their own demand.</p>	<p>Currently there is no financial incentive for customer to manage peak demand. Must be viewed as short term solution. Continuous re-education required to be effective. Customer behaviour is not consistent. Consistent load reduction not available to on short notice.</p>
Demand Load Management Smart Homes	<p>No network cost for equipment. Customer empowered to make choices. Some controls can be made transparent to customer. Installed with smart meters allows control to smaller regional sub areas e.g. subdivision. Good long term benefits.</p>	<p>Needs to be built into homes when constructed. Requires customer education. Requires peak load tariff structure or financial incentive for customers to commit. Slow uptake. Customer behaviour is not consistent. Consistent load reduction not available on short notice. Limited quantity of energy smart appliance equipment available in the marketplace. Requires internet connectivity for maximum benefit.</p>

Option	Advantages	Disadvantages
Demand Load Management Major Customers	Ability to reduce large loads for pre-defined periods of time or to reduce peak demand. Established commercial arrangements with the network operator. Horizon Energy Major Customers are actively practicing this	Must be planned for in advance. Normally unable to be activated at short notice due to effect on customer's production.
Embedded Small Generation, <2.5kW, User Owned. Solar, Wind	Non network cost. Displaces load from network. Generation at load site reduces losses. No RMA issues for network operator. A small number of solar installations have been installed	Reduces utilisation of network assets. Safety issues with reverse feeds and fault tripping. Affects kWh based pricing methodology. Will have variable utilisation and generation characteristic. Weather dependant. No match to network demand.
Embedded generation, customer owned, or customer owned diesel fuelled pumping stations	Non Network Cost. Especially suitable for peak load support for areas with limited supply capacity. Good redundancy for loss of supply for critical services. Network assets don't need to be sized for the peak loads.	Can improve utilisation of network assets. Safety issues with reverse feeds. Will have variable utilisation and generation characteristics. Cost of ownership high.
Embedded Diesel Powered Generation. Fixed installation Network Owned 300-2000kVA	Economic compared to major sub-transmission asset costs if the load is a short term peak rather than sustained. May be an option for Te Kaha. Auto start and loading can respond to demand load. Minimal RMA impact. Can be partly funded by Avoided Transmission costs if matched to peak demands.	Costly to run. Capital intensive. Short life (in comparison to other network assets). Requires continuous service (Fuel). Medium level maintenance requirements. Assets are stranded.
Portable Diesel Powered Generation. Network Owned. 300-1000kVA	Economic compared to installing permanent major sub-transmission assets if the load is a short term peak rather than sustained. Auto start and loading can respond to demand load. Minimal RMA impact. Portability allows relocation to other sites as required. Good solution for short term support or planned outages. Horizon Energy is investing in this technology	Costly to run. Short life (in comparison to other network assets). Requires continuous service (Fuel). High maintenance. Requires labour to connect and disconnect. Establishment time to set up if required in emergency.

Option	Advantages	Disadvantages
Wind Power, Large Unit >500kVA, Network Owned	Low capital cost per kW. Environmentally friendly.	Limited areas available with suitable wind resources. Difficult RMA process. Difficulty with voltage regulation when located a distance from zone sub and with local loads on same feeder. May require dedicated lines. Requires alternate source of supply on windless days. No match to network demand.
Wind Power, Small Unit up to 200kVA, Network Owned	Low capital cost per kW. Can be located at smaller load centres. Environmentally friendly. Network can support on windless days.	Limited areas available with suitable wind resources. Difficult RMA process. Requires alternate source of supply on windless days. Some voltage regulation issues if not located at loads. No match to network demand.
Geothermal Generation	High capital cost per kW. Environmentally friendly. Constant output. Large units have lowest installed and operating cost per kW.	High RMA impact. Restricted access to proven resource.
Mini Hydro Generator	Can be made environmentally friendly. Good for voltage regulation and network support. Low running costs. Two private units embedded in the network	Can be difficult RMA process. Limited suitable sites with hydro available close to loads or reticulation system.
Utilisation of customer owned emergency generators for network support	Non network cost. Could be used to support peaks or local outages.	Commercial arrangements would need to be established. Need reverse power and sync capability. Limited network control of availability. Not all known generators are ideal locations. Need to manage loading with local switching.

Table 5.8 – Non-Network Development Options

5.3.6. Energy Efficiency and Loss Reduction

The management of voltage and network losses have a number of different effects on load. While these are technically network options they are alternatives to the conventional network constraint solutions of installing larger or more conductors.

The summary and benefits of these solutions are described briefly in Table 5.9 along with areas where these initiatives have been used to good effect.

Loss Correction Initiatives	Advantages	Disadvantages
Voltage regulators	<p>Reduces the need to increase conductor size for low load, long distance distribution. Low capital cost compared to line upgrades.</p> <p>Used for Voltage correction on factory Feeder at Opotiki</p>	<p>Creates issues in meshed networks across tie points with voltage imbalance and phase angle shift Shorter service life than line upgrades. Increases power on resistive loads and increased volt drop immediately preceding the regulator.</p>
Capacitive reactive power correction at 11kV	<p>Economic fix to compensate for fixed reactive line losses and inductive loads if installed without switching. May be more economic than line upgrades. Corrects localised reactive power components.</p> <p>Used on Factory feeder. Planned for Galatea feeders</p>	<p>Large step ranges. Can create over-voltages in low load situations if capacitors are oversized. Expensive if switched. Can affect ripple control transmission? Cannot compensate for line i^2r resistive losses.</p>
Increase Zone or GXP Substation Bus Voltages	<p>Gives a higher delivery voltage and more power. Easy and economical to do. Reduces line current in a constant power application. Can reduce line losses slightly. Normally reduces transformer current.</p> <p>Horizon Energy Sets 11kv Zone Substation Voltage at 11.2kv</p>	<p>Can cause voltage quality issues for loads close to the substation. Increases power and current on constant (resistive) loads. Increase in electrical stress on network if taken too high.</p>
Higher delivery voltage (e.g. stepping from 11kV to 22 or 33kV)	<p>More power for the same conductor size. Longer transport distances. Reduced line losses for the same power. Same easement corridor can be used. Can be built dual circuit with 11kV.</p>	<p>Expensive - requires power transformers, line insulator, and clearances upgrades. Transformers and hardware are more expensive if used for distribution. Issues with meshing to adjoining networks operated at a different voltage.</p>
Parallel Power Transformers	<p>Lightly loaded parallel transformers reduce copper losses by square law. Provides n-1 redundancy. Provides overload resilience.</p> <p>Kope, Station Road, and Galatea are parallel transformer substations</p>	<p>Costly – two sets of switchgear and transformers are required. Large footprint. Increases the number of installed large transformer assets compared to load sharing from adjacent substations.</p>
Parallel operation of sub-transmission or distribution system	<p>Multiple lines can provide better utilisation and provides load balancing of existing assets, improved redundancy, less losses. Can delay load driven expenditure. Provides n-1 redundancy.</p> <p>Currently Practiced at Sub-transmission Level into Te Rahu and Galatea substations</p>	<p>Complex protection scheme required. Costly to implement but cheaper than new infrastructure.</p>

Table 5.9 - Non Network Load Support Options

5.3.7. Projects Planning Timeline

The implementation year of each project is established by the 10 year plan, based on Program Evaluation and Review Technique (PERT) planning methods. Project timing during the planning year is set to:

- Suit contractor labour availability;
- Manage lead time for material delivery; and
- Suit the availability of the network.

Potential labour overloads are identified early and external labour is used to supplement the available labour pool where required. The availability of specialist skills may have an impact on project timing as well but the main influence is engineering resources and major equipment delivery time. Horizon Energy uses standard times to plan for equipment delivery in Table 5.10:

Equipment Type	Delivery Lead Time
Power transformer 33/11kV	12-15 months
33kV indoor switchboard	12 months
11kV indoor switchboard	12 months
Building consents	6 months
Building construction	5 months
ESA approval	3 months
Railway crossing approval	6 months
Pole top circuit breakers	3 months
Distribution ground mount switchgear	3 months
Distribution transformers	2 months
33kV and 11kV cable	4 months
Overhead conductor	2 months
Protection relays	3 months

Table 5.10 – Planning Intervals

Where practicable, new customer connection projects are scheduled to meet the requirements of the customer.

5.3.8. Project Controls

- Budget control is managed by the General Manager Network and implementation is managed by the Service Delivery Manager. Expenditure is set by authorised approval levels;
- Project budgets are estimated by Planning and each project is re-priced prior to project expenditure approval (Capex approval) and issue for construction;
- Pricing model is a unit rate based model with the units agreed to by both Horizon Energy and its contractors;
- Major projects are broken down into sub projects to provide better control. Variations to the projects are approved prior to work commencing and there is a variation tracking process;

- Every project has a Horizon Energy Project Manager and a contractor's representative appointed to manage the project;
- All work teams must complete daily hazard assessments and supply these with the completed project documentation;
- There are staff competency controls over who can work on the network;
- All network switching is controlled from the Horizon Energy Control Room; and
- Audits on quality and safety are carried out by the Engineering and Control Room staff.

5.3.9. Construction Planning

The contractor provides construction resources and construction planning. Milestone dates are agreed between Horizon Energy and the contractor tasked with achieving these targets.

5.4. Demand Forecasting

Historical demand and growth rates are a good indicator of the future capacity needs. Other influences such as population growth, changing use patterns, seasonal variations, step change loads, changing demographics and consumer displacement must also be considered in the prediction of load growth.

Horizon Energy predominantly uses historical load growth and moderates this with known planned major step changes or other knowledge of influencing factors.

5.4.1. Load Forecasting Methodology

Load growth is determined in the first instance by analysing historical load performance for each zone substation and individual feeder. This is then extrapolated using the average historical growth. Any known planned developments, planned network re-configurations or step changes in load are included in future load predictions and modelled accordingly.

Individual feeder sections are checked for overloading across all load scenarios including reinforcement. Network constraints are identified and are loaded into the 10 year development plan for assessment as future projects.

All load data is collected from the SCADA Historian archive. Load studies are taken for each annual period 1 April to 31 March. The various analysis methods used are described in Table 5.11.

Analysis	Method	Limitations
Load Growth	The average load for each 30 minute period for one year using iHistorian data is graphed. Load duration curves are compared against previous years to compare growth change patterns. The fiscal year, 1 April to 31 March, is used.	Assesses the average growth. Does not give a result for short term peak loads within the 30 minute period. Due to different metering methods at each substation different load measurement methods are employed. MW indication is not as useful as MVA as it does not take into account reactive power, which gives a better indication of asset utilisation. Horizon Energy only has VAR measurement at two sites, Station Road and Plains; these are not currently recorded on iHistorian.
100 Peaks Load	The one hundred highest 30 minute load periods in any one year are averaged to provide a value. This method reduces the effect of transients and short term reinforcement peaks on the load and gives a good value to compare against successive years.	Includes reinforcement loads. Tends to slightly understate the full peak load applied to a substation / feeder.
Load Duration	Load duration determines the load (or utilisation) against the percentage of the total time for the period being studied. Measurement data used is the average load for every 30 minutes over the period being assessed. For most zone substations a one year period is used. If a site is of concern then a shorter period over the peak load season is further analysed. Load duration over successive years is useful for verifying load growth and graphically displays where the growth is occurring as a percentage of asset utilisation.	Does not take into account short term peaks within the 30 minute measurement period.
Maximum Load	Maximum load is the highest 30 minute peak for the measurement period (normally one year). This value is used in the load based asset replacement decision matrix.	Peak load data is not used for growth predictions as the peaks can be controlled using load control, but is monitored to ensure the network is capable of supplying the short term peak loads. Often the peak is a transient so comparison of peak growth per year can lead to erroneous growth predictions.
Load measurement- 3 rd quartile, average, median, 1 st quartile	These values provide additional data to assess the utilisation of the feeders and substations. Data is collected as described above.	Of limited use in network analysis except for highlighting any abnormal load growth patterns. Average growth is used to verify load growth in conjunction with the average 100 peaks value.

Analysis	Method	Limitations
Technical Losses	System technical losses are calculated from three different sources. 33kV and 11kV load flow modelling. Zone sub power transformer loss modelling. Distribution transformer loss calculated against median load. Low-voltage lines and cable losses (estimated). Total losses are the sum of the individual losses.	Load flow limitations are described above. Distribution transformer losses are calculated from median load and actual transformer manufacturer's data. Low voltage losses are estimated as 1% of the total losses.
Demand Management - Hot Water Heating	Domestic hot water loads estimated from load drop in response to ripple control signals	Not used in demand peak forecasting as the measurement for hot water heating loads have a high level of uncertainty, as well as uncertainty as to whether the load control is actually active for peak periods.
Demand Management - Other	Embedded or distributed generation, line losses management, and alternative energy sources.	The effects of other methods of energy displacement are not identified separately in the forecasting. The peak load measurement at each GXP already includes the load displacement measures applied within the network. Horizon has not received any formal requests for distributed generation connection during the last period. The effects of energy displacement, solar, geothermal, etc. are unable to be readily quantified but are not believed to be significant at present.

Table 5.11 - Methods of Load Growth Analysis

5.4.2. GXP and Zone Substation Load Forecasts

Future load predictions for GXP's and zone substations are determined from:

- The maximum 30 minute demand for the previous year; and
- The average growth rate measured over the last four years.

Where the substation data is inconsistent, as is the case for East Bank Road substation due to the influence of generation, an estimate of growth is made based on feeder data or general growth in the region. In any case background information is sourced from District and Regional Council plans, Statistics NZ and less formally through staff contacts and membership of local business organisations.

A change in the methodology has been applied for load control since 2008, when the emphasis changed to the management of demand coincident with the Lower North Island (LNI) demand rather than the management of individual GXP demand. Since then the non-coincident load at GXP's is seeing higher levels. This is noticeable in peaks incurred at Te Kaha and at Ohope substations where the peaks incurred were driven by load control restoration. In Figure 5.2, for Waiotahi, during 2006-2007 load control reduced the peaks to provide a very flat load profile, whereas in 2008 and 2009 there is no obvious load control flattening of peak demand.

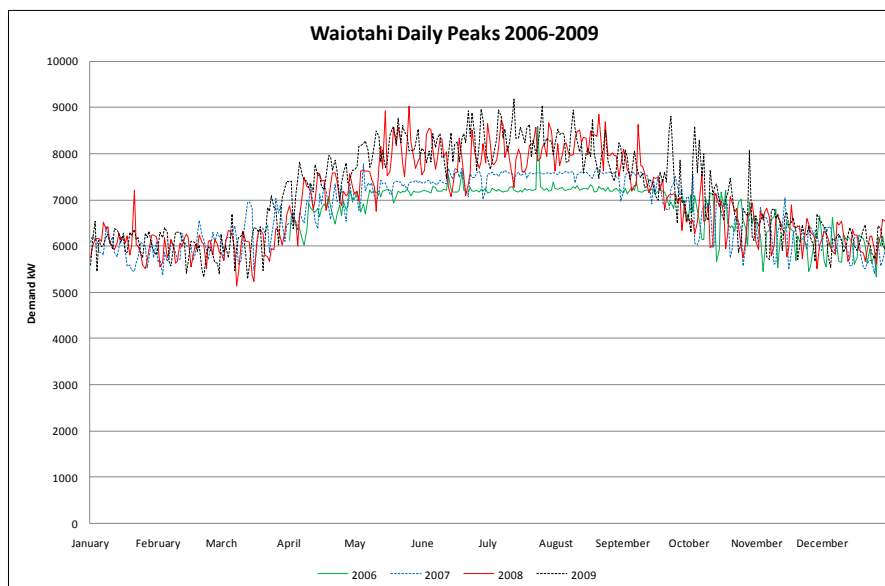


Figure 5.2 - Peak Loads, Waiotahi

Analysis of this load pattern shows that using the annual peak values to measure growth gives a higher growth rate than is actually present. The network growth rate is based on the average of the top 100 peaks, which is believed to more accurately represent the actual system growth and predictions shown in Table 5.12 and Figure 5.2.

Load Predictions			Historic Demand					
Zone Sub	N or N-1 Capacity (MVA)	Average Growth	2007	2008	2009	2010	2011	2012
East Bank	15	1.4%	7.4	6.4	5.4	7.7	6.4	8.3
Galatea	7.5	0.4%			4.3	4.5	4.8	4.6
Kaingaroa	5.3	0.0%	2.6	2.7	2.4	2.6	2.4	2.6
Kawerau	25	1.6%	28.0	25.7	18.9	18.3	19.0	17.2
Kopeopeo	16	2.1%	14.0	13.9	14.3	14.9	15.5	14.5
Ohope	5	1.0%	4.3	4.1	4.3	4.6	4.6	4.5
Plains	10	1.5%	8.3	5.7	6.0	6.8	6.2	6.6
Station Road	10	0.3%	8.4	8.4	8.8	9.2	8.4	10.1
Te Kaha	5	0.0%	1.2	1.5	1.6	1.8	2.1	1.5
Waiotahi	12	1.5%	8.8	8.0	9.2	9.4	9.4	9.3
Whakatane Mill	na	0.0%	22.4	22.4	22.4	24.5	24.5	24.5
CBD (2018)		2.7%						

Predicted Future Demand

Zone Sub	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Notes
East Bank	8.4	8.5	8.6	8.7	8.8	9.0	9.1	9.2	9.3	9.4	9.5	9.7	1
Galatea	4.6	4.6	4.6	4.7	4.7	4.7	4.7	4.7	4.8	4.8	4.8	4.8	
Kaingaroa	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2
Kawerau	17.5	17.8	18.1	18.3	18.6	18.9	19.2	19.5	19.7	20.0	20.3	20.6	3
Kopeopeo	14.8	15.1	15.4	15.7	16.0	16.3	8.2	8.5	8.8	9.1	9.4	9.4	7,9
Ohope	4.5	4.6	4.6	4.7	4.7	4.8	4.8	4.8	4.9	4.9	5.0	5.0	
Plains	6.7	6.8	6.9	7.0	7.1	7.2	7.3	7.4	7.5	7.6	7.7	7.8	
Station Road	10.1	10.2	10.2	10.2	10.3	10.3	10.3	10.3	10.4	10.4	10.4	10.5	6,9

Zone Sub	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Notes
Te Kaha	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	
Waiotahi	9.4	9.6	9.7	9.8	10.0	10.1	10.3	10.4	10.5	10.7	10.8	11.0	8
Whakatane Mill	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	4
CBD (2018)						6.0	6.2	6.3	6.5	0.0	0.0	0.0	5

Table 5.12 - Zone Substation Load Growth Prediction

NOTES

- 1 Growth is based on average feeder growth.
- 2 Negative growth predicted for Kaingaroa.
- 3 Growth based on feeders average growth past 4 years. Expectation is growth will reduce as population reduces.
- 4 WML load demand assumed to be static.
- 5 CBD will reduce demand load at Kope and Station Road.
- 6 Station Road shows load exceeding N-I capability.
- 7 Kope shows load exceeding N-I capability until load transfer to CBD.
- 8 No allowance made for possible future developments at Waiotahi.
- 9 Red Numbers indicate the sub exceeds its n-I capability.

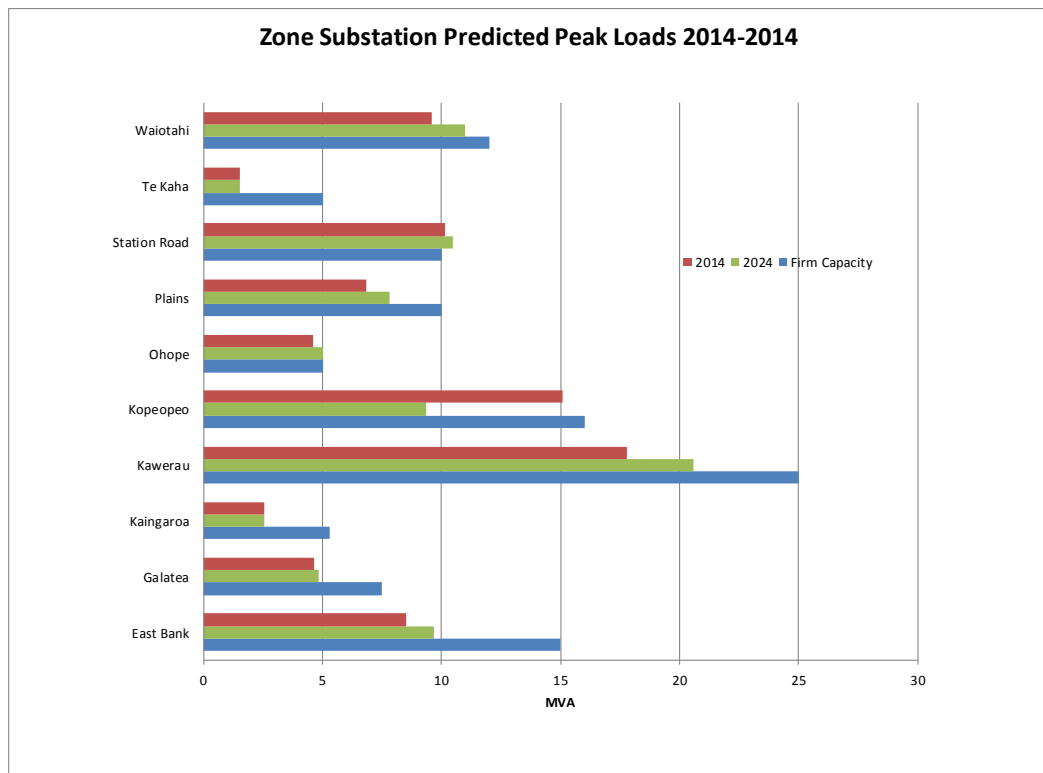


Figure 5.3 – Substation Load Predictions

Substation Capacity

The load prediction against the firm capacity of the sites is graphically illustrated in Figure 5.3. Narrative on the load characteristic of each substation is in the individual zone substation sections that follow.

The substation firm capacity shown is the capacity as at 2013 and does not take into account planned upgrades. Where a substation is a single transformer substation the capacity is the full loaded rating of the transformer, otherwise the rating is the n-1 capability of the substation.

5.4.3. Effect of Non-Network Demand Management Initiatives on Load Forecasts

Methods of demand management are described in some detail in section 5.3.6. Table 5.13a and Table 5.13b, describes how the effect of these various initiatives impacts or is likely to impact on future load predictions. The impact or inclusion in load predictions is summarised for each initiative.

Option	Possible impact on load predictions	Effect on Network
Demand Load Management Ripple Control	Used for short term load peak load management. The effect is embedded in the peak load measurements and is therefore implicitly included in the projections.	The estimated instantaneous benefit of implementing ripple control during peak periods is less than 10MW across the whole network.
Demand Load Management Smart metering	Not allowed for as there are no units currently installed. Expected to have similar benefits as ripple control in the short term.	No impact.
Demand Load Management Customer Education	Not allowed for.	No impact.
Demand Load Management Smart Homes	Not allowed for as uptake and quantum unknown and new home growth is minimal across the region.	No known impact.
Demand Load Management Major Customers	Not allowed for but is an option that can be readily implemented. Currently Whakatane Mill Limited buys into the reserves market and do provide some peak load shedding. This is implicitly included in the peak load measurements that flow into the predicted demand forecasts.	Impact not quantified.
Embedded Small Generation, <2.5kW, User Owned. Solar, Wind	Reduced demand during daylight or wind periods.	Not allowed for separately as the effect of any of these in service is included in the peak load flow data that is used for load predictions.
Embedded generation, customer owned, or customer owned diesel pumping stations	Load reduction dependent on owner utilisation policy.	Not allowed for separately as the effect of any of these in service is included in peak load flow data that is used for load predictions.
Embedded Diesel Powered Generation. Non Portable. Network Owned. 300-2000kVA	Not allowed for as none currently on network but under consideration.	No impact.
Portable Diesel Powered Generation. Network Owned. 300-1000kVA	Not used for load reduction except during reinforcement. Not currently allowed for in load flow predictions.	Impact not quantified.
Wind Power, Large Unit >500kVA, Network Owned	None on network. No known installations are planned so therefore are not included in load predictions.	No impact.
Wind Power, Small Unit up to 200kVA, Network Owned	No installations on the network and none planned.	No impact.
Geothermal Generation	Effect is included in the load flow measurements. Not included in load flow predictions but the effect of loss of generation is included in feeder load capacity calculations.	Approximately 5MVA on Kawerau network.

Option	Possible impact on load predictions	Effect on Network
Mini Hydro Generator	Not allowed for separately as the effect of these being used is included in peak load flow data.	Approximately 200kW.
Utilisation of customer owned emergency generators for network support	Not allowed for in load predictions separately as currently no commercial arrangements have been made to utilise any of these for load management.	Impact unknown.

Table 5.13a – Impacts on Future Load Predictions

Loss Correction Initiatives	Impact on load predictions
Voltage regulators	Not allowed for separately. Voltage regulators tend to increase demand loads on resistive networks. The effect of these is included in the measured load flow calculations that forms the basis for forecast predictions.
Capacitive reactive power correction-network owned	Although these may be beneficial in line loss and consumer reactive power reduction, currently their benefits are not allowed for in forecast predictions.
Lower Zone Substation 11kV Bus Voltage	Beneficial in resistive networks to reduce load. Not allowed for in load forecast predictions but is an option during emergency conditions.
Increase Zone Substation 11kV Bus Voltage	Currently most zone substations are running a nominal 11.2kV bus. This is good for constant power applications (motors etc.) for reducing current flow and line losses. Not regarded as a viable way to manage load demand.

Table 5.13b – Impacts on Future Load Predictions

5.4.4. Grid Emergency Plans

In order to prevent a total system collapse under major grid disturbance conditions, under the terms of the Electricity Industry Participation Code Horizon Energy operates an Automatic Under-Frequency Load Shedding System (AUFLS). Set up in two groups, after a short time delay group one is designed to shed 16% of the load when the frequency falls lower than 47.8 Hz and group two a further 16% when the frequency falls below 47.5 Hz. This system is under review by Transpower.

In addition to the AUFLS system, Horizon Energy operates a Security of Supply Outage Plan (SOSOP), which includes a schedule of rolling feeder outages. Rolling outages are a last resort measure for managing severe energy shortages. Rolling outages will, wherever possible, disconnect feeders following the priority published on the Horizon Energy website. The number of feeders and the outage period for every week will depend on the level of saving required to meet target.

The MVA shedable load quoted is the averaged load across all seasons using four hourly actual measured average data.

Note that the Kawerau and Te Kaha GXP are Transpower GXP and Horizon Energy has no direct control of the feeders exiting of these grid exit points.

5.4.5. Edgumbe GXP Demand

Edgumbe load growth has averaged 2.9% over the last 10 years and 1.2% for the last five. Weighted individual zone substation growth rates indicate an organic growth rate of 1.6% for the complete Horizon Energy network. The dominant influence on the Edgumbe GXP load is Whakatane Mill Limited, a directly connected industrial customer. This consumer draws around 50% of the Edgumbe GXP loads.

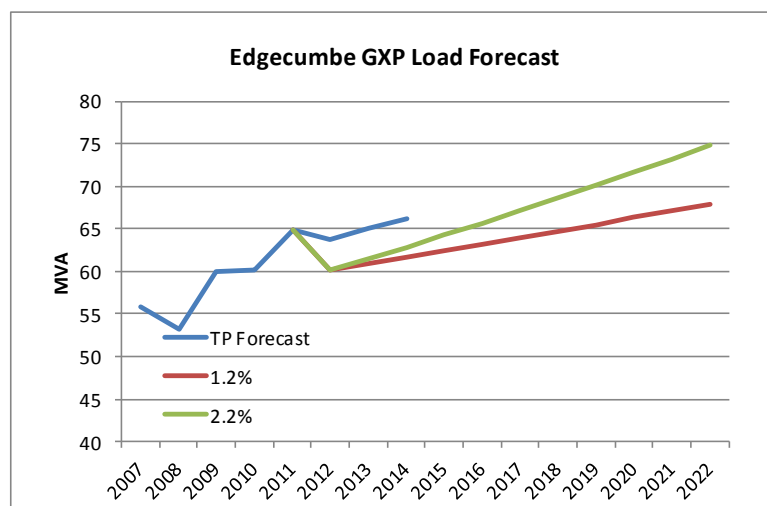


Figure 5.4 – Edgumbe GXP Load Growth Predictions

Two forward growth rates are shown in Figure 5.4. The low rate is the organic rate based on zone substation predictions. The high rate is the influence of Whakatane Mill Limited if they continue their growth rate at a 2% level. Whakatane Mill Limited has not yet completed their project forecasts so the full influence of their planned work is not known.

The Galatea region loads supplied by Edgumbe during 2009-10 have been removed from the peak loads and predicted loads. Galatea is normally supplied from the Aniwhenua power station.

5.4.6. Feeder Load Forecasts

Forward projections of feeder loads are shown in Table 5.14. The effect of planned load balancing and load re-allocation between feeders is not shown on this Table. Section 5.12, Kopeopeo Substation, further describes the plan to balance load between Kope, Station Road and the proposed Gateway substations.

Feeder 10 Year load predictions (MVA)to 2024					
Substation	Feeder	Growth rate	2014	2024	Notes
EAST BANK	ANCHOR 1	0.0%	3.9	3.9	1
	THORNTON	1.2%	2.2	2.5	2
	WEST BANK	1.4%	1.9	2.2	
GALATEA	GALATEA	1.4%	1.5	1.8	
	JOLLY ROAD	6.0%	1.9	3.5	
	MINGINUI	3.5%	0.7	1.0	
	MURUPARA	1.0%	1.6	1.7	
KAINGAROA	DUNN ROAD	0.0%	1.2	1.2	
KAWERAU	PAPER	0.0%	7.8	7.8	
	PULP	0.0%	10.5	10.5	
	KAWERAU	1.6%	4.6	5.4	
	MT EDGE CUMBE	0.0%	0.0	0.0	
	ONEPU	0.0%	4.6	4.6	3
	PLATEAU	1.6%	2.2	2.6	
KOPE	KING STREET	2.1%	3.1	3.8	
	REX MORPETH	2.1%	4.0	4.9	
	STRAND NORTH	2.1%	3.1	3.8	
	STRAND SOUTH	2.1%	2.9	3.6	
	VICTORIA AVENUE	2.1%	3.0	3.7	
OHOPE	HARBOUR	1.1%	2.4	2.7	
	POHUTUKAWA	0.8%	1.4	1.5	
PLAINS	AWAITI	3.1%	2.2	3.0	
	AWAKERI	0.8%	1.2	1.3	2
	ANCHOR 2	0.0%	0.0	0.0	
	MANAWAHE	1.4%	1.3	1.5	
	TE TEKŌ	4.3%	1.9	2.9	2
	WEST BANK	1.4%	1.9	2.2	
STATION ROAD	ANGLE ROAD	0.0%	1.4	1.4	2
	CITY SOUTH	0.0%	1.4	1.4	
	MOKORUA	0.0%	2.5	2.5	
	PIRIPAI	0.0%	2.2	2.2	
	RUATOKI	1.2%	1.6	1.8	
	TANEATUA	0.0%	1.0	1.0	
TE KAHA	TE KAHA	0.0%	0.7	0.7	
	WAIHAU BAY	0.0%	1.1	1.1	

Feeder 10 Year load predictions (MVA) to 2024					
Substation	Feeder	Growth rate	2014	2024	Notes
WAIOTAHİ	FACTORY	5.6%	3.0	5.2	3
	HOSPITAL	0.0%	2.7	2.7	3
	OPOTIKI	0.0%	2.5	2.5	3
	WAIMANA	3.9%	2.0	3.0	

Table 5.14 – Feeder Growth Predictions

Notes

- 1 Industrial load with no organic growth
- 2 Peak loads and peak growth driven by reinforcement
- 3 Growth used is the zone substation average over three years
- 4 Red font indicates feeder overloaded by 2023

The feeders supplying Fonterra have been excluded from this table as the loads are driven by the generation on the factory site. Various sub sections of feeders have been identified for load driven upgrades and these are detailed in the zone substation sections later in this document.

Commentary and forward work plans on the individual feeder utilisation, including maintenance, more detailed load analysis and support and development plans are covered under the feeder sections for each zone substation later in this document.

5.4.7. Kope, Station Road, and Gateway Aggregate Loads

Proposed feeder reallocations – Kope, Station Road and CBD Substations

With the planned integration of function between Kope, Station Road, and the proposed CBD substation, loads will be re-distributed to balance the loads at each of the substations. Figures 5.5 and 5.6 below show the feeder load re-allocations at Kope and Station Road substations.

When the CBD substation comes on line, the additional capacity of this substation will be integrated into this load sharing matrix as shown for 2019-20 years reducing demand on Kope substation.

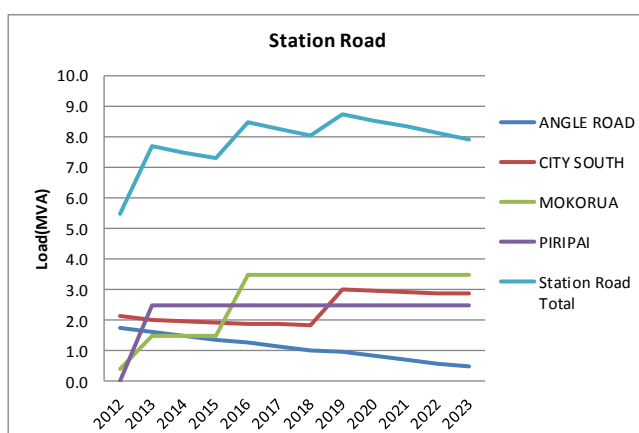


Figure 5.5 – Station Road Load Reallocations

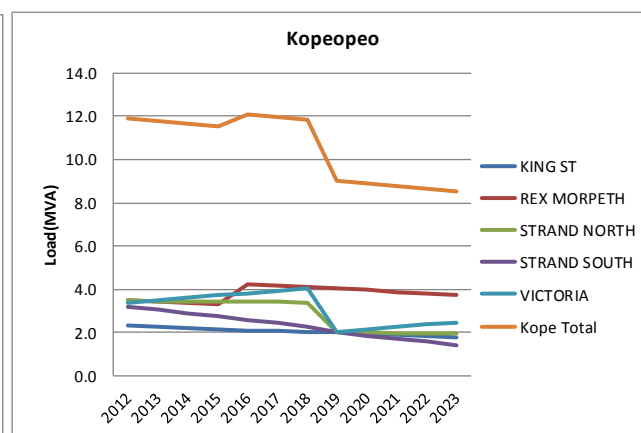


Figure 5.6 – Kope Load Reallocations

These load allocations will be reviewed as feeders between substations are upgraded to improve their load carrying capacity, and load growth patterns and supply risks are further studied.

Year	Load (MVA)	From	To	Purpose
2013	1.1	Rex Morpeth	Mokorua	Load balancing Kope-Station Road
2015	1	King Street	City South	Load balancing Kope-Station Road
2018 onwards	8.2	Station Road and Kope	CBD	CBD commissioning

Table 5.15 – Possible Load Movements, Whakatane Area

5.4.8. Customer Growth

There has been a rapidly decreasing rate of new connections over the last five years.

Long term predictions for all regional councils supplied by Horizon Energy are for a likely population drop beyond the 10 year planning period. The Eastern Bay of Plenty region has a population that is older than the national average and average income levels lower than the national average. This is likely to mean less housing replacement growth and load displacement as rural regions move into urban areas. This trend is starting to be seen as the connection growth rates are higher in urban supplied substations than rural. The exception is Te Kaha which is driven by holiday batch or lifestyle choices.

Net connections per year are shown in Figure 5.7.

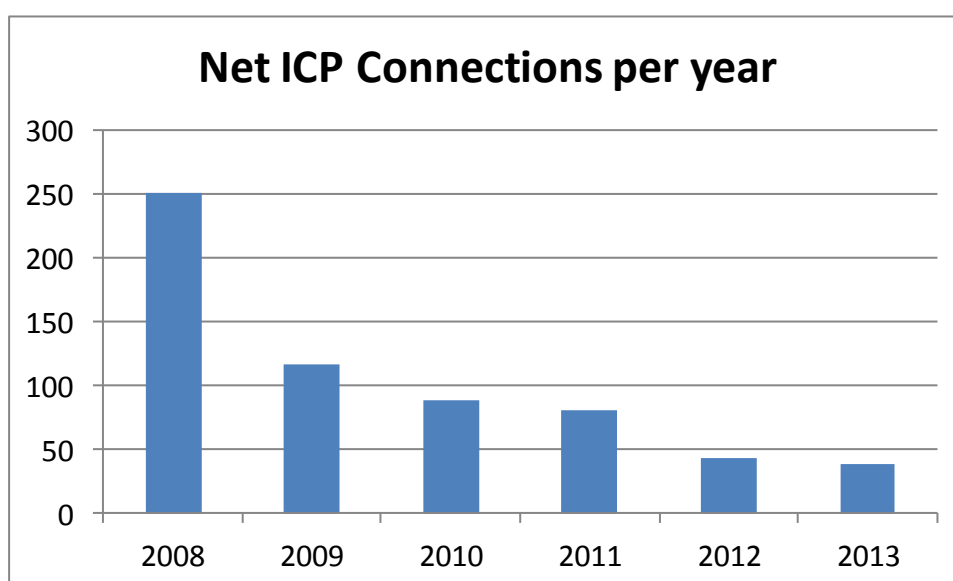


Figure 5.7 – Net Connections per year

The reducing rate of new connections is in line with area population statistics and long term population growth predictions released by Statistics NZ. On average, the annual rate of new connections has been 0.3 % per annum over the last five years and is declining.

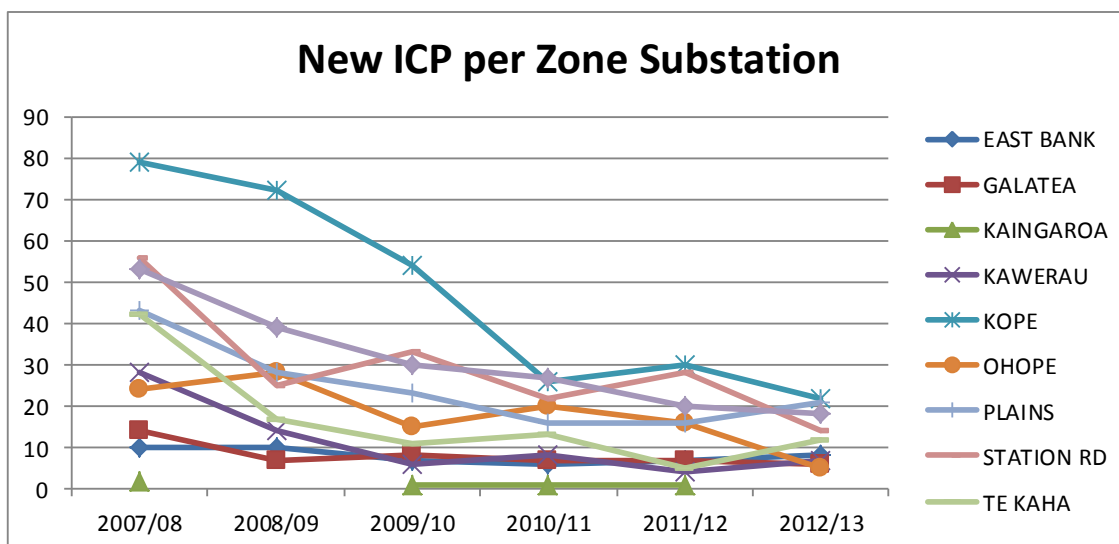


Table 5.16 – New ICP Connections per Zone Substation

Table 5.16 summarises the annual average ICP growth rate per zone substation for the last five years. The influence of these on the load at each substation is discussed further in each zone substation section.

5.4.9. Population Growth – Whakatane and Ohope Urban Areas

The Whakatane District Council Urban Growth Strategy document identifies areas of likely population growth within the Whakatane and Ohope regions. These areas are shown in Figure 5.8.

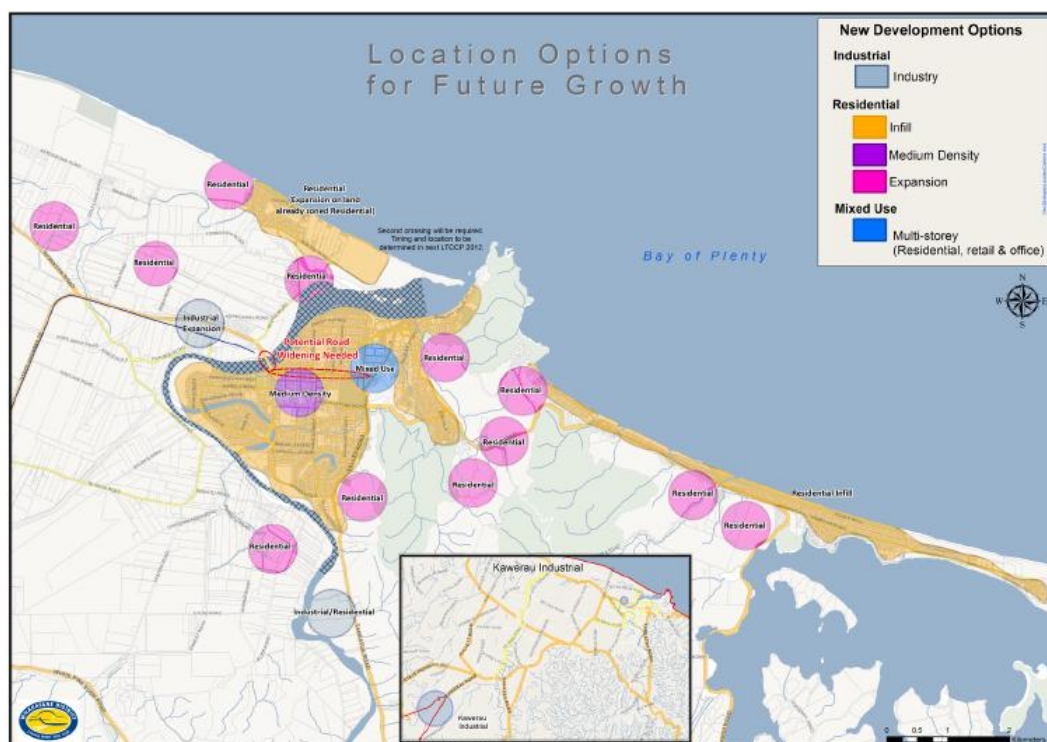


Figure 5.8 – Whakatane and Ohope Urban Areas

By 2050, Whakatane District Council (WDC) are projecting dwelling growth at an additional 2354 units in Whakatane and 1486 in Ohope.

At the existing peak demand per dwelling of 2.5kW, the additional load imposed on the network would be in the region of 10 MVA. This figure does not include the commercial growth that would arise to support the increased population but is well within the load capacity of the existing and planned zone substations to supply the Whakatane region, but the Ohope loads need to be considered more carefully. A potential increase of 1486 dwelling units, especially on the Harbour feeder, would put an additional load of 3.7 MVA onto Ohope substation, which is well beyond the capability of providing adequate reinforcement at 11kV.

A second feeder has been planned to split the Ohope Harbour feeder. This was started in 2012.

The average growth rate predicted by WDC is slightly below the Whakatane region demand load growth forecast by Horizon Energy.

5.4.10. *Future Loads-Electric Vehicles, Heat Pumps and Distributed Generation*



There is a lot of literature, mostly centred on Europe, discussing the likely effect of the growth of electric vehicles and small consumer distributed generation, mainly photovoltaic, on distribution network utilisation and stability. A number of the studies are academic or small base case studies, without any large volume installation experiences to call upon, but they all agree on the fact that electric vehicle uptake will increase with time, as batteries become more reliable and fossil fuels become more expensive, and that there will be requirements for distributed high capacity fast re-charging stations within locations where vehicles are congregated; parking buildings, supermarkets, places of assembly, as well as in the domestic sector.

Charging systems fall into two categories, fast charge for short term charges, mostly in city centres, and slower, demand managed charges for longer stay vehicles. A number of discussions consider the integration of vehicle smart charging with domestic smart homes to help balance demand, plus various methods of metering and charging for energy. One paper discussed using the energy stored in the vehicles batteries as a supply source for peak lopping.

Many studies consider that the development of electric vehicle infrastructure will drive the uptake of vehicles, rather than the other way around, and that the uptake could well start within the 10 year period; initially in larger urban areas as infrastructure gets developed. There is very little discussion on how this infrastructure will be funded when required. Currently there are no legislative guidelines in New Zealand around any of these issues.

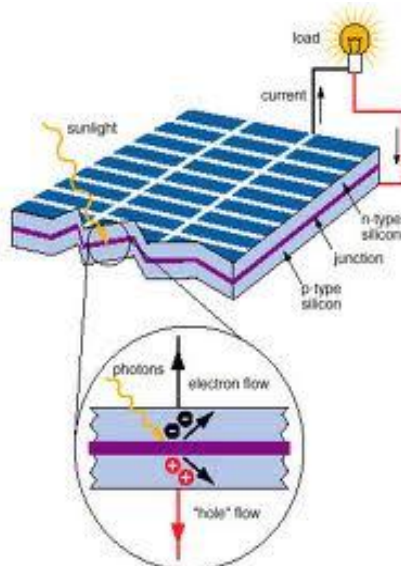
New Zealand is also starting to see an increase in trial systems using small photovoltaic domestic installations. Studies around these tend to focus on the effect of network low voltage instability issues rather than demand reduction, with concerns with reinjection into the low voltage network during outages, and how to manage fault conditions, since photovoltaic systems tend to be constant current devices and will therefore not trip conventional overcurrent elements. At present the uptake of domestic photovoltaic systems is low due to high capital costs, but as solar panel manufacturers increase manufacturing capacities and costs reduced, the uptake is expected to increase.



However, heat pump uptake in New Zealand has been occurring for some time. The BRANZ report [1] on heat pump growth predicted a 7.1 times increase in summer heat pump load and 2.5 times increase in winter heat pump load for the Bay of Plenty region by 2020. Initial Horizon Energy network studies indicate that across the network the summer load will still remain at levels below the winter loads. A study of load flows during summer 2010 determined that load increases of around 2 MVA through Te Rahu substation can be expected once the ambient temperature exceeds 27-28 deg. C.

Currently, Horizon Energy has no reliable, measurable way of determining heat pump uptake within the network.

None of these considerations are currently included separately in Horizon Energy future load predictions within the 10 year planning window, and cannot reliably be considered until there is more certainty around the uptake volumes and time frames for this to occur. However, utilisation during peak times is included in peak demand measurements that form the basis for predicting future growth.



[1] E528 Regional Heat Pump Energy Loads, (Page, Ian, 2009).

5.5. Grid Exit Points

5.5.1. Supply Points

Horizon Energy is supplied by four Transpower owned Grid Exit Supply Points (GXP). A fifth supply point is the Nova Energy owned Aniwhenua power station.

A Notional Embedding Agreement exists for the Matahina and Aniwhenua generating stations that makes them part of the Edgecumbe GXP for transmission pricing. That agreement expires at the end of March 2014. A prudent discount agreement is being negotiated. Aniwhenua has a limited 33kV direct electrical connection onto the Horizon Network.

Edgecumbe GXP supplies the network at 33kV; the other three Transpower owned grid exit points, Kawerau, Waiotahi and Te Kaha supply the network at 11kV.

The five bulk supply points are shown in Table 5.17 below:

Site	Capability	n-1	Constraint	Connection
Transpower Kawerau	110/11kV, two transformers T1, 20/26/27 MVA T2, 20/25/25 MVA	Yes	Transpower owns the 11kV distribution switchgear that Horizon Energy directly connects to.	11kV
Transpower Te Kaha	50kV/11kV, 4 x 1 phase transformers 2.5/2.5/2.5 MVA Upgrade to 7.5 MVA in 2013	No (a)	Te Kaha supplied from a single 50 kV circuit from Waiotahi GXP. Transpower owns the 11kV distribution switchgear.	11kV
Transpower Waiotahi	110/11kV, 2 transformers T1, 10/12/13 MVA T2, 10/12/12 MVA T5, 11/50kV transformer 2.7/2.7/2.7 MVA	Yes (a)	Waiotahi is supplied from a single 110kV circuit from Edgecumbe GXP.	11kV
Transpower Edgecumbe	220/33kV transformers T7, 50/66/67 MVA T8, 50/60/60 MVA	Yes	50MVA rating exceeded for less than 1% of the time per year. 33kV Switchgear is programmed for replacement by Transpower	33kV
Nova Energy Aniwhenua	33kV, two transformers T1, 8/14 MVA T2, 8/14 MVA	Yes (a)	Aniwhenua has two transformers but only one outgoing 33kV feeder. One unit has been out of service for most of 2012-2013.	33kV

Table 5.17 – GXP Supply Points

Notes:

Transpower transformer ratings **/**/** are for continuous/summer/winter respectively as published by Transpower.

Note (a) Duplicate distribution elements that are constrained by a single restriction as described in the comments.

5.5.2. Edgecumbe GXP

Edgecumbe has two 220/33kV fixed tap transformers supplying the Transpower owned 33kV bus system which supplies Horizon Energy's 33kV sub-transmission circuits. These transformer ratings are detailed below:

Transformer	Voltage	Continuous rating	Summer 24 hour overload	Winter 24 hour overload
T7	220/33kV	50 MVA	66.5 MVA	66.8 MVA
T8	220/33kV	50 MVA	66.8 MVA	66.8 MVA

Transpower advise that the forecast Edgecumbe load will exceed the transformers' n-1 capacity from 2013.

Edgecumbe 33kV bus

The 33kV supply from the Edgecumbe Transpower substation is taken from a double bus outdoor structure.



Figure 5.9 – Transpower's Edgecumbe 33kV Switchyard

The 33kV bus was originally designed to allow sections to be removed for maintenance with the affected circuits fed from the top bus. Modern work practices no longer allow the minimum approach distances that were allowable in the past; resulting in a need to remove larger sections of the bus from service at any time maintenance is required. Operationally this is difficult to undertake while still maintaining supply to all customers.

Transpower have indicated they will convert the Edgecumbe 33kV outdoor switchgear to indoor within the next five years (Transpower 2012 AMP).

The 11kV system supplied from the Edgecumbe GXP, Plains, East Bank, Station Road, and Kopeopeo substations, is set up as a Dyn3 vector group. There is a mixture of transformers in the system configured as Dyn11 or Dyn3. Dyn11 transformers have phases rolled to provide a Dyn3 vector group.

5.5.3. Kawerau GXP

Kawerau has two Transpower owned on-line tap 110/11kV transformers and 11kV switchgear that Transpower have scheduled to replace in 2018-20 (Transpower 2012 AMP).

Transformer	Voltage	Continuous rating	Summer 24 hour overload	Winter 24 hour overload
T1	110/11kV	20 MVA	25 MVA	27 MVA
T2	110/11kV	20 MVA	26 MVA	27 MVA

Horizon Energy feeders are directly connected to the Transpower 11kV assets. The impact of larger replacement transformers will need to consider the effect on the already high Kawerau region fault levels.

Due to the single stage of transformation from 110kV to 11kV the vector group of the 11kV network supplied from Kawerau is -120 degrees out of phase with the Edgecumbe network.

5.5.4. Waiotahi GXP

Waiotahi has two Transpower owned on-line tap 110/11kV transformers. These will exceed their n-1 capability by 2013 and Transpower have scheduled to replace these between 2019-21 (Transpower 2012 AMP).

Transformer	Voltage	Continuous rating	Summer 24 hour overload	Winter 24 hour overload
T1	110/11kV	10 MVA	12 MVA	13 MVA
T2	110/11kV	10 MVA	12 MVA	12 MVA
T5	11/50kV	3 MVA	3 MVA	3 MVA

Transpower have stated that future investment at Waiotahi will be customer driven.

The vector group of the 11kV network supplied from Waiotahi is -120 degrees out of phase with the Edgecumbe network connections to Ohope and Station Road sub stations.

5.5.5. Te Kaha GXP

The Transpower owned single phase transformer bank at Te Kaha, 50kV and 11kV switchgear is scheduled for replacement 2013.

Transformer	Voltage	Continuous rating	Summer 24 hour overload	Winter 24 hour overload
T1	50/11kV	2.25 MVA	2.25 MVA	2.25 MVA

Horizon Energy has entered into discussions with Transpower regarding the future ownership model for the Waiotahi and Te Kaha assets.

5.5.6. Customer Connections

The number of customers per GXP supplied from these grid exit points as at 31 March 2012 are detailed in Table 5.18.

GXP	2010-11	2011-12	2012-13
Aniwhenua	1722	1725	1728
GXP Edgecumbe	14498	14529	14545
GXP Kawerau	3006	3006	3010
GXP Te Kaha	1031	1036	1039
GXP Waiotahi	4315	4311	4302
Grand Total	24572	24607	24624

Table 5.18 – Customer per GXP

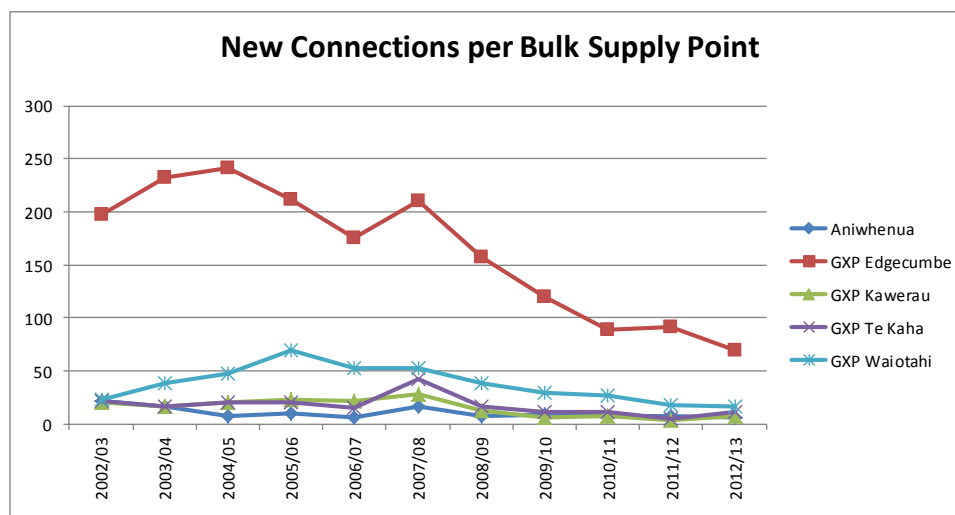


Figure 5.10 – Customer Connections per Bulk Supply point

New connections per bulk supply point per year over the last 10 years are shown in Figure 5.10. The connection rate is reducing in line with published population predictions.

Figure 5.11 shows the continuing negative trend in new connections per year since 1997. This downward trend is unlikely to show a significant reversal within the planning period and prediction is supported by statistical data from Statistics NZ.

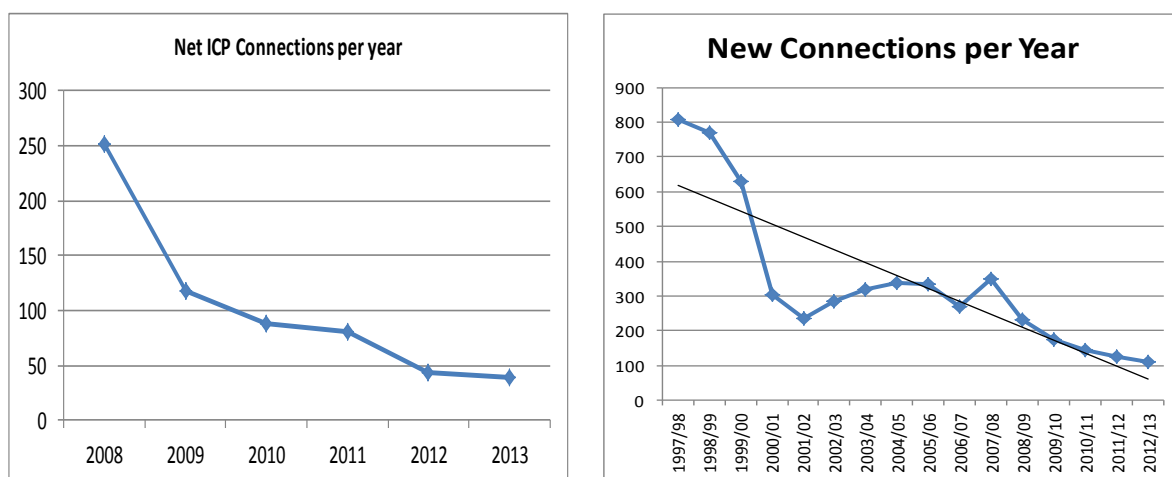


Figure 5.11 – Customer Connections

The charts above show the net (new connections less disconnections) connections across the complete network per year and the gross number of new connections per annum since 1998.

5.5.7. GXP Load Growth

Load growth and load predictions for the GXP sites are included in Section 5.4.

5.6. Sub Transmission

5.6.1. 33kV Sub-transmission

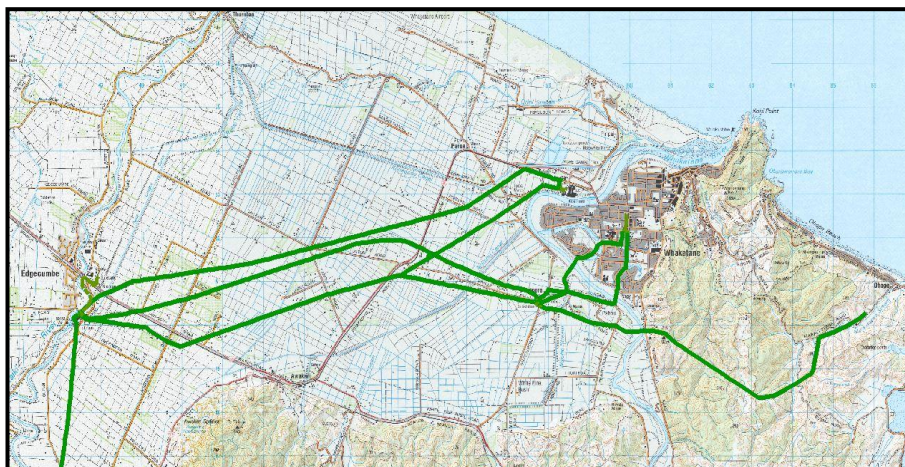
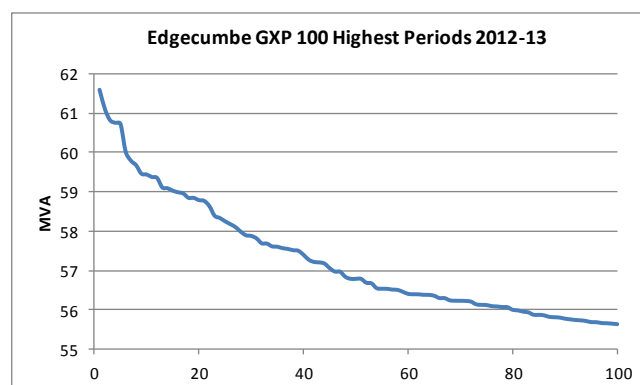
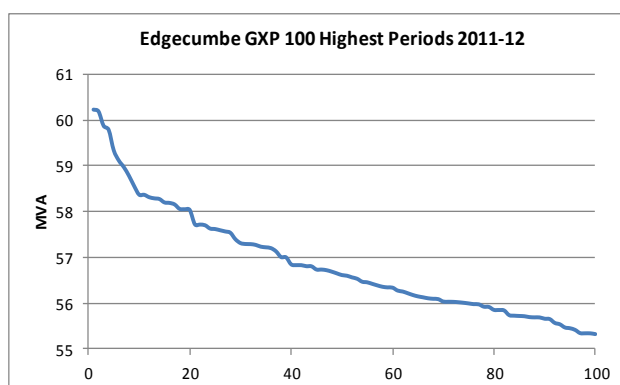


Figure 5.12 – Edgecumbe GXP 33kV Sub-transmission

- Seventeen 33kV sub-transmission circuits network wide;
- Total length of 178km;
- Three circuits from the Edgecumbe GXP supply the Whakatane urban region and are redistributed at the Te Rahu substation;
- Two circuits dedicated to Whakatane Mill Limited;
- Two circuits supply zone substations at Edgecumbe;
- One circuit is a backup supply to Galatea; and
- One feeder runs from Aniwhenua power station to Snake Hill and then splits into two feeders to supply Galatea with a further single feeder from Galatea to Kaingaroa.

The Edgecumbe GXP load curves are shown in Figures 15.13a, b and c. The data is taken from the actual load current from the Edgecumbe feeders.

Figures 5.13a, b – Edgecumbe GXP highest periods load profile



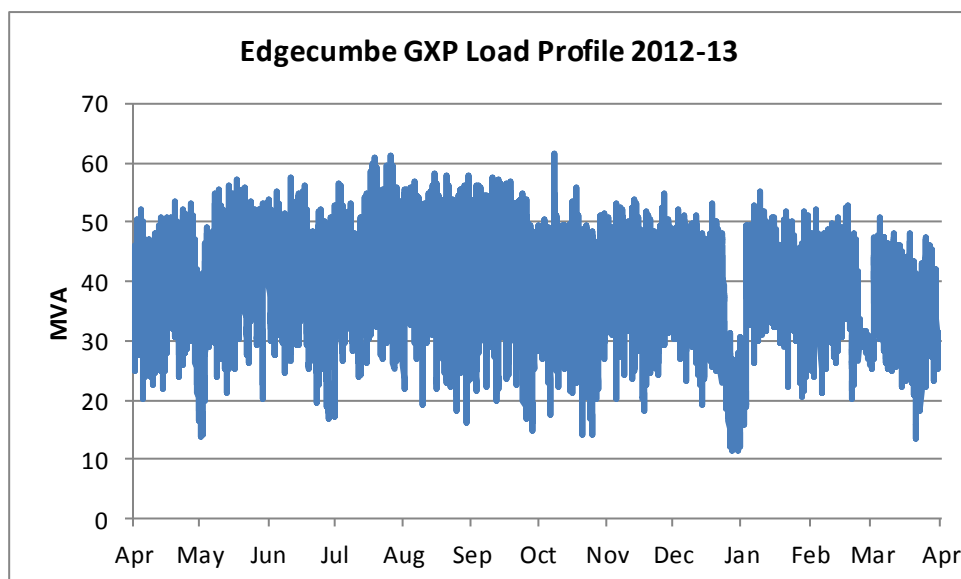


Figure 5.13c – Edgecumbe GXP Load Profile

Comments on sub transmission

- During most of 2009-11 Galatea loads were connected to the Edgecumbe GXP following the failure of a transformer at Aniwhenua. This added around 4-5 MVA onto the Edgecumbe bus. This is not a normal configuration and was restored to the normal configuration briefly in August 2011, but was subsequently returned to Edgecumbe to allow work on the second Aniwhenua transformer;
- The Edgecumbe 33kV system has no reinforcement interconnection to other sub transmission systems apart from the circuit to Galatea and its connection to the Aniwhenua supply point;
- Te Rahu South and WBM South feeders share common structures; and
- Te Rahu Central and Te Rahu North share structures. Under certain fault conditions this arrangement was believed to cause dual feeder trips due to line clash. This fault condition was verified in 2013 and remedial works instigated to prevent the lines from clashing.

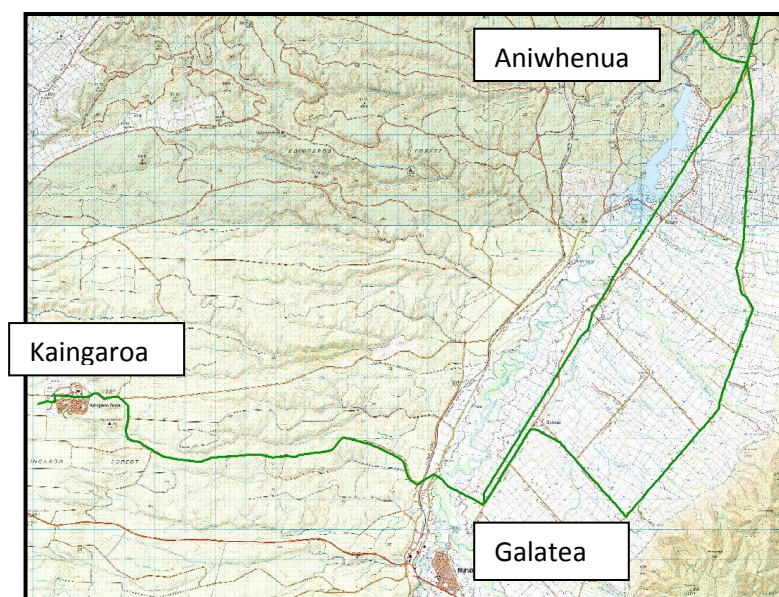


Figure 5.14 – 33kV Sub-transmission from Aniwhenua to Galatea and Kaingaroa

5.6.2. Snake Hill Circuit

The Galatea region is connected to both Edgumbe GXP and Aniwhenua power station, with Aniwhenua historically the primary connection point and Edgumbe the back-up supply. During 2009 Aniwhenua T1 failed and the 33kV supply was switched to Edgumbe whilst the transformer was out of service for repair.

The Snake Hill feeder connected to Edgumbe was always considered the back-up supply to Galatea. During 2013 Nova Energy, the power station operator informed Horizon Energy that it would not make the supply available due to technical issues with the Aniwhenua transformers. This condition elevates the priority of the Snake Hill feeder out of Edgumbe to being the primary source of supply to the region rather than the back-up supply. Consequently, a number of projects that have been planned to improve the reliability of this regional supply are being accelerated. It is expected that Aniwhenua will become the primary supply again in the future.

In addition to the constraint at Aniwhenua, Transpower have imposed a limit on the number of fault operations the Edgumbe connection at CB52 can sustain.

There are a number of options being considered to improve the system resilience:

- Improved protection at Snake Hill switching station to reduce damage risk to the Aniwhenua transformers;
- Improvements to the Snake Hill circuit configuration to improve resilience;
- Circuit breaker external to Edgumbe GXP to allow for more fault operations;
- A 110/11kV transformer and connection to the Aniwhenua 110kV circuit to bypass the Aniwhenua transformers if a permanent connection to Aniwhenua is not viable;
- A second line into Aniwhenua to connect to the Kopuriki circuit providing two direct feeders into Galatea;
- The Snake Hill circuit is considered uneconomic to upgrade the conductor size to a conductor with sufficient capacity to reduce the volt drop to acceptable levels compared to other alternatives. Likewise a dual circuit is not economically viable;
- Creating a bus section at Galatea to supply Kaingaroa; and
- The use of stand by generators.

Constraints on the existing snake hill circuit are

- The Snake Hill sub-transmission feeder from Edgumbe has load limitations due to voltage drop at full load when supplying Galatea and Kaingaroa, and is functionally only capable of supplying about 6.5MVA before the 33kV voltage drop at Galatea and Kaingaroa exceed the transformers tap changers capability to maintain the 11kV voltage; and
- Similarly the ability to transmit beyond 15MW from Aniwhenua across the 33kV to Edgumbe is limited by voltage limits.

The 33kV schematic is shown in Section 5.6.3. The proposed Gateway substation is shown on Figure 5.15.

5.6.3. 33kV System Schematic

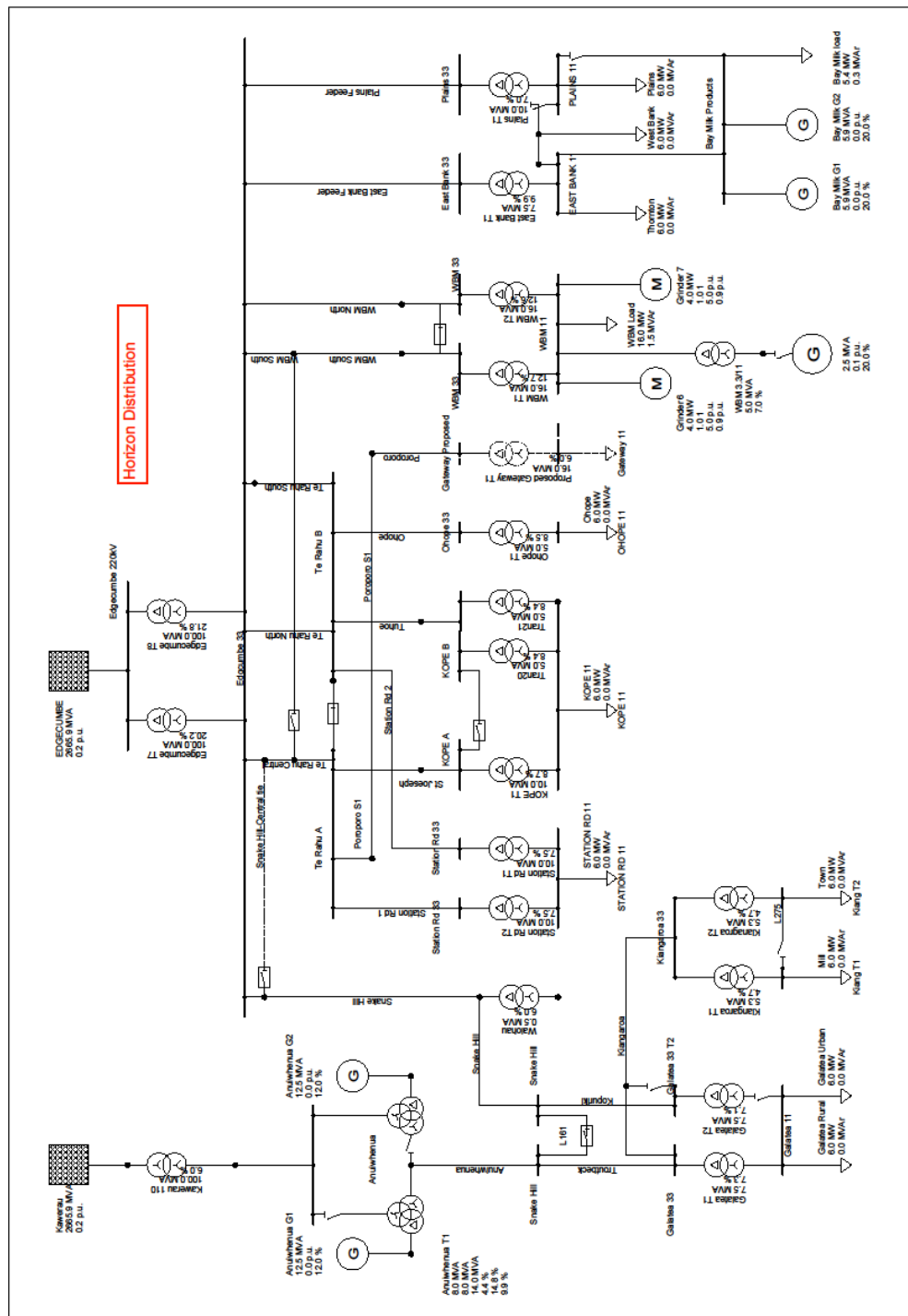


Figure 5.15 - 33kV System Schematic

5.6.4. Summary of 33kV Distribution Assets

Sub-transmission Assets

Table 5.19 below summarises Horizon Energy's sub-transmission line assets.

33kV Feeder	Source	Supply CB	Destination	Conductor	Rating (MVA)	Length (km)	Date	Comments
Aniwhenua	BOPE Aniwhenua power station	A34	Snake Hill	120mm ² DOG 7/1.57 ACSR	17.1	2.2	1977	Single line to Aniwhenua. A project has been identified to add a second line into Aniwhenua to support additional load at Galatea or Kaingaroa.
East Bank Road	Transpower Edgecumbe	112	East Bank Road Sub	185mm ² 3 x 1c Al XLPE	20.1	1.7	1987	No issues.
Kaingaroa	Galatea	270	Kaingaroa	105mm ² WASP AAC	5.3	17.7	1995	Single line, no redundancy. No plans to add additional line. Protection grading issue with Aniwhenua.
Kopuriki	Snake Hill	NA	Galatea T2	120mm ² DOG 7/1.57 ACSR	17.1	17.2	1969	No issues.
Ohope	Te Rahu substation	TR19	Ohope	120mm ² DOG 7/1.57 ACSR	7.1	9.6	1974	Single line, no redundancy. Management plan is to improve maintenance on the line and to support Ohope at 11kV.
Plains	Transpower Edgecumbe	162	Plains Substation	185mm ² 3 x 1c Al XLPE	14.4	0.1	1965	No issues.
Snake Hill	Transpower Edgecumbe	52	Snake Hill	120mm ² DOG 7/1.57 ACSR	20.1	35.7	1960	Restricted in ability to support additional load at Galatea and Kaingaroa. Very long feeder through some rugged terrain. Total load capability around 6.5MVA before Galatea voltage drop exceeds tap changer range. CB 52 has sync capability.
St Joseph's	Te Rahu substation	TR13	Kope T1	105mm ² WASP AAC	17.4	4.2	1989	Soil thermal resistivity issues reduce load capacity of cable sections entering Kope Substation to 13MVA.
Station Road I	Te Rahu substation	TR11	Station Road T1	300mm ² 3 x 1c Al XLPE	13.3	0.3	2010	Replaced overhead line 2010.

33kV Feeder	Source	Supply CB	Destination	Conductor	Rating (MVA)	Length (km)	Date	Comments
Station Road 2	Te Rahu substation	TR20	Station Road T2	300mm ² 3 x 1c Al XLPE	13.3	0.3	2010	Replaced overhead line 2010.
Te Rahu Central	Transpower Edgecumbe	102	Te Rahu substation TR14	122mm ² HARE 7/1.86 ACSR	23.0	12.1	1969	Shared structures with Te Rahu North.
Te Rahu North	Transpower Edgecumbe	82	Te Rahu substation TR16	158mm ² CRICKET 7/5.36 AAC	22.9	11.9	1980	Shared structures with Te Rahu Central.
Re Rahu South	Transpower Edgecumbe	142	Te Rahu substation TR18	122mm ² HARE 7/1.86 ACSR	20.2	11.7	1974	Shared structures with WBMS.
Troutbeck	Snake Hill	NA	Galatea T1	120mm ² DOG 7/1.57 ACSR	17.1	23.7	1982	No Issues.
Tuhoe	Te Rahu substation	TR17	Kope T2	Part 105mm ² WASP AAC and part 120mm ² DOG ACSR	17.4	3.7	1996	Soil thermal resistivity issues reduce load capacity of cable sections entering Kope Substation to 13MVA.
WBM North	Transpower Edgecumbe	62	Whakatane Mill	158mm ² CRICKET 7/5.36 AAC	22.9	12.7	1975	No Issues.
WBM South	Transpower Edgecumbe	122	Whakatane Mill	120mm ² DOG 7/1.57 ACSR	20.1	13.2	1980	Insufficient capacity to support Mill full load. Shared structures with Te Rahu South.

Table 5.19 – Summary of 33kV Distribution Assets

Notes

Line ratings are the protection pick up settings. Actual conductor ratings are listed in the standard conductor components section of this AMP.

5.6.5. Te Rahu Switching Station

In 2010 a \$1.7M project was completed to install a ten panel 33kV circuit breaker switchboard at the Te Rahu switching station to enable the three lines supplying Whakatane and Ohope to be run in a parallel configuration onto a distribution bus that would then re-distribute supply to Kopeopeo, Station Road and Ohope substations.

The project was reliability driven to address single circuit overloading issues with Kope and Station Road. This configuration provides a full-time n-1 redundancy to the 33kV sub transmission circuits into Station Road and Kope zone substations, as well as providing improved load distribution across the three feeders which reduces network losses.

The Figure 5.16 and Table 5.20 show the Te Rahu site load for 2009 to 2013. Te Rahu supplies power to about 10,726 customers, 44% of the network customers.

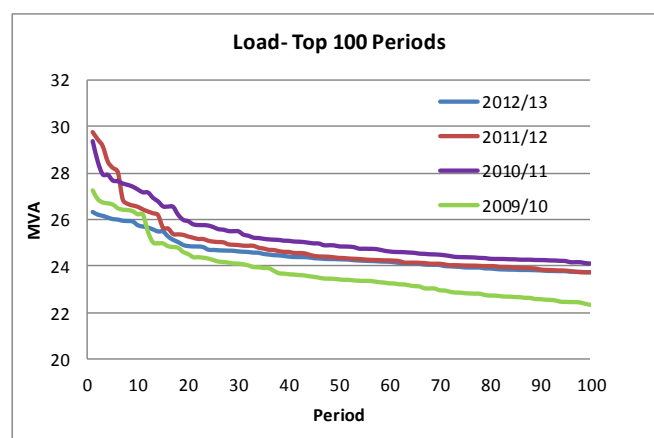
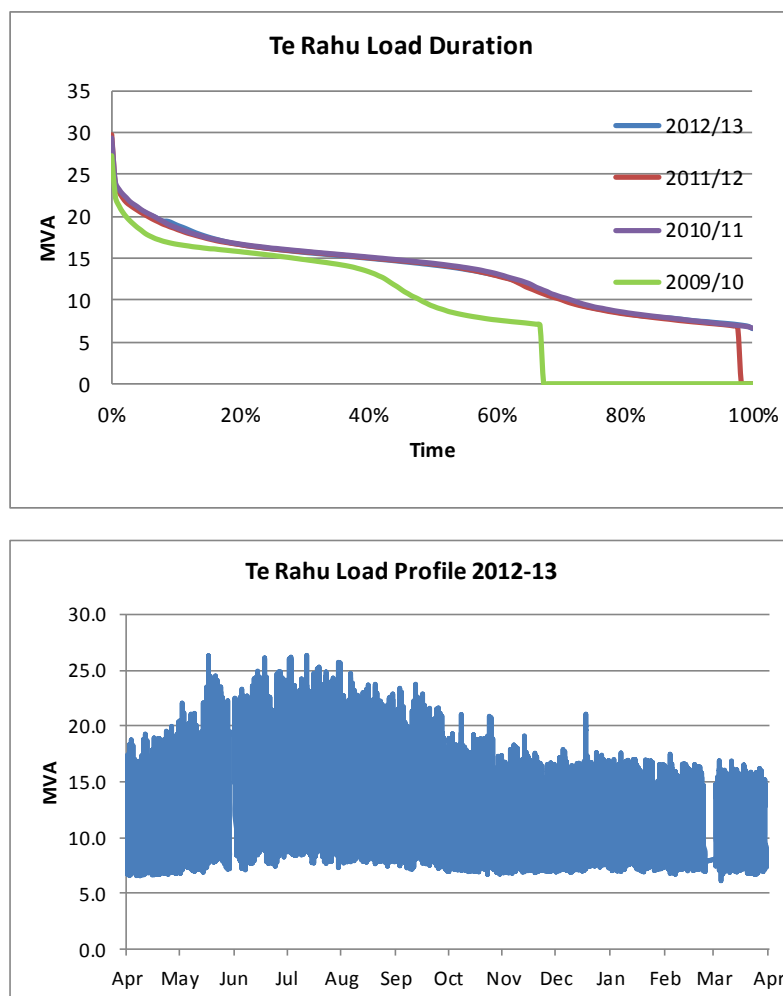


Figure 5.16 – Te Rahu Peak Load Curves

Utilisation and load growth at Te Rahu are shown in Table 5.20 and Figures 5.17. These values give the most accurate indication of the load growth for the Whakatane and Ohope urban region. The Maximum measured peak value has reduced from previous years due to an improved load control restoration algorithm that has reduced the peak loading on the network following restoration after a period of load control.

Te Rahu Load Statistics (MVA)						
	2009/10	2010/11	2011/12	2012/13	% increase 2012/13	Ave incr per year
Maximum	27.3	29.4	29.8	26.3	-11.5%	-5.2%
Average	8.9	13.5	13.2	13.4	1.6%	-0.4%
Average -Top 100 Periods	23.8	25.2	24.8	24.5	-1.4%	-1.5%

Table 5.20 – Te Rahu Load Statistics



Figures 5.17a, b, – Te Rahu Load Profile and Load Duration

Table 5.2I summarises the major assets within the Te Rahu Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV switchboard	Areva GHA, non-withdrawal, Vacuum, gas insulated, 10 panel, extensible	36kV 25kA 630 Amp feeder 2000 Amp bus	2010	No Issues.
Incomer 33kV cables	630sqmm ² Al XLPE 3 x 1c 4 feeders	28 MVA	2010	Thermal backfill installed to increase cable ratings.
Outgoing feeder cables	300sqmm ² Al XLPE 3 x 1c 5 feeders	16 MVA	2010	Thermal backfill installed to increase cable ratings.
Local service	Supplied from Station Road	200kVA		Dual changeover supply installed.
Control Building	Concrete block construction, colour steel roof	56 square meters	2010	No Issues.
Protection	SEL 351S mirrored bit relays	na	2010	No Issues.
SCADA	SEL 3530 signal processor	na	2010	Fibre optic connection to Station Road.
DC Battery Bank	Eaton APS3 24V DC	110 Ah	2010	No Issues.

Table 5.2I – Te Rahu 33kV Substation Assets

5.6.6. Te Rahu and Station Road Substations – Lifeline Risk Assessment

Risks and vulnerability of the Te Rahu and Station Road substation sites from a CDEM lifelines perspective are summarised in Table 5.22 below:

Service	Vulnerability
Critical Services	Te Rahu is integrated with Station Road for the supply of services. Local service power and communications are shared. Te Rahu does not have any staff amenities as these are located at the adjacent Station Road substation. Station Road substation also houses the disaster recovery site for the network operations, as well as the critical commercial computer data backup systems.
Disaster Recovery SCADA System	The disaster recovery system is a fully operational remote site for the Horizon Energy network operations and control function and provides SCADA access to the control systems if the main operations control room in Commerce Street, Whakatane is rendered inoperable.
Communications	Primary communications to the two sites are by a meshed private microwave radio network and fibre optic network. The network runs from a site located at Commerce Street to Station Road and Edgecumbe. The network is self-healing, so data can feed in either direction if one of the links is down for any reason.
Site Access Requirements	Both sites have full automation for control of the distribution network equipment located at each site. Communication to the sites for control purposes is by private radio network described above. As long as the radio network remains running the sites can be controlled from the Commerce Street control room. Access is required in the case of: 1) Loss of communications. 2) Abandonment of Commerce Street control room. 3) Maloperation of equipment.
Road Access	The Te Rahu site has been built above the 100 year flood inundation level. Main roads accessing the site are Te Rahu Road to the East and North by Paroa Road onto Te Rahu Road, and from the South by Station Road via White Pine Bush Road. Egress from Whakatane to the North is across the Landing Road bridge and to the South by Taneatua Road and White Pine Bush Road.
Alternative Access	There is sufficient clear land to land a helicopter on the Te Rahu site.

Service	Vulnerability												
Total Loss of Te Rahu	<p>Total loss of Te Rahu would result in a sustained outage of power to Whakatane, Taneatua, Ohope, and surrounding districts. There is limited redundancy/capacity from adjacent 11kV supplies fed from either Waitotahi or the Edgecumbe Plains and East Bank Road substations, but these are of low capacity.</p> <p>There will be some security of supply offered by the proposed Gateway switching and zone substation in the case of a half bus outage but this project will not be complete until 2015.</p> <p>Contingency plans include holding sufficient materials to erect temporary 33kV lines to bypass the substation. This is detailed in the contingency planning risk assessment documentation.</p> <p>Long term this risk is planned to be mitigated by the development of the Gateway 33kV substation.</p>												
Natural Hazards	<p>Natural hazards that the sites could be exposed to are:</p> <table> <tr> <th>Hazard</th><th>Risk</th></tr> <tr> <td>Flood</td><td>Low</td></tr> <tr> <td>Earthquake</td><td>High</td></tr> <tr> <td>Tsunami</td><td>Low</td></tr> <tr> <td>Volcanic activity</td><td>Low</td></tr> <tr> <td>Wind</td><td>Low</td></tr> </table> <p>Disaster recovery plans are held in the Horizon Energy disaster recovery quality manual.</p> <p>All switchgear is located within the building and is protected from environmental effects. The design of the switchgear is such that there should be no appreciable heat build-up in the building. The incoming supply and feeder lines are cable connected to overhead lines. The overhead lines are exposed to the elements, and as such, the lines are regarded as providing a lower level of security than the equipment at Te Rahu.</p>	Hazard	Risk	Flood	Low	Earthquake	High	Tsunami	Low	Volcanic activity	Low	Wind	Low
Hazard	Risk												
Flood	Low												
Earthquake	High												
Tsunami	Low												
Volcanic activity	Low												
Wind	Low												
Human Habitation	<p>Te Rahu and Station Road are unmanned sites. Manning is required only if communications are lost, or if the Commerce Street control room is unusable. Station Road substation has no facilities apart from ablutions so long term habitation is unsustainable without external support.</p>												
External Services	<p>At Station Road tank water is available from the roof and sewage is septic tank. Power is supplied from the Station Road substation local service transformer. There is no telephone at either of the substations. Un-interruptible power supplies installed to provide power system resilience to the computer systems. All critical services are on 24 volt battery banks and the site is configured for the connection of a generator.</p>												

Table 5.22 – Te Rahu and Station Road Lifeline Risk Assessment

5.6.7. *Proposed Gateway Substation*

Development of a substation at Gateway Drive has been discussed for some time in preceding AMP's. The driver for this substation has been:

- Projected urban load growth in Whakatane around the Hub/Piripai area;
- Load displacement from the Kope substation to the Gateway region;
- Gateway Drive is centrally placed for expected future load growth within the Whakatane, Gateway, Keepa Road, Piripai and Coastlands regions;
- Backup supply to Te Rahu substation; and
- Direct benefit to a major connected customer.

The two 33kV feeders that supply the Carter Holt Harvey Paperboard Mill (Whakatane Mill) run in close proximity to the Gateway site. One of these circuits does not have an all-time rating suitable to meet the full load requirement of the Mill so that the integration of these feeders into the Gateway 33kV bus will provide additional support for the Mill supply as well as providing support for Gateway and Te Rahu Road.

The 33kV development of Gateway is planned to continue but the 11kV development has been deferred until 2024 in favour of developing a CBD substation, unless there is significant load increase in the Piripai area. With the existing loading, a Gateway substation would only supply about 4 MVA, with most of the load being displaced from Station Road.

5.6.8. *Proposed CBD Substation*

A study of load flows and projected growth indicates that an 11kV CBD substation has a more beneficial effect than an 11kV substation at Gateway is likely to have. A substation in the CBD region has:

- Access to five feeders;
- Located close to load centres;
- Support from Kope substation;
- Positioned in an area that is actively developing and has the potential to be further developed;
- Currently there are a number of properties available that have low improved capital value that would be suitable as a substation site;
- Reduces the load driven need to upgrade feeder cables between Kope and CBD; and
- Provides the ability to balance load between Kope and CBD and reduces the total load on Kope substation.

Sizing of the Kope replacement transformers has been done based on the assumption that a CBD single transformer substation will be developed and that Kope and a CBD substation will provide mutual support to each other.

5.6.9. *33kV Integration with Whakatane Mill*

Integration of the five 33kV transmission lines, and the coupling of Te Rahu and Gateway bus sections by using the Poroporo feeder will provide sufficient capacity to support a total load of up to 75 MW whilst still retaining an n-1 line redundancy.

Using the 17MVA Poroporo feeder in a live bus arrangement to reinforce both Te Rahu and Gateway, the load restrictions currently applying to the Whakatane Mill during a single line outage are eliminated. Double line outages at either of the 33kV substations will be supported using the Poroporo feeder but with some load restrictions applied. Future plans include an upgrade of Dog conductor sections of Poroporo feeder to rate the feeder at 24MVA.

This arrangement is shown schematically in Figure 5.18 below:

PROPOSED 33kV NETWORK

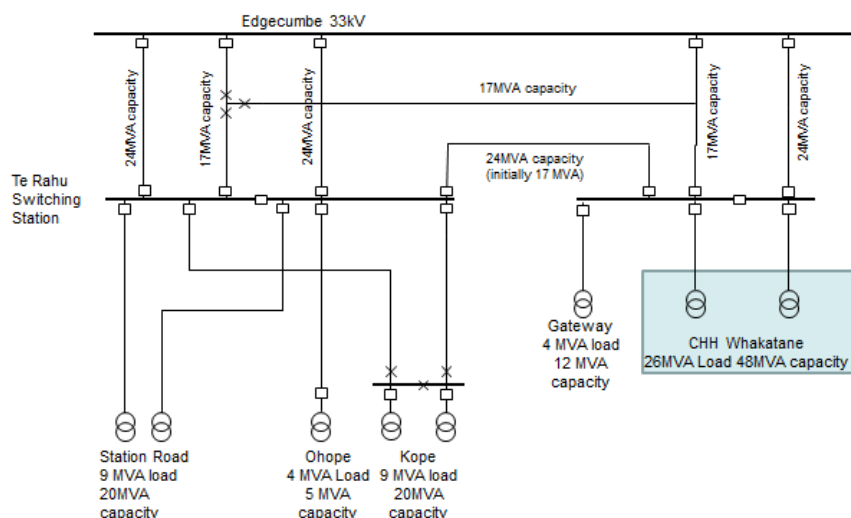


Figure 5.18 – Te Rahu and Gateway Integration

Proposed 33kV System Integration:

Integration with the Whakatane Mill has the benefits summarised below. Concept discussions have started with Mill staff to determine the level of integration that is appropriate for both companies.

Benefits of Integration with the Whakatane Mill:

- Treating Station Road and Kope substations as 4 x 10MVA transformers provides 11kV n-1 capability of 30MVA;
- Allows retirement of the Mill 33kV switchgear;
- 3 x 33kV lines to Gateway provides a minimum n-1 capacity of 34MVA;
- Nearest network 11kV feeder is 200 meters and is adjacent to three feeders (Hub East, Hub West, Piripai North);
- Allows cost sharing; and
- 11kV interconnection cannot be achieved without a break before make connection as the WML transformers are a Dy11 vector group whereas the Horizon Energy network supplied from Edgumbe is Dy3 vector group.

5.6.10. Whakatane Mill Limited (WML)

Whakatane Mill Limited is a major consumer on the network, with two dedicated 33kV lines supplying the site. The site has a peak demand load of 26MVA. The load demand is very cyclic due to a wood pulp grinding process, which applies a variable load of 11MW due to motor driven log grinding machines.

Load growth on the site had been fairly static following a step change in 2004 after a machine upgrade apart from the 2009-10 year, when the load growth was 6.5%.

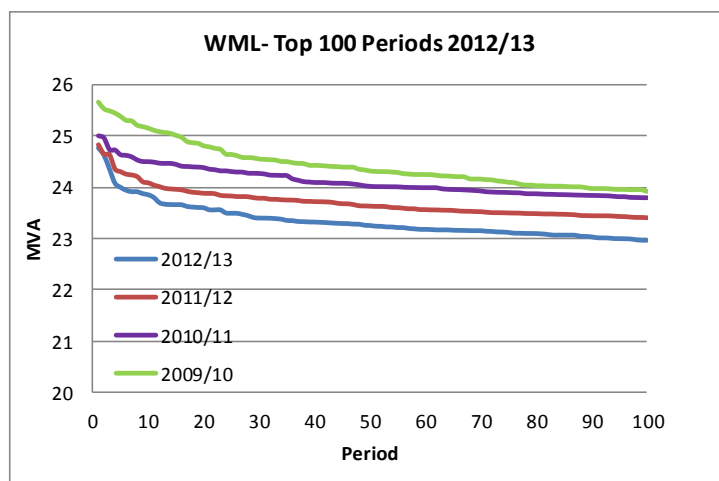


Figure 5.19a – Top 100 Load Periods

The peak loads for the subsequent years are down due to WML running embedded generation and employing peak load management methods.

For future load growth, until further data or step change information is available a 0% growth is used for forward load prediction.

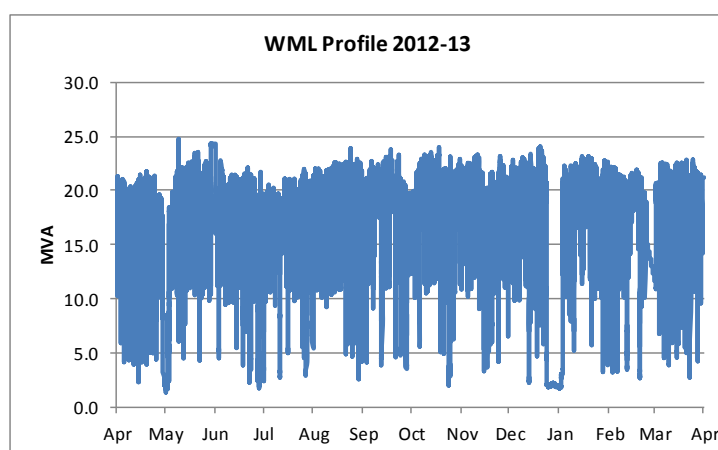


Figure 5.19b – WML Annual Load Profile

5.6.11. System Substation Cross Support Capability

A meshed distribution system provides the ability to support zone substations from adjacent substations using 11kV feeders. This flexibility of supply is strong in the Edgecumbe Plains and Whakatane areas but further out in Waiotahi and Galatea there is no ability to mesh between substations. Kawerau and Waiotahi are zone substations that are adjacent to Edgecumbe GXP supplied sites but are out of phase, and are able to be meshed after an outage.

The Figure 5.20 shows the overlapping interconnectivity between the substations and table 5.23 gives the approximate level of reinforcement that each interconnected substation can provide to its neighbour.

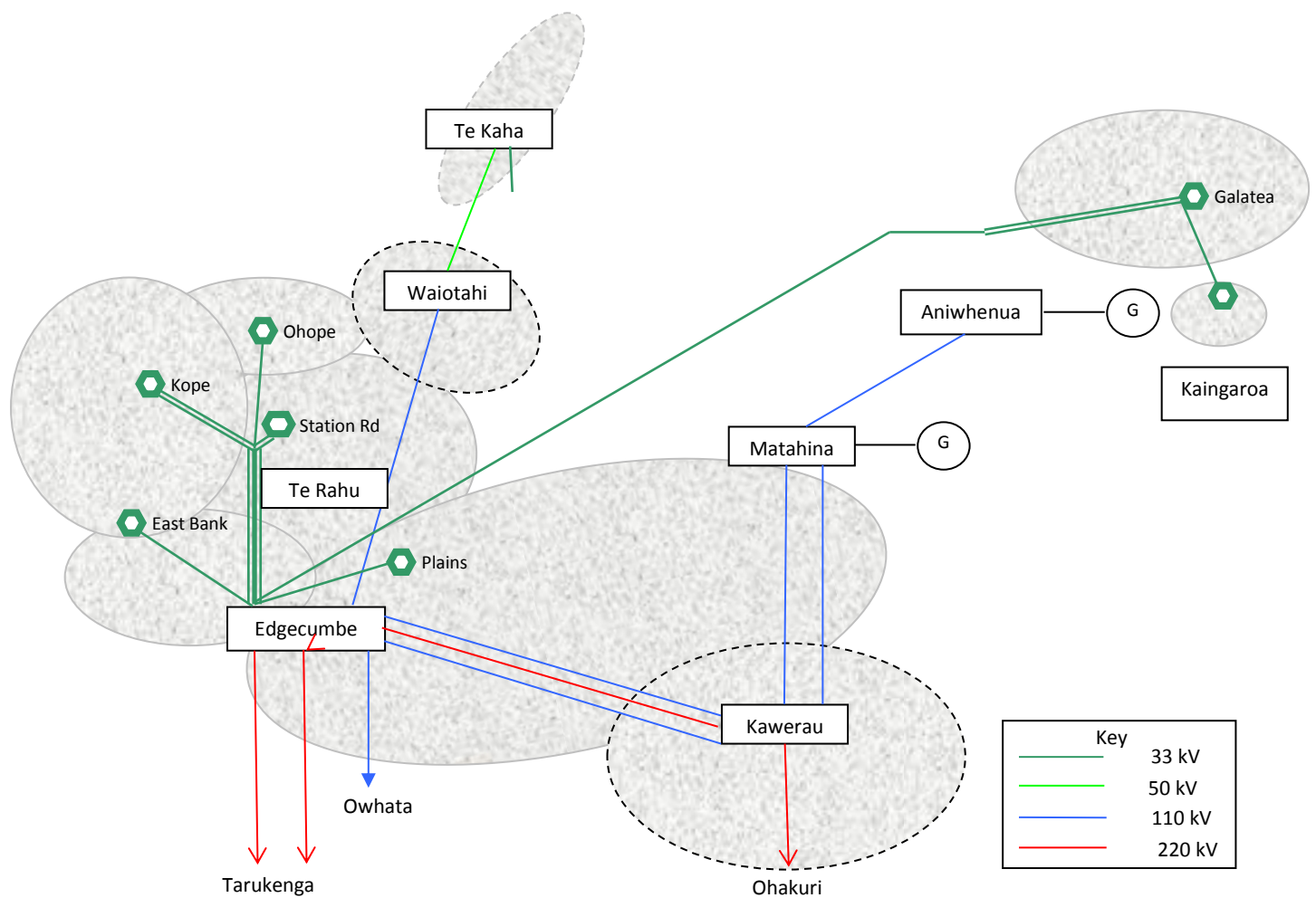


Figure 5.20 – Overlap of 11 kV network

	Te Kaha	Waiotahi	Ohope	Station Road	Kope	Plains	East Bank Road	Fonterra	Kawerau	Galatea	Kaingaroa
Max Demand (MW)	2.2	9.7	4.7	8.6	16	6.4	6.6	7	19.6	4.9	2.5
Te Kaha											
Waiotahi			1*	1*							
Ohope		1*		14							
Station Road		1*	3		12	2	1				
Kope				12							
Plains				2			11	4	2*		
East Bank Road				1		11		8			
Fonterra						4	8				
Kawerau						2*					
Galatea											
Kaingaroa											

* Indicates that a phase shift exists

Table 5.23 – Zone Substation 11kV link capacities

Studies to improve meshing and reinforcement options are being reviewed at least annually, with a focus on the interconnect ability between Kope and Station Road being a major component of the Kope reinforcement plan.

5.6.12. Sub-transmission and Zone Substation Development Plans

Sub-transmission and major zone substation projects are covered in Appendix C. Each project is summarised along with alternative options considered and plans for implementation or further engineering study requirements.

A series of development plans for Waiotahi are also included with the proposal to develop a new substation at Opotiki at either 110kV or 33kV. This proposal is discussed in some detail in the Waiotahi Section 5.17.

5.7. Zone Substations

The following sections describe in detail the zone substations and feeders that comprises the Horizon Energy network.

Substation	Section
East Bank	5.8
Galatea	5.9
Kawerau	5.10
Kaingaroa	0
Kopeopeo	5.12
Ohope	5.13
Plain	5.14
Station Road	5.14.10
Te Kaha	0
Waiotahi	5.17
Waiohau	5.18
Fonterra	5.19

Table 5.24 – Zone Substations, Section References

In August 2011 an independent inspection by Mitton Electronet was commissioned for each zone substation. The inspections have made a number of recommendations to bring the substations up to current standards and have identified a number of risks that require mitigation. A number of the recommended works are already being dealt with by substation upgrades already in the plan. Others have been scheduled into the plan.

A common theme across substations is fire risk caused by having transformers installed too close to each other or too close to control buildings, based on AS2067-2008 specifications. Some fire risk mitigation projects have been initiated, in other substations the risk will be engineered out as the substation transformers and switchgear are upgraded.

5.8. East Bank Zone Substation

5.8.1. System Description



The East Bank Road substation, built in 1987 to support the then Anchor dairy factory, is located about one kilometre from Edgecumbe, along East Bank Road, directly to the East of the Fonterra dairy processing plant and is the primary connection point for the Fonterra site. The Fonterra factory has a 10MW cogeneration facility onsite that operates over the dairy season and supplies the site electricity and steam requirements. During the production period excess generation is exported from the site as indicated by the negative readings on the load duration graphs. The manufacturing plant is generally closed down during the winter non-dairy season; however the cogeneration plant is operated at times to assist the generator in meeting their demand reduction contract that applies for the Edgecumbe GXP.

5.8.2. Service Area Covered

East Bank substation supplies the Thornton area through to Matata, Edgecumbe town, and Fonterra. East Bank is connected to the Plains substation with a high capacity 630 amp 11kV tie feeder, and this enables each substation to support the other in the event of a loss of 33kV supply.

Thornton Feeder

Rural Thornton feeder runs along the East side of the Rangitaiki River to Thornton, and to Matata. It has tie points to Manawahe and Awaitei feeders, supplied from Plains substation, Angle Road supplied from Station Road substation, and to West Bank feeder. Tie points are being automated as part of the series of reliability projects.

West Bank Feeder

West Bank feeder supplies Edgecumbe town. It has tie points to Awaitei and Thornton feeders. West Bank feeder is a 12MVA capacity link feeder that connects Plains and East Bank substations. Edgecumbe town is supplied from a mid-point tee on the interconnection cable.

Anchor 1

Direct link to the Fonterra dairy factory site.

5.8.3. Description of Assets

Table 5.25 summarises the major assets within the East Bank Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV Cable	East Bank 33kV Feeder	3 x 1 core 33kV XLPE 185sqmm Al Rated 16.4 MVA	1986	Direct connect to Transpower Edgecumbe 33kV CB 112
33/11kV Transformer T1	3 phase Tyree	7.5 MVA ONAN 15 MVA OFAF 9.93% Z Dyn 11	1987	No known issues
T1 Tapchanger	Ferranti	33kV 300 amps (CER 480 amps) 11 steps	1987	Tap change drive mechanism partially flooded during 2004 storm requires increased maintenance
11kV Distribution Switchboard	Reyrolle, LMVP vacuum circuit breakers, 6 panel including bus coupler	Circuit breakers 630 amp Fault rating 25kA 3 sec Bus rated 1250 amps	1986	Blast doors installed 2011 Trip circuit monitoring installed 2013
Control Building	Wooden frame, wooden clad building		1986	Good Condition

Asset	Description	Rating Data	Date of Manufacture	Comments
SCADA	SEL 241 I RTU		2013	
DC Battery Bank	Switchtech 48V			
Local Service	ABB	200kVA	1987	Good Condition
Transformer Protection	SEL 787		2013	
Feeder Protection	SEL 751A		2013	
33kV Protection	SEL751A		2013	
Tap Change Controller	Reg DA		2009	
Communications	Fibre optic		2013	

Table 5.25 – East Bank Substation Assets

5.8.4. Substation Utilisation

The following table and figures show the load characteristics for the East Bank substation:

East Bank -Load Statistics MW						
	2010	2011	2012	2013	% increase 12-13	% Increase 3 years
Maximum	7.5	6.3	8.1	7.2	-10.9%	7.4%
Average	0.45	1.32	0.75	0.61	-18.5%	-26.9%
Average-Top 100 Periods	5.80	5.58	7.22	5.59	-22.6%	0.0%

Table 5.26 – East Bank Substation Assets

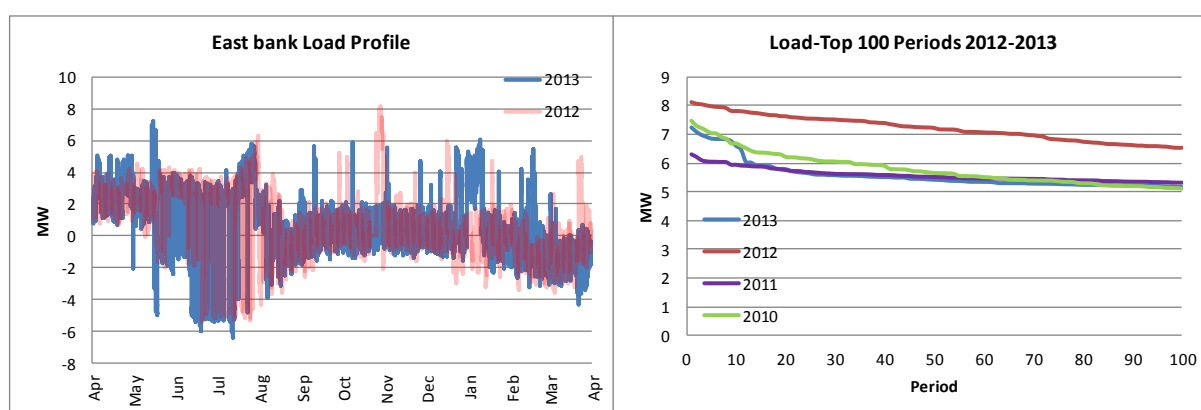


Figure 5.21a – East Bank Load Curves

Figure 5.21b – East Bank Profile

The load variability is driven by the variability of Fonterra production, generation, and load control restoration.

Plains and East Bank substations provide redundancy to each other through the 11kV interconnection tie. The co-incident loads for these two substations for 2012-13 are shown in fig 5.22. The coincident peaks are slightly lower than they were during 2012, but still exceeded the Plains T1 ONAN rating for 102 periods. The risk is the ability of the Plains 10MVA transformer bank to supply the loads in the event of an outage of East Bank with no generation at Fonterra. This risk is considered low but significant also when considering the age and overall condition of the Plains T1 bank, so the planned age driven replacement of Plains single phase transformer bank has been brought forward.

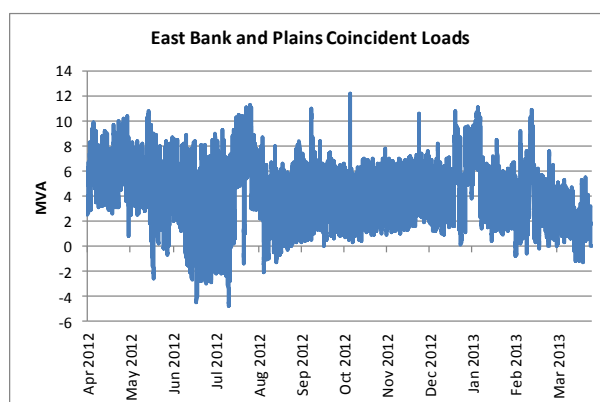


Figure 5.22 – Plains plus East Bank Coincident Loads

5.8.5. Load Growth

The substation load growth is determined at the feeder level for the two feeders supplying the rural and domestic consumers, Thornton and West Bank. The variability of the Fonterra factory loads and generation make the actual measured MVA load for the East Bank substation meaningless, so for load prediction purposes a load growth of 1.4% has been used based on the feeder load growth factors.

5.8.6. Constraints

There is a high capacity 650 amp tie between Plains and East Bank substations on the West Bank feeder that also supplies Edgumbe urban loads. This feeder, when operated in parallel with Plains and East Bank, increases the fault level on the West Bank feeder to 13kA and up to 8kA in parts of Edgumbe town. Some installed components are not rated to this fault level so even though this mode of operation is used very infrequently, remedial work is included in the plan.

Plains and East Bank power transformers have miss-matched impedances and tap steps. This can cause high circulating currents when the substations are operated in parallel. Intelligent tap change controllers were installed in 2009 to help manage this.

The substation protection systems have been upgraded in 2013.

Lifeline Risk Assessment

Risks and vulnerability of the East Bank substation site from a CDEM lifelines perspective are summarised in Table 5.27 below:

Vulnerability	East Bank	Mitigation
Total Loss of East Bank Substation	East Bank substation is a single feeder substation with one three phase transformer.	There is a high capacity 11kV link between East Bank and Plains substations in case the 33kV supply is not available. There is 11kV meshing to provide support at the 11kV feeder level.
Communications	Primary communications to East Bank substation is by a single link UHF radio from Putauaki radio site repeater. Communication is used for remote control of switching operations and load monitoring.	Not critical for operation as systems can be operated manually.
Site Access Requirements	Access is required in the case of: <ul style="list-style-type: none"> • Loss of communications • Abandonment of Commerce Street control room • Non operation of equipment 	Roads accessing the site are East Bank Road North from Edgecumbe, and East Bank Road South from Thornton. There is sufficient clear land to land a helicopter near the East Bank substation site if required.
Natural Hazards	Natural hazards that the sites could be exposed to are: <ul style="list-style-type: none"> • Flood • Earthquake • Tsunami • Volcanic activity • Wind 	Risk: <ul style="list-style-type: none"> • High • High • Low-medium • Low • Low Disaster recovery plans are available to all staff.
Network Impact Risk	Supplies 5% of the network customers, mostly rural.	Fonterra has on site generation that can run in island mode to supply the site in an outage of the supply network.
Human Habitation	East Bank is an unmanned site.	Access window and door alarms to SCADA.
External Services	All critical services are on 24 volt battery banks.	

Table 5.27 – East Bank Lifeline Risk Assessment

5.8.7. East Bank Substation Feeders

East Bank substation feeders are summarised in Table 5.28 below:

Feeder	Thornton	West Bank	Anchor I
Type	Rural	Urban	Industrial
Overhead (km)	61.4	7.3	0
Underground (km)	5.6	4.4	0.3
ICP Connections	363	770	1
Substations	92	32	na
Installed Tx Capacity (MVA)	5.6	4.4	na
Maximum Load (Amps)	133	167	254
100 Peak Load (Amps)	115	97	203
5 year average growth rate	0.0%	1.4%	na
Feeder Utilisation at Average 100 Peaks	41%	35%	51%

Table 5.28 – East Bank Substation Feeders

Thornton Feeder

- Rural feeder; and
- Growth rate over 5 years is 0%. Minus 3% growth 2012-13

There is a tie point at Thornton Road to Angle Road feeder along SH2 that is Squirrel conductor and is limited to 2MVA that was upgraded in 2012. All other tie points are 4MVA or better.

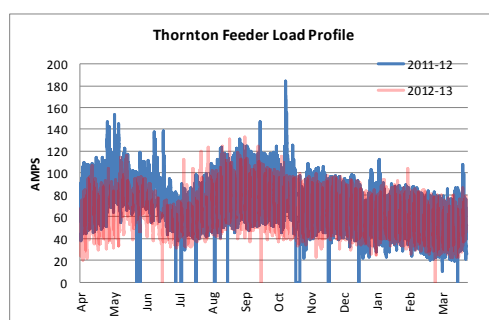


Figure 5.23 – Thornton Feeder Load Curves

West Bank Feeder

- No load constraints with the West Bank feeder;
- The load curves show the effect of reinforcement on this feeder due to having multiple tie points with adjacent feeders Awaiti and Thornton; and
- Actual growth rate is higher than the network average.

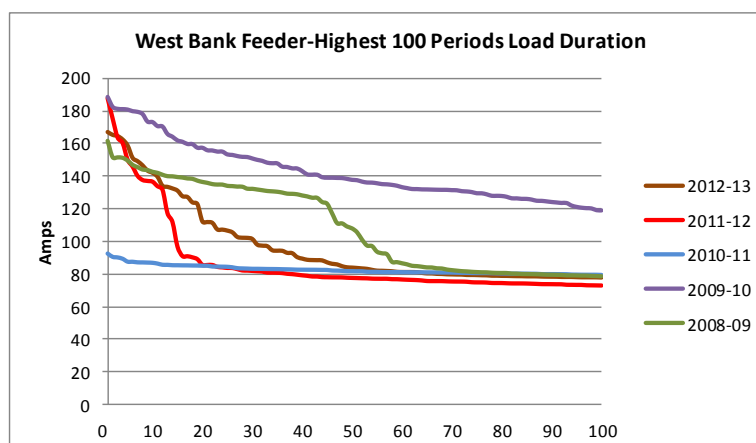


Figure 5.24 – West Bank Feeder Load Curves

Anchor I Feeder

- Primary supply to Fonterra processing plant;
- The feeder operates as import or export depending on the on-site generation capability;
- The feeder is a 400mm² Al XLPE cable installed in 1988;
- Growth is distorted by embedded generation and it is not possible to get a meaningful measure of the true growth rate for this feeder using load flow; and
- Anchor feeder is limited to 400 amps, which is below the generation capability of the site. There are no plans to increase this rating and Fonterra manage the generation to suit the feeder capacity when required.

5.8.8. Faults and Outages

Thornton Feeder

- Long rural feeder. It is exposed to the normal faults associated with the rural environment;
- Due to its proximity to large bodies of water a lot of unknown line faults or circuit breaker re-closes at dawn or dusk are believed to be bird strikes;
- Vehicle impact has historically caused some large outages;
- A lot of the feeder length is coastal and exposed to a salt air environment; and
- Condition assessment data has not yet been fully analysed. Based on the historical faults performance of this feeder it is assumed that the overall condition is below average.

5.9. Galatea Substation

5.9.1. System Description

Galatea substation is a dual transformer substation located about two kilometres north of Murupara, on Galatea Road. The site is fully rural and has four 11kV feeders used to supply approximately 1550 customers. It is supplied from two 33kV feeders from Snake Hill switching station that is in turn fed by one feeder connected to the Aniwhenua power station and one feeder connected to the Edgumbe GXP.



5.9.2. Service Area Covered

Galatea substation supplies the Galatea region from four feeders, ranging from the North of the Galatea valley to Ruatahuna in the South East and includes the towns of Murupara and Minginui. The Galatea substation also contains a switching station for the 33kV spur line to the Kaingaroa substation.

The four 11kV feeders are as follows:

Minginui Feeder	Minginui feeder runs past Murupara and supplies Minginui and Ruatahuna. This area is very rugged, running through forest and native bush. Being a spur line there is no ability to mesh the system to Minginui to provide additional support from other feeders. Some generator connection points have been installed in strategic locations on the feeder to aid in restoration of supply or maintenance activities.
Murupara Feeder	Murupara feeder supplies the town of Murupara and is a mixture of overhead and underground conductors. Murupara feeder is supported through its connections to the Jolly Road and Galatea feeders.
Jolly Road	Jolly Road feeder runs East then North from Galatea substation substantially along Troutbeck Road. The feeder is predominantly a Dog conductor and supplies rural customers. This feeder is inherently reliable and is meshed in several places with the Galatea feeder.
Galatea Feeder	Galatea feeder is a rural supply feeder. It is connected to Jolly Road feeder with five tie points and to the Murupara feeder by one tie point. It has a small 100kW embedded hydro generator owned by Nova Energy at the extreme end of the feeder. Automation was installed in the 2010-11 year to automate some of the tie points for reliability and reinforcement.

5.9.3. Description of Assets

Galatea substation is a two transformer 15MVA 33kV/11kV zone substation. The two 33kV incoming lines are bussed together by a normally open tie switch using an overhead bus structure that also supplies the 33kV line to Kaingaroa. Normal configuration for Galatea is to run the two transformers live, one supplied from the Edgecumbe GXP via the Snake Hill line and the other supplied from Aniwhenua power station. This arrangement allows quick switching from one supply source to the other in the event of a 33kV feeder failure.

Difficulties with this arrangement are that the line from Edgecumbe is 58km long and from Aniwhenua it is 19 km. This line impedance difference causes volt drop issues due to line losses when switching although this is managed operationally.

Galatea has high technical losses when being supplied from Edgecumbe, with technical losses calculated from 12.3% to 15.5% as shown on Figure 5.25.

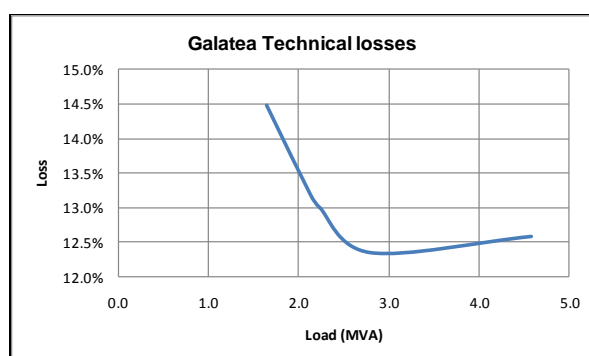


Figure 5.25 – Galatea Technical Losses

A project to install additional circuit breakers at the Aniwhenua connection point has been planned to provide improved protection to the Aniwhenua supply transformers and also allow the two feeders supplying Galatea from Snake Hill to be run in permanent parallel, reducing line losses and improving reliability.

Both Galatea power transformers are 7.5 ONAN MVA three phase transformers.

A full replacement of the 11kV system is in progress for 2013-14 using an indoor arrangement.

Studies on earthing and general compliance to modern substation standards are being undertaken and are expected to spawn a number of other projects required to ensure the substation complies with modern requirements.

The transformers were installed in 1980 and are currently considered at over half life. When the substation load approaches the n-1 capacity of the transformers cooling fans will be installed to increase the load capacity of the transformers. There have been recent issues with tap changer arcing that is managed with an increased level of servicing.

A project has been initiated to install 33kV line circuit breakers and to run the Kaingaroa line as a live 33kV bus section. This will improve the supply quality to Kaingaroa and will allow the two 33kV lines into Galatea to be run in full parallel, reducing line impedance and consequential volt drop back to Snake Hill.

Installation of feeder 11kV fixed capacitor banks at the remote ends of each of the feeders is proposed to help compensate for localised inductive loads and inductive line losses and to improve end of line voltages.

Galatea Substation Assets

Table 5.29 summarises the major assets within the Galatea Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV Bus	Overhead	Not available		
33kV Circuit Breaker 126, 123, 124, 127	GEC JB424 Bulk Oil	33kV, 400 Amp, 8.76kA 3 sec	1972	No issues. Under consideration for replacement.
33/11kV Transformer T1 and T2	3 phase Tolley	7.5 MVA ONAN Z 7.92 % T1, 7.11 T2 Dyn11	1980	No Issues.
T1 Tap changer	Associated Tap Changer type F323 33/300	33kV 76 amp 23 steps	1980	No issues.
T2 Tap changer	Associated Tap Changer type F323 33/300	33kV 76 amp 23 steps	1980	Failed 2010 due to faulty tap step resistor. Two subsequent failures attributed cause is most likely inferior previous repairs.
11kV Bus	Overload	na		Difficulty with maintenance due to minimum access distance (MAD). Scheduled for replacement 2013-14.
11kV Feeder Circuit Breakers	Cooper Power KFE Vacuum		1972	Scheduled for replacement 2013-14.
Control Building	Block construction		1960	No issues.

Asset	Description	Rating Data	Date of Manufacture	Comments
SCADA	Leeds and Northrup (Foxboro) C50 RTU		1991	Hardware has exceeded the ODV life. Replacement with industry standard DNP3 capable devices has been scheduled 2013-14.
DC Battery Bank	Switchtech 24V		1960	No issues. Upgrade to 48V planned 2013
Local Service	Pole mount 30kVA transformer	30kVA		No Issues. Ground mount conversion planned
33kV Protection	Alstom MCGG			No issues.
Feeder Protection	GEC CAG		1991	Relays have no metering capabilities. An upgrade project has been planned to improve metering capabilities 2013-14.
Transformer Protection	GEC CDG			Obsolete – Scheduled for replacement 2013-14.
Tap Change Controller	GEC VAA			Obsolete – Scheduled for replacement 2013-14.
Load Control	Mitsubishi PLC			No Issues.
Auto Re-close	Mitsubishi FX – 48MR-DS PLC			No Issues.
Communications	Exicom Hawk 450Mhz UHF radio			Radios are scheduled for replacement 2013 with IP radios.
Ripple Injection Plant	Motor Generator	750 Hz	1969	Obsolete equipment and frequency. Concept plan to install smart metering being investigated.

Table 5.29 – Galatea Substation Equipment

5.9.4. Substation Utilisation

Galatea Load Statistics (MVA)							
	2009-10	2010-11	2011-12	2012-13	% increase 2012-13	Ave incr per year	2012-13 n-1 utilisation
Maximum	4.6	4.9	4.7	4.5	-4.8%	-0.7%	60%
Average	2.3	2.2	2.1	2.4	14.2%	1.5%	32%
Average-Top 100 Periods	4.27	4.53	4.32	4.31	-0.1%	0.4%	58%

Table 5.30 – Galatea Load Statistics

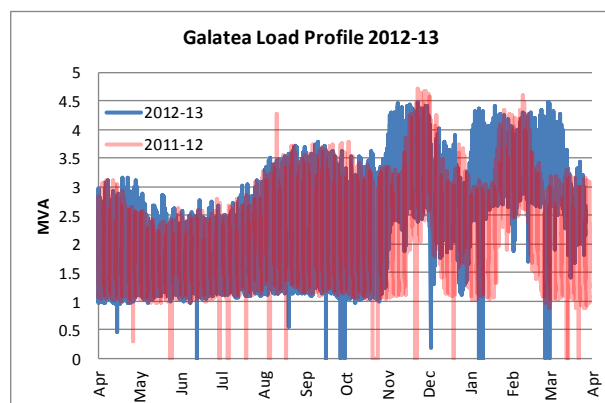


Figure 5.26a – Galatea Load Profile

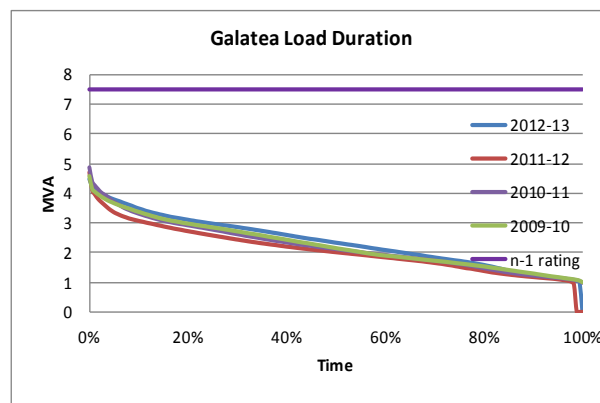


Figure 5.26b – Galatea Load Duration

- Galatea region load is a predominately rural with some urban load;
- The rural load is dominated by summer peaks due to irrigation and is variable depending on the prevailing weather conditions and length of the dry season; and
- The start of the dairy milking season in mid-July to August creates a seasonal peak during spring prior to the irrigation load starting in November.

5.9.5. Load Growth

Peak loads during summer is self-managed by the consumers who have set up their pumping systems to irrigate at night. Daily load curves show the night time load is greater than the daytime load with an extended evening peak during summer. The average load growth since 2007-08 reported in 2011 was 4.7% and has trended downwards to the current 1.5% average growth.

Load growth and the ability of the substation equipment to supply will not be a concern for several years. What is of concern is the ability to supply Galatea from Edgecumbe via the Snake Hill circuit and maintaining voltage within tolerance with the increasing load. This issue is expanded on in Section 5.9.6.

5.9.6. Constraints

When supplied from Edgecumbe the losses on the 33kV circuit are very high; when the combined loads Kaingaroa and Galatea approaches 7 MVA the transformers voltage regulators saturate and are no longer able to control the 11kV voltage at either bus. This restricts the additional load that can be added to the network at these locations and still maintain quality of supply. Various options have been considered to remedy this including 33kV capacitor banks, 11kV capacitor banks and/or an additional sub-transmission line between the Snake Hill switching station and Aniwhenua.

A second line to Aniwhenua provides the best technical solution. This has been scheduled for 2016.

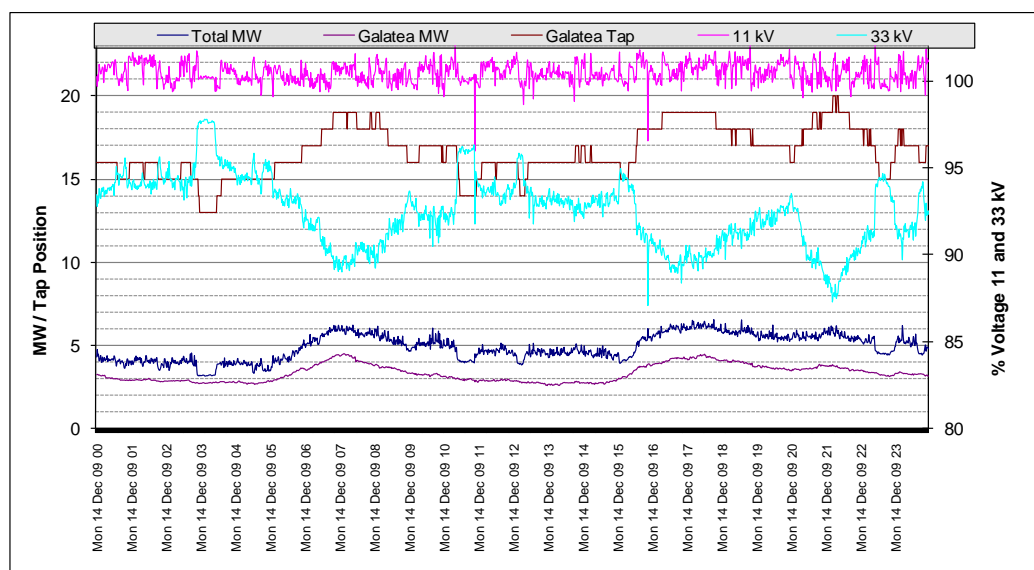


Figure 5.27 – Tap Position

The chart above shows the tap position compared to 33kV line voltage when supplied from Edgcombe. Full transformer tap range is 23 taps.

5.9.7. Lifeline Risk Assessment

Risks and vulnerability of the Galatea substation site from a CDEM lifelines perspective are summarised in Table 5.31 below:

Vulnerability	Galatea	Mitigation/risk
Total Loss of Galatea Substation	The substation is a dual feeder substation with two three phase transformers	No ready solution in place. Temporary generator for each feeder.
Partial loss	Fully redundant site	Built in.
Communications	Primary communications is by a single link UHF radio from Mount Putauaki repeater radio site. Communication is used for remote control of switching operations, load and security monitoring.	Not critical for operation as systems can be operated manually, with delays.
Site Access Requirements	Access is required in the case of: <ul style="list-style-type: none"> Loss of communications Abandonment of Commerce Street control room Non operation of equipment 	Vehicle access via Galatea Road, past Matahina Dam. There is sufficient clear land to land a helicopter near the substation site if required.

Vulnerability	Galatea	Mitigation/risk
Natural Hazards	Natural hazards that the sites could be exposed to are: <ul style="list-style-type: none"> • Flood • Earthquake • Tsunami • Volcanic activity • Wind 	Risk <ul style="list-style-type: none"> • Low • High • None • Low • Low Disaster recovery plans are held in the Horizon Energy disaster recovery quality manual.
Network Impact Risk	Supplies 7% of the network (including Kaingaroa) mixed urban and rural	
Human Habitation	Galatea is an unmanned site	Access door alarms to SCADA.
External Services	All critical services are on 24 volt battery banks	

Table 5.31 – Galatea Lifeline Risk Assessment

5.9.8. Galatea Substation Feeders

Galatea substation feeders are summarised in Table 5.32 below:

Feeder	Minginui	Murupara	Galatea	Jolly Road
Type	Rural	Urban	Rural	Rural
Overhead (km)	80.7	32.7	61.8	54.5
Underground (km)	0.5	6.4	1.2	0.5
ICP Connections	290	827	230	204
Substations	84	76	109	98
Installed Tx Capacity (MVA)	3.1	5.9	4.2	3.0
Maximum Load Amps	43	88	93	94
100 Peak Load Amps	36	80	79	90
5 year average growth rate	3.5%	1.0%	1.4%	6.0%
Feeder Utilisation at Average 100 Peaks	13%	28%	28%	32%

Table 5.32 – Galatea Substation Feeder

Minginui Feeder

- Low growth;
- Large irrigation loads on this feeder;
- End of line voltage levels are not seriously affected by this level of load; and
- New circuit breakers installed on the line to Minginui, just past Murupara.

A customer initiated project to install a new line into a remote village was being planned for 2010-11 but is delayed due to financial constraints and easement issues. If it proceeds, this line will connect to the Ruatahuna line and will be constructed as a single wire earth return circuit. Horizon Energy would have preferred a non-network option but the customer wanted grid connection.

The Minginui feeder is older than most in the network but, due to its inland location away from salt air, is in very good condition for its age. In 2006 an unanticipated snow storm caused a large section of the line to collapse and the Ruatahuna region was supplied by generators for several months until the line was rebuilt. This storm was classed as a 100 year event and as such Horizon Energy decided that they would not alter design standards to cater for this abnormal event, although it is anticipated that the repaired line is more robust than the previous circuit.

There are no reinforcement options for the remote end of Minginui feeder apart from generation.

Murupara Feeder

- Load growth is below average for the network and likely to remain so due to urban population displacement; and
- Additional SCADA controlled devices installed to provide remote switching and sectionalising in the event of any fault.

Galatea Feeder

- The Galatea feeder has a number of irrigation schemes installed which have contributed to the load growth;
- This feeder is unusual in that the main backbone of the feeder is a Ferret conductor, rated at 4MVA, instead of the more common 6MVA rated Dog; and
- This is not an issue at this stage due to the low loads supplied although it does cause additional losses and volt drop at the end of line.

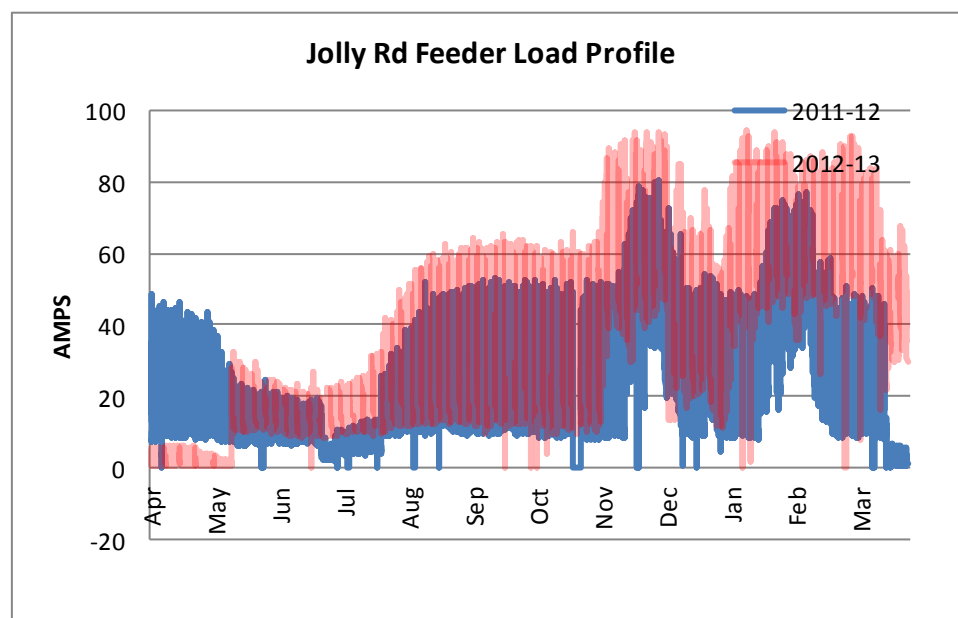
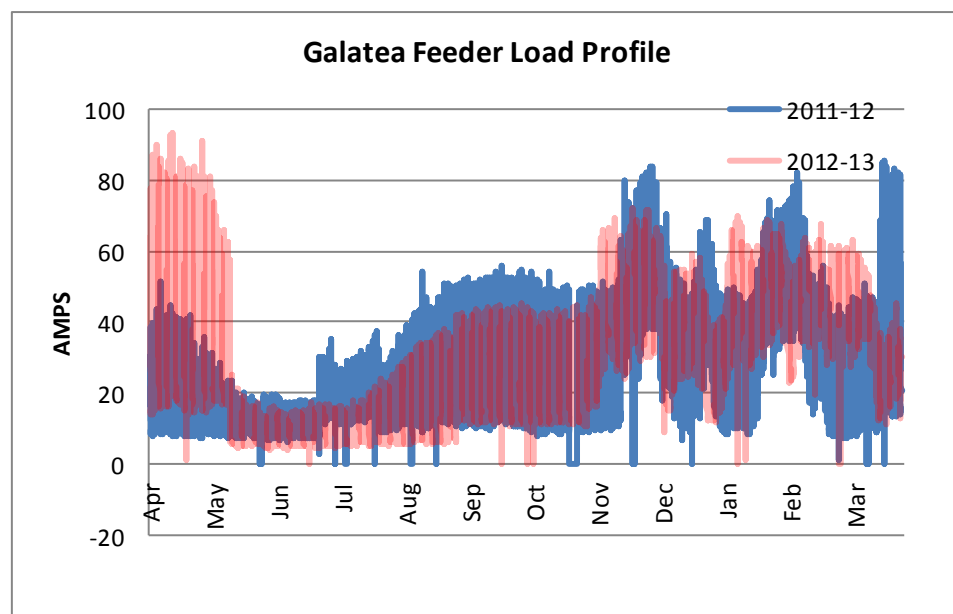


Figure 28 – Galatea and Jolly Feeders Load Profile

Galatea feeder comparing two years loads, showing the effect of weather on irrigation loads.

Jolly Road Feeder:

- Feeders load profile charts show the re-allocation of load between the two feeders;
- This feeder has had load growth due to irrigation;
- The load will increase as a result of some load transfer from Galatea feeder;
- There are no load constraints with this feeder; and
- Two of the tie lines to other feeders are constructed from smaller conductor, Squirrel and Ferret, which at this stage do not provide restrictions for load reinforcement by the Galatea feeder. There are two larger conductor tie lines available for reinforcement.

5.9.9. Fault Analysis

- The Galatea region has a relatively low rate of faults, as the network is generally in good condition;
- Due to the remoteness of the region from support staff, it suffers from high fault duration times; and
- This remoteness has been the key driver in the extensive reliability enhancement projects being undertaken in the region.

5.10. Kawerau Substation

5.10.1. System Description

The Kawerau GXP substation is a Transpower owned 110kV to 11kV substation and the Horizon Energy 11kV distribution network is directly connected to the Transpower assets. The Kawerau system load is dominated by large industrial loads and 5.2MW of Embedded Generation. The variation in load for the commercial and domestic base is very small in comparison to the industrial load.

Dedicated Transpower assets supplying the distribution network comprise a dedicated 11kV 10 circuit breaker bus and two 110/11kV transformers.

The Kawerau system has six feeders summarised below.

The Paper feeder was released back to the network due to an industrial site that no longer required the exclusive use of this circuit reducing load in 2009. This feeder now has a low level of industrial load on it that has recently been switched into the Paper feeder from the Kawerau feeder.

Due to the transformer arrangement of 110/11kV the Kawerau feeders are out of phase with any 11kV feeders sourced from the Edgumbe GXP.



There are two embedded geothermal generation plants connected to the system. These are discussed further in the Onepu feeder section.

Horizon Energy substation assets are located in a small building adjacent to the Transpower site.

Being in a geothermal area, Kawerau has a high level of H₂S induced corrosion, especially in the areas to the North of Norske Skog and in the lower lying areas in the town. Air break switches tend to have a higher than average failure rate due to environmental induced corrosion and high fault levels. Fully enclosed line switches are a good option for the Kawerau environment.

In 2013 a preliminary request to connect a large geothermal generator was received. Feasibility studies to connect this supply to the Pulp and Paper feeders through a new zone substation are underway with possible implementation 2015-16 if approved.

5.10.2. Service Area Covered

- Kawerau** The Kawerau feeder supplies the urban area of Kawerau. The Kawerau feeder is tied to the Plateau feeder at three places. In 2010 a circuit breaker was installed at one of the tie points between the Kawerau and Plateau feeders to allow reverse feeding of faults on either feeder. This was also undertaken to provide a reduced fault level, due to the back feed nature of the configuration, when fault finding in the section close to the Kawerau substation.
- A second circuit breaker was installed to feed a spur line that runs through a park and into a rural area to reduce the impact of faults in this zone on the main feeder.
- Plateau** Plateau feeder is the second feeder into the Kawerau town and the primary supply to the commercial area. It has tie points to the Kawerau feeder for support.
- Onepu** The Onepu feeder is rural and runs North from the substation along SH30. It is connected to a 300^{mm}² cable that is installed under the Norske Skog log yard to connect the geothermal generators TGI and TG2. This feeder also supplies the CHH Lumber site and the Norske Skog effluent treatment ponds, which both act as a 'load soak' for the generation supplied to the feeder. The Onepu feeder is supported by the Plateau feeder which can also provide an alternative path for the generation and provides reinforcement in supply for the treatment ponds.
- Plans for 2012 include splitting Onepu feeder to reduce overload risks when the embedded generation is not available.
- Paper** The high capacity Paper feeder was released by SCA in 2009. It has been re-configured to supply the Kawerau industrial zone and also still serves as a back-up supply for SCA. The load is light on this feeder, which has a summer no wind rating of 650 amps.
- Pulp** The Pulp feeder is the primary supply to SCA Hygiene. A back-up supply is available from the Paper feeder. Reducing to a single feeder in 2009 reduced the fault level on the SCA Hygiene site from 13kA to around 8kA.

5.10.3. Description of Assets

Table 5.33 summarises the major assets within Kawerau Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
Control Building	Wooden frame metal clad building		1988	No issues.
SCADA	Leeds and Northrup (Foxboro)		1992	Hardware has exceeded the ODV life.
DC Battery Bank	Switchtech 24V		1988	No issues.
Local Service	ABB transformer	200kV	1988	No issues.

Asset	Description	Rating Data	Date of Manufacture	Comments
Ripple Injection Plant	Zellweger static inverter 315/750hz Type SFU-G		1988	Study underway for replacement alternatives.
Ripple Control Plant Circuit Breaker	Yorkshire SCS circuit breaker		1999	No issues.
PLC – Load Control Plant	Mitsubishi AIS with RCS RC02 Conitel comms. interface		1999	Non-standard communications system. Seems to work okay with no issues.
Communications	Exicom Hawk 450Mhz UHF radio			

Table 5.33 – Kawerau Substation Assets

5.10.4. Substation Utilisation

Kawerau substation utilisation is affected by the industrial demand and embedded generation. Actual domestic consumer growth is shown at feeder level in the feeder Section 5.10.5. The Kawerau load reduced in 2008 with a 10MVA load reduction at the SCA Hygiene industrial site that was offset slightly by a new timber processing plant starting up in winter 2008. Overall utilisation is below the firm capacity of the GXP.

Kawerau -Load Statistics MW						
	2010	2011	2012	2013	% increase 2012-13	% Increase 3 years
Maximum	17.9	18.6	17.2	16.9	-1.5%	-4.7%
Average	11.76	12.16	10.54	9.27	-12.0%	-11.9%
Average-Top 100 Periods	17.20	17.79	16.19	15.00	-7.3%	-7.8%

Table 5.34 – Kawerau Load Statistics

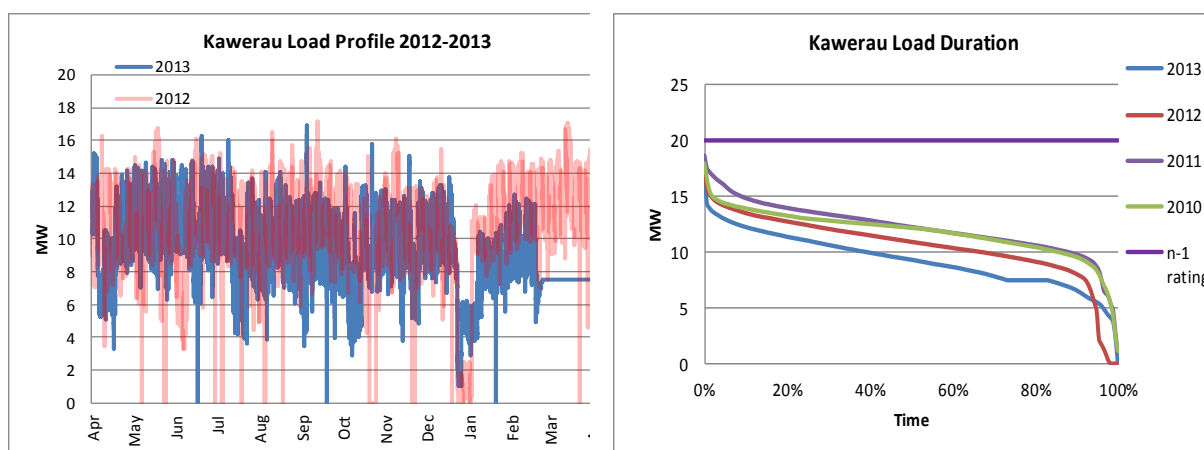


Figure 5.29 – Kawerau Load Profile

5.10.5. Load Growth

Individual feeder load growth is discussed in the Feeder Section's. The overall reduction in load is due to a reduction of industrial loads at SCA Hygiene.

5.10.6. Constraints

The Kawerau substation 11kV bus has a very high fault level which requires high fault rated cables and equipment to be used close in to the substation. Some of the equipment and cables identified on the Kawerau, Plateau and Onepu feeders are marginal for the fault levels that they are required to manage.

5.10.7. Kawerau Substation Feeders

Kawerau substation feeders are summarised in Table 5.35.

Feeder	Kawerau	Mt Edgecumbe	Onepu	Plateau	Paper	Pulp
Type	Urban	Rural	Rural	Urban	Industry	Industry
Overhead (km)	6.7	-	10.0	8.6	1.3	2.8
Underground (km)	8.7	-	4.2	13.3	0.7	0.1
ICP Connections	1674	6	66	1222	40	3
Substations	43	4	34	53	-	-
Installed Tx Capacity (MVA)	12.1	0.12	7.04	10.07	-	-
Maximum Load Amps	255		269	147	550	566
100 Peak Load Amps	234		242	112	409	553
Growth Rate	13.9%		-1.0%	-10.7%	na	-0.7%
Feeder Utilisation at Average 100 Peaks	84%		87%	40%	63%	85%

Table 5.35 – Kawerau Substation Feeder

Kawerau and Plateau Feeders

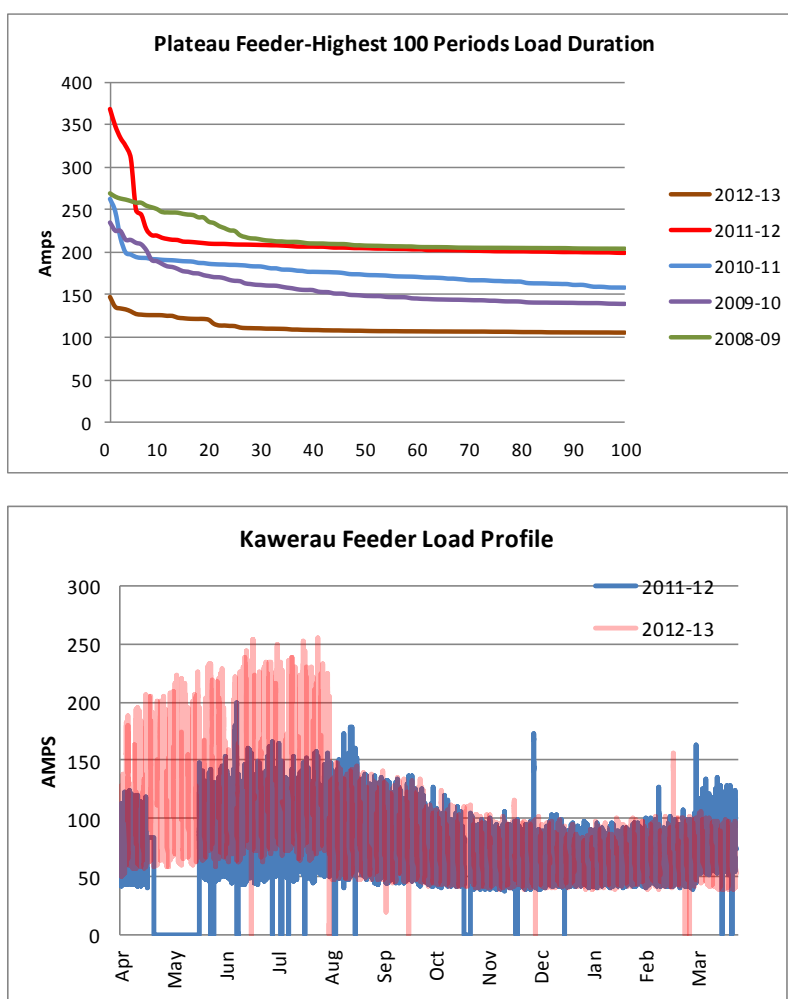


Figure 5.30 – Plateau Feeder Load Curves

- Kawerau feeder carried high loads when Plateau feeder failed during 2011;
- Kawerau and Plateau feeders show moderate growth consistent with average network growth patterns;
- Load growth will continue to be monitored to ascertain if feeder upgrades are required. Load growth has been increasing but long term predictions are for a population decline that is predicted to be faster than organic load growth;
- Kawerau and Plateau feeders have high fault levels close to the substation. The feeder cable from the Kawerau substation is rated below the maximum fault level presented from the 11kV bus. There is no plan to remedy this at this stage;
- Poor soil thermal resistivity due to the volcanic pumice nature of the soil lowers the full load rating of all the cables installed in the Kawerau region. This is not an issue at this stage except during peak load reinforcement periods. The soil resistivity exceeds 3Km/W;
- There are a large number of Magnefix Ring Main units in Kawerau that have been scheduled for condition based replacement during the next 15 years. Priority is given to replacing units on the main feeders or where the units are difficult to maintain due to number of customers supplied and outage availability; and
- Plateau feeder has a large length up Valley Road that has no reinforcement backfeeds. This affects maintenance works as well as reliability. A project has been

initiated to install a tie from Kawerau feeder to Valley Road to provide an alternative supply path.

- When supplying reinforcement loads both Plateau or Kawerau feeders can be loaded up to 90% of the feeder's full rated capacity. * The Plateau feeder main backbone conductor from River Road into the town is insulated to 33kV.

Onepu Feeder

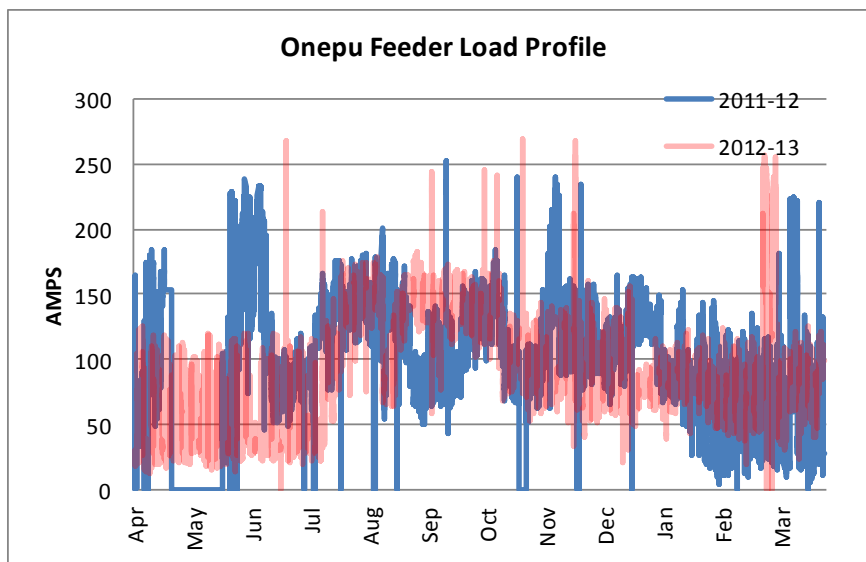


Figure 5.31 – Onepu Load Feeder

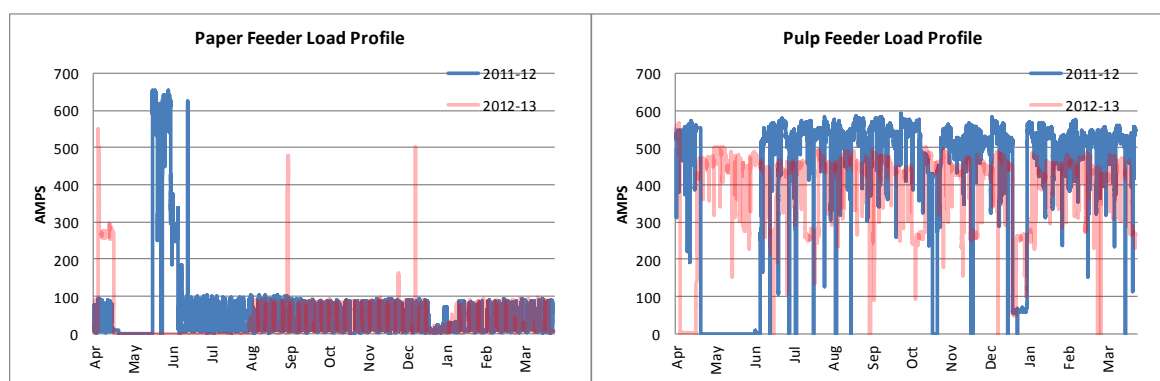
- Onepu feeder load profile is driven by generation;
- There is little rural load on the feeder so rural load growth can be assumed to be negligible, although there has been some additional loads added in supporting geothermal generation sites;
- The industrial load is a timber mill adjacent to the TGI generation plant and the Norske Skog effluent treatment ponds;
- Onepu feeder has a restriction on capacity if all load is off and the generation is operating to maximum. This is managed operationally by feeding some of the generation into the Plateau feeder. A no load situation is rare due to the 24 hour continuous operation of the local industry;
- A project was started 2013 to split Onepu into two feeders and upgrade the cable to TGI, TG2 and the lumber plant;
- Kawerau District Council is working to re-zone land as industrial along SH30, North of Kawerau. This area is supplied by the Onepu feeder and, if the development proceeds, the feeder loading and utilisation will be looked at as a step change;
- The feeder cable connecting the feeder to the Kawerau bus is marginal for the fault level incurred;
- A length of paper lead SWA cable running across the old Kawerau airfield that supplies the Norske Skog effluent treatment ponds is showing signs of UV degradation on the outer sheath but the cable test is satisfactory; and
- The Norske Skog aeration ponds are supplied by Horizon Energy owned transformers. These are open bushing ground mounted IMVA transformers in fenced enclosures. The enclosures are in poor condition and are being refurbished. The transformers are between 25-30 years old. A series of projects has been initiated to reduce the risk imposed by the exposed bushings by removing the transformers in turn, refurbishing the transformers, enclosing their bushings, and bunding the sites. This should enable these transformers to continue to give reliable service for the rest of their lives.

Mt Edgecumbe Feeder

- A number of faults have occurred on this feeder due to logging activities close to the Kawerau Substation. Owing to the fault levels these have had an effect on adjacent feeders due to voltage dip and SCA Hygiene has suffered from voltage dip induced outages. Logging operations have been completed in the region close into the substation so this problem should not occur again;
- Lightning is now the main cause of outages on this section of line as it spans the mountain top; and
- This feeder will be reconfigured onto Kawerau feeder in association with splitting the Onepu feeder to release the circuit breaker for the new Tarawera feeder.

Pulp and Paper Feeders

- These feeders were originally installed to supply the Caxton Paper Mill, now SCA Hygiene;
- SCA Hygiene released the Paper feeder in 2008 following a step load decrease and the feeder was re-designated to supply the Kawerau industrial zone;
- Paper feeder supplies the Kawerau industrial park and is a back-up supply to SCA Tissue. Pulp feeder is dedicated to SCA Hygiene; and
- The reduction on Pulp Feeder is a load reduction at SCA Hygiene.



Figures 5.32a and 5.32b – Onepu Paper and Pulp Load Profiles

5.10.8. Faults and Outages

- Historically the Kawerau feeders have had a low number of faults; but
- Due to the number of customers on the feeder and remoteness from support fault staff, any faults that do occur on Plateau or Kawerau incur high numbers of SAIDI minutes;
- High fault currents often cause secondary faults or further equipment damage;
- Both the Kawerau and Plateau feeders have small rural overhead sections along Spencer Avenue which are exposed to vegetation;
- Sectionalising circuit breakers were installed in urban Kawerau in 2010-11 to reduce the impact of faults;
- The Kawerau area was one of the first underground areas in the network using XLPE cable;
- There have been some failures with old XLPE cable and replacements have been scheduled for arterial route cables; and
- The Kawerau District Plan calls for all new circuits to be underground, although this is a discretionary activity.

5.11. Kaingaroa Substation

5.11.1. System Description

The Kaingaroa substation is located approximately 80km from Whakatane. It supplies the town of Kaingaroa and two timber processing plants, which dominate the load. The load within the Kaingaroa village is very small in comparison to the industrial base and the local population at the Kaingaroa village is declining.

Kaingaroa substation was built in 1994, is constructed on forestry land and is the newest substation in the network. Access to the substation is through the Kaingaroa Lumber Mill site. This was done to reduce the incidence of vandalism on the site.

Distribution of the 11kV supplies after the 11kV circuit breakers is by an ABB five switch SD Ring Main unit which serves as an 11kV bus system.

The station is normally operated with one transformer supplying the Mill load while the other transformer supplies the village. This arrangement was proposed from commissioning to ensure the common point of coupling between the village and the Mill is on the 33kV system. The reason for this is to reduce the volt drop annoyance that the village may see from the operation of the large motors on the Mill site. The impedance of the transformers was also chosen to assist in the reduction of this impact.

A project is underway to supply Kaingaroa from a 33kV bus section at Galatea which provides a greater level of security of supply to the Kaingaroa circuit.

5.11.2. Service Area Covered

There are four feeders; Dunn Road feeder that supplies the town, and three feeders that supply the Kaingaroa Lumber Mill. The Dunn Road feeder services 187 consumers. Two of the other feeders supply directly to the two transformers on the Mill site and the third supplies a transformer located in the Mill yard.



5.11.3. Description of Assets

Table 5.36 summarises the major assets within the Kaingaroa Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV Bus	Overhead aluminium conductor	Not available	1994	
33kV Circuit Breaker KA102 and KA202	Cooper Power VWVE38X With Form 4C controller	38 kV 560 amp Fault rating 12kA	1994	No issues.
33/11kV Transformer T1 and T2	3 phase ABB ground mount open 33kV bushing	4 MVA ONAN 5.33 MVA ONAF 4.68% Z Dyn11	1994	No Issues.
Tap Changers	ABB UBBDT 200/150 Range +8% to – 16%	33kV 200 Amp 25 steps	1994	Transformer tap changer failed early in the transformer life. An increased frequency of maintenance is recommended by ABB on these tap changers. Maintenance interval 100,000 operations, tap life 500,000 operations.
Tap Change Controller T1	RMS model 2VI62K4		1994	No issues.
Tap Change Controller T2	RMS model 2VI64S – BBBAA		2010	Replaced failed controller.

Asset	Description	Rating Data	Date of Manufacture	Comments
11kV Distribution Switchboard KA31 and KA32	Reyrolle, LMVPT/QMRC vacuum circuit breakers	Circuit breakers 630 amp Fault rating 25kA 3 sec Bus rated 1250 amps	1994	Manufacturer has recently issued a modification to improve door blast resistance and allow closed door racking and improved chamber venting.
Control Building	Portacom metal clad building		1994	No issues.
SCADA	Leeds and Northrup (Foxboro) C50		1994	Hardware has exceeded the ODV life. Programming hardware obsolete.
DC Battery Bank	Switchtech 24V			No issues.
Local Service	ABB transformer	30kVA	1994	No Issues.
33kV Protection	Cooper Power Kyle form 4C		1994	No issues.
Feeder Protection	Reyrolle NEI GAD		1994	Relays have no metering capabilities.
Transformer Protection	Reyrolle 5B3		1994	No issues.
Communications	Exicom 159Mhz VHF radio		1994	Radios are scheduled for replacement 2014.

Table 5.36 – Kaingaroa Substation Assets

5.11.4. Substation Utilisation

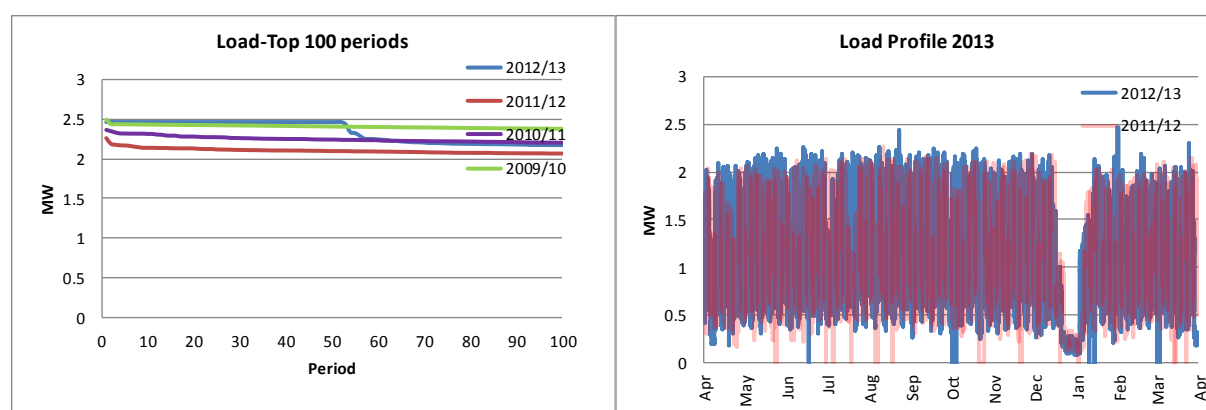
Kaingaroa -Load Statistics (MW)							
	2010	2011	2012	2013	% increase 2012-13	Avg incr per year	n-1 Utilisation
Maximum	2.5	2.4	2.3	2.5	8.9%	-0.4%	46%
Average	1.42	1.34	1.28	1.32	3.1%	-2.4%	25%
Average-Top 100 Periods	2.4	2.3	2.1	2.3	11.4%	-0.9%	44%

Table 5.37 – Kaingaroa Load Statistics

The Kaingaroa load is dominated by the industrial sawmilling load. Dunn Road feeder supplies the town and a smaller timber processing site, and has 24 substations with an installed capacity of 3.4MVA.

Load growth is static with a slightly declining profile.

There have been pre-feasibility requests for an additional 1MVA load and an embedded generating connection but these are not yet formal requests to connect.



Figures 5.33a and 5.33b – Kaingaroa Load Curves and Load Profile

Constraints

If a reserved load of 2500kW at Kaingaroa is ever uplifted the complete 33kV system including Galatea, will suffer voltage compliance issues when supplied from Edgecumbe CB52 during high load periods.

The single 33kV line from Galatea to Kaingaroa provides no redundancy. Reliability of this circuit is managed by regular line inspections and vegetation control. There are no load restrictions at Kaingaroa apart from the issue of support when the normal supply from Aniwhenua is disrupted and the alternate supply from Edgecumbe is used. There are two SCADA controlled switches located at the Galatea substation that switch the Kaingaroa line between the two Galatea 33kV feeders but these are not an automatic change-over, requiring operator intervention.

5.11.5. Faults

Due to the remoteness of Kaingaroa and the travel time from Whakatane, faults tend to take a long time to resolve but have a low SAIDI impact due to the low number of customers served. There is only one fault response person located in Murupara.

5.12. Kopeopeo Substation

5.12.1. System Description

The Kopeopeo (Kope) substation is a two transformer 20MVA 33kV/11kV zone substation located in the Whakatane Kopeopeo business area on the King Street service lane. The Kope substation was partially redeveloped in 1991 when the control building was constructed and new 11kV switchgear installed adjacent to the transformer site. The site is bounded by residential housing on three sides.

The two 33kV incoming supplies are connected to an overhead 33kV bus that is normally run open. T1 transformer is a 10/13.3 MVA transformer. T2 was replaced in 2013 with a 12/16 MVA unit.

5.12.2. Service Areas Covered

Kope substation supplies the Whakatane urban region from five feeders; Strand North, Strand South, Rex Morpeth, Victoria and King Street feeders as shown in Table 5.38 below:

Feeder	Area Supplied
Strand North	Primary supply to the Whakatane CBD. Supplies a mix of domestic and commercial customers. This 11kV feeder is completely underground.
Strand South	Primary supply to the Whakatane CBD. Supplies the Heads and Hillcrest. This 11kV feeder is completely underground apart from a small section up Waiewe Street and supplies a mix of domestic and commercial customers.
Rex Morpeth	Supplies domestic and commercial customers on Goulstone Road and Commerce Street. This feeder is mostly underground. There are two schools supplied by this feeder.
Victoria Avenue	Load is predominantly domestic. There are two schools on this feeder. Mostly overhead conductor but the Awatapu end from Kowhai Street is underground.
King Street	Supplies the Kopeopeo commercial area, the hospital, and domestic loads in the lower King Street region to the South. Mix of overhead and underground.

Table 5.38 – Service Areas Covered



Kopeopeo Substation 2013 showing new T2 transformer behind T1 transformer

5.12.1. Description of Assets

Table 5.39 summarises the major assets within the Kope Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV cable	Tuhoe feeder St Joseph's feeder	3x 1 core 33kV XLPE 185sqmm ducted aluminium conductor Defined conditions rating 10MVA	1986	Soil thermal resistivity rating is 3Km/W, tested in 2010. This de-rates the cables capacity by 0.76 to 13.2 MVA.
33kV Circuit Breaker KS10	3 phase ASEA type HLC36/630B Serial number 2177/514	33kV 600 amp Fault rating 11.6kA 3 seconds	1967	No known issues. Replacement with indoor equipment scheduled
33kV Circuit Breaker KS4	3 phase ASEA type HLC36/630B Serial number 2177/513	33kV 660 amp Fault rating 11.5kA 3 seconds	1967	No known issues. Replacement with indoor equipment scheduled
33/11kV Transformer T1	3 phase ASEA	10 MVA ONAN 13.3 MVA ONAF 8.69% Z Dyn11	1986	Transformer has no oil containment. Transformer connected as Dyn3
T1 Tapchanger	Ferranti DS300	33kV 300 amps (CER 480 amps) 15 steps	1986	No issues.
33/11kV Transformer T2	ABB 3 phase transformer ABB 3 phase unit with Reinhausen vacutap	12MVA ONAN 16MVA ONAF 11.47% Z@ 16MVA Dyn11	2013	ABB Biotemp environmentally friendly synthetic transformer oil installed. Transformer connected as Dyn3

Asset	Description	Rating Data	Date of Manufacture	Comments
11kV Cable	Transformer T1 to switchgear	6 x 1c 630sqmm AL XLPE	2010	
11kV Cable	Transformer T2 to switchgear	6 x 1c 630sqmm AL XLPE	2013	
11kV Distribution switchboard	Reyrolle, LMVPT/QMRO vacuum circuit breakers, 8 panels 7 circuit breakers and bus coupler	Circuit breakers 630 amp Fault rating 25kA 3 sec Bus rated 1250 amps Incomer 800 Amp	1991	Without upgrading the 800 Amp incomers limits the maximum usable single transformer size Kope to 16MVA
Control Building	60m ² wooden frame metal clad building		1991	No issues.
SCADA	SEL 2411 RTU		2013	
DC Battery Bank	Eaton 48V	450Ah	2013	
Local Service	ETEL	50kVA		A re-design of local service completed 2012
33kV Protection	SEL751		2013	
Feeder Protection	SEL751A		2013	
Transformer Protection	SEL 787 and 751A relays		2013	Earth fault and transformer differential
Tap Change Controller	SEL 2414		2013	

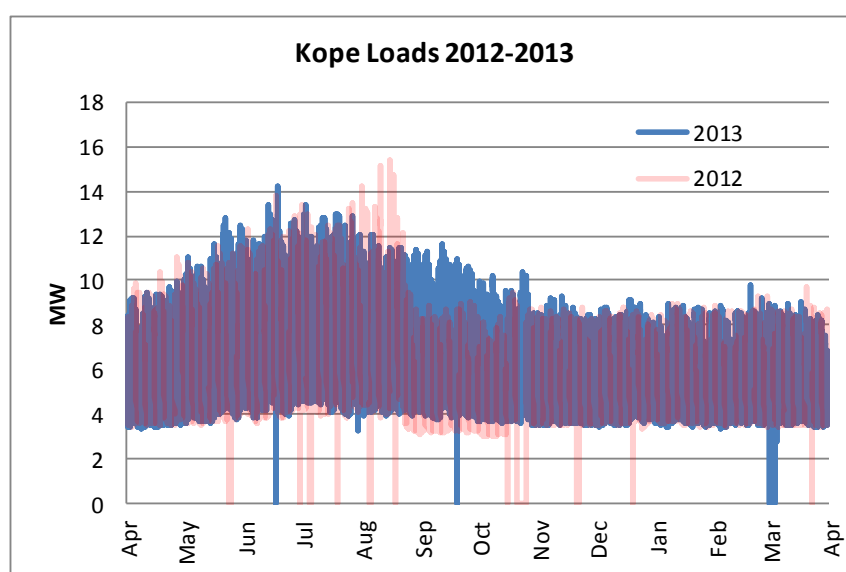
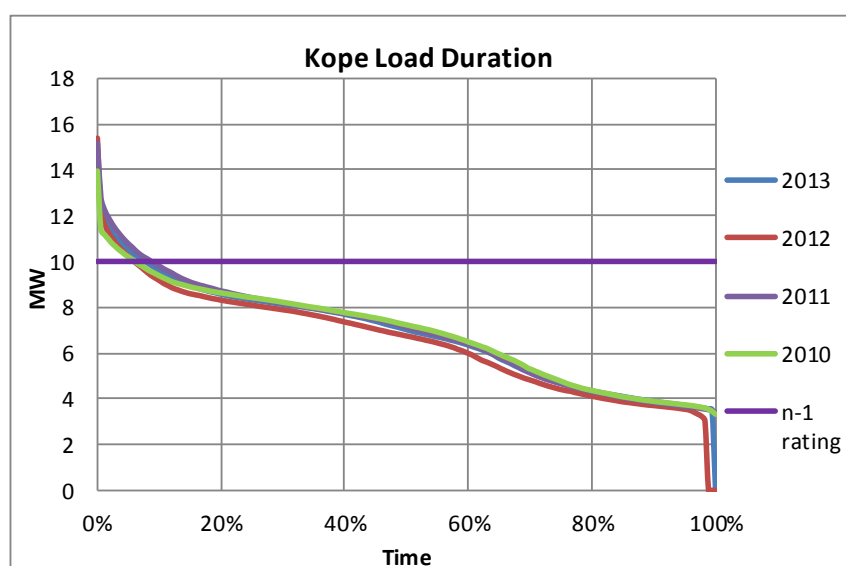
Table 5.39 – Kope Assets

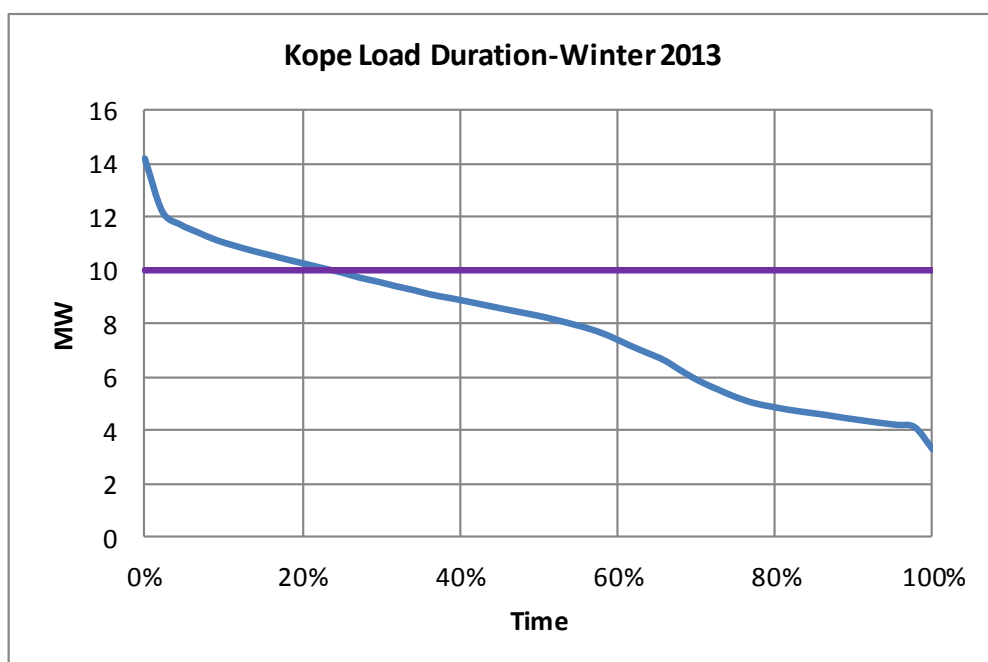
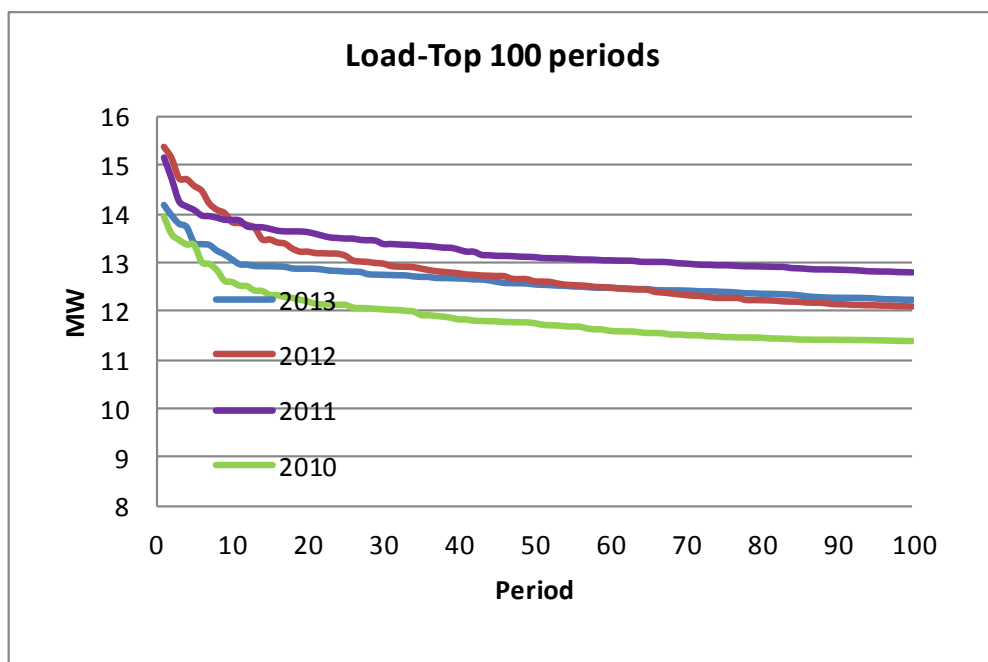
5.12.2. Substation Utilisation

Kope substation is the most heavily loaded substation within the Horizon Energy network. The following table and figures below indicate the load profile and load duration data for 2009 to 2013. The substation exceeded its n-1 capability for 27% of the time during winter 2012, up from 25% in 2009.

Kope - Load Statistics (MW)							
	2010	2011	2012	2013	% increase 2012-13	Avg incr per year	n-1 Utilisation
Maximum	14.0	15.2	15.4	14.2	-7.8%	0.6%	142%
Average	6.85	6.89	6.48	6.82	5.3%	-0.2%	68%
Average-Top 100 Periods	11.9	13.3	12.8	12.7	-1.3%	2.1%	127%

Table 5.40 – Kope Load Statistics





Figures 5.34a and 5.34b– Kope Load Duration charts

5.12.3. Notes on Load Growth

- Peak load reduction is due to an improved load control algorithm that reduces restoration spikes;
- Population growth within the town is restricted to infill housing or apartments. A Whakatane District Council report in 2007 indicated there was the potential to develop approximately 200 residential dwellings within the Whakatane town but in the last three years there has been little building activity;

- The Whakatane Urban Growth Strategy, issued by the Whakatane District Council, has identified the Kopeopeo area bordered by Stewart Street, Hinemoa Street, Victoria Avenue, and King Street as an area for high density (Intensification) population growth for up to 25 dwelling units per hectare;
- Significant commercial developments include a 2013 refurbishment at the Whakatane Hospital and the Te Whare Wananga o Awanuiarangi expansion completed 2012.



Figure 5.35 – WDC Kopeopeo Intensification Area

- As growth around the Kopeopeo supply area increases, further load will be shed from Kope substation onto the adjoining Station Road substation, and the proposed substations at Gateway Drive and the CBD substation.

5.12.4. Constraints

- Kope Substation exceeded n-1 capability for around 23% of the time during winter 2012. The new T2 transformer has corrected this;
- Soil thermal resistivity at Kope was tested in 2010 with the resultant fully dry thermal resistivity exceeding 3.0Km/W. This lowers the thermal full load rating of all the feeder cables into and out of the Kope substation to 13.2 MVA. Large lengths of the 33kV feeder cables and 11kV feeder cables are installed under asphalt and the soil condition is totally dry in these areas. A project has been identified to correct this; and
- Incomer circuit breakers are 800 amps (15.2MVA @ 11kV). There is no plan to correct this at this stage.

5.12.5. Substation Vulnerability

Risks and vulnerability of the Kope substation site from a CDEM lifelines perspective are summarised in Table 5.41 as follows:

Vulnerability	Kope Substation	Mitigation
Communications	Communication is used for remote control of switching operations, load and security monitoring.	A fibre optic ring to provide communication resilience and mesh Kope, Station Road and Gateway has been laid.
Site Access Requirements	Access is required in the case of: <ul style="list-style-type: none"> • Loss of communications • Abandonment of Commerce Street control room • Non operation of equipment 	Risk of loss of urban road access is low. Roads accessing the site are King Street service lane accessed from either Victoria Avenue or James Street. There is sufficient clear area to land a helicopter close to the Kope substation site.
Total Loss of Kope Substation	Total loss of Kope substation, or the two 33kV feeders supplying Kope, or the two transformers, would result in a sustained power outage to the complete Whakatane urban area, including the CBD. Limited supply is available from adjoining substations but with insufficient capacity to fully supply all customers.	Connection of 11kV to adjoining substations. Probability of rolling outages to manage load.
Partial Loss of Kope Substation	Partial loss of one Kope transformer, or one of the two 33kV feeders supplying Kope, could result in a short power outage to the complete Whakatane urban area, including the CBD.	Connection to adjoining Station Road substation.
Natural Hazards	Natural hazards that the sites could be exposed to are: <ul style="list-style-type: none"> • Flood • Earthquake • Tsunami • Volcanic activity • Wind 	Risk: <ul style="list-style-type: none"> • Low • High • Medium • Low • Low
	Disaster recovery plans are held in the Horizon Energy disaster recovery quality manual.	
Network Impact Risk	Kope is critical to Whakatane urban area and supplies 21% of the network.	Limited support from Station Road.
Human Habitation Risk	Kope is normally an unmanned site.	Electrified security fence to deter unauthorised access. Access door alarms to SCADA.
External Services	Power is supplied from the Kope substation local service transformer. There is no telephone at the substation. All critical services are on 24 volt battery banks.	

Table 5.41 – Substation Vulnerability

5.12.6. Kope Substation Feeders

Kope substation feeders are summarised in Table 5.42 below:

Feeder	Rex Morpeth	Strand North	Strand South	King Street	Victoria Avenue
Type	Urban	Urban	Urban	Urban	Urban
Overhead (km)	0.6	0	0.24	4.2	5.6
Underground (km)	5.3	6.3	6.8	0.6	2.6
ICP Connections	878	1085	921	1000	1388
Substations	23	24	18	15	18
Installed Tx Capacity (MVA)	6.3	6.9	6.1	4.5	3.9
Maximum Load Amps	217	173	176	235	170
100 Peak Load MVA	202	155	147	156	150
5 year average growth rate	4.1%	-0.4%	-2.5%	12.1%	2.1%
Feeder Utilisation at Average 100 Peaks	72%	41%	44%	56%	39%

Table 5.42 – Kope Substation Feeders

5.12.6.1. Rex Morpeth Feeder

- Urban supply feeder, mostly underground;
- The feeder supply cable exiting from Kope substation was upgraded to 300sqmm in 2012;
- The Rex Morpeth feeder had shown an above average load growth over the past three years but this growth has slowed down;
- Growth driven by increased commercial developments in Commerce Street, including a new supermarket. This load growth is expected to continue to increase but at a lower rate, as the CBD region expands and lower value commercial buildings and residential dwellings around the Commerce Street/Merritt Street areas are redeveloped;
- The region supplied by Rex Morpeth has been predominantly zoned business 1 and business 2 within the Whakatane District Council District Plan;
- Peak maximum loads are due to reinforcement of the Strand South feeder by this feeder;
- In 2010 a high capacity connection was made to the new Mokorua feeder to provide mid-point feeder reinforcement. Various 95sqmm cable sections are progressively being upgraded to maximise the load capability of this connection.

Constraints

- The Rex Morpeth feeder is approaching its maximum rating when used for supply reinforcement for the Strand South feeder. The Strand South feeder does not have sufficient spare capacity to fully reinforce Rex Morpeth feeder whilst supplying its own load;
- A new 185sqmm tie cable was installed in 2011-2012 along Douglas Street onto the new high capacity Mokorua feeder supplied from Station Road. This link provides a second reinforcement option for the Rex Morpeth feeder. Some existing sections of the 95sqmm cable restrict full 100% level of reinforcement; and

- Load sharing between Mokorua and Strand South does provide full reinforcement.

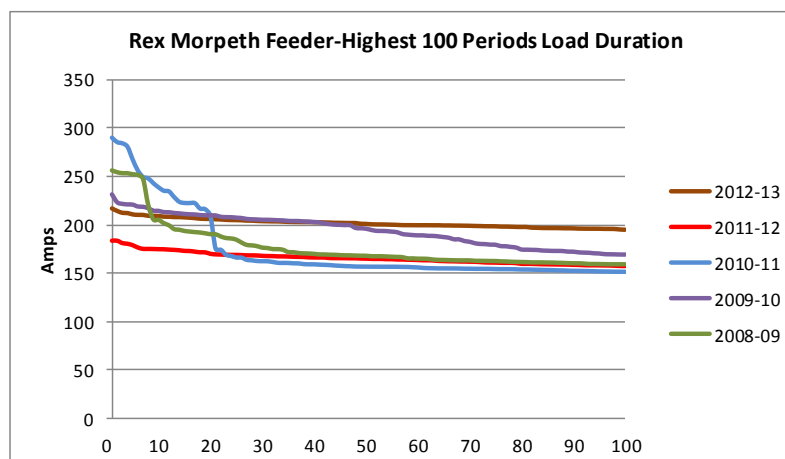


Figure 5.36 – Rex Morpeth Load Curves

5.12.6.2. Strand North Feeder

- Strand North feeder has seen negative load growth, mainly attributed to lack of growth in the Whakatane CBD commercial area and business displacement to the Hub area. Load is expected to increase as commercial confidence increases and empty commercial premises are occupied; and
- The Strand North and Strand South feeders provide reinforcement support to each other at four separate tie points.
- Various Sections of 95sqmm cable along Bracken Street have been upgraded to provide load reinforcement capability.

Constraints

- There are currently no constraints with this feeder

5.12.6.3. Strand South Feeder

- Growth is influenced by transferring loads from Mokorua and City South feeders.

Constraints

- During peak periods Strand South does not have sufficient capacity to fully reinforce Rex Morpeth feeder. Some sections of the 95sqmm conductor have been scheduled for loading driven replacement.

5.12.6.4. Victoria Feeder

- The first sections of the Victoria feeder are overhead with underground sections at Kowhai Street through to the Awatapu subdivision. The Victoria Avenue feeder has tie point connections to the King Street, City South, and Piripai feeders;
- 6MVA tie cable across the Landing Road Bridge to the Piripai feeder provides reinforcement to the Hub and Coastlands domestic loads from Kope;
- Load is predominantly domestic. There are two schools on this feeder;
- Load growth has been above average over the past three years, attributable to infill housing and upgrades at the Whakatane Intermediate School, and re-distribution of load at the hospital. Winter load is increasing which may be driven by domestic heat pump installations; and

- The Victoria feeder has no known supply constraints.

5.12.6.5. King Street Feeder

- Load growth value outlined above is due to reinforcement;
- King Street feeder supplies the Whakatane Kopeopeo business and local domestic areas;
- Primary feeder to the Whakatane Hospital;
- The hospital upgrade is expected to increase the feeder load in 2013; and
- There are no known supply constraints.

5.12.6.6. Faults and Outages

- Rex Morpeth feeder has had no equipment failure outages during the previous ten years; and
- An upgrade program during 2008/11 was completed on all critical ring main units to ensure a better seal for interconnection bus couplings due to the high failure rates that were being experienced.
- Strand South and Victoria have both suffered a number of faults on air break switches and ring main units.
- Partial discharge testing of ringmain units has identified a number of potential faults that have been averted by proactive repairs

5.12.7. Kope Substation and Feeders Development Plans

Kopeopeo loading

The load management plan for Kope substation is to distribute the existing load between Kope and Station Road substations in the short term, and once completed, the proposed Gateway substation and/or CBD substations in the longer term. The Kope substation will be predominantly re-configured to supply the Whakatane CBD from the three existing 11kV feeders that run to that area.

The new Kope T2 transformer installed 2013 was sized using a 50 year expected life. Loading calculations determined that two 24MVA transformers were the appropriate sizes to support the future loads. For Kope substation to support a 24 MVA transformer the switchgear, 33kV, and 11kV feeders would all need replacing, as well as additional feeders installed. A better solution that provided more versatility and had a better NPV return is to procure smaller 16MVA transformers for Kope that match the existing installed distribution, and to develop a 16MVA substation located in the Whakatane CBD to cater for the additional future loads.

Until a CBD substation is established, load sharing between Station Road and Kope substations will be used to manage load. Load prediction data for the combined substations is included in Section 5.4 Demand Forecasts. If Station Road and Kope are considered as four separate transformers supplying common loads then the n-1 capability of the two sites combined is 30MVA.

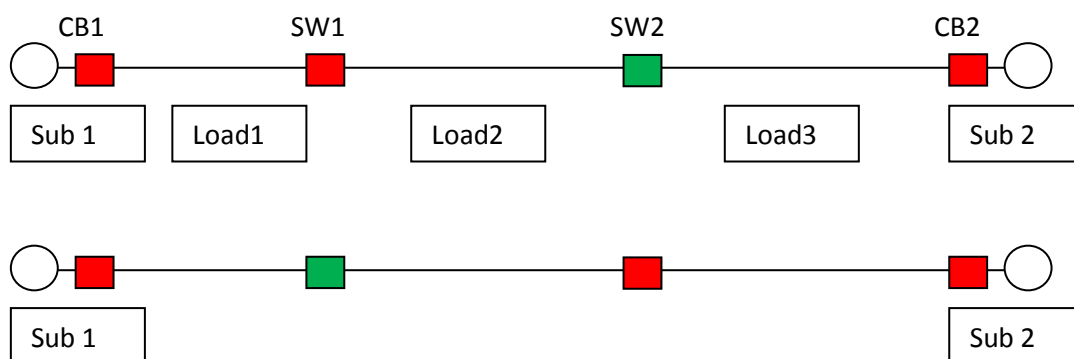
To enable the load to be moved between Station Road and Kope, various sections of feeder conductor have been identified for upgrade to enable greater load carrying capability. Ultimately automated switches and/or circuit breakers with intelligent protection schemes between the three substations will enable the operator to selectively switch load as required in the case of overload or loss of main supply.

Automated Load Transfer and Fault Restoration

A simple way to describe this principle to share the load is shown below. Automated switches or circuit breakers at 1/3 or similar points on feeders between the substations allow the load to be shifted between substations by opening or closing the switching devices.

If the devices are circuit breakers with intelligent protection the line could be run in an open or closed ring configuration with both ends live, with the protection controlling the switching. If switches are used, SCADA can provide the intelligence and operate switches if the load exceeds predetermined levels.

In the following sample, SCADA, monitoring the load at both Sub 1 and Sub 2, detects that load has exceeded the pre-set parameter at CB1, and that CB2 has capacity to take the load beyond SW1, so automatically closes SW2 then opens SW1 to transfer load 2 to Sub 2.



The same principle can be applied to faults on meshed circuits. If the load through each switching point is known then logical decisions can be made to transfer the load to match the supply availability.

All switchgear currently being installed is either capable of SCADA control or capable of being upgraded to SCADA control.

Feeder Development

Certain feeder conductor sections have been identified for upgrade as the load approaches the reinforcement capability of the feeders. Replacement is scheduled when feeders under reinforcement exceed 110% of the cable section capacity. Load growth is continually monitored to determine timely scheduling for replacement of cable sections.

Horizon Energy has run an overhead to underground plan in conjunction with the Whakatane District Council and the Eastern Bay Energy Trust up until 2009. This has been temporarily put on hold at the instigation of the Whakatane District Council but is expected to be resumed 2015.

Kope T1 and T2 Replacement

Kope T2 transformer was replaced in 2013 with a 12/16 ONAN/ONAF transformer.

With the substation peak load exceeding 15MVA the substation still does not achieve a 100% N-1 capability. The only way to achieve this is to replace T1 and continue with the off-loading of loads to other substations. Replacing the T1 transformer would provide an opportunity to have matched low impedance transformers for improved load sharing. This project, coupled with removal of the outdoor 33kV bus and installation of 33kV indoor circuit breakers would transform Kope into a modern, n-1 capacity substation with a planned life of 50 years.

The T1 transformer, scheduled for replacement in 2044, could easily be relocated and is a good match for:

- Replacing the Plains single phase transformers,

- New CBD substation;
- New Gateway Substation; and
- Ohope Substation T1 replacement.

A risk assessment in 2011 identified a number of issues with the Kopeopeo substation. In summary, the major risks identified are:

- The small spacing between the two 33/11 kV transformers and proximity to the control building creates a common fire/explosion risk. This has been partially resolved with the placement of the new T2 transformer
- There are no oil containment bunds for the 33/11 kV transformer.
- The 33kV bus section minimum clearances are an identified risk

Procurement of a transformer matched to T2, complete with bio-degradable synthetic oil which is fire retardant would resolve the fire risk as well as reducing the environmental impact.

5.13. Ohope Substation

5.13.1. System Description

The Ohope substation is a single bank 5MVA 33kV/11kV zone substation located at Ohope on Maraetotara Road. The 9.3km, 33kV Dog conductor sub-transmission circuit that supplies this site is fed from the Te Rahu substation. The transformer bank consists of four single phase 1.66MVA units.

The Pohutukawa and Harbour feeders are supplied from the Ohope substation.

5.13.2. Service Area Covered

Feeder	Area Supplied
Pohutukawa	West from Ohope substation. Predominantly overhead but underground along West End. This feeder has a tie point connection to the Station Road substation via the Mokorua feeder.
Harbour	Supplies the region East of the Ohope substation. This feeder is also a mix of overhead and underground and supplies the Cheddar valley as well as the Harbour/Ocean Road areas of Ohope. This feeder is supported by its connection to the Pohutukawa feeder and to the Waimana feeder that is supplied from the Waiotahi substation. Break before make is required for the latter due to the phase shift that exists between the two substations.

Table 5.43 – Service Areas Covered



5.13.3. Description of Assets

Table 5.44 summarises the major assets within the Ohope Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV Circuit Breaker CB80	English Electric OKW3, minimum oil	600 amp, 17.5kA Is		Poor condition. Scheduled for age/condition based replacement.
33/11kV Transformer T1	n x 1 phase Bonar Long	1.667 MVA ONAN 8.46%, Dyn11	1962	Transformer is scheduled for load based replacement 2013.
T1 Tap changer	Fuller Electric type EH	33kV, 76 amps 15 steps – 6.25+12.5%	1962	Will be replaced with Transformer mounted tap changer.
11kV CBs	Cooper power KFE Vacuum		1978	Scheduled for age based replacement.
Control Building	60m ² Concrete block building		1978	No issues.
SCADA	Leeds and Northrup (Foxboro)		1991	Replacement with industry standard DNP3 capable devices has been scheduled.
DC Battery Bank	Switchtech 24V			No issues.
Local Service	ABB transformer			
33kV Protection	GEC Multilin SR760	Transformer Protection	1999	Recently failed due to flat battery.
Tap Change Controller	Reyrolle SuperTapp RVM/5m		1991	Tap change controllers are approaching ODV end of life, although no reliability issues are being experienced.
Communications	Exicom Hawk 450Mhz UHF radio			Radios are scheduled for replacement.

Table 5.44 – Ohope Substation Assets

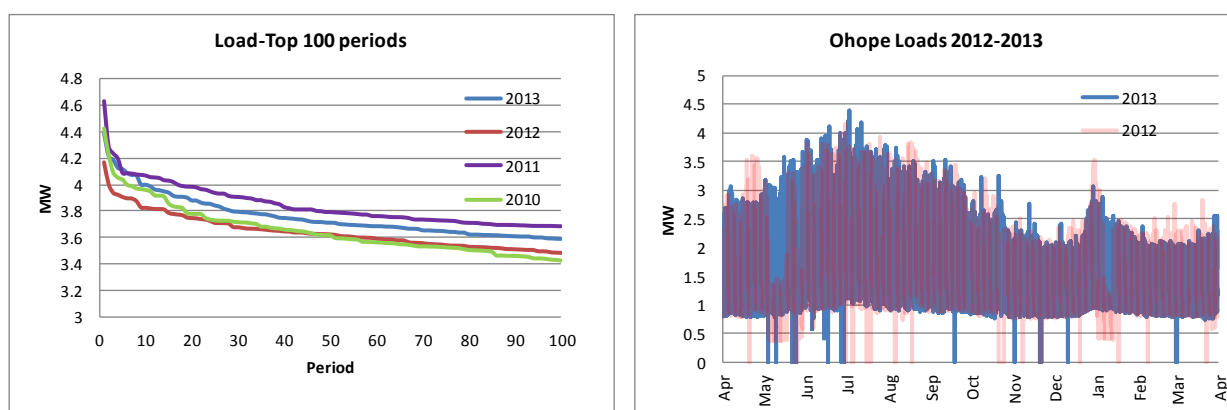
5.13.4. Substation Utilisation

Ohope loads have stabilised due to improved load management controls. A warm 2011 winter saw a reduction in maximum and average demand.

Ohope - Load Statistics (MW)							
	2010	2011	2012	2013	% increase 2012-13	Avg incr per year	n Utilisation
Maximum	4.4	4.6	4.2	4.4	5.3%	-0.3%	88%
Average	1.62	1.58	1.53	1.61	5.0%	-0.3%	32%
Average-Top 100 Periods	3.7	3.8	3.6	3.8	3.2%	1.0%	75%

Table 5.45 – Ohope Load Statistics

5.13.5. Load Growth



Figures 5.37a and 5.37b – Ohope Load Curves and Load Duration

Load growth is flat over the 4 year measured period. The load has increased over the previous year.

The Whakatane District Council has a block of land suitable for up to 250 domestic residences at the harbour end of the Ohope spit. Once released and developed, this could add another 6-800kW of peak demand to the system. In the longer term higher density domestic developments could be expected for Ohope, especially on the Pohutukawa feeder.

There is ongoing development of lifestyle blocks and quality housing being built in the peninsulas that overlook the Ohiwa Harbour.

The Ohope load demonstrates a peak over the December-January holiday period each year.

5.13.6. Constraints

- The 33kV feeder to Ohope is a single point of supply risk; and
- Ohope has reinforcement from the Station Road substation via the tie between the Mokorua and Pohutukawa feeders.

The Mokorua feeder was upgraded in 2009 to help improve the voltage profile when supplying Ohope. However, during peak loads there is likely to be voltage quality issues at the Eastern end of the Harbour feeder under those circumstances.

Enhanced maintenance of the Ohope 33kV feeder is still the most cost effective means of providing security of supply to Ohope, although the strengthening of ties between both the Station Road and Waiotahi substations is still required to improve support to Ohope.

A possible new substation between Ohope and Whakatane in the Mokorua region would provide support for Ohope as well as catering for any development on the land block between Otarawairere and Whakatane. Any such substation would only be developed if the load in the area dictated.

There are no load constraints with the Harbour feeder supplying the domestic region, but the harbour side of this feeder has no alternative supply. A project to split the feeder and install a third feeder out of the Ohope substation as support started 2013.

The section of the Harbour feeder through to Waimana is a Ferret conductor and whilst the conductor is physically capable of carrying the Ohope load the full load voltage drop makes this an unsuitable feeder for supplying the full Ohope substation load. Support is really only available for the Harbour feeder load with some loss of quality along the harbour end of the feeder. There is also a phase shift between these two feeders which requires a break before make scenario.

5.13.7. Lifeline Risk Assessment

Vulnerability	Ohope	Mitigation
Total Loss of Ohope Substation	Ohope substation is a single feeder substation with one three phase transformer.	Limited reinforcement at peak loads from Station Road and Waiotahi.
Communications	Primary communications to Ohope substation is by a single link UHF radio from Putauaki radio repeater site. Communication is used for remote control of switching operations, load and security monitoring.	Not critical for operation as systems can be operated manually.
Site Access Requirements	Access is required in the case of: <ul style="list-style-type: none"> Loss of communications Abandonment of Commerce Street control room Non operation of equipment 	Roads accessing the site are Pohutukawa Avenue East from Wainui, Opotiki and West from Whakatane. There is sufficient clear area to land a helicopter near the Ohope substation site if required.

Vulnerability	Ohope	Mitigation
Natural Hazards	Natural hazards that the sites could be exposed to are: <ul style="list-style-type: none"> Flood Earthquake Tsunami Volcanic activity Wind 	Risk: <ul style="list-style-type: none"> Low High High Low Low Disaster recovery plans are available to all staff.
Network Impact Risk	Supplies 8% of the network customers, mostly urban.	
Human Habitation	Ohope is an unmanned site.	Access door and window alarms to SCADA.
External Services	All critical services are on 24 volt battery banks.	

Table 5.46 – Lifeline Risk Assessment

5.13.8. Ohope Feeders

Ohope substation feeders are summarised in Table 5.47 below:

Feeder	Harbour	Pohutukawa
Type	Urban Rural	Urban
Overhead (km)	44.4	4.0
Underground (km)	14.0	6.6
ICP Connections	1291	739
Substations	127	20
Installed Tx Capacity (MVA)	7.2	3.1
Maximum Load Amps	144	148
100 Peak Load Amps	125	72
Growth Rate	1.1%	0.8%
Feeder Utilisation at Average 100 Peaks	45%	26%

Table 5.47 – Ohope Substation Feeders

Both feeders are a mix of overhead and underground. The growth rate is positive which is consistent with organic growth. There are no load constraints with either feeder. The feeders cross support each other adjacent to the substation.

5.13.9. Fault Analysis

Faults on these feeders have a high SAIDI impact due to the population density. Restoration time is relatively short for Pohutukawa due to the ability to mesh with Harbour and Station Road, but the Harbour feeder has no ability to reinforce the urban section.

The domestic Harbour feeder section is seven kilometres in length. The rest of the feeder supplies the rural Wainui Valley region, connecting to the Waiohau supplied Waimana feeder at Kutarere. This spur is protected by a circuit breaker where it branches from the main line, which prevents rural faults from affecting the domestic supply. An automated tie point switch at Waimana allows remote connection of the Waimana feeder to supply this load but as the Waiohau supply is out of phase with Edgecumbe then the feeder must be isolated prior to closing.

5.13.10. Ohope Development Options

Ohope is a difficult area to reinforce with a single 33kV feeder into the area and having a single transformer substation. With the eventual load driven upgrading of Ohope TI there are different options to upgrade the transformers and to address the Ohope support issue.

The table below introduces considerations to different options for Ohope reinforcement alternatives.

	Upgrade Options	Advantages	Disadvantages
1	Replace TI with a larger transformer	Most economic option. Good fit onto existing site. Can be installed while the existing bank is still in service.	No transformer redundancy. No 33kV redundancy.
2	Install a second 5MVA bank at Ohope	Provides good redundancy but will not provide redundancy at peak load beyond 2013 (load control will extend this to 2017).	Existing site would need to be expanded to accommodate two three phase banks.
3	Install two 7.5/15MVA transformers (or larger)	Provides ideal solution for transformer redundancy. Good security of supply beyond 2050. Can fit on the existing substation site if staged.	Costly option. Low transformation utilisation ratios. Does not solve the single 33kV supply issue.
4	Install one 7.5/15 MVA transformer at Ohope and one 7.5/15MVA transformer at Mokorua	Provides split substations. Provides backup supply from a separate 33kV sourced transformer. Mokorua transformer can be used to support Mokorua and Hillcrest area through to the Whakatane Heads. Mokorua substation can be used to reduce load at Kope.	More costly than option 3. Requires new 33kV line to Mokorua. This can be along existing 11kV route. Would require upgrade of Pohutukawa feeders to be able to support Harbour feeder.

	Upgrade Options	Advantages	Disadvantages
5	Install 110kV supply to Ohope off the Waiotahi line and install 110kV/11kV sub or 110/33/11kV sub	110kV Line route relatively easily achieved. Could provide better reinforcement to Waiotahi if established at 33kV. Very long term lifecycle solution.	Very high cost. Potential easement issues with 110kV line. 110/11kV introduces phase shift to Station Road but eases phase shift to Waiotahi. Cannot be considered in isolation to Waiotahi and Kope development plans.
6	Install one 7.5/15MVA transformer at Ohope, one 5MVA at Mokorua, and one 5MVA at Kutarere	Would integrate well with Waiotahi, Ohope and Kope development plans. Provides support from two auxiliary substations in case of a loss of 33kV to Ohope. Ohope can also support both other substations. Can be staged over several years.	High cost. Possible to contain costs by re-using Kope 5MVA banks, although these are old and not recommended. Requires Waiotahi/Opotiki project to be completed. High cost for 11kV and 33kV conductor upgrades to move energy between the three sites.
7	Install diesel generation to support the load	Relatively easy solution. Can be used for peak lopping.	High capital cost. High ownership cost. High kWh generation cost. Would require additional support as load grows. Creates stranded assets. Noise and consents.

Table 5.48 – Ohope TI Load Driven Replacement

The preferred option is to replace Ohope bank with a single transformer, Option 1. This single transformer would work well in conjunction with Option 6, staged over a number of years, to provide a long term solution that would provide firm reinforcement for Ohope until beyond 2040. Figure 5.38 shows the various sites discussed. The Kope 10/13 MVA transformer could be used instead of a new 7.5/15 MVA.

Running the existing bank into overload, the existing bank can sustain a 130% overload for up to 4 hours without damage (per IEC60354), then a load driven upgrade can be deferred well into the 2020's.

Alternatively, Option 1 is installed initially, and a second transformer can be installed at Ohope once the load increases beyond the capability of the 11kV reinforcement from Station Road to support the load. This enables the existing single phase transformers at Ohope to be retired.



Figure 5.38 – Ohope Region Substations Options

33kV Mokorua Substation Development Concept

A concept discussed above is to develop a single transformer substation at Mokorua. The Mokorua load is residential and is supplied from the Station Road substation Mokorua feeder. The average peak load of this feeder is 3.1MVA, of which about 2MVA is the Mokorua region domestic load.

A single substation would be able to support Mokorua domestic load as well as the Whakatane CBD load, and would provide 11kV reinforcement for Ohope, Pohutukawa and Harbour feeders. Load reduction at Station Road and Kope would defer load driven replacement of Station Road and/or Kope transformer banks. Reinforcement for a substation at Mokorua would be from Ohope and/or Kope.

The existing 11kV feeder cable supplying City South could be upgraded to 33kV and supplied from the Ohope 33kV feeder with a reinforcement tie to St Joseph's feeder relatively easily.

Figure 5.39 shows how a meshed network of transformers could work to provide cross linking support to each other and reduce the risk of single unit failures, while allowing low cost, single transformer modular substations to be built. This substation would not provide the benefits of a CBD substation and would only be developed if there was extensive domestication of the Mokorua region.

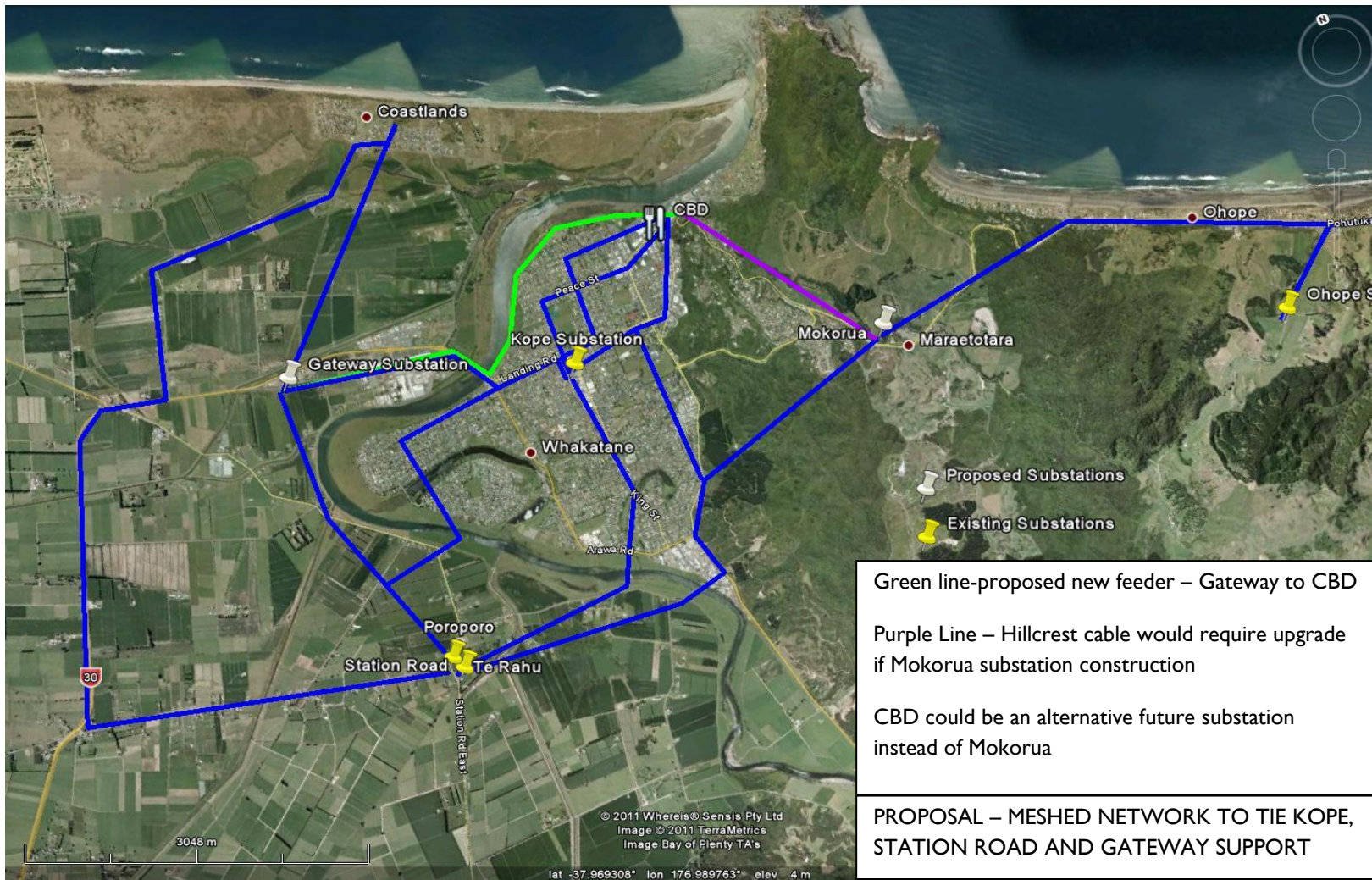


Figure 5.39 – Meshed Network Concept Sketch

5.14. Plains Substation

5.14.1. System Description

Plains substation is located adjacent to the Transpower Edgecumbe grid exit point and due to its close proximity to East Bank Road substation is used to supply the surrounding rural area, parts of Edgecumbe town and at times the Fonterra milk factory.

The rural load profile is dominated by the influence of dairying which sees a load increase in August each year. There is little urban load connected to this substation. Due to the proximity to Edgecumbe GXP 33kV bus the fault levels are high at this substation.

Plains substation is made up of three single phase transformers with a fourth transformer available on site as a spare. The spare can be brought into service within 12 hours by reconnecting the 33kV and 11kV cables from any of the other units to the spare transformer. There is a high capacity 11kV tie between this and East Bank Road substation that can carry the full load of either substation.



5.14.2. Service Area Covered

Plains supply the wider Edgecumbe rural area from four feeders.

Awaiti Feeder	Awaiti feeder supplies the Plains area through to Braemar Road. The land profile is generally flat. There are a large number of small farm and lifestyle blocks supplied by this feeder. The feeder has tie point connections to Manawahe and Te Teko feeders as well as East Bank Road substation, West Bank and Thornton feeders.
Awakeri Feeder	Rural feeder that covers the area from SH30 Awakeri to McDonalds Road, has tie points to Te Teko and Thornton feeders. Predominantly small farm and lifestyle blocks.
Manawahe Feeder	Manawahe feeder runs to the West from Plains substation to Matata and beyond. The first section has very few customers with the customer base closer to Matata and to the West, and inland to Manawahe. The feeder has full capacity tie points to the Awaiti feeder and Thornton feeders.
Te Teko Feeder	Supplies the village of Te Teko and surrounding rural areas. Connection points to Kawerau Onepu feeder (phase shift applies) and the Awaiti and West Bank feeders.
Anchor 2	Alternative low capacity (4MVA) tie to Fonterra.
West Bank Feeder	Alternative high capacity (12MVA) tie to the East Bank Road substation.

5.14.3. Description of Assets

Table 5.49 summarises the major assets within the Plains Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV Cable	Direct connect to the Transpower 33kV switchgear	240 mm ² Copper, XLPE insulated		No Issues
33/11kV Transformer T1	n x 3.3 MVA single phase transformers Electromechaniche, 6.94% impedance	10MVA ONAN	1966	Distance between the transformers and to the switchroom does not provide sufficient space as an effective fire barrier. Transformers have no oil containment
T1 Tapchanger			1966	There have been problems in the past with the tap change mechanisms falling out of step.
11kV Distribution Switchboard	Reyrolle, LMVPT/QMRO vacuum circuit breakers, 8 panels 7 circuit breakers and bus coupler	Circuit breakers 630 amp Fault rating 25kA 3 sec Bus rated 1250 amps	1999	Blast resilient doors fitted 2011.
Control Building	Two structures, one 60m ² Wooden frame metal clad building and the other portacom		1991	No issues.
SCADA	Foxboro	P2	1991	System is obsolete with no spares. Scheduled for upgrade 2013.
DC Battery Bank	Switchtech 24V		1991	No issues.
Local Service	ABB transformer	200kVA		No Issues.
Feeder Protection	SEL 351A		1999	IP conversion scheduled 2014

Asset	Description	Rating Data	Date of Manufacture	Comments
Tap Change Controller	Aeberle Reg DA		2009	No Issues.
Communications	Fibre Optic loop		2013	
Ripple Control	Zellweger SFU-G/120	33kV injection	1989	Injected at 33kV controls all zone substations supplied out of Transpower Edgumbe. System is being assessed for upgrade options.
Ripple Control PLC Controller	Mitsubishi		1999	

Table 5.49 – Plains Substation Assets

5.14.4. Substation Utilisation

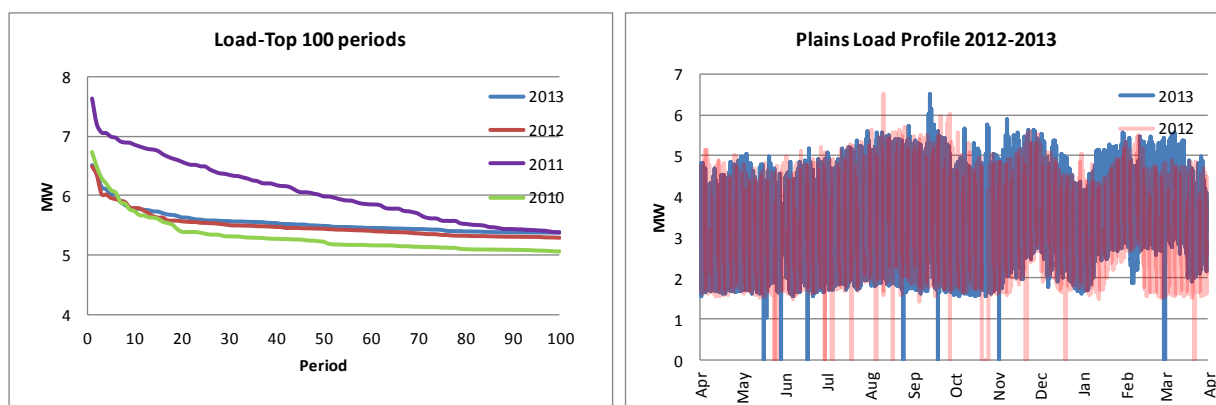
Plains -Load Statistics MW							
	2010	2011	2012	2013	% increase 2012-13	Avg incr per year	n-1 Utilisation
Maximum	6.7	7.6	6.5	6.5	0.3%	-1.1%	65.1%
Average	3.12	3.22	3.17	3.41	7.6%	3.2%	34.1%
Average-Top 100 Periods	5.3	6.1	5.5	5.6	1.1%	1.5%	55.5%

Table 5.50 – Plains Load Statistics

Plains substation has a very flat annual profile due to the mix of dairy and domestic loads. There is a slight load increase due to irrigation between December and March. There are a large number of lifestyle blocks in the region, which contribute to the domestic profile offsetting the rural demand.

Plains is a support substation for East Bank and Fonterra and the high load seen on the 100 peaks chart in 2010-11 is attributed to Fonterra support following a cable failure at East Bank zone substation.

5.14.5. Load Growth



Figures 5.40a and 5.40b Plains Load Curves and Load Profile

The peak loads at Plains needs to be monitored during reinforcement. Organic growth is above the network average and the peak load will need managing as it approaches the substation capacity of 10MVA.

Constraints

If Plains is required to support East Bank with no Fonterra embedded generation available the total load exceeds 14MVA.

The Plains transformer bank has been scheduled for an early upgrade due to:

- Fire risk mitigation;
- Lack of oil containment;
- Potential overload during reinforcement; and
- Unreliable tap changer operation.

5.14.6. Lifeline Risk Assessment

Risks and vulnerability of Plains substation site from a CDEM Lifelines perspective are summarised in Table 5.51 below:

Vulnerability	East Bank	Mitigation/Risk
Total Loss of Plains Substation	The substation is a single feeder substation with one, three phase transformer bank.	Linked to East Bank Road substation at 11kV to provide full redundancy.
Partial Loss	Spare single phase transformer held on site.	Eight hour restoration onto spare bank.
Communications	Primary communications is by a single link UHF radio from Putauaki radio repeater site. Communication is used for remote control of switching operations, load, and security monitoring.	Not critical for operation as systems can be operated manually, with delays.
Site Access Requirements	Access is required in the case of: <ul style="list-style-type: none"> Loss of communications Abandonment of Commerce Street control room Non operation of equipment 	Roads accessing the site are Hydro Road South from Edgecumbe, and Hydro Road North from SH 30. There is sufficient clear area to land a helicopter near the substation site if required.
Natural Hazards	Natural hazards that the sites could be exposed to are: <ul style="list-style-type: none"> Flood Earthquake Tsunami Volcanic activity Wind 	Risk: <ul style="list-style-type: none"> High High Low Low Medium Disaster recovery plans are available to all staff
Network Impact Risk	Supplies 11% of the network – Rural plus urban Edgecumbe.	-
Human Habitation	Plains is an unmanned site.	Access door alarms to SCADA.
External Services	All critical services are on 24 volt battery banks.	-

Table 5.51 – Lifeline Risk Assessment

5.14.7. Plains Substation Feeders

Plains substation distribution feeders are summarised in Table 5.52 below:

Feeder	Awaiti	Awakeri	Manawahe	Te Teko
Type	Rural	Rural	Rural	Rural
Overhead (km)	77.7	40.6	133	94.8
Underground (km)	6.2	9.0	6.9	7.8
ICP Connections	538	446	769	871
Substations	183	146	224	215
Installed Tx Capacity (MVA)	8.1	7.75	6.7	8.2
Maximum Load Amps	139	84	69	110
100 Peak Load Amps	110	64	65	92
Growth Rate	3.1%	0.8%	1.4%	4.3%
Feeder Utilisation at Average 100 Peaks	39%	23%	23%	33%

Table 5.52 – Plains Substation Feeders

Manawahe Feeder

- Condition assessment of this feeder has highlighted a large number of crossarms in poor condition but few pole defects. Of 1217 pole site inspections, 25 poles were marked as having defective components; the feeder sections running across the plains were installed in 1967 and have a high percentage of line fittings in poor condition. These have been grouped into projects for refurbishment. The Dog conductor is in good condition, as are most of the poles;
- The projects detailed below are to refurbish the Manawahe assets in zones over a five year period. Priority is given to the start of the feeder and to the village of Matata. There may be a case to justify undergrounding portions of the township if the other parties to the undergrounding agreement contribute. Due to the spur line nature of the feeder a lot of the work will be completed live line or with generators to support the load;
- There are sections of Hard Drawn Bare Copper (HDBC) conductors that will be assessed for likely replacement as part of this project. HDBC conductor tends to corrode when exposed to a coastal environment but the sections in this feeder are inland. HDBC cannot be worked on using live line techniques; and
- Figure 5.41 indicates the structure defects that have been identified for correction (blue dots) on this feeder in the Manawahe area.

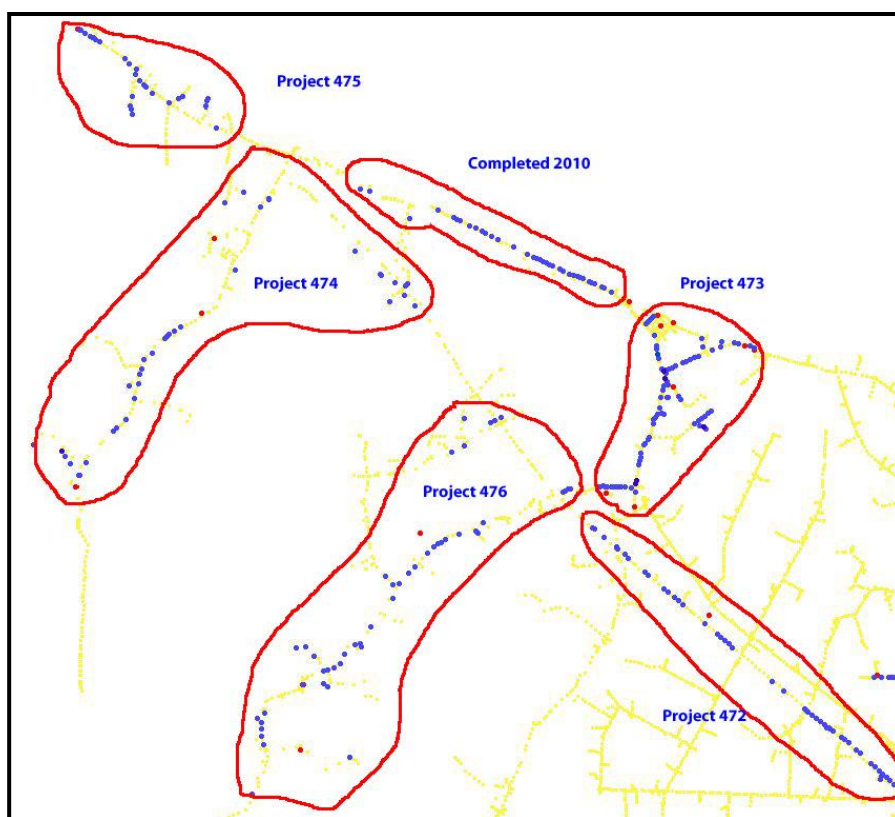


Figure 5.41 – Manawahe Feeder Upgrade Program

Te Teko, Awakeri and Awaiti Feeders

- Load growth is above average compared to the rest of the network;
- Load is all rural with a mix of lifestyle and dairy farm blocks;
- There are a number of lifestyle developments along Braemar Road, as well as a water bottling and a water pumping scheme. Some irrigation has also been installed on the Awaiti, Awakeri, and Te Teko feeders. Awaiti feeder annual profile is shown in the chart below; and
- High utilisation on all feeders is due to reinforcement to adjacent feeders.

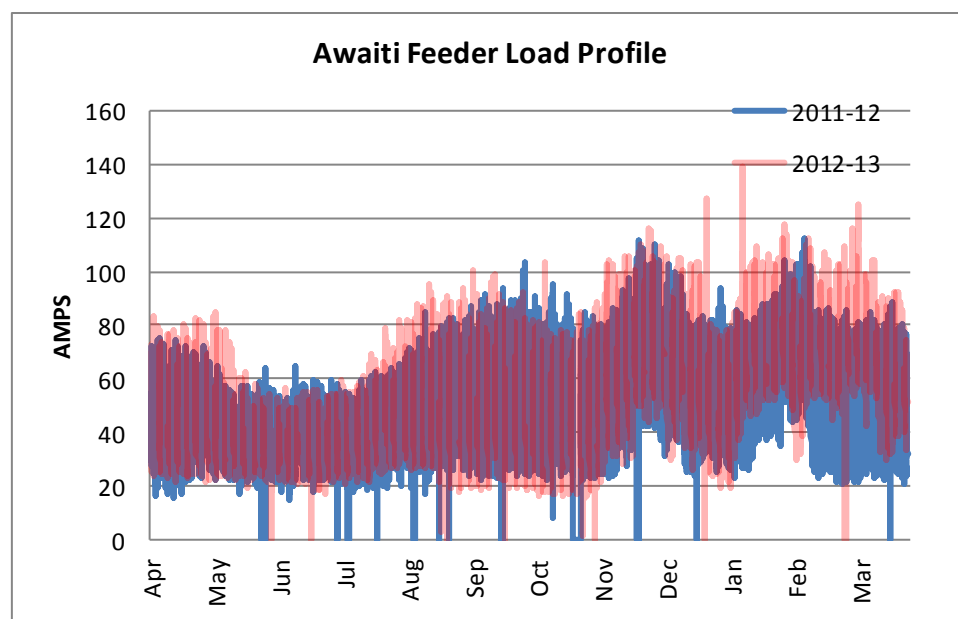


Figure 5.42 – Awaiti Load Profile

5.14.8. Faults and Outages

Manawahe

Historically, Manawahe feeder has been a poor performer. Due to its historical performance the Manawahe feeder was targeted in 2009 for a high level of expenditure on reliability improvement initiatives. The feeder has long sections of line that are rural and run through forested land so although the number of faults may not reduce, the SAIDI impact should improve.

Te Teko

The Te Teko feeder has had a number of vehicle impacts on SH30 between Te Teko and Kawerau in the past, as well as some intentional damage incidents.

Awaiti, Awakeri

Awaiti has traditionally been a poor performer with a number of the faults being due to vehicle impact. Tree and possum contacts are common around the Braemar Road area where there is a high density of vegetation.

Awakeri feeder covers flat ground and is relatively free of vegetation.

5.14.9. Plains Development Plans

The majority of the planned feeder projects are to install circuit breakers, sectionalises, or automated tie switches to mesh the network and improve system reliability.

Manawahe and Te Teko are historically poor performing feeders, hence the high level of planned expenditure on these two feeders.

5.14.10. Plains TI Transformer replacement

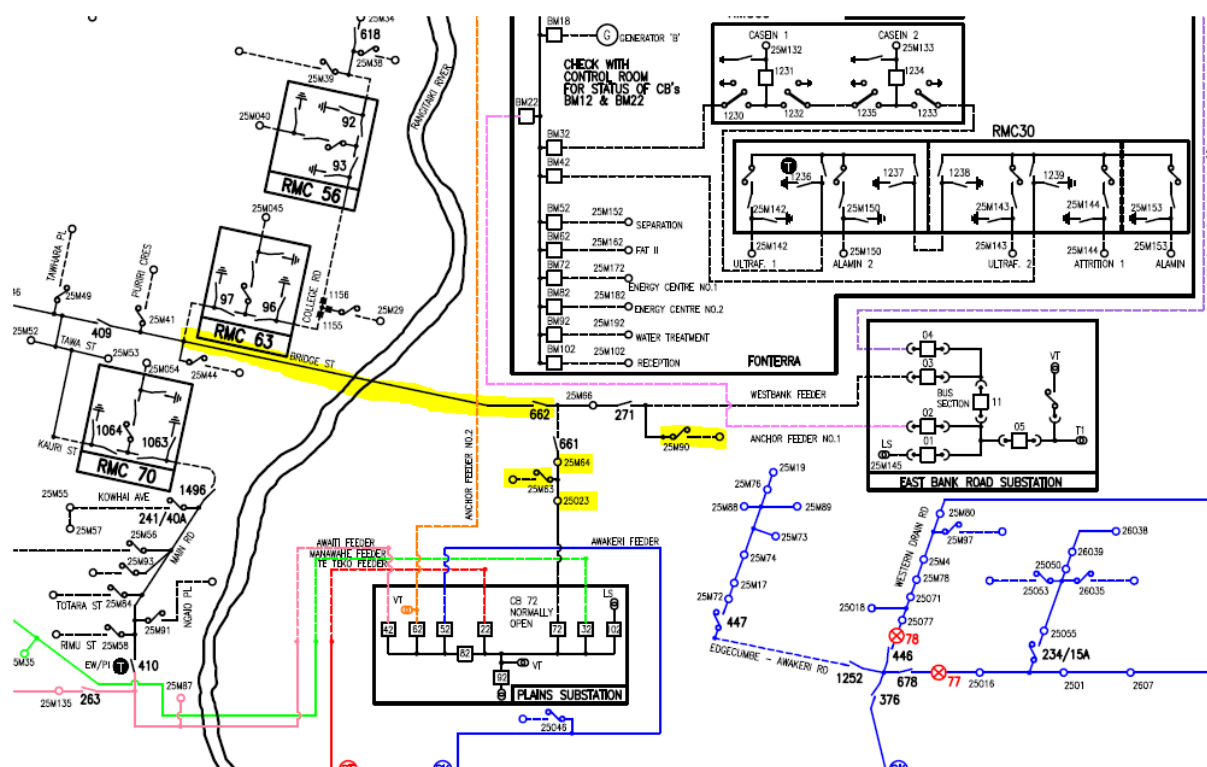
A risk assessment of the Plains substation in 2011 identified a number of issues. In summary, the risks identified are:

- The small spacing between the two 33/11kV transformers creates a common fire/explosion risk.
- There are no oil containment for the 33/11kV transformers.
- The incoming 33kV two pole structure is too complex and busy.

Operationally the transformers are 47 years old as at 2013 and are undersized to carry the maximum combined back-up load of East Bank and Fonterra. Horizon replacement policy is 55 years but these factors coupled with the risk assessment justify an accelerated replacement program on these transformers. This project is further described in Appendix C.

5.14.11. Plains-East Bank tie feeder

There is an 11kV tie feeder between Plains and East Bank that provides the cross-substation support to each substation. Although rarely used, this feeder requires a high level of security as befitting an L2 supply. With the existing configuration of the West Bank feeder being supplied as a spur off this feeder, and having a number of transformers on the feeder as well, the supply is not as secure as it could be.



West Bank Tie Feeder

A project is under consideration to make the tie feeder a dedicated back-up feeder between the substations, reducing the feeder exposure risk.

Considerations include:

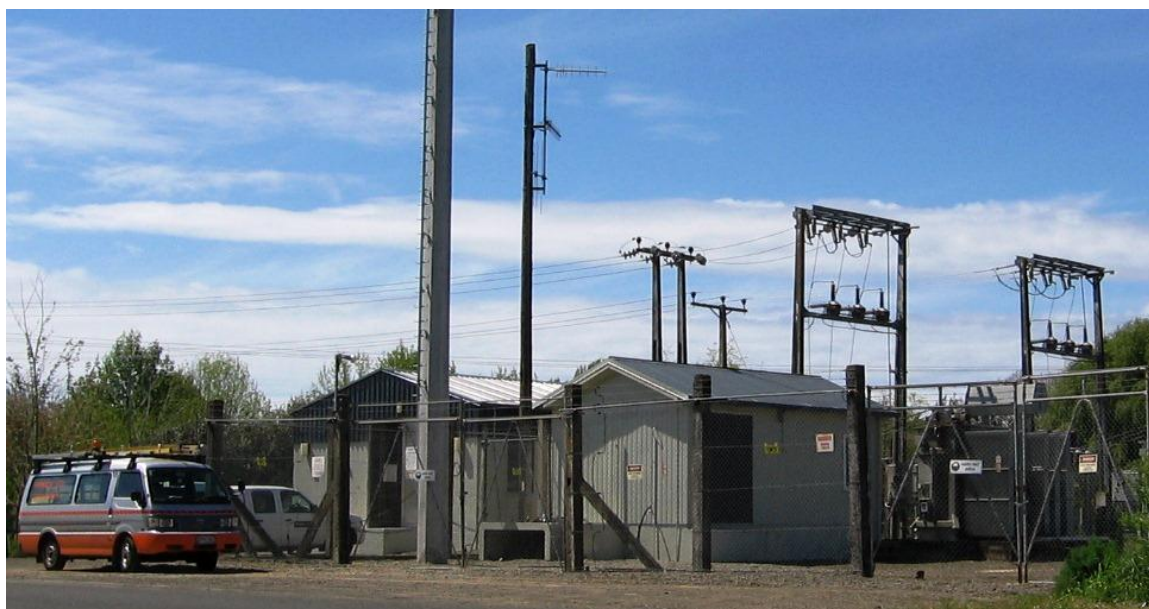
- Undergrounding the tie feeder between P72 and EB03 (Rangitikei Feeder) and running a separate cable to switch 662 to create a new feeder;
- Automating 662 and other tie points around Edgecumbe to enable remote switching of 662 to remove the West Bank spur line from the tie feeder and to improve response times; and
- Removing the transformers on the feeder to improve the security of supply.

Final decisions on the preferred options have not yet been made.

5.15. Station Road Substation

5.15.1. System Description

Station Road substation is a two transformer 20MVA 33/11kV zone substation located about three kilometres from Kope substation in the rural area of Poroporo, servicing 3,424 customers. The Sub-transmission to Station Road is supplied directly from Te Rahu station by 33kV cables installed in 2010.



This substation services a mix of rural and urban customers.

Strong integration with Kope substation through the development of increased capacity 11kV circuits provides dual support between the two substations. A series of projects to strengthen the distribution feeders between the two substations was started in 2009 and will continue for some years to come.

Station Road substation is also the primary reinforcement substation for Ohope.

Te Rahu substation is integrated with Station Road for communications and provision of local service supplies. The communications network uses the Station Road node as a switching node to provide alternative routing between the communication repeater sites. The Station Road substation also houses the SCADA system disaster recovery equipment, which comprises a remote master station terminal and IT data backup equipment.

5.15.2. Service Area Covered

Station Road substation supplies the areas of Taneatua, Ruatoki, Mokorua, Coastlands, the Plains area out to Angle Road, SH30 to Awakeri and the Hub commercial development. Also parts of the southern suburbs of Whakatane are supplied up to the open points on the feeders that interconnect to the Kope substation feeders.

The Mokorua Feeder was rebuilt in 2010 from an existing spur line off one of the existing feeders. Constructed with Krypton 152sqmm aluminium conductor, this feeder supplies the Mokorua domestic load and will provide a high capacity link to Ohope and to the Rex Morpeth feeder for reinforcement of Kope.

Angle Road	Angle Road feeder supplies the rural area around SH30, Angle Road, Powdrell Road, and provides a tie to support Coastlands. There are tie points to the Awakeri and Thornton feeders.
City South	<p>This feeder currently supplies the Valley Road and Mokorua domestic loads. Recent conductor upgrades have increased the capacity of this conductor to 8MVA but the 185sqmm aluminium cable at the substation limits the feeder to 6MVA. There are no plans to upgrade the 185 cable at this stage.</p> <p>The upgraded City South feeder will be used to supply some of the domestic loads currently supplied by the King Street feeder which will take some load off the Kope substation. It will also provide reinforcement to the Victoria feeder.</p>
Mokorua	<p>This feeder was constructed in 2010 from a spur line off the Piripai feeder and re-conducted with Krypton 152sqmm aluminium conductor. A new RPS circuit breaker was added as an extension to the GEC switchboard in Station Road.</p> <p>The purpose of this feeder is to provide a dedicated feeder to the Mokorua subdivision and then continue as a reinforcement feeder for the Ohope Pohutukawa feeder.</p> <p>A larger conductor was chosen to reduce voltage drop as well as future proofing the feeder for potential load increases.</p> <p>Supplying Mokorua off this feeder allows City South, which used to supply Mokorua, to be dedicated to supplying the lower King Street urban area, which then allows this load to be moved onto Station Road from Kope.</p> <p>This feeder has a 4MVA link to the Rex Morpeth feeder to provide reinforcement to the Rex Morpeth and Commerce Street loads.</p> <p>City South is connected to Mokorua by a weak (35mm²) link at Hillcrest that provides limited support to the CBD and Heads area.</p>
Piripai	<p>Running North from Station Road, the Piripai feeder supplies the Hub commercial development and the Coastlands residential area. Piripai is the most heavily loaded feeder from the Station Road substation and has tie points to the Angle Road, City South, and to Kope's Victoria feeder.</p> <p>Tie points are automated between Piripai and Thornton feeders</p>
Ruatoki	Ruatoki feeder runs South from Station Road and supplies the Ruatoki rural region. This feeder is tied to the Taneatua feeder to provide cross feeder support. This feeder also has a low capacity tie to Waiotahi substation via the Waimana feeder but this supply is out of phase so the supply must be isolated prior to resupply.
Taneatua	Taneatua feeder runs South from Station Road to the Taneatua township and supplies a mix of domestic and rural loads. The Taneatua feeder is relatively lightly loaded. There are tie points to the Ruatoki and Mokorua feeders.

5.15.3. Description of Assets

Table 5.53 summarises the major assets within Station Road Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV Cable	Station Road 1 Station Road 2	400A	2010	Soil thermal resistivity rating is 3K.m/W, tested in 2009. This de-rates the cables to 0.76 of their full load rating.
33kV Circuit Breakers	Areva GHA non withdrawable gas insulated	33kV 630 amp Fault rating 40 kA 3 seconds	2010	Circuit Breakers are located at the Te Rahu switching station.
33/11kV Transformer T1	Bonar Long	10 MVA ONAN 7.5 Z Dyn11	1966	Transformer has oil containment with an on-site oil water separator system.
33/11kV Transformer T2	Bonar Long	10 MVA ONAN 7.5 Z Dyn11	1966	Transformer has oil containment with an on-site oil water separator system.
T1 and T2 Tap Changer	Fuller Electric type F311-33/200	33kV 300 11 steps	1966	No issues.
11kV Cable	Transformer T1 to switchgear	2 runs of 3 x 1c 185sqmm Al	1996	
11kV Cable	Transformer T2 to switchgear	2 runs of 3 x 1c 185sqmm Al	1996	
11kV Distribution Switchboard	GEC VMX Vacuum withdrawal circuit breakers	Circuit breakers 630 amp Fault rating 25kA, 3sec Bus rated 1250 amps	1996	No issues.

Asset	Description	Rating Data	Date of Manufacture	Comments
11kV Distribution Switchboard CB29	Reyrolle LMVP	630 amps 1250 Amp bus bars 25kA, 3sec	2010	Coupled to GEC switchgear with a joggle chamber.
Control Building	77m ² concrete block building		1984	No issues
SCADA	Leeds and Northrup (Foxboro)		1991	Hardware has exceeded the ODV life. Total data throughput capacity is limited by Foxboro proprietary communication protocol. Replacement with industry standard DNP3 capable devices has been scheduled.
DC Battery Banks	Intergy Invensys 24V Switchtech 48V			Batteries replaced 2011.
Local Service	ABB transformer	200kVA		Local service transformer is connected to an ABB SD RMU onto Piripai feeder, with an alternative connection to Taneatua feeder. A project to improve reliability of local service supplies has been planned.
33kV Protection	SEL 351S		2010	Located at Te Rahu switching station.
Feeder Protection	SEL 351A		2003	No Issues.
Transformer Protection	SEL 787 differential relays		2010	
Tap Change Controller	Reyrolle RVM/5, RTMU/I		1991	Tap change controllers are approaching end of life, although no reliability issues are being experienced.
Communications	Exicom Hawk 450Mhz UHF radio Fibre Optic ring			Radios are scheduled for replacement with fibre optic link.

Table 5.53 – Station Road Substation Assets

5.15.4. Substation Utilisation

Station Road -Load Statistics MW							
	2010	2011	2012	2013	% increase 2012-13	Avg incr per year	n-1 Utilisation
Maximum	8.5	8.2	10.4	9.9	-5.5%	5.5%	98.7%
Average	4.28	4.23	4.52	4.41	-2.3%	1.0%	44.1%
Average-Top 100 Periods	7.9	7.6	9.5	8.0	-16.3%	0.3%	79.9%

Table 5.54 – Station Road Load Statistics

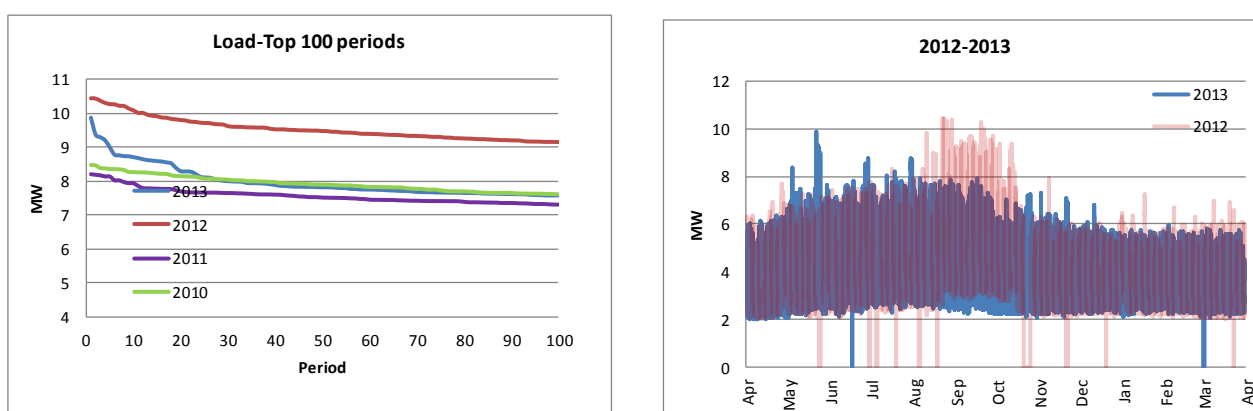


Figure 5.43a and 5.43b – Station Road Load Curves and Load Profile

The high increase in load growth 2011-12 was attributed to load shifting between Kope and Station Road. Reduction in 2012-13 is partly attributed to a changed load control algorithm which reduces restoration peaks.

For assessing organic load growth the total loads through Te Rahu are used to determine future load predictions due to the inter-dependencies of Station Road and Kope substations.

5.15.5. Constraints

Station Road is a crucial substation for providing reinforcement support to Kope substation. Apart from the Piripai feeder supply cables requiring upgrading, Station Road has no load related constraints.

Station Road load is being managed as part of an integrated load management policy with Kope and the future Gateway substations.

5.15.6. Lifeline Risk Assessment

Risks and vulnerability of Station Road substation are included in the Te Rahu substation section.

5.15.7. Development Plans

- During 2010 Station Road was integrated into the 33kV Te Rahu switching station. The 33kV overhead lines and circuit breakers were removed and replaced by underground cables that directly connect the transformers to the Te Rahu 33kV bus system;
- The plan for load growth management is to share load between Kope, Station Road and the proposed future Gateway substation. This will be achieved by conductor replacements to increase the line capacity between Station Road and Kope to enable dynamic load transfer between the substations;
- The longer term view for the four sites, Kope, Station Road, Gateway, and eventually a CBD substation are to treat these as six separate transformers with sufficient distribution capacity between the sites to enable any five transformers to be able to carry the load, providing an n-1 redundancy. The current combined transformer capacity of Kope and Station Road is 40MVA and the combined load is around 24MVA;
- Station Road substation has had a lot of refurbishment work over the last 10 years and is one of the more up to date substations on the network. Due to the critical nature of Te Rahu and its close integration with Station Road, a project to provide improved supplies for local service is to enhance the reliability of the local service for both substations. The local service supply also has a connection point to install a generator unit if required; and
- Station Road substation had been previously identified as a potential site to install a ground fault neutraliser. The substation services an extensive rural area and has a large number of faults on both the Ruatoki and Taneatua feeders, but due to urban feeders is deemed unsuitable for a ground fault neutraliser unless the system is run in a split bus configuration, with the rural feeders on one bus and urban on another. This configuration has implications on reliability and reinforcement switching and is an undesirable configuration.

Station Road Feeders

Station Road feeders are summarised in Table 5.55 below:

Feeder	Angle Road	City South	Mokorua	Piripai	Ruatoki	Taneatua
Type	Rural	Urban	Urban	Rural/Urban/Commercial	Rural	Rural
Overhead (km)	48.6	16.4	-	24.5	97.0	40.8
Underground (km)	6.5	7.0	-	8.4	7.4	1.5
ICP Connections	450	1144	31	677	671	451
Substations	120	58	*	78	185	84
Installed Tx Capacity (MVA)	6.6	7.8	*	7.3	5.6	3.7
Maximum Load Amps	126	98	197	140	91	106
100 Peak Load Amps	76	72	129	115	81	50
Growth Rate	-2.1%	-12.6%	NA	-2.8%	1.2%	-8.1%
Feeder Utilisation Average 100 Peaks	27%	26%	46%	18%	29%	18%

Table 5.55 – Station Road Feeders

Angle Road

The indicated growth rate is due to increased periods of reinforcement during previous years for adjacent feeders. The Angle Road feeder will eventually be split and part supplied from the Gateway substation. True organic load growth for Angle Road is closer to 0%.

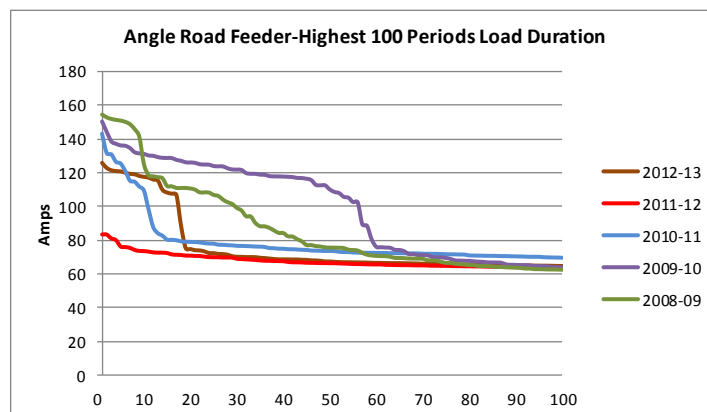


Figure 5.44 – Angle Road Load Profile

City South

City South load has reduced because of load transfer to the new Mokorua feeder. This feeder is a main tie feeder between Station Road and Kope and in 2011 the Mokorua urban loads were transferred to the Mokorua feeder.

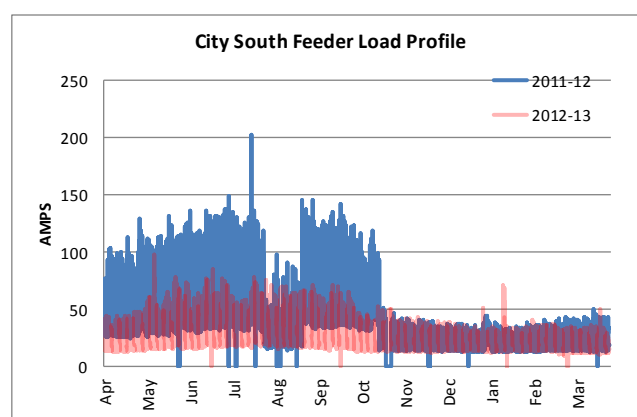


Figure 5.45 – City South Load Profile

Upgrading the 185sqmm feeder supply cable will allow the feeder to be used to capacity to support Kope via King Street and Victoria feeders.

A weak section of conductor across the river to Arawa Road has been scheduled for upgrade to allow full use of this feeder for support.

Piripai Feeder

High load growth from 2006 to 2008 was due to the development of the Hub commercial complex. The 2010-11 growth is more in line with normal expectations. Utilisation factor is high but is limited by the zone substation 95sqmm aluminium feeder cable. This cable is scheduled for replacement to improve the load reinforcement capabilities for this feeder.

There are no load constraints with the Piripai feeder. The domestic region of Coastlands is supplied by Piripai which is reinforced by a high capacity cable tie to Kope substations Victoria feeder installed in 2008.

Piripai has a commercial load profile, driven by the Hub commercial centre.

Ruatoki and Taneatua

These rural feeders have shown minimal growth. Ruatoki is more rural than Taneatua, which supplies the town of Taneatua. Peak load is driven by those times where the feeder is used for reinforcement of others and this is shown on the load duration curves. Utilisation is well within the capability of the feeders. Taneatua load growth is not expected to increase beyond the network average. Ruatoki is rural with a spring peak and load driven by dairy farming.

Mokorua Feeder

The Mokorua feeder was commissioned in August 2010 supplying initially an industrial pump load. Mokorua subdivision domestic loads have been added in 2011. Mokorua is the primary support feeder to Ohope from Station Road.

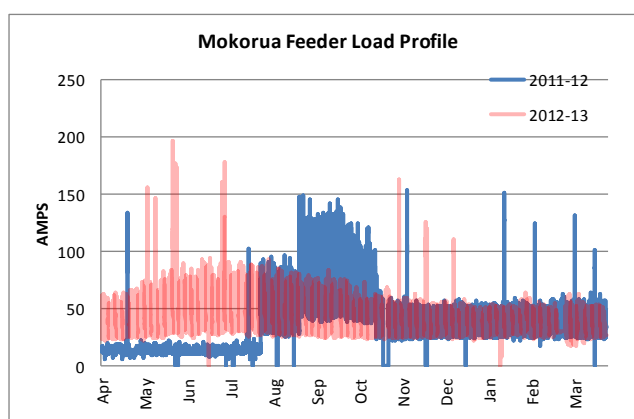


Figure 5.46 – Mokorua Load Profile

5.15.8. Faults

Ruatoki feeder was a poor performer and more circuit breakers and sectionalisers were recently installed to improve the response to faults. The remaining feeders are performing well although Taneatua and Ruatoki have tended to have a number of vehicle impacts.

5.15.9. Station Road Development Plans

Station Road substation is relatively modern and in good condition and has had some major investment over the previous years. Projects planned for Station Road substation within the 10 year planning period are:

- RTU upgrade;
- Transformer upgrades;
- Feeder integration with Kope substation; and
- Protection relays age driven replacement.

5.16. Te Kaha Substation

5.16.1. System Description

Te Kaha substation is a Transpower owned GXP substation located close to Te Kaha settlement on the East Cape peninsula, about 100km from Whakatane. The Te Kaha substation is supplied directly from a single Transpower owned 50kV line from the Transpower Waiotahi GXP. Horizon Energy owns no zone substation assets at Te Kaha apart from a SCADA terminal and communications. The Transpower substation supplies two Horizon Energy feeders; the Te Kaha feeder that runs to the South West and the Waihou Bay feeder that supplies the coast to the North East.

The Te Kaha system displays a relatively flat normal load profile but the peak is driven by the influx of visitors over the summer holiday period. The graph in Section 5.16.4 shows the impact of visitors to the area during the Easter and Labour weekend holiday periods.

The system suffers from some reliability issues due to the long Transpower line that supplies this location, the terrain that it runs through and the difficulty for staff to access the area due to its remoteness. Due to the small permanent load, small embedded generation plants may provide a viable short-term solution to quality of supply issues and short term peak loads. At this stage, apart from the use of temporary diesel generation, no generation systems have been installed within the distribution system.

Transpower used two mobile generators on site after significant sustained outages in 2011 and had used these on a number of occasions in the last 12 months. These have since been removed.

Due to the line being located mostly in a coastal environment, there is an accelerated rate of corrosion and degradation of the conductors and transformers.

Transpower have scheduled a transformer bank replacement for Te Kaha in early 2014.

5.16.2. Service Area Covered

Te Kaha substation services approximately 1,023 customers and covers a region from South of the Motu River to East Cape, approximately 60 kilometres from end to end and supplies the coastal settlements of Te Kaha and Waihou Bay. The network has no links to other networks.

Te Kaha Feeder	The Te Kaha feeder runs South West from Te Kaha to West of the Motu River. A lot of the line is built over rugged terrain and is built parallel to the coast road but inland on private property.
Waihou Bay Feeder	The Waihou Bay feeder runs North East from Te Kaha, past Waihou Bay and on to East Cape. There are no alternative supplies for this feeder.

5.16.3. Description of Assets

Te Kaha Substation Assets

Table 5.56 summarises the major assets within Te Kaha Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV Bus	Transpower owned	Not available		Overhead strung bus, wooden poles
50/11kV Transformer T1	4 single phase transformers	2.25MVA ONAN Dyn11		Transpower owned. One transformer faulted in 2010 but was repaired
11kV Distribution Circuit Breakers	Cooper Power KF circuit breakers	200 Amp		Transpower owned. Reclose type units that have been configured as line breakers
Control Building	Weather board building with metal roof			Transpower owned
DC Battery Bank		24V 150Ah		Transpower owned
Communications	Exicom Hawk 450Mhz UHF radio			Radios are scheduled for replacement 2012

Table 5.56 – Horizon Energy Owned Te Kaha Assets

5.16.4. Substation Utilisation

The table and graphs below show the load profile and load data for Te Kaha substation:

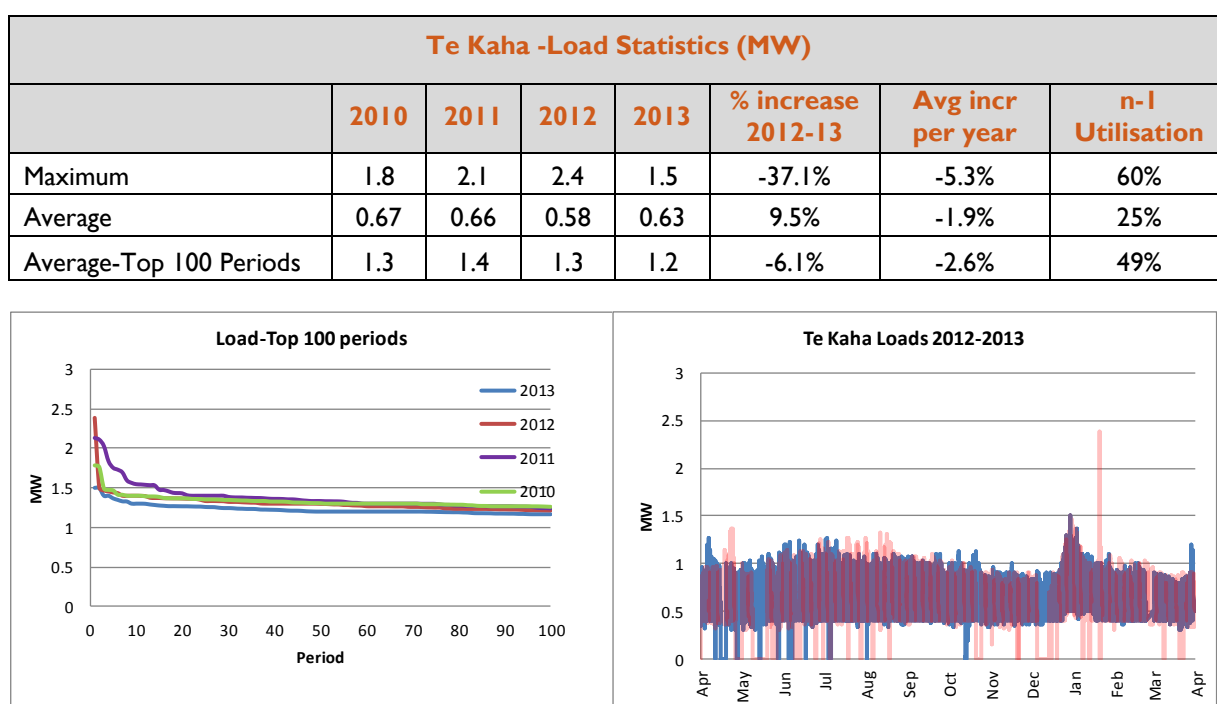


Table 5.57 – Te Kaha Load Statistics

5.16.5. Load Growth

The average 100 peaks for the previous years had shown growth of 5.1%. These peaks mostly occur during the summer holiday period. Load growth is regarded as static.

The maximum peak of 2.1 MW in 2011 was created by a load control restoration period. This is not regarded as an indication of the real load growth for this region but is indicative of the need to monitor the Te Kaha load and to manage the load control more efficiently to avoid these peaks. Horizon has instigated a study to better manage the load control restoration to reduce the restoration spikes.

There is limited capacity in the system to support additional large loads. At this stage the only indication of additional load to be added is 600kW due to a proposed irrigation scheme.

5.16.6. Constraints

- The long 11kV distribution line of the Waihau feeder has end of line supply quality issues particularly at high loads;
- Due to the distance from the supply source and the manner that the 50kV is created at Waiotahi substation, the system has a low fault level. This poses issues in the clearance of earth faults on the system and is managed through the installation of intermediate sectionalising re-closing circuit breakers;
- There are high levels of line corrosion due to the proximity of the distribution lines to the coastal environment. Horizon Energy runs a continuous program of line section replacements and refurbishment;
- The Transpower 50kV supply line has a poor performance history due to its nature of construction, the terrain through which it passes and land use issues;
- Peak loads hit 2.1MW. This short term spike is abnormal and was driven by load control restoration;
- There is limited ability to support any new large loads;
- Summer load exceeds winter load;
- Only one spare phase of the 50/11kV transformer; and
- Network is not meshed. Mobile generation can support the feeders but Horizon Energy owns one 1MVA and two 300kVA generators. Larger generators have to be sourced from Tauranga if required to support the full load of the network.

5.16.7. Development Plans

Te Kaha substation is supplied at 50kV. This voltage is uncommon within the Transpower system and there has been discussion between the parties related to the conversion of the supply voltage to 33kV.

The two 11kV distribution feeders are protected by Cooper Power KF circuit breakers owned by Transpower.

There is a project to improve communications to Te Kaha and the local region. This is driven by a need to improve voice communications for safety of workers in the area and for network switching purposes. A UHF radio link into Te Kaha substation is being developed to improve network data transfer between Te Kaha and Whakatane.

Improved metering on the feeders is also being discussed with Transpower.

Horizon Energy has a set maintenance allocation budgeted for Te Kaha each year to enable the progressive upgrade and replacement of sections of the lines to improve reliability.

In 2008 a feasibility study was completed to assess the viability of installing wind generation at East Cape. The study summarised that although there was likely to be sufficient wind to support power generation development, the costs of getting sufficient line capacity to get the power out to the load centres made the project uneconomic unless development was completed on a very large scale. Small scale developments, up to 200kW, can be embedded into the distribution network where the local load assists in the management of the voltage profile.

5.16.8. Te Kaha Feeders

Table 5.58 below summaries the feeders out of Te Kaha substation:

Feeder	Te Kaha	Waihou Bay
Type	Rural	Rural
Overhead (km)	33.5	77.0
Underground (km)	0.3	0.4
ICP Connections	413	610
Substations	83	168
Installed Tx Capacity (MVA)	2.7	4.2
Maximum Load MVA	na	na
100 Peak Load MVA	na	na
Growth Rate	na	na
Feeder Utilisation at Average 100 Peaks	na	na

Table 5.58 – Te Kaha Feeders

The individual feeders are not metered. Load flow modelling indicates that the Te Kaha feeder is around 1/3 of the load flow of the Waihou Bay feeder. Feeder load is not an issue, but fault levels and voltage drop at the end of the lines is.

5.16.8.1. Fault Analysis

Due to poor communications, distance from support staff, and no meshing capability, all faults in the Te Kaha region tend to be of a long duration. Equipment issues have been cracked insulators or conductor faults. The fault level is very low so there is often insufficient energy available to actually destroy a cracked insulator meaning that it can take some time to find and resolve the fault. Increased maintenance on these lines seems to be having an effect on reducing the fault rate.

Additional feeder sectionalisers have been installed over the period 2010-12 to enhance the ability to identify the location of faults and ensure that the least number of customers are affected. One of the initiatives that is also being investigated is the installation of permanent diesel generation sites on the system to provide both fault and maintenance support.

5.16.8.2. Te Kaha Region Projects

Development of the Te Kaha substation is a Transpower issue and will be dependent on the development or conversion of the 50kV line from Waiotahi. Transpower are upgrading the Te Kaha TI in 2014.

5.17. Waiotahi Substation

5.17.1. System Description

Waiotahi substation is a Transpower owned 110kV to 11kV grid exit point substation. It is supplied by a single circuit 110kV line from Edgumbe. The substation has two 10MVA 110/11kV transformers to provide an n-1 capability beyond the 110kV line.

Transpower has tentatively scheduled the end-of-life replacement of the transformers between 2019-2021.

Horizon Energy has four feeders supplying the Opotiki region supplied from this substation, providing power to 4314 customers. The Opotiki area, to the East of Waiotahi, is fed via three 11kV feeders. The longest feeder is the Factory feeder that supplies the loads East of Opotiki. A fourth feeder runs West from the Waiotahi substation and supplies the Waimana Valley rural load.

Due to the location of Waiotahi with respect to the load centre that it supplies there are quality of supply issues at the extreme ends of the feeders, especially when large loads are introduced to the system.

Waiotahi has no links to any other distribution systems to the East and only a weak 11kV connection to Ohope and Station Road substations to the West. This, along with the phase shift that exists to the West, leaves the network with limited additional support.

5.17.2. Service Area Covered

Waiotahi substation services the Opotiki District from Waimana to Hawaii, including the Waiotahi, Waioeka, Motu and Otara valleys. The only town in the supply region is Opotiki, which is approximately eight kilometres from Waiotahi. The Waiotahi supply area is the largest geographical area covered by any single substation within the Horizon Energy system.

Factory Feeder	<p>The Factory feeder is the longest feeder in the network with 266 kilometres of line. The dominant load on the Factory feeder is a Kiwifruit processing plant and cool store.</p> <p>This feeder is sectionalised and protected by three line breakers installed after Opotiki which isolate the various spur lines in the event of faults.</p> <p>The Factory feeder includes two SWER circuits that extend supply into the inland regions of the area. The Waioeka SWER line was constructed in 1965, it is 37km long with 85 structures. The Toatoa SWER was constructed in 1966, it is 25km long with 63 structures. Both these circuits were constructed using predominantly larch poles. These poles are now 45 years old and are in poor condition.</p> <p>Asset condition assessment has highlighted groupings of poor condition assets along the Waiotahi valley area and other isolated areas. These have been grouped into upgrade projects for this region.</p> <p>There is a number of large kiwifruit frost protection pumping stations installed to the East of Opotiki which, when they operate, are affected by the low voltage levels created. These sites are required to be available to operate during the kiwifruit budding season of September to October if there is a likelihood of frost occurring.</p> <p>A voltage regulator was installed in 2010 to improve voltage regulation following a low voltage issue that occurred during the winter of 2009.</p> <p>There are a number of large dairy installations and a small number of irrigation systems on the feeder but these do not appear to be causing issues for the network at this stage.</p>
Hospital Feeder	<p>Hospital feeder supplies the Northern part of Opotiki town and the Ohiwa and coastal region west of Opotiki. During winter the feeder has also been switched to supply the coastal region loads of part of the Factory feeder.</p>
Opotiki Feeder	<p>Opotiki feeder supplies the Southern part of Opotiki town and the Eastpack processing plant. When built, sections of this line were constructed to 33kV clearances, but insulated at 11kV. The feeder is one of the more reliable feeders in the network due to its predominantly urban load.</p>
Waimana Feeder	<p>Waimana feeder supplies the Waimana and Matahi Valley regions, and Ohiwa Harbour to Waiotahi beach. It has tie points on to Ohope substation Harbour feeder, Station Road substation Ruatoki feeder, Hospital and Factory feeders. The Harbour and Ruatoki feeder ties are automated. Both tie points are limited in their support capacity by sections of 50sqmm Ferret conductors but can provide full support for the Waimana feeder but not for the full Waiotahi substation loads.</p>

5.17.3. Description of Assets

Waiotahi Substation Assets

Table 5.59 summarises the major assets owned by Horizon Energy within the Waiotahi Substation:

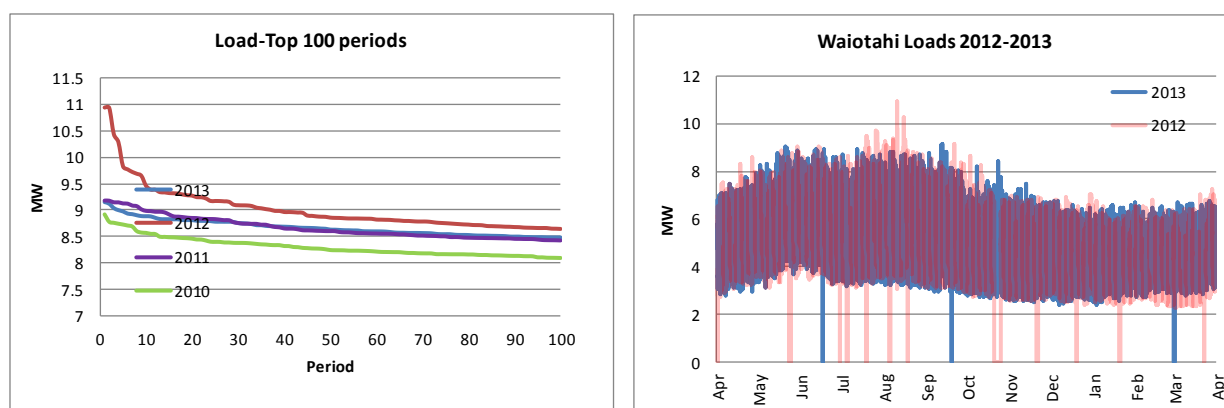
Asset	Description	Rating Data	Date of Manufacture	Comments
11kV Feeder CBs	Cooper Power KFE pole mounted	400 A; 6kA	1976	Replacement scheduled.
11kV CBI29	Ripple Plant supply breaker, MK1A	Unknown		Obsolete circuit breaker. To be replaced
Control Building	Wooden frame metal clad		1976/1992	Good Condition.
SCADA	Foxboro P2CPU			Replacement with industry standard DNP3 capable devices has been scheduled.
Local Service	ABB transformer ground mount	200kVA		No Issues.
DC Battery Bank	Switchtech 24 Volt			No Issues.
Feeder Protection	Cooper Power KFE electronics		1976	Scheduled for replacement pending the development of Opotiki substation.
Communications	Exicom Hawk 450Mhz UHF radio			Radios are scheduled for replacement 2012.
Ripple Injection Plant	Zellweger static inverter 315/750hz Type SFU-G3		1992	Study underway for replacement options.
PLC – Load Control Plant	Mitsubishi AIS with RCS RC02 Conitel communications interface		1996	Non-standard but no other issues.
PLC – Auto Reclose	Mitsubishi FI-60MR-ES			Obsolete. Tied to CB replacement.

Table 5.59 – Waiotahi Substation Assets

5.17.4. Substation Utilisation

Waiotahi - Load Statistics (MW)							
	2010	2011	2012	2013	% increase 2012-13	Avg incr per year	n-1 Utilisation
Maximum	8.9	9.2	10.9	9.1	-16.4%	0.9%	76%
Average	4.96	5.05	5.06	5.19	2.5%	1.5%	43%
Average-Top 100 Periods	8.3	8.7	9.0	8.7	-4.0%	1.5%	72%

Table 5.60 – Waiotahi Load Statistics



Figures 5.47a and 5.47b – Waiotahi Load Duration and Load Curves

Although the region has a mix of urban and rural loads, the load pattern is typically urban with high winter and reduced summer loads. There are peaks in September and October that are driven by kiwifruit frost protection. There is a small amount of irrigation load on this system at this stage. The majority of the frost protection is on the Factory feeder and this creates its own problems with voltage support.

The Waiotahi loads exclude the Te Kaha load.

5.17.5. Load Growth

The annual load growth between 2007 and 2011 at 4.9% was substantially higher than the predicted growth of 2.5%. The growth rate has flattened and predicted growth is closer to 1.5%. The load growth is predominantly on the three feeders supplying to the East, being the town of Opotiki and the coastal regions. Waimana feeder has experienced little growth.

Opotiki population growth is growing at a rate of 0.5% (Statistics NZ). Industrial load has increased by IMVA since 2008 on the Factory and Opotiki feeders. The load increase on the predominantly domestic Hospital feeder suggests that heat pumps may be a contributing factor to the load growth.

Potential step load increases that have been proposed in the Opotiki region are an aqua farm development, up to 3MVA, a wood processing plant, IMVA, and if the Opotiki harbour development occurs to support the proposed off-shore mussel farm, there may be a growth associated with this.

5.17.6. Constraints

The load to the East is increasing on the Factory feeder to the point that isolated cases of voltage collapse have occurred when frost protection systems are operating. This is currently managed by diverting load to the Hospital feeder and with the installation of a voltage regulator during 2010. This is only seen as an interim measure.

There is limited capacity to supply additional loads due to voltage support issues. Also the ability of the feeders to support each other is becoming limited at periods of peak load. An additional load of 1MVA at Opotiki due to any of the possibilities identified above would severely strain the system.

The Waiotahi GXP has a summer peak loading capability of 12MVA per transformer. Peak load has exceeded 10MVA and is predicted to exceed 12MVA by 2014.

5.17.7. Development Plans

The location of a substation at Waiotahi is historical and does not reflect the optimal supply point for the system load as it now stands. The ideal location is to have a GXP or zone substation located in Opotiki. This is discussed further in Section 5.17.13.

Voltage regulators are an option to support the voltage but these in isolation have limited use unless used away from the major loads to support remote areas. They do nothing to reduce feeder loading into Opotiki town, and they actually increase the peak load current and consequently voltage drop in the lines before the regulator.

Scheduled upgrades within the planning period:

- Waiotahi substation feeder circuit breakers;
- Ripple control unit;
- Local service supply;
- RTU and communications; and
- Three Poletop circuit breakers around Opotiki.

These have all been identified as projects in the AMP 10 year project plan but are deferred until final decisions are made on the Opotiki/Waiotahi substation development projects.

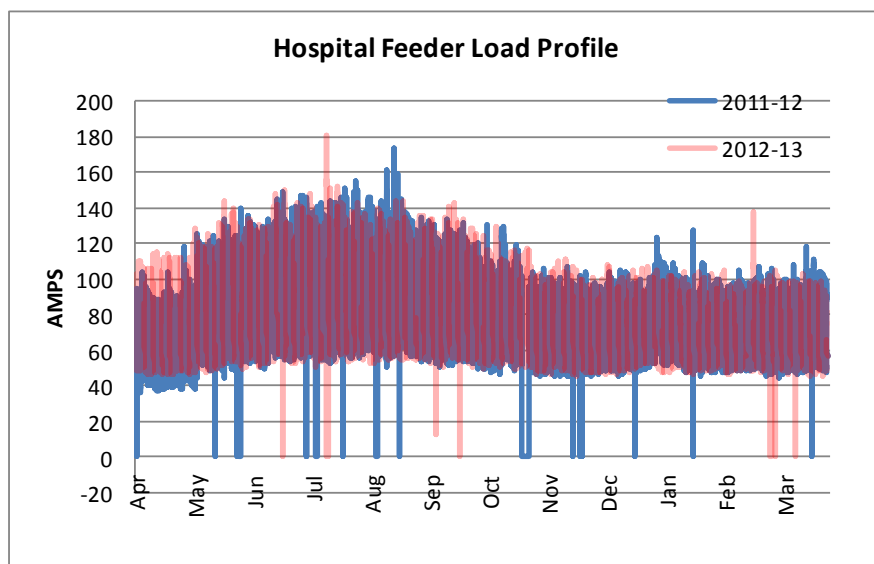
5.17.8. Waiotahi Feeders

The Waiotahi feeders are summarised in Table 5.61 below:

Feeder	Factory	Hospital	Opotiki	Waimana
Type	Rural	Rural/Urban	Rural/Urban	Rural/Urban
Overhead (km)	258.3	39.0	17.3	124.0
Underground (km)	7.7	7.8	1.4	4.6
ICP Connections	1163	1344	937	869
Substations	414	110	34	228
Installed Tx Capacity (MVA)	16.8	9.3	7.0	7.3
Maximum Load Amps	185	180	168	133
100 Peak Load Amps	142	142	129	98
5 year average growth rate	5.6%	-1.8%	-0.2%	3.9%
Feeder Utilisation at Average 100 Peaks	51%	51%	46%	35%

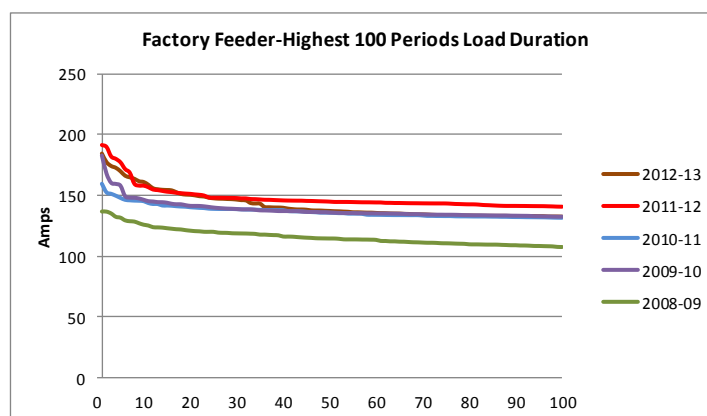
Table 5.6I Waiootahi Feeders

Due to the load management between the feeders involving the re-allocation of loads to maximise the use of the voltage regulator, individual feeder load growth historical measurements are meaningless for forward prediction. The change in load profiles on the Hospital feeder between 2010-11 and 2011-12 is shown below, where in 2011 the coast load of the Factory feeder which was supplied from Hospital was put back onto the Factory feeder.

**Figure 5.48 – Hospital Feeder Load Profile**

Factory Feeder

Peak loading of the Factory feeder is over 50% of the line rated current. Load has constantly increased on this feeder each year. Repeatable annual load measurements on this feeder are distorted by the practice of periodically switching load onto the Hospital feeder during winter.

**Figure 5.49 – Factory Feeder Load Curves**

Opotiki Feeder

A 500kVA additional load installed at the EastPack packaging company had a major influence on the 2009-10 load. Utilisation growth during peak periods is high, as it is for all the Waiotahi feeders. This feeder reinforces Hospital and factory, and has had some load reallocations as part of the Opotiki region load management.

Hospital Feeder

Load values are distorted by switching Factory feeder loads onto the Hospital feeder. Peak loads exceed 50% of the feeder rating and will become an issue in the longer term as loads increase.

The main concern with all three feeders is the peak load on the feeders and ability for the feeders to reinforce each other during high load periods without suffering excessive voltage drop. The planned Opotiki substation will remove these constraints by providing a central point to distribute from close to the load centre.

Waimana

The Waimana feeder had minimal load growth over the five year period. Feeder loads are low and there are no load restraints on the feeder. If the regional development plan ends up with no 11kV substation at Waiotahi, which is an option, then voltage regulators will support the Waimana feeder supplied from the new Opotiki substation.

5.17.9. Faults Performance

Overall, the total number of faults has trended downwards from 2010. The high level of faults 2009-10 were vegetation, which has been addressed with increased vegetation management.

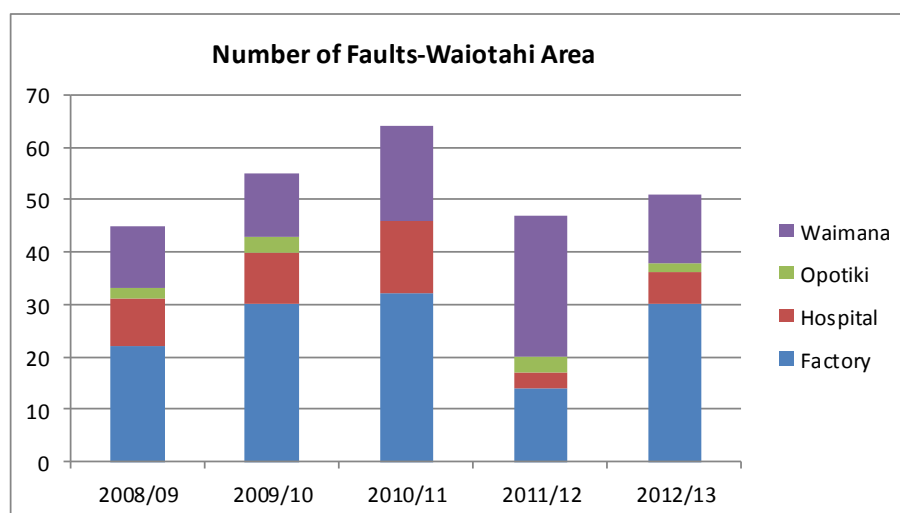


Figure 5.50 – Waiotahi Number of Faults

A number of the faults are equipment related and following inspections, a number of refurbishment programs are planned to improve the overall condition of the feeders.

Waimana

This feeder has a high number of faults and is amongst the worst 10 feeders on the network. Some reliability improvement projects have been installed on this feeder, as well as an increased focus on vegetation management, which should reduce the impact of faults on consumers.

5.17.10. Constraints

The Factory feeder is heavily loaded and suffers from voltage quality issues at the extreme ends of the feeder. Voltage swings between high load and low load are approaching the maximum voltage variation limits. A regulator was installed in 2010 to regulate the voltage on the Factory feeder East of Opotiki.

Reinforcement support for the Factory feeder is provided by both the Hospital and Opotiki feeders. With all feeders approaching 50% utilisation during peak periods, and predicated system load growth, cross support between the feeders will require careful management during high load periods. Development of the Opotiki substation will alleviate these issues.

The Waimana 11kV system is out of phase with its two tie points to the Ohope and Station Road substations.

5.17.11. Asset Condition Assessment

Due to the Factory feeder running along the coastal region to the East of Opotiki the feeder does have some localised degradation where the assets are exposed to the coastal environment.

The Factory feeder has had a high percentage of its length condition assessed. The SWER lines have not been assessed, but of the 1259 sites assessed 65 (5.1%) were marked as requiring work within five years. A number of these are pole replacements, predominantly replacing river run poles. The rest are crossarm or guying issues. The map below (Figure 5.51) shows assets identified as requiring work within five years. Red dots are poles, blue dots are crossarms. The circled areas show assets that have been grouped into projects to overhaul complete line sections. As more condition data is received other areas will be grouped into projects.

In the Waiotahi network such projects are difficult due to the lack of meshed reinforcement and consequently a lot of the work will be completed using live line work crews and generation to maintain supply.

Four steel lattice towers on the Factory feeder are in poor condition. Maintenance will give the towers an estimated working life of 15 years. In lieu of maintaining the towers consideration is being given to actually replacing the towers with 23 metre concrete poles. These have a longer life and a smaller footprint.

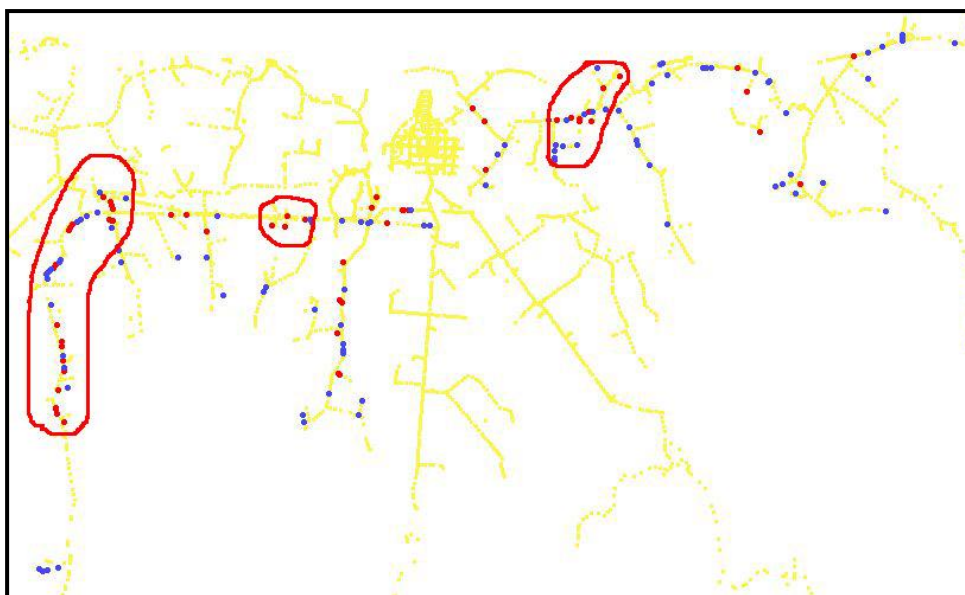


Figure 5.51 – Factory Feeder Pole Condition

5.17.12. Development Plans

Due to the Opotiki substation development proposed in section 5.17.13, planned upgrade works for all the feeders around Opotiki and exiting Waiotahi are held until the Opotiki substation concept plans are finalised. Remedial work on existing assets, based on condition, are being scheduled, especially in remote areas where the work at Opotiki will not affect the feeder configuration. Where possible, tie points are being established around Opotiki to assist the meshing capability of feeders to enable work in developing the Opotiki substation to be completed with minimal disruption to supplies.

There are a number of reliability projects for all of the feeders, however projects around Opotiki are deferred until decisions on the development of the Opotiki substation are finalised as this will likely alter the final configuration of the distribution system out of Opotiki. Reliability devices on the coastal part of the feeder will still be required and are scheduled to be installed from 2013 onwards.

5.17.13. Opotiki Substation Development

Preliminary concept designs have been undertaken for developing either:

- A 33kV substation at Opotiki; and
- A 110kV to 33kV substation at Waiotahi; or
- A 110kV substation at Opotiki.

Load flow and load growth studies indicate that a 33kV substation would reach the full N-1 security capacity of two 33kV circuits by 2020 at the earliest if there are no step load increases prior to this. After this a third line would need to be constructed to maintain N-1 security.

The two 33kV lines could be attained by converting the 11kV Opotiki feeder line route and converting the 50kV Te Kaha feeder to 33kV. A third line would require either a green field route or a conversion of the Opotiki feeder to a dual circuit 33/11kV feeder. Alternatively the Te Kaha circuit could be re-configured into Opotiki at 110kV to provide an N security circuit from Edgumbe.

The installation of a IMVA generator into the Waiotahi system at Opotiki, delivered in 2013, will provide short term support for the region but is not a permanent solution. It does provide voltage support, allowing the Opotiki substation development to be deferred, but will not address the step load restrictions.

To provide support to the Factory feeder to the east, a small substation at Torere or Hawaii, supplied from the Te Kaha feeder, would provide reinforcement and would provide N-1 security to this area.

Forward load predictions for the Opotiki region are shown in Figure 5.52 below:

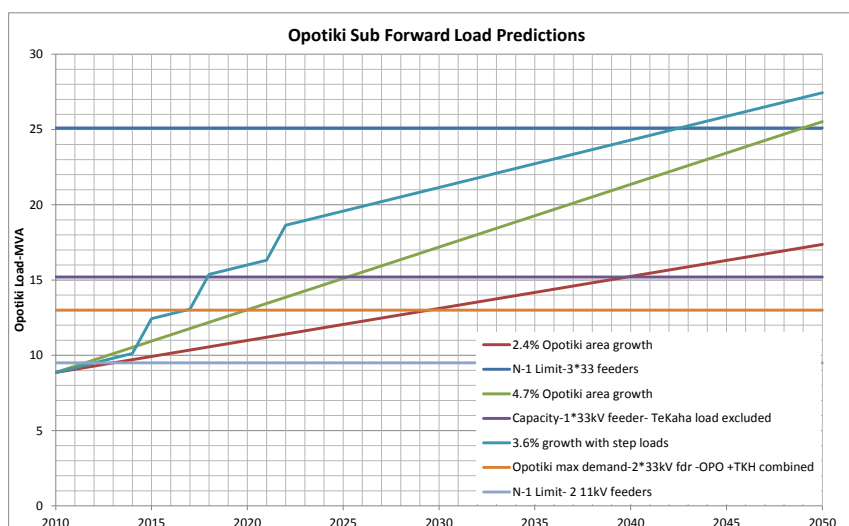
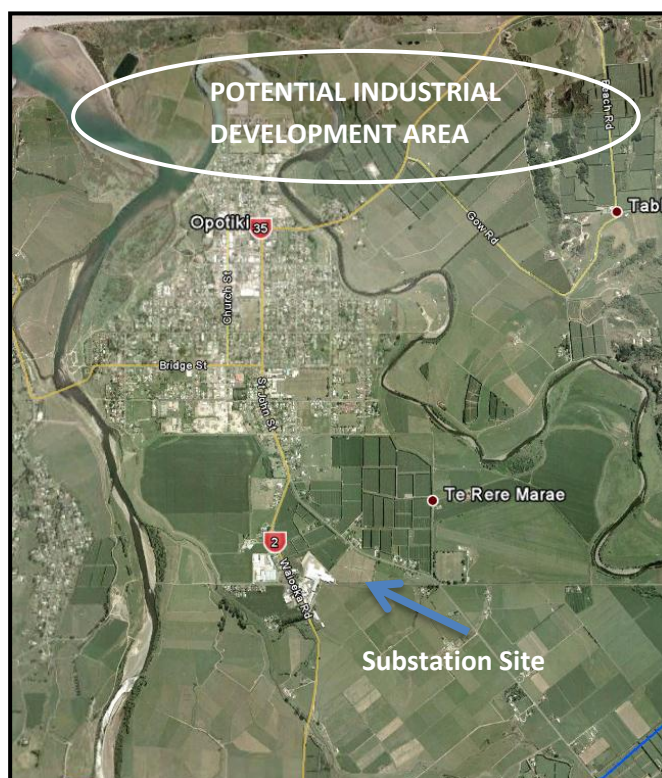


Figure 5.52 – Opotiki Sub Forward Load Predictions



Opotiki Area Substation Site

Scope of Project

Until decisions are made regarding development at 110kV or 33kV, and the supply connection arrangements, the project scope cannot be fully defined as there are very different ownership, design, and build requirements between the two different concepts. Procurement of the East Coast transmission assets from Transpower is an option that is still being considered, as these assets would provide advantages to the Opotiki substation development.

5.18. Waiohau Transformer – Snake Hill Line

5.18.1. Description Of Assets



A 500kVA, 33/11kV transformer is installed at Waiohau North in the Galatea valley, connected via fuses to the Snake Hill 33kV feeder. The valley where the substation is located is normally supplied from Plains Substation via the Te Teko feeder. The transformer was installed due to the radial and remote nature of this system in order to provide an alternative supply to this valley.

There are a number of operational restraints that need to be considered when this alternative arrangement is used. The Snake Hill 33kV line runs between the Edgumbe 33kV bus and the Snake Hill switching station. Also terminated at Snake Hill are the two feeders that supply the Galatea and Kaingaroa substations and the line that runs down to the Aniwhenua Power Station. The supply configuration for Galatea is normally through the Snake Hill switching station from Aniwhenua, with the Snake Hill circuit live from Edgumbe, with no load flow, with CB52 closed.

The Waiohau transformer is energised at all times with a SCADA controlled breaker on the 11kV side of the transformer open. If the substation is required to be used for an alternative supply to the Te Teko feeder then this breaker can be remotely closed.

No on-load tap change provision is available on this transformer and the transformer is only used as an abnormal supply arrangement.

5.18.2. Development

There are no development plans for this substation.

Table 5.62 summarises the major assets within the Waiohau Substation.

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV Bus	Snake Hill feeder	280 amps		
33kV Cable	185 sqmm AL 1x3c XLPE	33kV	1998	Used as connectors for the transformer to the line fuses.
33/11kV Transformer T1 25V011	Three phase Turnbull and Jones	500kVA ONAN 25.25 Amp 5.97% Z, Dyn11	1966	Fixed tap 2.5%, 5 steps, 0-10%. Run energized with no load flow.
11kV Cable	25sqmm AL 3x1 core XLPE	11kV	1998	Used as connector between transformer and 11kV breaker.
11kV Circuit Breaker CBI77	Poletop mounted Cooper Power KFE with SCADA control			
Local Service 25V010	Poletop transformer	7.5kVA 1 phase		
Transformer Protection	33 kV Fuse			
Communications	Tait E band VHF radio			New 2012.

Table 5.62 – Assets Installed at Waiohau Substation

5.19. Fonterra Substation

5.19.1. Description Of Assets

Fonterra substation is an 11kV substation supplying the distribution assets for Fonterra Edgecumbe. The 11kV distribution assets are owned by Horizon Energy with the demarcation point being the 400V terminals at the transformers.

The Fonterra system was developed in two stages. The initial development in 1988 coincided with the development of East Bank Substation and comprised 11 circuit breakers and distribution transformers. The Cogeneration plant was added in 1997 along with a further two circuit breakers.

The Cogeneration is owned and operated by Nova Energy (formally Bay of Plenty Electricity) with ownership of the synchronising and protection system by Horizon Energy.

A summary of assets located at Fonterra:

Asset	Description	Rating Data	Date of Manufacture	Comments
Switchroom	Block construction naturally vented, owned by Fonterra			
11kV Circuit breakers BM14, BM18	Yorkshire YSF6 SF6 gas insulated, withdrawable	12kV, 25kA, 630 amp	1996	
11kV Circuit breakers BM12, BM22	Yorkshire YSF6 SF6 gas insulated, withdrawable	12kV, 25kA, 1250 amp	BM12, 1996 BM22, 1987	No spares available for BM22
11kV Circuit breakers BM16, BM32, BM42, BM52, BM62, BM72, BM82, BM92, BM102,	Yorkshire YSF6 SF6 gas insulated, withdrawable	12kV, 25kA 630 amp	1987	Obsolete, no spare parts available
Transformers	13 * 11kV distribution Transformers.	1.5 MVA *6 1 MVA *3 500 KVA *2 750 KVA *2	1987 to 2009	Some transformers are heavily loaded and are being monitored
SCADA	Foxboro	P2 processor	1991	System is obsolete with no spares. Scheduled for upgrade 2014
Protection elements	Mixed generation ABB and Areva		1987 to 1997	Scheduled for upgrade 2014
DC supplies	48V DC Switchtec		1987	Due for assessment

5.19.2. Condition of Assets

During 2013 an on-site inspection of all the 11kV assets was completed. It was identified that the 11kV YSF6 circuit breakers installed in 1987 are now obsolete with spare parts no longer available. No decisions have yet been made on the management of the obsolescence risk with this equipment.

- Obsolescence details per type of MV equipment.

Brand	Range	Type	End of Com Year	Obsolescence Year	Qty
Obsolete equipment					11
Merlin Gerin	YSF6	-	2001	2002	11
Equipment no longer commercialised but spare parts guaranteed					2
Merlin Gerin	YSF6	-	2001	(*)	2

There have been failures of some of the ABB and Areva protection equipment which have been picked up in routine testing. This has driven a project to upgrade the protection equipment, scheduled for 2014.

Part of the upgrade project has been to commission a review of the system, using IEC/IEEE/PAS 63547 guidelines, of the protection scheme installed, which includes an extensive inter-trip scheme between Edgumbe GXP, Plains and East Bank substations and Fonterra. The review recommended a simplification of the protection scheme and elimination of the functional and operational interdependencies between the distribution network and the generation, so that each can service its specific function without the distraction of meeting the needs of the other.

The key recommendations from the report are:

- The existing incomer protection at Fonterra 11kV bus should be upgraded to modern, numerical relays that can provide the recommended protection elements and logics;
- Anti-islanding protection should be installed at the Fonterra 11kV bus using the communications network to transmit system phase and frequency to the incomer relays;
- The existing cascading inter-trips can be removed, as they will no longer be necessary when the new scheme is implemented;
- Protection grading should be reviewed across the whole network, including Fonterra's 11kV feeders and Nova Energy's generators, as well as Horizon Energy's network protections;
- The neutral grounding arrangements for the 33/11kV transformers and the generators should be upgraded;
- The generator synchronising system ownership should be transferred to Nova Energy, and an upgrade of generator controls should be considered to suit the new protection arrangements; and
- Horizon Energy and Nova Energy should enter into an operating agreement which explicitly recognises the roles and responsibilities set out in IEC/IEEE/PAS 63547.

This project is being worked on for a planned implementation start during winter 2014 pending agreement with Fonterra and Nova Energy.

5.20. Rural Distribution Reliability Projects

A study in 2009 identified 236 individual projects, with a total value of \$5.3M, to improve the reliability of the rural distribution networks. Over 50% of the projects have been implemented.

The projects range from circuit breaker replacements, new installations, tie point switch automation, line sectionalisers, drop out sectionalisers and line fuses.

Engineering studies have started on implementing fully automated self-healing meshed networks, controlled by SCADA, with minimal controller intervention. No policy has yet been formed on this concept of using unmanned automation to reconfigure the network to restore or minimise outage areas as studies have yet to be completed on the safety and reliability aspects before any decisions to implement this is made. All equipment currently being specified will be capable of being used in this mode if the decision is made to proceed.

The viability of each individual reliability project and the equipment type selection is based on:

- An assessment of feeder reliability and the SAIDI performance of the feeder;
- The expected saving in SAIDI minutes by completing the individual installation;
- The number of customers retained by the installation and the expected fault response time; and
- Installation cost per customer saved.

Horizon Energy considers an individual reliability project is viable if:

- The cost per customer retained is under \$200;
- Implementing the project improves network meshing and enables a significant back-feed capability to be attained; and
- The individual site is required to support a larger scheme.

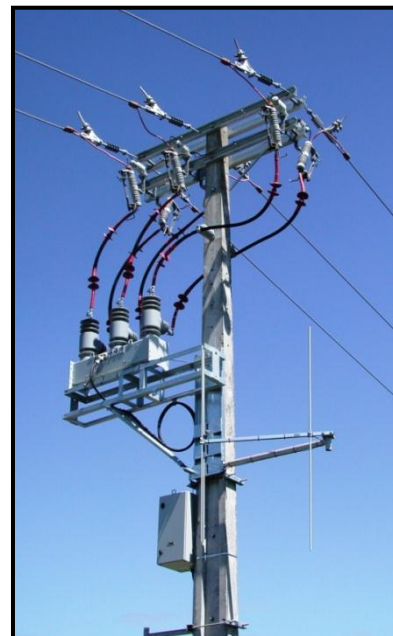
Using the cost per customer model allows various equipment options to be considered to maximise the returns on capital spent. Equipment options considered are:

- Circuit breaker;
- Sectionalisers circuit interrupter;
- Spur line fusing;
- Drop out sectionalisers;
- Automated switches; and
- Fuses with fuse saving technology.

All circuit breakers, sectionalisers and switches will have full SCADA control.

The limitation on using sectionalisers is the number that can be installed in series downstream of a circuit breaker to retain a two attempt reclose capability:

- Rural circuit-breakers set to operate three reclose attempts before forcing the circuit breaker to lock out;
- Sectionalisers are set to have two reclose attempts before lockout;
- This limits the design to the installation of one circuit breaker and one sectionaliser on a section of line, with additional sectionalisers on spur lines radiating off the main line, before a second circuit breaker is required to be installed; and
- Circuit breakers supplying urban feeders are set with a single operation and these circuit breakers will lockout on first trip.



Priority Order

The priority order for installing reliability projects is based on the overall reliability of individual feeders and the planned installation order is summarised in Table 5.63 below:

Year/Substation	Project Cost
2014	\$535,845
East Bank Edgecumbe	\$535,845
2015	\$774,302
Ohope	\$479,642
Plains	\$233,546
Waiotahi, around Opotiki	\$61,115

Table 5.63 Reliability Projects Priority Order

5.21. Zone Substation Circuit Breaker Upgrades

There are a number of zone substation circuit breaker upgrade projects scheduled in the 10 year plan. These circuit breaker replacements are driven by obsolescence and reliability of the existing equipment, with Waiotahi, Ohope and Galatea substations having distribution pole top bulk oil KFE circuit breakers being used as primary switchgear. In addition to circuit breaker replacements, there are three new substations planned over the planning period. There is benefit in considering a modular and standard design approach for these equipment types.

Horizon Energy intends to standardise on one type of switchgear and a full evaluation process was carried out during 2012. It is planned that some of the switchgear will be pre-loaded into transportable buildings and some will have dedicated block buildings. It is appropriate with existing sites to consider pre-loaded transportable buildings in order to reduce the construction time on site and the need to extend existing buildings. All new 11kV distribution will be indoor switchgear.

Outdoor equipment will still be considered for 33kV switchgear but indoor may be preferred for aesthetic or security reasons, especially in the case of a substation in urban areas.

The first of these modular 11kV substations was designed in 2012 and installed in 2013-14.

The earliest start planning schedule for these projects is below:

Zone Substation	Year	Number of Circuit Breakers	Status
Galatea	2013	8	Complete 2014
Ohope	2013	2	Complete using pole-top Nova CB's. Indoor conversion deferred.
Waiotahi	2015	5	Proposal to Transpower 2013
Kaingaroa	2015	7	Deferred
Opotiki	2017	10	In Planning
Whakatane CBD	2017	6	Under consideration pending load driven requirement
Gateway	2021	9	Deferred pending load driven requirement

Table 5.64 – Project Planning Schedule

Considerations of portable style building compared to a permanent building:

- Pre-painted steel clad, foam insulated Portacom style buildings have become a viable alternative to the traditional concrete block switchroom construction;
- Plains and Kaingaroa Substations have Portacom buildings for 11kV switchgear. A Portacom style building on a raised pile or steel frame foundation of 1.8m or sunk concrete base would allow adequate cable access requirements;
- Portacom buildings have a 40 year design life but are generally considered to have an operational life in the order of 25-30 years in coastal environments, which is less than the life of the switchboard. Re-cladding a Portacom is considered a major refurbishment;
- A Portacom style building becomes marginal in terms of cost should it be erected on a concrete pad foundation rather than on piles;
- This type of construction is less secure than a concrete block construction;
- Portability allows each building and switchgear to be fully constructed off site and transported to site as an assembly, reducing the on-site construction time and providing opportunities for factory based assembly and testing;
- Erecting piles and a steel frame basement structure is less site intrusive than a full block basement building;
- Portable buildings can be designed to cater for the particular requirements of substations, including fire rating, security, explosion venting, under floor access and floor weight loadings; and
- Relocation and re-use of a transportable building is an option.



6. Asset Lifecycle Management Planning

6.1. Maintenance Practices

6.1.1. Introduction

This Section of the Horizon Energy Asset Management Plan describes the policies relating to the design, maintenance, operation and renewal of network assets. Also included is specific asset lifecycle information for major asset groups that outlines maintenance and replacement strategies and practices that are applied to them.

The operational practices used by Horizon Energy to operate and maintain the network are described first, followed by a description of each asset category and discussion on specific asset types, their overall condition, and any policies developed around these assets. This is followed by individual projects and work plans that have been identified to replace or refurbish the assets.

6.1.2. Lifecycle Asset Management Concepts

The main objective of maintenance is to keep an asset in service to reach its design life and purpose. Horizon Energy's maintenance drivers include:

- Ensuring safe operation;
- Ensure regulatory compliance;
- Maintaining or improving network reliability;
- Minimising asset lifecycle costs;
- Extending asset lives; and
- Ensuring the asset is fit for purpose.

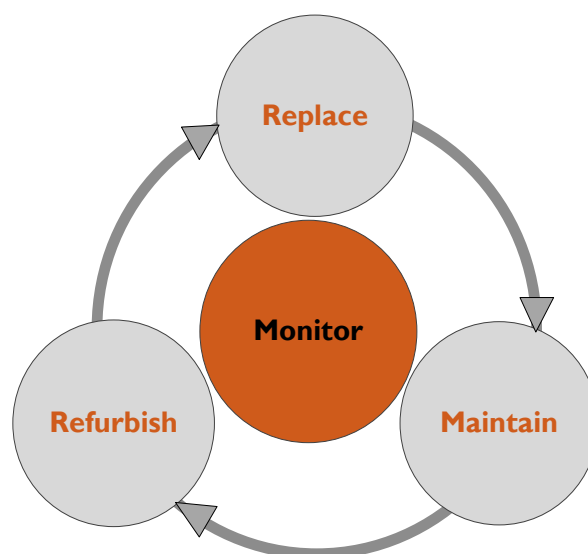


Figure 6.1 – Asset Ageing Lifecycle

The asset lifecycle infers that a continuous process keeps the asset functional throughout its life. It is this *function* that is maintained throughout the lifecycle. As technology evolves new equipment is made available to the industry then the equipment may be replaced or upgraded to maintain the *function* that is required of the system. The purpose of maintenance is to keep the asset functional until such time as it becomes uneconomic to refurbish. Replacement options are then assessed to determine the best replacement method, equipment or system.

Monitoring or condition assessment of assets triggers its own set of questions; the answers then determine the lifecycle management policy appropriate to that particular asset or asset group.

Is the asset to be:

- Maintained?
- Run to failure?
- Refurbished?
- Replaced?
- Replaced when?
- Replaced with a better product?
- Can the asset be improved? or
- Is the asset still required?



Figure 6.2 – Asset Decision Wheel

Asset renewal strategies are based around the need to replace assets that have either failed, are at high risk of failure, a safety hazard or are obsolete. A lot of replacement work is driven by load or capacity upgrades, and a lot of remedial work is condition driven. The table below summarises the primary asset renewal strategies currently in place.

Asset type	Communications equipment			X
	Buildings, fences		X	
	Earthing systems		X	
	Battery chargers		X	
	Batteries			X
	SCADA			X
	Crossarms		X	
	Poles		X	
	LV Substations		X	
	Pillar boxes, link boxes		X	
	Low voltage cables	X	X	
	Polemount transformer 100kVA+		X	X
	Groundmount transformer 100kVA +		X	X
	Polemount transformer < 100kVA	X		
	Ground mount transformer <100kVA	X	X	
	Surge arrestors	X		
	Ring Main Units		X	X
	Overhead expulsion fuses	X	X	
	Pole Mount circuit breakers			X
	11kV Overhead lines		X	
	11kV PILC Feeder cables			X
	11kV XLPE/PILC to single transformer	X	X	
	11kV XLPE feeder cables			X
	Protection			X
	Zone substation switchgear		X	X
	Zone substation transformers		X	X
	Ripple Control plant	X		X
Air break switches		X		
Sub-transmission lines		X		
Sub transmission cables		X		

6.1.3. Routine Maintenance

The baseline equipment maintenance schedule is determined according to the criteria in Table 6.1 below:

Operational History	<p>Frequency of use is used to modify the manufacturers standard service intervals for the following equipment types:</p> <ul style="list-style-type: none"> • Tap changers • Poletop circuit breakers • Re-closers • Load break switches • Voltage regulators 																						
Time Based Servicing	<p>Items that are not monitored for operational history are serviced either on a time based routine or by exception. Time based routine inspections include:</p> <table> <tr> <td>• Zone substation inspections</td><td>Monthly</td></tr> <tr> <td>• Earth bank testing</td><td>10 year</td></tr> <tr> <td>• Protection testing (mechanical relays)</td><td>3 year</td></tr> <tr> <td>• Protection testing (electronic relays)</td><td>5 year</td></tr> <tr> <td>• Zone substation transformer oil/DGA tests</td><td>Annual</td></tr> <tr> <td>• Thermal imaging critical circuits</td><td>Annual</td></tr> <tr> <td>• Partial Discharge testing RMU</td><td>2 year</td></tr> <tr> <td>• Poletop devices battery replacement</td><td>3 year</td></tr> <tr> <td>• Radio system compliance testing</td><td>Annual</td></tr> <tr> <td>• 33kV lines and terminations</td><td>Annual</td></tr> <tr> <td>• Vegetation control</td><td>Species related</td></tr> </table>	• Zone substation inspections	Monthly	• Earth bank testing	10 year	• Protection testing (mechanical relays)	3 year	• Protection testing (electronic relays)	5 year	• Zone substation transformer oil/DGA tests	Annual	• Thermal imaging critical circuits	Annual	• Partial Discharge testing RMU	2 year	• Poletop devices battery replacement	3 year	• Radio system compliance testing	Annual	• 33kV lines and terminations	Annual	• Vegetation control	Species related
• Zone substation inspections	Monthly																						
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• Zone substation transformer oil/DGA tests	Annual																						
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• Poletop devices battery replacement	3 year																						
• Radio system compliance testing	Annual																						
• 33kV lines and terminations	Annual																						
• Vegetation control	Species related																						
Load Based Maintenance	<p>No individual assets are subjected to load based maintenance routines at this stage.</p> <p>Horizon Energy does not routinely perform cable condition or transformer assessment tests due to load, unless a specific issue has been identified.</p>																						
Visual Condition	<p>Asset condition assessment is being integrated into proactive maintenance and replacement policies.</p> <p>With the remaining life inspection program that is presently used, condition is based on a 1 year, 2 year, 5 year, >10 year visually assessed remaining life. Maintenance and planned replacement schedules or projects are individually adjusted based on the condition assessment process.</p>																						
Measured Condition	<p>Recent partial discharge testing of oil filled ring main units has been used to defer time based servicing. A number of faults have been detected and remedial actions put in place, including repair and/or replacement.</p> <p>Thermal Imaging is used to assess assets on critical feeders and zone substation assets. Test results have initiated works to repair assets prior to failure.</p>																						

Reactive	<p>Equipment classes that have no specific scheduled routine maintenance activities and tend to be maintained in a reactive manner include:</p> <ul style="list-style-type: none"> • 400V pillar boxes, excluding concrete boxes • 400V switchgear • Distribution transformers < 200kVA • 400V lines and poles • 400V customer connections • 400V cables • 11kV cables (excluding terminations)
Proactive Replacement	<p>Proactive equipment replacement, upgrade or maintenance is driven by a number of different criteria. These include:</p> <ul style="list-style-type: none"> • Load • Condition • Planned obsolescence • Customer driven • System enhancement • Known faulty equipment types e.g. concrete pillar boxes and stainless steel DDO's

Table 6.1 – Asset Maintenance Criteria

6.1.4. Faults Management

Horizon Energy operates a 24/7 fault response system. Controls function is undertaken by the manning of the control room from 7:00am until 9:00pm Monday to Friday, and by an operator callout system outside of these hours. The on-call network controller has remote SCADA access from home and a VHF radio to allow fast response to network faults.

Field fault response is provided by contractors who cover the various regional locations of the network. Energy retailers use a call centre to reports faults from consumers in various areas. The dispatched faultmen are able to work directly for the customer if the problem is on their system, or in the event of a network fault, they are coordinated in the restoration process by the Horizon Energy network controller.

There is a second response backup available on standby if the first response faultmen is over loaded with work, has worked excessive hours, or needs assistance due to the complexity of the work. Likewise the duty control operator has backup operators available should they need support.

In the event of a network fault, the SCADA system is programmed to send an alarm message to the network controller's home SCADA console, and to call the operator's cell phone. If this message is not responded to within a defined time period the SCADA escalates the message to the next operator and continues this process until the message is acknowledged.

Faults issued by the network controller are logged in a work management system. Individual faults have no assigned priority; the priority is determined by the network controller depending on the criticality of the service or number of customers who may be affected by the incident.

The controllers maintain a list of essential services and these get priority of restoration.

Priority services include:

- Whakatane Hospital;
- Zone substations;
- District Council sewage and water pumps;
- Flood pumps;
- Major industrial customers;
- Commercial zones; and
- Customers with identified medical equipment reliant on supply.

Horizon Energy has within its Quality System details of the essential services that require attention. The system also identifies the load shedding priority order and process that must be undertaken in either a network or grid emergency, or as instructed by the Transpower system operator.

Currently the management of data for electrical supplies to medical equipment is with energy retailers. Horizon Energy is looking at control procedures that will provide a higher level of confidence in the management of essential services, and the management of supplies to medical equipment users will be incorporated into these procedures.

6.1.5. Control Practices

In addition to the fault activities defined above the other core functions of the control room are:

- Monitor contractor safety when working on the network;
- Monitor the distribution system for quality compliance;
- Manage load flow;
- Respond to and manage network faults;
- Process switching requests, write switching schedules, direct switching operations for planned maintenance and issue permits to work;
- Manage new customer connections and disconnections for revenue or safety reasons;
- Manage the MARIA metering and ICP registry;
- Manage metering reconciliation for retailers; and
- Manage any works undertaken near network assets e.g. a high load that may pass through the area.

6.1.6. Defect Management

Defects are urgent or non-urgent faults, or damaged equipment, that are identified by staff and are raised on a notification of defect form. Any member of Horizon Energy staff or contractors can raise a defect. The public can also advise defects through either their retailer or by direct contact to Horizon Energy. The latter is being encouraged with stickers being added to public assets that advise a safety warning and give a 0800 contact number.

Defect priorities are assessed as follows:

Priority	Definition	Action
Red Tag Priority 3	Defected item (normally a pole) has a red tag affixed to the pole when it is deemed unsafe to climb. Once the pole is red tagged no person may climb the pole unless it is supported in some manner.	Red tag poles must be replaced within three months.
Priority 1 Immediate repair required	The equipment is unsafe, non-functional or about to cause a loss of supply.	Work is required to start as soon as practicable and be complete within 48 hrs.
Priority 2	Asset is defective or below standard but is not an immediate hazard nor likely to cause an imminent loss of supply.	Work is planned and scheduled but must be complete within one month.
Priority 3	Asset is defective or below standard but is not an immediate hazard nor likely to cause an imminent loss of supply.	Work is planned and scheduled. Work required within three months.
Priority 4	Asset is defective or below standard but is not an immediate hazard nor likely to cause a loss of supply within six months.	Work is planned and scheduled. Work required within six months.
Priority 5	Asset is below standard condition with no visible defects and is not likely to become a hazard or cause an outage in the near future.	Work is included in the AMP to monitor the condition and inspect again after five years.
No action required	Asset is not a hazard and is unlikely to become a hazard or cause a loss of supply.	Close defect in defects register.

Table 6.2 – Defect Priorities

6.1.7. Vegetation Control

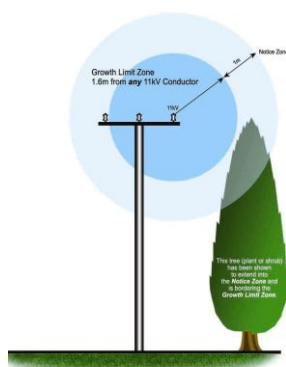
Vegetation is managed according to the following practices:

- Horizon Energy has a vegetation management division within its contracting subsidiary;
- A database is maintained of hazardous trees and vegetation that encroaches within the control zone for all 11kV and 33kV lines;
- High risk trees outside the control zone are also logged in the data base;
- Vegetation inspections are scheduled six monthly for 33kV lines and annually for critical 11kV lines. Difficult to access areas are patrolled by helicopter;
- In some cases, for high growth areas, a more regular inspection may be undertaken; and
- Results from the vegetation patrols drive the cut plan and letters are to be issued to the tree owners.

The basic tree management process related to dealings with landowners and the public is specified by Government regulation.

Trees found to be causing a hazard from within the growth limit zone are trimmed, and owners of trees within the notice zone are notified in writing.

The tree legislation gives little control over trees that are outside the notice zone and yet may pose a threat to the line due to a fall hazard. The majority of recent outages have been caused by trees that have been outside of the notice zone.



Trees within purpose planted forests that are within the fall zone pose a particular risk as the harvest planner consider these trees to be unsafe to harvest. They are being left unmanaged by the forestry company for the network to remove.

The control zone for vegetation is:

GROWTH LIMIT ZONE		
Line Voltage	Growth Limit Zone	Notice Zone
33kV lines	2.5m	3.5m
11kV lines	1.6m	2.6m
400/230V lines	0.5m	1.5m

Table 6.3 – Growth Limit Zones

During 2010-11 there was an increase in vegetation related faults. The Company has recently increased its vegetation team capacity by acquisition of a local business and has shown a reduction in tree defects since 2012.

The operational budget for vegetation control was increased for 2012 however there were still 17 vegetation faults for the year, although a number of these were out-of-zone trees.

6.2. Asset Lifecycle Management

The lifecycle of any particular asset is determined by making an assessment of its:

- Existing condition;
- Age in service compared to design life;
- Known history of that particular asset (make and model);
- History of asset type;
- Service conditions to which the asset is exposed;
- Environmental conditions the asset is subjected to;
- Maintenance regime undertaken;

- Criticality to the network for that specific asset and asset type; and
- Functionality of the asset.

End of life asset management relies heavily on planned maintenance carried out, linked to age and condition. The following sections describe the policies used to determine asset replacement.

6.2.1. *Standard Asset Replacement Policies*

The asset replacement policies are summarised below:

Zone Substation Transformers

Horizon has assumed all zone substation assets have been maintained to the manufacturers specifications and are under-utilised; therefore have the extended life as defined in the 2004 ODV handbook. Replacement is scheduled when either of the following conditions is reached:

- Asset age 55 years. (ODV Handbook standard life 45 years, extended to 60 years for well-maintained assets);
- Peak load during reinforcement exceeds 110% of the n-1 capability of a dual bank or 110% N capability of a single bank;
- Transformers are rated according to IEC60354 which defines the allowable overload capability of transformers for two and four hour overload periods.

Ring Main Units

Handbook standard life of 40 years but is modified by condition, maintenance, partial discharge testing and known industry type issues. Horizon Energy changes the planned life by the following amounts:

- Andelect Series -2 to -5 years
- ABB SD -4 to +4 years
- Magnefix -5 to 0 years
- ABB Safelink 0 years (1st installation 2008)
- Schneider RM6 0 years (1st installation 2009)
- RTE 0 years
- All others 0 years

Distribution Transformers

Handbook standard life is 45 years, 55 years with a formal maintenance regime. Horizon Energy has no formal maintenance program for distribution transformers. Replacement is scheduled:

- Under 100KVA run to failure, replaced as defects;
- Pole mounts 100 KVA and over, 45 years scheduled replacement. All pole top transformers replaced due to age or condition are replaced with ground mount transformers; and
- Ground mount transformers 45 years if outdoor; most transformers at this age are attached to Magnefix or RTE units and are being replaced when the switchgear has reached the lifecycle replacement date. These units are being replaced with transformers with 11kV switchgear attached as an integral unit.

11kV XLPE Cables

Handbook life is 45 years. Horizon Energy's replacement policy is:

- Load driven;
- Type specific for known faulty cable batches; and
- Scheduled age based replacement is not addressed at present.

11kV PILC Cables

Handbook life is 70 years. No cables this age have been identified on the network. 1957 is the first recorded PILC cable which is due for replacement in 2027.

Lines, Poles, and Low Voltage Assets

No age replacement policy has yet been determined. Currently all replacement work is condition based via the inspection, defect process or fault driven.

Poletop Circuit Breakers

Handbook life is 40 years.

- Horizon Energy's policy is 40 years, all existing field devices over 40 years old are scheduled to be replaced by 2014 (excludes devices in Zone substations).

Zone Substation 11kV Switchgear- Outdoor

All poletop outdoor switchgear scheduled to be replaced by 2015.

Zone Substation 11kV Switchgear- Indoor

Handbook life is 45 years.

- 1st indoor switch gear (East Bank Substation) reaches 45 years old in 2031.

ABS

No policy of age driven replacement. Currently all replacement work is condition based via the defect process or fault driven. The network is considering enclosed vacuum switches as an alternative to air insulated ABS's for operational reasons.

33kV Zone Substation Switchgear (Outdoor)

Handbook life is 40 years.

- All except Kaingaroa are due for replacement now. Ohope and Kope have been scheduled, Galatea not yet scheduled.

Low Voltage Cables PVC/XLPE

Handbook life is 45 years.

- Load driven;
- Run to failure.

6.2.2. Condition Assessment

Condition assessment is used to drive asset replacement according to the following criteria:

- By using both asset age and condition to determine the priority for replacement means that no asset is arbitrarily replaced just on age alone;
- Due to the volume of assets in the system, and the unknown ultimate life of certain asset types, a simple age based asset replacement program is not sustainable, nor is it good maintenance practice;
- The age/condition priority is refined by the importance of the particular asset to the network reliability;
- Assets close to zone substations in the feeder arterial routes are assigned higher priorities than assets further out, or at lower voltages, as the number of customers affected reduces with distance;
- Assets that can introduce human risk if they fail in service e.g. poles, are prioritised based on the defect red tag system;
- Condition assessment of poles, conductors and crossarms is used to ascertain the general overall condition of groups of assets. When there are clusters of assets identified with a high number of defects, or have a high concentration of assessed low condition assets, then these are being grouped into projects and a full upgrade is scheduled for that cluster. These projects are designed using new technology, to be fit for purpose. It is not always that a like-for-like replacement is the best option.

The following tables generally describe the priorities given to assets or clusters of assets for either replacement or refurbishment. A higher number of points are prescribed for higher priority works.

Condition Assessment	Description	Points
0	Assessed condition > 10 year	0
1	Assessed condition 5 year	1
2	Assessed condition 3 year	2
3	Assessed condition 1 year	3

Table 6.4 – Condition Assessment

6.2.3. Reliability

A reliability factor is added to the asset replacement priority. The reliability factor is assessed according to the previous performance history of the asset and reflects the needs of the network to remove or replace the asset class.

Reliability Factor Description	Priority
Equipment that has no history of failure or is very reliable, lightly loaded, well maintained, and the asset group is expected to have a life longer than the ODV defined life.	0
Equipment that is reliable, lightly loaded, has had average maintenance, minor or few faults and the asset group is expected to reach ODV life.	1
Equipment that has had a history of failure, has operational faults, has been heavily loaded, poorly maintained, and the asset class is not expected to reach its design life.	2
Equipment that has been identified for accelerated replacement.	3

Table 6.5 – Reliability Factor

6.2.4. Safety Factor

All equipment is assessed for safety. This assessment is applied to each asset type to provide a benchmark for operational safety, and the safety hazards that the asset may pose to workers and the general public.

The first principle of safety management is to eliminate, isolate or minimise any risk. Any asset that is identified as a potential hazard, or likely to become a hazard, is defected in the first instance. Assessment of the asset will then determine the appropriate action to manage the hazard. This may be accomplished through altering the operational procedures in the way the asset is operated, or an engineering solution may be applied where the asset is repaired, upgraded, or replaced as appropriate.

Non-defected assets are assessed using the safety factor assessment below:

Safety Factor Description	Priority
Equipment has no known safety related issues and meets all currently applicable manufacturing and safety codes.	0
Equipment has no known safety issues and meets codes applicable at date of manufacture, but does not comply with existing codes or standards.	1
Equipment has safety or operational issues that can be managed operationally.	2
Equipment has safety or operational issues that cannot be managed operationally but does not pose a hazard in normal operation.	3
Equipment type is classed unsafe in operation and has a 'do not use' status but is not an immediate hazard.	4

Table 6.6 – Equipment Safety Assessment

6.2.5. Network Criticality

Network criticality is an assessment of the importance of an individual piece of equipment to the overall reliability of the network. This is determined by the number of customers that would be affected if the equipment were to fail in service and the time it would take to restore service. Considerations are:

- The ability to bypass equipment or to re-supply the network;
- The distance from fault support personnel; and
- The ease of access is factored in to the criticality assessment.

This score is used to help set the priority of works for replacement, and is used to determine the frequency of routine maintenance and inspections.

Description	Points
Less than 100 customers affected, or less than 300 customers affected but able to be bypassed either automatically or manually.	1
More than 100 but less than 300 customers. No ability to bypass.	2
Between 300 and 500 customers. Ability to restore from alternate means within one hour.	3
More than 500 customers, able to restore from alternate sources within one hour.	4
More than 500 customers, restoration time greater than one hour.	5

Table 6.7 – Network Priority

6.2.6. Asset End of Life Re-use Policy

Retired assets will be considered for reuse in less critical services if they are in good condition and are refurbished prior to use. Certain quantities of units will be retained for spares. Reuse policies for equipment that is retired due to condition modified age are in Table 6.8.

Equipment	End of life – Reuse Policy
Nine-insulator air break switch	Following refurbishment, anywhere except in automation circuits
Magnefix	Spares only
RTE	Spares only
Andelect series I	Scrap
ABB Series 2 SD, SD3, SDAF	Anywhere except main feeders
Pole – River Run	Scrap
Pole – Tauranga	Scrap
Pole – Hardwood	Scrap
Pole – Softwood	Scrap
Pole – Larch	Scrap
Pole – Concrete pre-stressed	Anywhere if in undamaged condition
Crossarms, insulators	If under 10 years old, anywhere
KF, KFE Circuit breakers	Spares only
Power Transformer >1MVA	Assessed on a case by case basis
Transformer – tub sub	Scrap
Pole mount Distribution Transformer >75kVA	No re-use except as spares if in good condition. (75kVA max on poles)
Transformer 3 ph <30kVA	Scrap
Transformer 1 ph <15kVA	Scrap
Transformer others	Detailed condition assessment
Protection equipment	Spares only
Primary circuit breakers	Assessed on a case by case basis

Table 6.8 – Equipment Reuse policy

6.3. Management of Asset Classes

Planned maintenance intervals and the activities undertaken are tailored to suit each different type of asset. The task definition and interval is based on an assessment of the age of the equipment, overall condition, historical performance and consequences of failure. The following sections summarise the maintenance regime for major equipment classes by type.

6.3.1. Ring Main Units

The following details the various types of Ring Main units installed on the network and the lifecycle management practice that is applied to each type of unit.

Horizon Energy has approximately 250 ring main units, from seven different manufacturers, installed across the network.

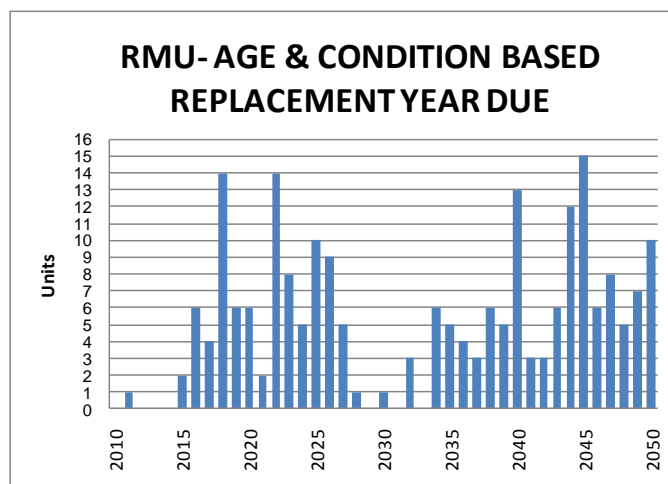


Figure 6.3 – Ring Main Replacement Program

Figure 6.3 shows the condition modified end-of-life replacement program for all ring main units installed on Horizon Energy's network, based on their standard life. Actual replacement is assessed on a unit by unit basis depending on the project priority assessment criteria, and due to either condition or network improvement plans there are several units planned for replacement before the times indicated in Figure 6.3.

Following condition assessment of 92 ring main units, 10 were identified as faulty, with the majority of the faults being corrosion of the external enclosure.

Partial discharge testing of Ring Main Units has determined a number of defects with cables terminations and switchgear. A number of assets have been accelerated for replacement and a number of defects entered to repair cable terminations.

6.3.1.1. Holec Magnefix Ring Main Units Maintenance

Magnefix switchgear is a compact fully insulated Ring Main Unit for application in 12-15kV distribution networks. The unit is epoxy resin insulated, and is modular in construction such that it can be configured to meet the needs of specific switching applications. The most commonly used units consist of isolating links and fused load-break links. The following photo shows a unit that is equipped with four isolating links on its left and fuse combination on the right. This fuse unit would generally be used to connect a local transformer to the network. The nominal current of the links is 400 Amp.

Modern variants of the Holec Magnefix units are still being manufactured.



Figure 6.4 – Typical Magnefix Arrangement

Maintenance Schedules

All Magnefix switchgear is inspected on a bi-annual basis. The inspection is carried out to determine the overall condition of the switchgear, the condition of the terminations and vegetation and insect infestation control. Past experience with the Magnefix units show that an accumulation of moisture and dust on the surface of the Magnefix switchgear causes electrical discharge and eventual breakdown if left uncleaned. Failure of the terminations is also common unless regular cleaning is carried out. A Magnefix inspection checklist is completed for each unit inspected. These bi-annual outages are costly due to the work required to connect generation to support the loads during the cleaning process and this maintenance cost plus overall condition is driving a replacement program.

Lifecycle Management

The lifecycle management assessment criteria for this switchgear type are determined in Table 6.9.

Quantity on Network	43
Reliability Factor	1
Safety Factor	3
Network Criticality	Assessed Per Unit

Table 6.9 – Typical Magnefix Assessment

Magnefix units are operated by removing the link caps on the circuits being disconnected. The biggest disadvantage operationally is that each phase is isolated individually by physically removing the links. As such Magnefix units rate at a lower operator safety factor than equipment that is fully enclosed and breaks and makes all three phases together. The units will be proactively removed from service in less than the expected life for 11kV switchgear.

Figure 6.5 shows the retirement schedule for Magnefix switchgear based on age and condition assessment. Units in good condition will be considered for reuse as emergency spares. The actual replacement schedule is slightly different to Figure 6.5 due to some Magnefix replacements being accelerated to fit in with cable and transformer replacement projects.

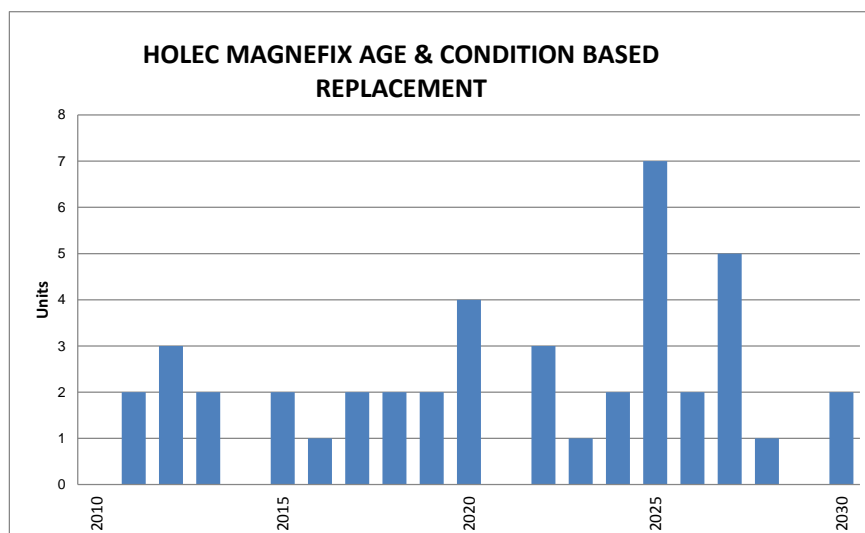


Figure 6.5 – Magnefix Replacement Schedule

6.3.1.2. ABB/Andelect SD Series

The ABB SD Series 2 oil filled switch range is designed for use on distribution systems to switch 3-phase currents of 400-600A at voltages up to 12kV. SD switches were available in a variety of configurations made up from either a switch or an automatic tripping switch fuse (activated by a fuse striker). The range is discontinued from August 2012.

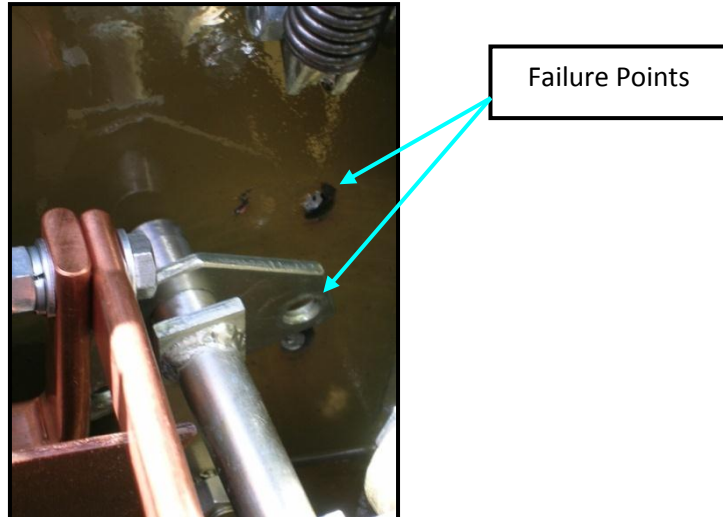
The unit was available as a Ring Main Unit (RMU) comprising of two switches and one fuse switch within the one tank, or as separate units of single, double and triple switches and a single fuse switch that can be connected in any combination required. Each switch or fuse switch has an associated cable earthing switch as part of the module.

There are two series of SD switches installed on Horizon Energy network. The earlier Series 1 switch was manufactured by Anderson Electrical under the brand name Andelect. These differ from the later ABB Series 2 switches by having a common cable chamber for all cables, whereas the Series 2 has a separate chamber for each cable connection. This improves the fault containment between chambers.

Known Problems

The SD series Ring Main Unit can be extended by bolting a second unit to a bus extension on the first unit, normally to extend a three unit assemble into four units. The interconnection bus chamber can be subject to failure if not sealed correctly against water ingress. In 2009 a program was completed to re-pack the bus connection chamber on all RMU's of this type with an ABB supplied waterproof compound. A reduction in the frequency of faults from this weakness is expected but PD testing has determined that the bus extension is still a continuing source of failure.

Instances have been reported in New Zealand of some Series 1 units faulting when being operated due to a failure of a welded stud that holds the switch operating mechanism. This fault is apparent by a failure to close correctly. One incident recorded that the SD unit caught fire, and a recommendation was issued to the industry not to use the Andelect Series 1 switches when attempting to live onto suspected faults.



Currently Horizon Energy has a policy of prioritising early replacement of in-service Andelect Series 1 switchgear. A switching procedure has been implemented for their operation to ensure the safety of the operator. Where these units have been identified as being in critical switching locations within the network, they have been programmed for replacement.

A number of these units have recently been identified with varying levels of electrical partial discharge on either the cable terminations, bus extension bushing, or internal. Any Andelect series 1 Ring Main Unit that requires remedial work is scheduled to be replaced rather than repaired.

Maintenance Schedules

SD units are inspected annually. This inspection covers, among other things, oil loss, rust, termination condition, weed and bug infestation, ground condition or slumping and graffiti, as well as earth bank testing.

SD units are categorised into two categories for maintenance of the insulation oil. Units on main feeders that are potentially subjected to fault passage are scheduled for an oil change every five years. Units on spur lines or secondary feeder lines are programmed for a 10 yearly oil change.

ABB recommends the oil be changed if the switch is used three times to break fault current. Horizon Energy does not currently have a method of recording the number of non-fault operations of these switches and hence the maintenance schedule above for main feeder RMU's. Planned integration of switching schedules with the new asset management systems and GIS system will enable this detail to be obtained by using the switching schedules to record usage and drive the maintenance program.

Lifecycle Management

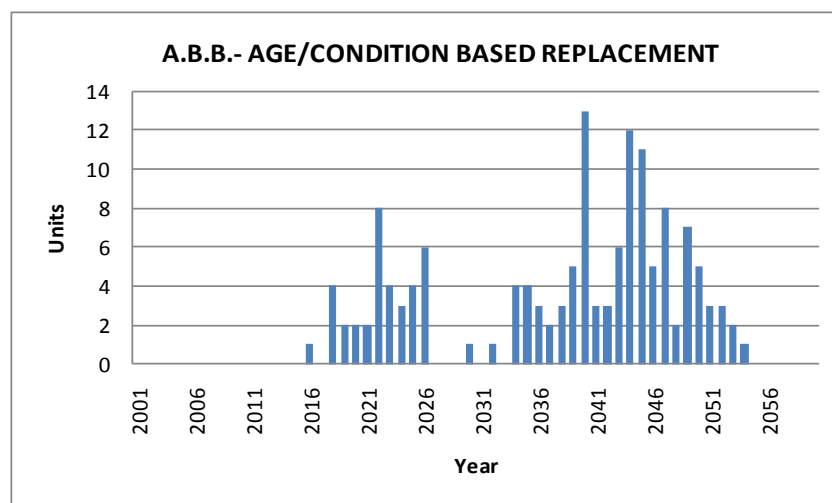
SD Series 2 units are expected to reach or exceed their ODV life. Very few units are switched onto faults. Horizon Energy has no centralised recording system to track the number of close-on-fault operations of RMU's so it is not possible to determine if units are degrading due to fault switching. The main driver for replacement will be the desire to install increased automation as the SD units cannot be retrofitted for automation.

Series 1 Andelect Units will be prioritised for replacement over the Series 2 Units due to the cable box arrangement and the potential failure of the internal mechanism.

Quantity on Network	50
Reliability Factor	1
Safety Factor	3
Network Criticality	Assessed Per Unit

Table 6.10 – Andelect SD Series 1

Quantity on Network	75
Reliability Factor	1
Safety Factor	1
Network Criticality	Assessed Per Unit

Table 6.11 – Andelect SD Series 2**Figure 6.6 – ABB SD Replacement Schedule**

6.3.1.3. ABB Safelink SF6 Ring Main Unit

ABB Safelink Units have been installed on the network since 2008. They were selected for their ability to be automated and their low maintenance requirements due to the replacing the insulating oil with SF6 gas. ABB also provides backup support for its locally manufactured products. The units installed on the Horizon Energy network have a modified locking arrangement on the mechanical interlocks to enhance operational safety of both the operator and the network.

The ABB SF6 insulated Safelink switch enclosure is a gas-tight welded stainless steel compartment. All components within the SF6 insulated tank are maintenance free for the life expectancy of the unit. Units are manufactured as either a three or four switch/fuse unit assembly depending on what is required for the specific location requirement. The units can also be supplied with an environmental enclosure that fully encloses the unit for tidy installation within a public environment. ABB operates a worldwide gas recovery network for the disposal of SF6 gas at the end of life of the unit. The manufacturer recommended life span exceeds 30 years for indoor service.



All units are installed with cable fault indicators to assist with fault finding.

The ABB series 2 SafeLink Units with full automation was released in August 2012. These units have been selected to be installed at tie points in line with Horizon Energy's feeder automation program.

Lifecycle Management

Maintenance is limited to annual inspection, vegetation control, and general overall condition of the switch unit and kiosk. SF6 gas pressure is monitored by a pressure gauge and will not allow any operation if a low gas pressure is detected. The ABB Safelink Units are new to the network and therefore there are none due for replacement within the current planning period.

6.3.1.4. ABB SafePlus SF6 Switchgear

Horizon Energy has two SafePlus circuit breaker units installed in Kawerau on an industrial site used for the control of one 1MVA and one 2MVA transformer.



SafePlus is a modular, completely sealed extendable SF6 system with a stainless steel tank containing all the live parts and switching functions. A sealed tank with constant atmospheric conditions ensures a high level of reliability as well as personal safety and a virtually maintenance free system. As an option, an external busbar can be provided to obtain full modularity. The pressure system is defined as a sealed for life system with an operating life time of 30 years. The leakage rate is stated as less than 0.1% per year.

Maintenance Schedules

All components in the SF6 tank are maintenance free for the declared life expectancy of the unit. If the panels sustain any scratches or damage, these must be repaired with paint to prevent corrosion. Mechanical parts are positioned outside the tank and behind the front panel. This enables easy access and replacement if required.

The protection relays installed on the circuit breakers are scheduled for testing as per the maintenance schedule for electronic relays.

The units are inspected on a yearly basis with the standard checks made to ensure condition and operation is appropriate.

6.3.1.5. Schneider RM6

Merlin Gerin/Schneider RM6 switchgear comprises one to four integrated, low dimension functional units. This self-contained, totally insulated unit comprises a stainless steel, gas-tight metal enclosure, sealed for life, which groups together the live parts, switch-disconnector, earthing switch, fuse switch or the circuit breaker, one to four cable compartments for connection to the network or to a transformer.



Horizon Energy has three RM6 units recently installed as roadside Ring Main Units on the network, enclosed in aluminium enclosures for weather protection. Two of these have been set up as feeder circuit breakers to provide mid-point circuit protection and automated tie point connection, controlled through the SCADA system. The other has been installed to provide circuit breaker protection to a 1000kVA transformer installed at Whakatane hospital.

Maintenance Schedules

The RM6 switchgear is regarded as maintenance free apart from annual inspections to control weeds and insects, and five yearly testing of the electronic protection relays. Due to the high H₂S environment in Kawerau the inspection will entail a full assessment of the condition of the internals, cable connections and overall condition of the RTU unit.

Lifecycle Management

The RM6 has a published life span of 30 years. In Kawerau, due to the atmospheric conditions, this may be shortened but future condition assessment will influence any replacement decision.

6.3.1.6. CANZAC RTE Switchgear

The CANZAC RTE units are in-line oil insulated rotary 11kV transformer switches directly connected to a distribution transformer. Horizon Energy has 17 RTE units in service as at 2012 in the Whakatane urban region. The switches are reliable in operation but must be operated using a hot stick. The transformer/switch assembly is mounted in a fibreglass cubicle. This means the cable terminations are not sealed against vegetation growth as is the practice with modern switchgear. The mechanical cable support is in an awkward location and in many instances the cable has been installed with limited mechanical support. There are also no arc containment or explosion barriers between the incoming and outgoing cables, as can be seen in the accompanying photograph. The transformer fuse links tend to be a weak point with the switchgear.



The RTE also has no means of integral earthing for the incoming and outgoing cables.

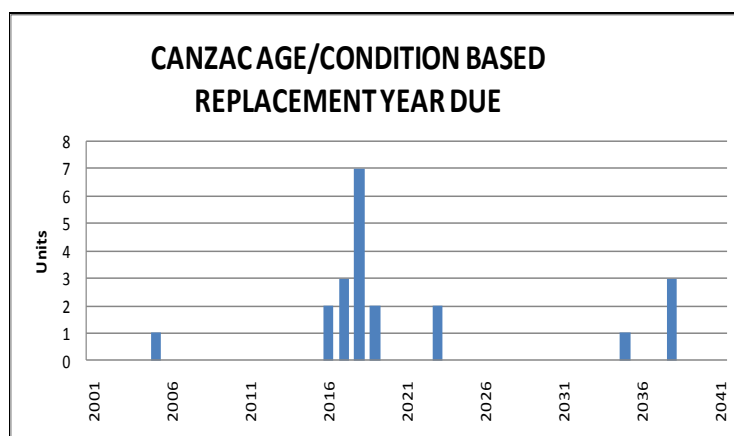
Maintenance

Maintenance is limited to bi-annual inspections and clearing away of any debris and vegetation.

Lifecycle Management

Due to the lack of cable earthing, Horizon Energy has formed a policy of replacing RTE's that are adjacent to each other with a switch unit that does have earthing capability. The transformer and RTE are replaced with a total pad unit, and the redundant transformer is tested and refurbished as a stand-alone transformer if its overall condition is good.

The age modified condition replacement schedule is shown below. Unit replacement will depend on actual condition and risk assessment.



6.3.1.7. Merlin Gerin Ringmaster

There are two Yorkshire/Schneider Ringmaster Ring Main switch units installed on the Fonterra site and one in Kawerau on the ripple control plant. These were installed in 1997 and are in excellent condition. Their expected end of life replacement falls outside the planning period.

The Ringmaster is a gas insulated MV outdoor 11kV switchgear in either three or four switch configuration. The gas insulated switches are sealed for life and require no maintenance. Maintenance is limited to periodic inspection of the physical condition of the housing and gas pressure checks.

Lifecycle Management

Ringmaster units will be replaced at their nominal end of life age of 45 years pending risk and condition assessment.



6.3.2. Overhead Assets

6.3.2.1. Poles

Horizon Energy has about 22,300 poles in the network. These are a mix of concrete and wooden poles from various manufacturers with varying age. Nominal expected life of a concrete pole is 60 years and a wooden pole is 40 years. Modern pre-stressed concrete poles are expected to exceed this lifecycle and the recent inspection results

seem to support this. Historically, poles have been inspected either as part of the vegetation inspection process or for specific projects of fault works.

Poles are also being inspected in detail as a part of the asset inspection and data capture project that is underway. Any defect poles are red tagged and a job is issued to have the pole replaced within 3 months.

All poles are being individually numbered during the inspection process to assist in their lifecycle management.

Table 6.12 below is a list of pole types extracted from GIS. The total quantity of poles logged on the network is increasing as stub poles and multi pole structures are being identified as individual assets.

Pole Type	Number on Network
Bay	53
Bay T	280
Concrete	4,707
Hardwood	683
Larch	294
Concrete	274
Tauranga Concrete	1,116
Other	4
Pine	615
Pre-stressed Concrete	9,909
Steel	43
Timber	619
Unknown	3,749
Total	22,346

Table 6.12 – Pole Schedule

Poles Lifecycle Management

Condition assessment of a sample of 3806 poles identified that 202 poles, or 5.3% of the poles inspected, have defects of some sort. Pole inspection includes all connected assets:

- Chipped concrete;
- Crossarm or insulator faults;
- Loose or poor condition guys;
- Exposed aggregate; and
- Timber splitting or rot.

Areas having a high density of assets with low remaining life are being grouped into specific projects, as it is more cost effective to upgrade complete sections of feeders between isolation points rather than replace assets individually. This approach sets a new baseline for condition for the whole section of the upgraded feeder.

Table 6.13 summarises the asset inspection fault data for a sub-set of inspected poles.

Pole Type	Remedial work required within			
	1 Year	3 Years	5 Years	Defect Urgent
Stub Poles	3%	0%	77%	20%
Hardwood	0%	0%	80%	20%
Larch	7%	0%	79%	21%
11kV Sub Total	20%	14%	58%	7%
Hardwood	7%	50%	36%	7%
Larch	100%	0%	0%	0%
Tauranga Concrete	20%	0%	60%	20%
Concrete	50%	0%	50%	0%
Pre-stressed	22%	6%	50%	22%
River Run	23%	9%	67%	0%
33kV Sub Total	50%	0%	50%	0%
Hardwood	100%	0%	0%	0%
Pre-stressed	0%	0%	100%	0%
LV Sub Total	4%	10%	64%	22%
Hardwood	6%	17%	56%	22%
Iron Rail	0%	0%	0%	100%
Larch	3%	83%	0%	13%
Pine	0%	0%	100%	0%
Pre-stressed	0%	0%	50%	50%
River Run	0%	0%	100%	0%
Steel	100%	0%	0%	0%

Table 6.13 – Pole Inspection Results

River Run poles are reinforced concrete poles that were produced by a local pole manufacturing plant during the 1950s. These poles are now showing signs of decay with cement weathering exposing aggregate and have a high incidence of 1-5 year assessed remaining life.

Larch poles are mainly used for low voltage road crossings and SWER lines. These poles have a tendency to rot below ground level and split longitudinally. They have generally been replaced in the past in area blocks. Future replacement priority will be by condition. There has been extensive use of larch poles on the Waioeka and Toatoa SWER lines and these are now in very poor condition. Waioeka and Toatoa have had the majority of the poles replaced in a five year project to upgrade the SWER lines.

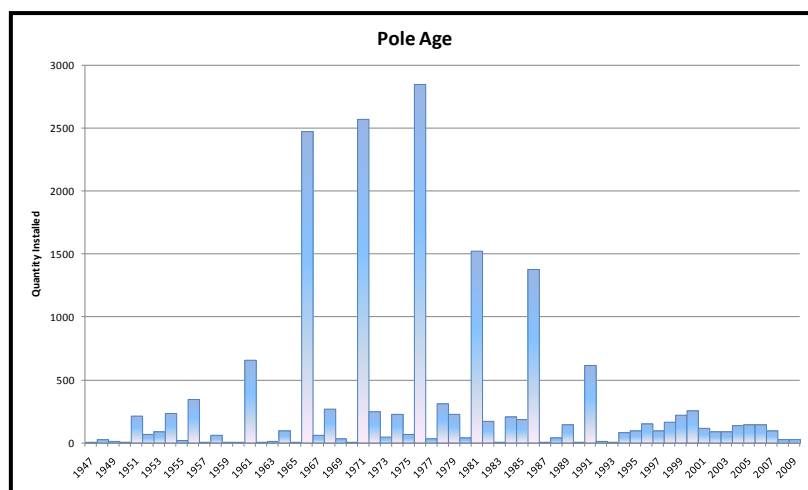


Figure 6.7 – Poles installed by year

Figure 6.7 shows the poles installed by year.

6.3.2.2. Overhead Asset Ownership

Horizon Energy Asset Ownership Policy is to own all 33kV, 11kV and low voltage distribution assets. Low voltage distribution assets are owned up to property boundaries unless they supply two or more customers or by agreement with the landowner.

As part of the asset inspection process, land owners are informed if the assets on their property are defective or at risk and a refurbishment service is offered to the property owner.

6.3.2.3. Crossarms, Conductor and Insulators

Crossarms, insulators and the conductor they support make up the components that form the pole assemblies for overhead lines. Their condition and their lifecycle management have a large bearing on the overall reliability of the network.

Each component on a pole assembly has a different life expectancy:

- Hardwood crossarms tend to have an expected life about half that of concrete poles, and invariably fail due to rot, splitting and insulator hole enlargement;
- Insulators degrade due to the interference from pollution and/or lightning; and
- Galvanised fitting and guy wires corrode resulting in a need to be replaced, especially in coastal regions.

Failure mode analysis has identified one series of 11kV insulators used on the network that has been causing problems. These insulators have a tendency to develop hairline cracks between the top of the pin and the insulator binding which cause intermittent faults, especially when they get wet after an extended dry period. The cracks in many cases may be due to lightning 'puncturing' through the insulation at the top of the insulator. These insulators were used extensively across the network and it is not feasible to replace them in bulk except during a planned area upgrade.

Conductors have a theoretical age profile similar to poles. The actual life expectancy is dependent on a number of conditions:

- Environment;
- Loading stresses;
- Corrosion;
- Vibration;
- Binding failure;
- Tension;
- Interference from trees; and
- Arcing faults from clashing.

A large proportion of the Horizon Energy network is located in a coastal environment and due to corrosion these coastal assets tend to age faster than inland assets. This is recognised in a higher planned refurbishment program scheduled for works in coastal regions.

Aluminium conductor steel reinforced (ACSR) cables in coastal environments can develop stress corrosion due to a slow galvanic reaction once the insulating grease between the aluminium and the steel is washed away. Horizon Energy has specified all aluminium alloy conductors (AAAC) which have no steel core to replace ACSR. AAAC has a number of advantages:

- Higher current carrying capacity;
- Lower volt drop per meter;
- Easier to handle for installation;
- No dissimilar metals, eliminating galvanic action corrosion; and
- A lower ultimate tensile strength.

Horizon Energy has a network wide replacement policy for galvanised steel conductors and copper conductors in coastal regions.

A project started in 2012 to raise the clearance of overhead lines across roads, starting with state highways. Horizon is currently undergrounding all low voltage road crossings for high loads travelling from Tauranga to Kawerau.

Horizon Energy's installation standards specify that lines are to be installed one meter higher than the legal minimum clearance; however a number of road crossing lines do not meet the Horizon Energy standard, even though they do meet the minimum legal requirement, and these will be worked on as a priority.

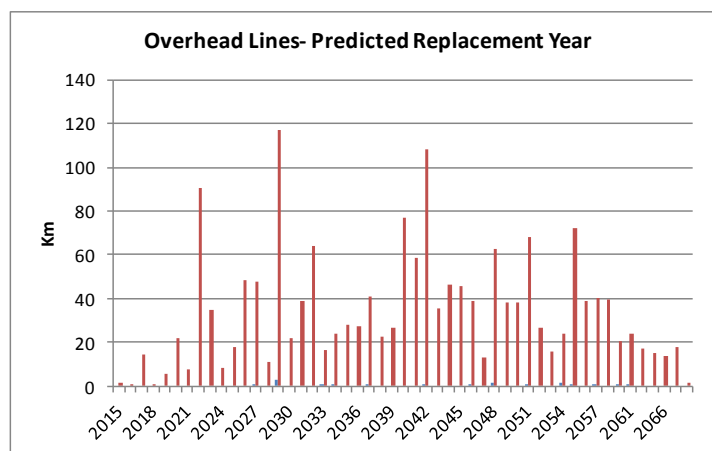


Fig 6.8 Overhead Lines Replacement Profile

Forward predictions for overhead line replacement are shown on Figure 6.8 above, based on a nominal 60 year life expectancy. Average replacement length required per annum is 34 kilometres, although it is expected inland conductors will exceed this life expectancy.

6.3.2.4. Air Break Switches

There are approximately 450 11kV air break switches on the network. Most of these are non-load break switches.

There is no specified maintenance practice for these devices in rural networks and they are replaced or repaired on a failure basis.

Switches that are inspected using thermal imaging are:

- Zone substations;
- 33kV switches;
- 11kV in Kawerau on Pulp, Paper and Onepu feeders; and
- Others as identified due to condition or customer requirements.

Lifecycle Management

There is no planned end of life replacement policy for air break switches. It is anticipated switches will last for 35 years and will be replaced on a defect or condition assessed basis. Horizon Energy has embarked on a replacement for air break switches at a rate of 10 per year

6.3.2.5. Voltage Regulators

As at 2012 there is only one voltage regulator in the network, located at Opotiki on the Factory feeder.

Maintenance is scheduled as:

- Two yearly inspection and functional operational verification;
- Five yearly full service including oil tests and insulation resistance.

The maintenance schedule is modified by the number of operations count and a full service is scheduled for regulators that have completed 100,000 operations.

Lifecycle Management

These units have a standard handbook life of 55 years.

6.3.2.6. Capacitor Banks - Un-Switched

As at 2012 there is only one capacitor bank in the network, located at Opotiki on the Factory feeder.

There are no active components and hence no maintenance requirement for these units apart from inspection as part of normal lines inspections.

Lifecycle Management

There is no planned end of life replacement policy for capacitor banks. It is anticipated capacitor banks will last for 40 years and will be replaced on a defect or condition assessment basis.

6.3.3. Distribution Substations and Transformers

There are over 3,300 transformers on the network.

Distribution transformer failure rates are very low, with most overhead transformers being changed either due to failure from being damaged by lightning, or changed due to a larger unit required to cater for customer load increases.

The majority of rural transformers damaged by lightning are either at the end of spur lines or before open switches on tie points. There appears to be no obvious failure trend related to age for transformers damaged by lightning strikes.

The tendency for end of line transformers to be damaged is thought to be caused by the voltage doubling affects due to the reflection of the voltage surge. Data on lightning damaged transformers is still being collected following storm events, and the cost benefit of installing surge arrestors on all end-of-line transformers, to reduce the likelihood of failure, is being assessed using this data. When new transformers are installed at the end of lines they are now being fitted with surge arrestors.

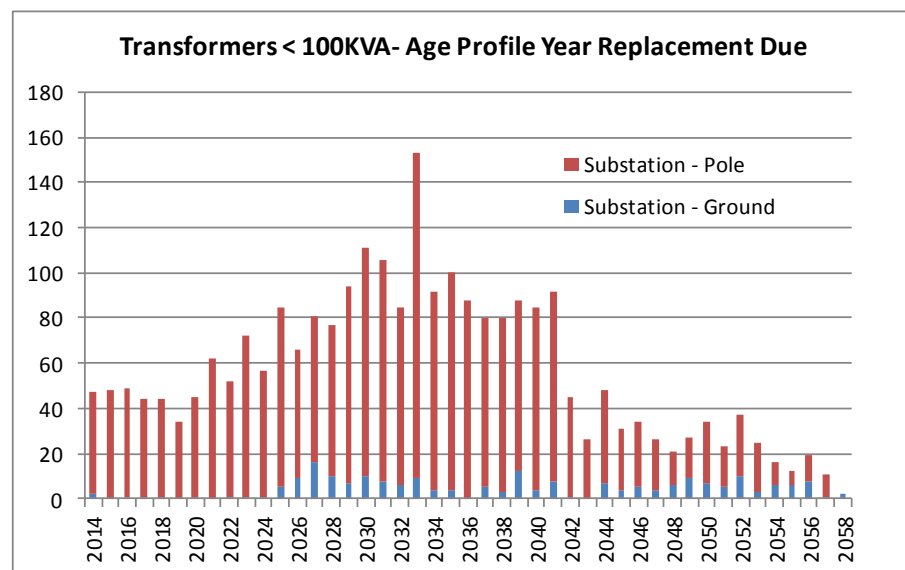


Figure 6.8a – < 100 kVA Transformers Predicted end of life profile

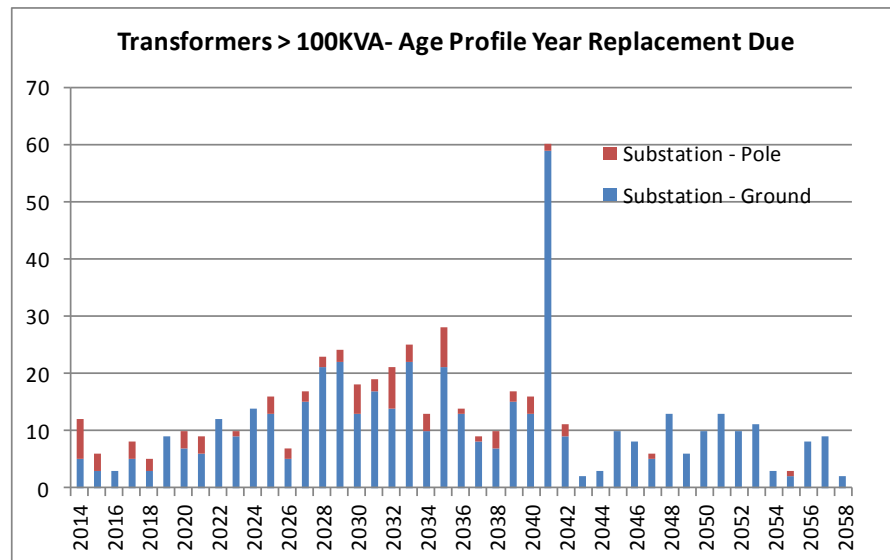


Figure 6.8b – > 100 KVA Transformers predicted end of life profile

The transformer predicted end of life profile (Figure 6.8a and b), indicates a future liability as transformers continue to age towards their end of life, and it is expected that annual maintenance spending on transformer replacement and overhaul will increase over the next 20 years. This has not currently been factored in detail into forward budget forecasts as the steep rise in end of life is towards the end of the planning period.

Figure 6.8b shows the predicted end of life for transformers over 100kVA. The replacement of pole mount transformers will incur significant cost as the network policy is to ground mount transformers 100kVA and over. Average annual replacement requirement for transformer 100kVA or greater is eight transformers, which includes an average of two ground mount transformers per year scheduled for replacement as part of the RTE and Magnefix replacement program over the next 30 years.

Figure 6.9 compares transformers that have been changed due to defects or faults over the last five years and the required number to meet the ELB standard replacement life is shown below. This shows the uplift in expenditure on transformers over the last two years. Transformer replacements for transformers greater than 100kVA have been programmed into the asset replacement schedules.

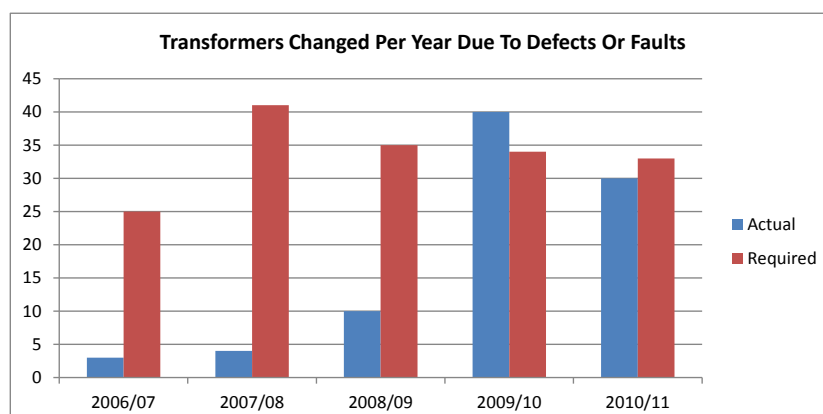


Figure 6.9 – Transformers Changed Per Year due to Defects/Faults

A significant number of transformers are currently beyond their expected life. Some have been scheduled for replacement with the Magnefix and RTE upgrades. Large poletop transformers have been scheduled for replacement with ground mounted transformers. Ground mounted units will be assessed for condition and risk, and scheduled for replacement if this is warranted.

Transformers older than 45 years						
Rating (kVA)	100	150	200	250	300	Total
Ground	5	4	13	7	1	30
Pole	7	2	3	5		17

Transformer Lifecycle Management

The transformer refurbishment policy for transformers that are returned from service due to load driven changes, maintenance replacement, or damage is summarised below:

- Small pole mount transformers with external galvanising in good condition and no visible damage and which have not been removed due to a fault can be free issued for installation on the network after simple insulation resistance and continuity tests without further work;
- All transformers with cores built pre 1978 are written off due to their high no-load losses;
- Any pole mount unit less than 50kVA that has been removed due to an electrical fault condition, or if the unit is over 30 years old, is written off;
- All other pole mount transformers are assessed for repair. If the expected repair cost (including transport), is greater than 75% of the replacement cost, then these are to be written off;
- All ground mounted transformers less than 100kVA are assessed on both electrical and mechanical characteristics. If the case is in poor condition or of a design that would no longer be approved then the whole unit is written off. If the case and paint are in in good condition and the unit has not faulted then it can be treated the same as a small overhead unit;
- Any transformer less than 100kVA that is assessed for repair, and if the expected repair cost (including transport) is greater than 75% of the replacement cost, then the transformer will be written off; and
- Pad mount units 100kVA and above are assessed for repair. If the expected repair cost (including transport) is greater than 75% of the replacement cost, then the transformer is written off.

As part of the assessment process the future use of the transformer is considered. If a transformer is of a type that would only be used as spares and not for new installations, e.g. open bushing type that would normally be replaced with a pad mount; if stock levels of that type and size are adequate then the unit will be written off.

Transformer Service Life

Horizon Energy has no evidence of any age induced failure patterns with transformers. Transformers are a thermal device and their load carrying capacity and actual electrical life is influenced by load. Rural transformers peak utilisation factor average is between 18 to 23 per cent, and the range for urban transformers is between 35 to 80 per cent. With these levels of utilisation the transformers can be expected to exceed their standard ELB life as defined in the ODV



handbook. It is generally physical condition or the need to service connected load that drives asset replacement.

Consideration is being made to instigate a program to condition test the larger ground mounted transformers. The use of transformer demand metering is also being considered but at present no decisions to implement either of these policies has been made.

The transformer installation policy has the maximum size of pole mounted transformer as 75kVA. The cost and convenience that is provided by micro subs now means that more often transformers are ground mounted even in rural areas. A number of aged pole mounted transformers greater than 100kVA have been identified for replacement with ground mounted units. These are scheduled based on age, condition, the number of customers and utilisation factor. The majority of these transformers are located in urban regions.

Small pole mount transformers are generally managed on a run to failure mode due to:

- Limited impact on the network of individual small pole mounted transformers;
- Relatively low replacement cost of individual units;
- Uncertainties of loading and utilisation; and
- Costs and difficulties of actually completing electrical condition testing on these transformers.

Asset Data Capture

Close to 10% of transformers were marked as either defective, or with less than five years of life remaining. The majority of defects noted are tank or kiosk corrosion and the five year life assessment related more to the surface condition of the transformer or kiosk than the electrical condition of the transformers.

A small rural transformer will generally not be replaced due to surface rust unless significant deterioration is detected. Larger ground mounted transformers that have serious corrosion are replaced with a new or refurbished unit and the old unit assessed, and if suitable due to age and type, sent to a service agent for refurbishment. The service agent assesses the cost of refurbishment and a decision is made to either accept the repair or to scrap the asset.

Transformer Load Assessment

A method of assessing the estimated peak load of the transformers based on total kWh supplied to customers has been developed, and by using this tool with verification by actual load measurement, a number of overloaded transformers, or transformers at risk, have been identified for upgrade. Priority has been given to transformers 100kVA or greater.

Projects

For the 2012-13 year a number of transformers have been targeted for refurbishment or replacement. Further detail is provided on these projects in the following project Section.

A future project in the latter part of the 10 year plan is to install load and condition monitoring equipment on to larger ($\geq 300\text{kVA}$) transformers. This project is intended to make use of communications systems to monitor transformer utilisation and operating temperatures as a means of predicting ultimate life and asset condition.

6.3.4. Network Automation Devices

Table 6.14 shows the number of protective or automated switches in the distribution network as at October 2013.

Network Automation Devices

Quantity On Network	Manufacturer										
Type		1984	1988	1989	2007	2008	2009	2010	2011	2012	2013
Automated RMU switch only	ABB Safelink										7
Automated RMU with CB	ABB Safeplus					1					
	Schneider RM6						1	1			1
Circuit Breaker	KF		3								
	KFE	1	3	3							
	NOVA						1	2	7	13	4
	Viper				1						
Fuse saver	Siemens										3
Sectionaliser	ENTEC							6	18	15	3
Drop out Sectionaliser	AK						1		9	2	
Grand Total		1	6	3	1	1	3	9	34	30	18

Table 6.14 – Protective or Automated Switches

- McGraw Edison KFE/KF circuit breakers are being phased out and replaced by Cooper Power Nova 15 circuit breaker;
- New tie and sectionalising switches being installed are fully enclosed Entec LBS switches, which being fully sealed from the effects of environmental corrosion and having a non-arcing switching environment, are expected to have a longer lifecycle and better reliability than air break switches;
- Schneider RM6 units are installed when ground mounted circuit breakers are required; and
- ABB fully automated Safelink gas insulated switches are installed on important points.

A number of installed pole top circuit breakers have no SCADA control due to there being poor radio coverage into various remote sites. This has improved on some sites with the installation of new VHF radio frequencies and some of these previously uncontrolled devices have been identified for upgrade to SCADA control.

Sectionaliser

Other protective devices used are line mounted sectionalisers and drop out sectionalisers. These devices work on the principle of detecting a fault current passing through the device that exceeds a pre-defined threshold, and then relying on the upstream circuit breaker to isolate the fault. Once the fault has been isolated by the circuit breaker, the sectionaliser opens (or drops out in the case of a drop out device) and the upstream circuit breaker then closes to restore power to the line before the sectionaliser. If the sectionaliser has no communications to the SCADA master station then the consumer is relied on to identify the power outage.

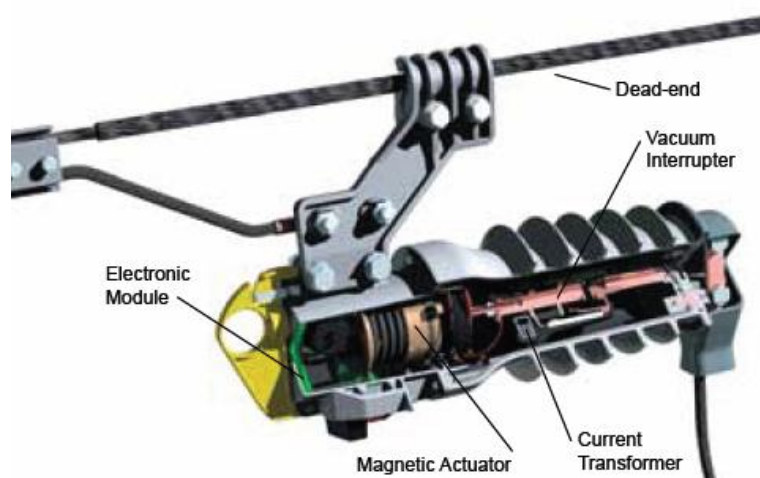


The AK drop-out sectionalisers have proven to be intermittent in operation and their use has been discontinued.

Fuse saver

A new device on the market in 2011 is a fuse saver. The FuseSaver™ is a self-powered, electronically controlled, single-phase fault interrupting device that is installed in series with a fuse to protect that fuse from transient faults. The fuse saver operates on the first fault passage. If the fault re-occurs within a defined time the fuse operates to isolate the faulty section from the supply.

These have been trialled successfully and are approved for installation on the network. Recent development has been a communications package that allows the fuse saver to communicate to a master station. One of these is set up for a trial in 2013.



Fuse Saver

SCADA Controlled Devices Maintenance Policy Maintenance Activities

- Remote controlled devices have their battery changed on a five yearly cycle as part of their routine maintenance;
- Circuit breakers have protection element tested 5 yearly;
- This routine was adopted to reduce the number of equipment failures due to battery failure and allows more economic batteries to be installed;
- Oil Breakers (Cooper Power KFE, KF, GN) have the oil changed and are protection tested every three years;
- The modern gas insulated switches and circuit breakers are classed as maintenance free so their maintenance program is to cycle the switch and continue the five yearly battery replacement cycle, and to give the units a general condition inspection.

Life Cycle Management

- Poletop devices are being replaced on an age modified condition basis;
- All existing KFE oil filled devices will be replaced by 2015;
- Nominal life for modern equipment is 35 years although this is probably optimistic for the electronic controllers and these can be expected to be replaced once during the devices lifetime; and
- Fusesavers have a nominal battery life of 10 years and is replaced complete with the communications module.

6.3.5. 11kV Cables

- There is extensive cable reticulation in the Kawerau and Whakatane urban areas, mostly XLPE cable;
- No routine cable testing program in place at present;
- A cable replacement program has been set up for main feeders in Whakatane based on projected load growth and estimations of when the cables are likely to either become overloaded, or be unable to support reinforcement loads;
- A batch of early generation XLPE cable in the network has had water treeing failures in the past and a section of this cable on the Ohope/City South tie feeder was tested with a Tan-Delta tester in 2010. This cable was found to have a low tan-delta test but passed a VLF test, and was recommended for monitoring and retesting in the near future. Due to its criticality as a tie feeder to Ohope, this cable has been scheduled for replacement; and
- Other batches of this cable in Kawerau are scheduled for replacement.

Cables Maintenance

The asset condition assessment process currently excludes underground assets. As the cables age, some form of condition testing will be required to determine failure likelihood and to establish replacement priorities. XLPE cables most at risk are those manufactured prior to 1970, due to a lack of understanding at that time of the effects of material impurities in the moulding process on electrical stress degradation with time. There are very few XLPE cables this age.

A cable condition assessment program is under consideration, decisions on whether to outsource this to a third party to provide the service or to procure equipment and complete testing in-house, have yet to be made.

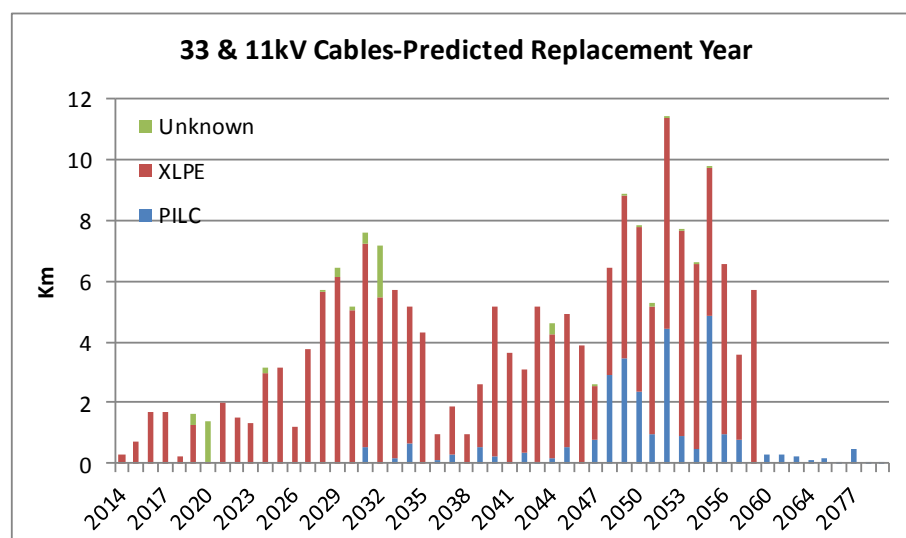
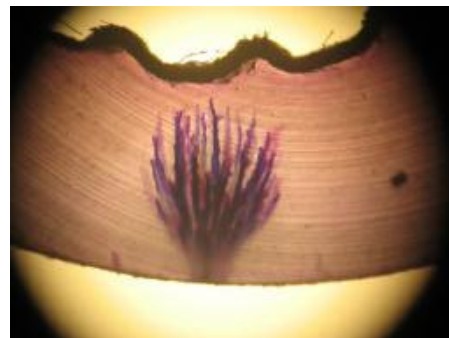


Figure 6.10 – 33kV and 11kV Cables Age Profile

The forward looking age replacement profile shows the probable future of 11kV and 33kV cable replacements. As with all asset replacements condition, load and reliability will be the primary drivers for replacement. Due to their generally lightly loaded condition, most cables are expected to exceed their standard life.

Faulty Cable Testing

A faulted 95sqmm XLPE 11kV feeder cable tested by Olex determined that the presence of large contaminants (0.7mm) in the insulation of the cable manufactured in 1971 was the likely cause of the cable failure. Pictures below show the fault location and a microscopic view of a vented tree in the XLPE insulation, but no electrical stress tree is present in the insulation. This cable failed following an extended period of overload during reinforcement.



Horizon Energy does not have a policy of testing every faulted cable, but following this failure a quantity of the same batch of cable was identified in service. Similar cable has failed in service in Kawerau in 2011 and 2013 so when these cables are identified they are assessed for consequence of failure and scheduled for replacement. A section of this type of cable on the Ohope feeder tie to Station Road was replaced in 2013 as a precautionary measure, along with various sections in Kawerau.

6.3.6. Low Voltage Systems

Whakatane and Opotiki urban low voltage reticulation systems are being configured to be able to provide sufficient reinforcement to enable the removal from service of any one 11kV transformer and allow the loads to be carried by adjacent transformers. The loads can be supplemented by the installation of generation if required.

Load driven upgrades, over and above the requirements for reinforcement, will be implemented on a 'just in time' basis and will be driven by connection requests.

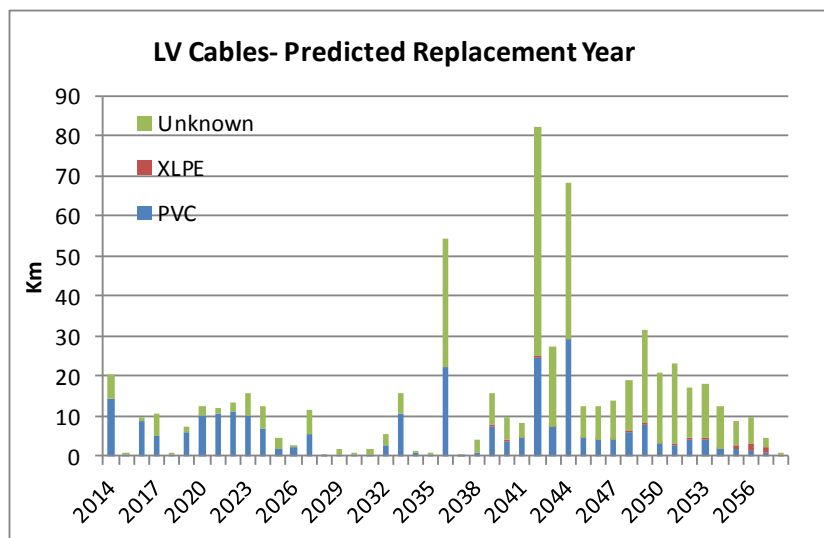
Horizon Energy has in place a long term undergrounding program for the urban areas of the network and other areas which are considered to have environmental or aesthetic value. Horizon Energy, the Eastern Bay Energy Trust, and the respective local District Councils jointly fund these works. Expenditure on some of these projects was deferred from 2010 by some of the District Councils due to recession driven financial pressures to constrain non-essential spending.

Effort is continuing in the interconnection of the LV system within the urban areas and in the production of LV schematics to assist in the operation of the network. In some cases augmentation of the LV assets has been required to address deficiency areas where load growth has caused stress to the existing network.



A multi-year project is scheduled to start in 2015 to install earthing at the ends of low voltage overhead lines neutral conductors.

The network has approximately 226km of low voltage overhead lines, and 165km of service lines, with approximately 264km of underground low voltage network assets. There is 203km of streetlight assets, both overhead and underground.



LV cable is currently managed on a run-to-failure mode, and additional costs have been budgeted in the forward work plans from 2017 onward for low voltage cable replacements. The spikes shown on the chart are data reset dates within the asset databases.

Maintenance

Apart from planned pillar box replacements most low voltage maintenance work is reactive, or overhead circuits repaired in conjunction with 11kV circuits when installed as an underbuilt structure.

During the asset inspection process it was determined that there is a compliance issue with earthing of the neutral conductor at the end of low tension conductor installations. To fully comply with MEN earthing requirements the neutral conductor should be earthed at the end of the conductor run, not just at the transformer supplying the low tension circuit. Special projects have been set up to remedy this issue.

Apart from defect or condition driven works there is no planned routine maintenance program for low voltage assets.

Life Cycle Management

Run-to-failure mode of operation means there is no planned end-of-life policy for low voltage assets. Ground mounted and overhead assets will be replaced on condition assessed, safety driven or failure basis.

Future budgets have made allowance for an increased expenditure on low voltage assets as the assets continue to age but no specific age based upgrades have been planned.

6.3.7. Load Control Plant

Description of Asset

A general overview of the ripple control transmitters is summarised in Table 6.15.

HORIZON ENERGY RIPPLE CONTROL TRANSMITTERS				
Location	Type	Date Commissioned	Injection	Frequency (Hz)
Galatea	Motor Generator	1969	11kV	750
Waiotahi	SFU-G/30	1992	11kV	317 and 750
Kawerau	SFU-G/60	1988	11kV	317
Plains	SFU-G/120	1999	33kV	317

Table 6.15 – Ripple Control Plant

- Demand side management strategy is to improve the efficiency of asset utilisation through minimising the magnitude of short duration peak loads;
- Four ripple injection plants positioned at key primary substations; and
- Load control has the capability to shed up to 3MW of interruptible load.

Operation Philosophy

A prime objective of the load management system is to minimise interconnection charges that apply at the various GXP's. The interconnection charge is based on the demand that is drawn at the GXP's that is coincident with the top 100 measured peaks for the lower North Island (LNI) Transpower demand region. A result of this operational philosophy is that if it is not an LNI peak, then no control is undertaken. The effect is that at many of the GXP's the demand at non LNI peak loads is allowed to reach levels that may stress the ability of the GXP assets sooner than they would have been had control been focussed on the GXP demand.

Short term peaks are being incurred on the network particularly when controlled load is restored. This is common with a number of utilities and is caused by the tendency to over-control ripple plants to minimise peak transmission charges from Transpower. A modification to the algorithm of the load control system has been implemented so that network restraints are not created due to large levels of load swing being generated as the load control is returned to normal.

This is especially crucial on substations like Ohope that is already heavily loaded, where if all the load control system channels are returned to normal at the same time after an extended period of load control, the load can approach the full rated capacity of the zone substation transformer. Simple time delayed restoration for each of the ten load control channels will smooth out the restoration peaks.

The dispatch of control signals is automated through the SCADA master station that uses information published to the internet by Transpower for the indication of the LNI load profile.

Maintenance Schedules

Horizon Energy has a service contract with Landis + Gyr for backup support and spare parts holding for the ripple plants that includes an annual service inspection, 24 hour phone support, and stock holding of critical spares. This contract is due to expire in 2014.

Lifecycle Management

Landis + Gyr recommend the replacement of a ripple plant after 20 years of service when the risk of component failure increases. Coupling cell components are regarded as highly stable, however the coupling capacitors are considered as having the greatest probability of failure. There are sufficient spare capacitors to replace one coupling cell held on contract in Auckland. New service parts are not manufactured for the SFU-G units and the number of critical spares maintained by Landis + Gyr is very limited.

The motor generator set that is used at Galatea is no longer supported by Landis + Gyr. Galatea operates at 750Hz and if replaced with a 317Hz unit would require replacement of all end-user receivers.

Replacement Assessment

- Load control is used for the reduction of Transpower interconnection charges that are treated as pass through costs. As such there is no opportunity for Horizon Energy to extract value from the assets that they provide and hence little incentive to replace the assets;
- There is benefit for retailers for cost reduction through the management of load away from times of high spot prices;
- Alternative options for demand management are summarised in Section 5.4.3 and form the basis for load management studies to consider options for replacing the ripple control system;
- A radio controlled smart system meter is being reviewed to assess its suitability for Galatea; and
- The continued operational function for the ripple control plants is under review and a run-to-fail with a no-replacement option is being considered.

Ripple Plant Replacement

Following a full study of the existing system in 2011, the following summary and recommendations were made from Landis + Gyr.

Study Conclusions

- SFU-G type converters and motor generators are not supported by Landis + Gyr and no spare parts are kept in stock. In the event of converter failure, a new SFU-K type converter will need to be freighted from Auckland and commissioned in place of the faulty converter. During this period of time, Horizon Energy run the risk of being out of Ripple control for a period of up to 24 hours;
- The existing Waiotahi Ripple Plant cannot be used if the network is upgraded to 33kV. The SFUG/30 converter rating is insufficient while the coupling cell is only rated for 11kV;
- Both the Galatea and Waiotahi regions have 750 Hz Ripple systems that are currently operational. Signal propagation at 750 Hz is poor and there is no guarantee of receiver operation;
- Moving the Kawerau Ripple Plant away from the Transpower GXP will reduce its absorption and therefore allow a higher level of Ripple signal to spill into the Kawerau network. The DC bus of the Kawerau Ripple Plant could charge up resulting in converter damage if spillover occurred while the Plant was injecting. Excessive Ripple signal spillover can also result in Ripple telegram corruption thereby causing receiver mal-operation.

Recommendations from Landis + Gyr

- The Kawerau Ripple Plant is to be kept in its original location. Moving the Ripple Plant away from the GXP will impact the absorption of the Ripple Plant;
- Provisions to be made to upgrade the existing Ripple Plant (converter and coupling cell) at Waiotahi prior to the proposed 33kV network upgrade. It is also suggested that all 750 Hz receivers be migrated to 317 Hz prior to the network upgrade so that the new Ripple Plant is not a dual frequency Plant. This is advantageous because the Plant would be cheaper and easier to manage;
- Provisions to be made to migrate the Galatea Ripple system (Ripple Plant and its receivers) to 317 Hz; and
- Horizon Energy to install redundant converters alongside the existing converters at Kawerau, Waiotahi and Edgecumbe. The redundant converters can be fitted with a manual changeover switch which will allow selection of the converter desired for operation. This would allow continuous service in the event of a converter fault. Alternatively a single redundant converter can be ordered and stored by Horizon Energy as a spare converter. In the event of a failure at Edgecumbe, Kawerau or Waiotahi the converter can be de-commissioned and the spare converter installed. Thereafter a Landis + Gyr Engineer may come on site to commission this converter.

High level (+/-30%) budgetary estimates (2011) to replace the load control plants are below:

Substation	Replacement Converter required	Budgetary price to replace converter	Budgetary price to replace entire Plant (2011)
Plains	SFU-K 403 (200 kVA)	\$120,000	\$300,000
Kawerau	SFU-K 203 (80 kVA)	\$75,000	\$200,000
Waiotahi	SFU-K 203 (80 kVA)	\$75,000	\$200,000
Galatea	SFU-K 103 (40 kVA)	\$60,000	\$160,000

These replacement projects have been included in the 10 year plan but implementation will be in consultation with retailers.

Smart metering technology is being investigated as an alternative to traditional ripple plant installations.

6.3.8. SCADA System

Description of Asset

Horizon Energy operates an IFIX HMI over a Foxboro SCADA system. The master station is located in the Horizon Energy control room in its main office at 52 Commerce Street in Whakatane.

The original SCADA was installed in 1992. The SCADA master station was replaced at the end of 2004 with a PC based Profacy IFIX Fsystem. The system has enhanced historian data storage and retrieval systems, alarm reporting and trending. It features remote terminal access for after-hours control staff, automatic fault and alarm calling and an escalating phone paging system.

Communications to each outstation is by fibre optic or radio communication. Outstation RTU's are located at each zone substation and communication repeater site, and at each pole top circuit breaker and controlled switch.

Outstations have components dating back to 1992 and these are being upgraded as substations are upgraded.

Maintenance Schedules

- Maintenance of the system is contracted to specialist SCADA providers, who maintain the master system and all software and upgrades;
- RTU remote stations maintenance is limited to visual inspections and battery bank maintenance; and
- There is an issue with firmware and hardware obsolescence within some of the RTU's and in the event of an outstation failure at a zone substation, there may be delays in restoring the service. A project was proposed to upgrade all stations to a common firmware level but this has been deferred and replaced with an upgrade project to convert the zone substations to a DNP3 protocol system over the next three years. This will see most of the old Foxboro RTU units either retired or upgraded.

Lifecycle Management

- A strategic upgrade to an IP based system is being implemented across all substations. The system will run dual protocols for three years as the existing Foxboro Conitel system is phased out and replaced with a DNP3 over IP system;
- IEC61850 communications protocol is under consideration for substations and has been implemented at the Galatea and Kopeopeo substations;
- SCADA master station servers are scheduled for replacement every five years;
- With progressive software and hardware upgrades the SCADA system is expected to have an indefinite life cycle, although this lifecycle is totally dependent on continued software, technical, and manufacturer support, plus the ability of the software to provide the functionality and integration required for future system automation and reporting requirements.
- Field equipment has a nominal life expectancy of 15 years. A number of existing field equipment components are approaching or have exceeded this age, but module replacement and the scheduled upgrade to IP based systems will reduce any risk of failure; and
- Invensys, the supplier of Foxboro equipment, in 2010 announced to all RTU users that the radio modem chip is no longer in production and that there are very limited spares stock available worldwide. With the migration of the communications system to an IP based radio system the modem will become redundant, but during the changeover period over the next three years, the system will be vulnerable to a modem failure. There is a functional work-around by using an external modem.

6.3.9. Communications System

The communications system provides voice communications, communications to pole-top circuit breakers and switches and high speed radio communications into the zone substations.

The system is configured with a high speed back-bone loop, with microwave radio from Plains, Pukehoko, Putauaki, and Commerce Street and a leased fibre optic circuit completing the loop from Commerce Street, Kope, Station Road, Te Rahu, East Bank, and Plains substations.

Radial links exist to Galatea, Kaingaroa, Ohope, Waiotahi and Te Kaha, and a spur line VHF repeater is located at Cape Runaway to provide voice and data communication to the coast region north east of Te Kaha.

The system was installed between 2010 and 2012, with the substation spur lines scheduled between 2013-2015.

Each repeater site has a battery system that allows a minimum of 12 hours uptime should local supply be lost. The Cape Runaway site has a 36 hour battery capacity due to the remoteness and lack of vehicle access to the site.

The installation stages are:

2009-10	Installation of backbone repeaters at Commerce Street, Pukehoko, Putauaki and Cape Runaway	Complete
2010-11	Voice radio network including vehicle radios and pole top radio repeaters	Complete
2011-12	Pole top radios switched to E Band. All A band licences relinquished	Complete
2012-13	Completion of fibre optic link from Plains to Commerce Street, including East Bank, Station Road, Te Rahu, and Kope substations	Complete
2012-14	Progressive upgrade of substation infrastructure to Ohope, Galatea, Kaingaroa and Waiotahi	In progress
2015-16	Third Poletop repeater channel	In Design

Maintenance Schedules

- Annual check of repeater transmit and receive power levels, which is a mandated verification of performance;
- Battery condition; and
- Batteries are replaced on a routine five yearly basis.



Lifecycle Management

Upgrade of the complete system started in 2010 with the installation of the back-bone repeaters and new VHF systems. Links to the zone substations are scheduled to be upgraded over the next three years which will enable the retirement of the existing links and repeaters.

- Individual components installed in the new system have a life expectancy between 8 to 15 years;
- As a system, the ultimate system lifecycle is undefined as the technology is evolving at such a high rate;
- IP technology and digital radio developments are not expected to diminish in the foreseeable future and the technology behind the radios and the IP infrastructure will be supported well beyond the planning period;
- Direct connection to Transpower ICCP (Inter-Control Centre Protocol) system will remove the connection requirements at GXP sites (Edgcombe, Kawerau, Te Kaha, and Waiotahi);
- Communications with load control plant bypassed by the Transpower ICCP will be by VHF Poletop radios; and
- A third poletop repeater is scheduled to provide additional radio channels as the number of installed controlled field devices start to impact the available pole-top radio bandwidth within the Plains-Whakatane region.

6.3.10. Earth Banks

Earth banks are a critical safety component of the network and have a structured maintenance regime.

Regulations require that earth banks are tested at a frequency determined by the asset owner, at a period not exceeding 10 years. Horizon Energy has opted for a 10 year testing schedule. There are in excess of 5000 discrete earth banks in the network requiring 500 to be tested in any one year.

Earth Bank Management

- A recent analysis of a large number of earth bank test results has determined that a high percentage of the rural sites tested would fail to limit the step-touch potential rise to safe limits in a fault;
- IEC 60479-1 defines the step and touch voltage limits dependant on soil resistivity. There is different allowable step and touch voltages for each different geographical region, based on different soil resistivity;
- This data has been incorporated into an earthing compliance manual which defines earthing installation methods;
- An amount is budgeted within the operations budget each year for earth bank testing. Approximately 500 earth banks are required to be tested each year to complete the earth bank testing within the 10 year period;
- A separate sum is budgeted to complete any remedial works identified during testing;
- If a site is determined to have a higher than allowable earth bank resistance resulting in non-compliant step or touch voltages during a fault, the cost to reduce the voltage to acceptable levels is assessed against a probabilistic analysis of risk against cost. Risk assessment factors include the probability of a fault at the location, the likelihood of people being present at the time of the fault, and the profile of the people likely to be present;
- The areas at highest risk of public harm are areas with overhead systems that are close to places where people congregate. These are priority areas for remedial works; schools, churches, maraes, beach resort areas etc. Mitigation works may include installing:
 - Larger earth banks;
 - Grading rings;

- MEN bonding; and
- Isolation of the risk from the site by the relocation of assets.
- The network region has four distinct areas of soil resistivity. Each area has its own different requirements for earthing to meet the touch potential limitation, and these are defined in the installation standards. These areas are shown in Figure 6.11.



Figure 6.11 – Soil Resistivity Chart

6.3.11. Substation DC Power Supplies

During 2011-12 there were been a number of failed DC rectifier units in zone substations. Power supplies are redundant units so the failures have not caused any loss of service, but they are symptomatic of a problem with ageing units. The DC units were all installed between 1992 and 1999 and direct replacement rectifiers are no longer available.

Reviews of modern equipment types and their supply voltages, demand loads, and the additional loads put upon substation systems has resulted in a decision to move the standard substation voltage to 48VDC, with battery banks designed for a 24 hour standby capacity. The substations DC supplies will progressively be upgraded as part of the substation communications and protection upgrade projects. DC-DC converters will provide legacy 24V and 12V supply requirements.

New substation equipment is being specified as 48VDC.

There is a single DC system for every substation except for Station Road. Station Road circuit breakers use 48V DC for circuit breaker closing, which introduces large spikes into the DC system. To mitigate this Station Road has a dedicated 48VDC supply dedicated to circuit breaker switching, with a second 48V bank for substation utilities. All other substation circuit breakers have spring charge systems which are supplied from the general DC supply for the substation.



DC Power Supplies Maintenance

- Batteries are sealed for life. Maintenance is limited to regular battery discharge testing, surface cleaning and visual inspection; and
- Modern controllers have full system monitoring, including controlled discharge testing, and fault alarming via Ethernet connection to SCADA and web browsers.

Lifecycle Management

- Batteries are scheduled for routine replacement every five years with annual testing to ensure the batteries still perform to their designed capacity;
- Rectifier and controller units have a 20 year life expectation. Due to the redundant installations these will be replaced on a failure mode basis; and
- Rectifier units replaced will be retained as spares.

6.3.12. Non-Network Assets

Non-network asset details are provided in accordance with subclause 1.4.3 of the Electricity Distribution Information Disclosure Determination 2012, being assets related to the provision of electricity line services but are not network assets. These assets include:

- Information and technology systems;
- Asset management systems;
- Office buildings and workshops;
- Office furniture and equipment;
- Motor vehicles;
- Tools, plant and machinery;
- And other items treated as non-system fixed assets under GAAP.

The lifecycle management of non-network assets follows the estimated useful life as disclosed within the Company's accounting policies, most recently set out in the Annual Report 2012. The estimated useful lives are as follows:

- Information and technology systems/Asset management systems:
 - Hardware 2 – 10 years
 - Software 5 – 10 years
- Office buildings and workshops 40 – 100 years
- Office furniture and equipment 10 years
- Motor Vehicles 5 – 10 years
- Tools, plant and machinery 2 – 10 years

The forecast capital expenditure on non-network assets as disclosed within Appendix A2 reflects this expenditure cycle.

Significant non-network projects planned or under development over the next five years include:

- Systems upgrade following the Electricity Distribution Information Disclosure Determination 2012;
- Asset management system and integration to GIS;
- ERP upgrade; and
- IT servers UPS system upgrade.

Horizon Energy owns two truck mounted 300KVA generator sets, purchased in the late 1990's and are considered to be approaching half-life. Full life retirement is scheduled for around 2025. Regular maintenance is scheduled in accordance with the engine manufacturer's recommendations. In 2012 the controllers on both generators were upgraded.

In 2013 the company took delivery of a containerised, transportable IMVA generator set and step up transformer. This unit is designed to be used for peak lopping, voltage support and fault restoration. The generator has full synchronising capability. It is planned that the units reside at Waiotahi to assist with the voltage support issues at Opotiki, but are available for re-location to other areas if required.

Maintenance schedules are defined by the equipment manufacturer. Policies around when the unit will be deployed on faults are not formalised, but due to the time required to mobilize relocating the units requiring cranes and heavy transporters, the generator will generally only be relocated for longer duration faults or planned outages.



6.4. Network Systems Development Options

Network asset major projects and development alternatives are summarised in Table 6.16 below:

Area	Issue	Options	Preferred Solution	Justification	Year
LV Reticulation Upgrades	To provide adequate reinforcement to minimise outages	Network 1. Upgrades of identified reinforcement weak spots and high load zones in areas of the Whakatane urban area 2. Provision of generator connection points Non Network 1. Localised generation	Engineered on a case by case basis. Upgrade heavily loaded transformers and cables to provide sufficient capacity to reinforce neighbouring circuits	To minimise outages in areas of the Whakatane urban area. Based on a completed study	As required for LV upgrades
Undergrounding program	To improve the environmental or aesthetic value of the community by undergrounding the overhead lines	Network Long term undergrounding program for the urban areas of the network and other areas	Need clear value to Horizon Energy	Covered by a cost share agreement with each District Council and the Eastern Bay Energy Trust	Deferred for 2013-14 for all Councils
LV Pillar Box replacements	Safety	Replacement program over five years to replace concrete and metal pillar boxes that are sub standard		Public safety	2010-2014
Load Control	Replacement of load control systems	Network Replace existing load control systems at Edgecumbe, Kawerau, Galatea and Waiotahi with optimal solution Non Network Investigations into smart metering and demand management Run-to-Failure with non-replacement	Still to be evaluated as part of the engineering study	The existing load control systems are beyond their economic life and require replacement. Replacement parts are no longer available for these units	2010-11 for engineering study Implementation starting 2013-14

Area	Issue	Options	Preferred Solution	Justification	Year
Poletop Circuit Breakers	To replace ageing circuit breakers	Network 1. Rolling programme based on replacement criteria Non Network 1. No options available	Based on replacement criteria of condition, test results the number of operations, the importance of the circuit breaker to the network, and the overall reliability of the feeder	Replacement parts are no longer available for these units	2009-2015
SCADA and Substation Automation	To upgrade to high speed communications systems	Network 1. Install high speed communications systems for each substation in conjunction with major planned works 2. Install high speed communications systems for remaining substations Kawerau, Plains and East Bank	Radio and fibre optic based communications systems for the SCADA system, using TCP/IP carriers and open protocols for substation data transfer	Enable each substation to provide improved metering and data collection, allow remote diagnostics of IED relays, sequence of event monitoring, intelligent or semi-automated switching schemes to be implemented,	From 2012 for remaining substations. 2017 for semi-automated/fully automated self-healing systems.
Feeders	Improve reliability	Implement smart system outage analysis and automated system recovery (after reliability projects completed)	Various options yet to be engineered	Provides self-healing system to meshed networks	2015-2017
11kV and 400V Overhead Distribution	To replace and upgrade end of life assets	Network Develop a planned replacement programme based on asset inspection process and load flow assessment Non Network No alternate options identified	Replace specific asset with modern equivalent based on weighted criteria that take into account condition, age, criticality to the network and previous history	To replace substandard or short life assets identified through the asset inspection process. Specific assets have poor functioning performance such as rotting poles, and rusting wires	Ongoing

Table 6.16 – Summary Network System Planned and Option Analysis

7. Risk Management

7.1. Introduction

Risk is managed through an on-going process of risk identification, design and safety assessment and the development of mitigation or risk removal strategies including routine inspections, maintenance and emergency response planning.

The risk assessment will reflect the potential impact on the business, including staff and public safety, the ability to maintain supply, environmental impact, legislative and financial exposures risk.

7.2. Risk Management Process and Methodology

7.2.1. Risk Process

Horizon Energy strives to manage risk in a responsible manner to enable business objectives to be consistently met, whilst recognising the potential impacts of its activities on the environment (community within which the Company operates). The risk management process is linked to the strategic and business planning process.

The risk management process is designed to ensure that:

- All significant risks to the Company and community are identified and understood;
- The highest risks that should be addressed in the short to medium term are identified, eliminated, monitored and managed;
- Risk reduction treatments which best meet business needs are applied; and
- Responsibilities for managing risk are allocated to specific staff.

The risk management process adopted by Horizon Energy is consistent with Australian/New Zealand Standard AS/NZ ISO 31000:2009 (see Figure 7.1), which defines the generally accepted process for Risk Assessment and Management.

Areas of impact, reflecting the extent of the consequences assessed, are in the following broad areas:

- Regulatory risk;
- Business practice risk;
- Financial risk;
- Asset risk from physical events;
- Health and Safety risk to staff, contractors and the general public; and
- Loss of information and intellectual risk;
- Environmental impact risk.

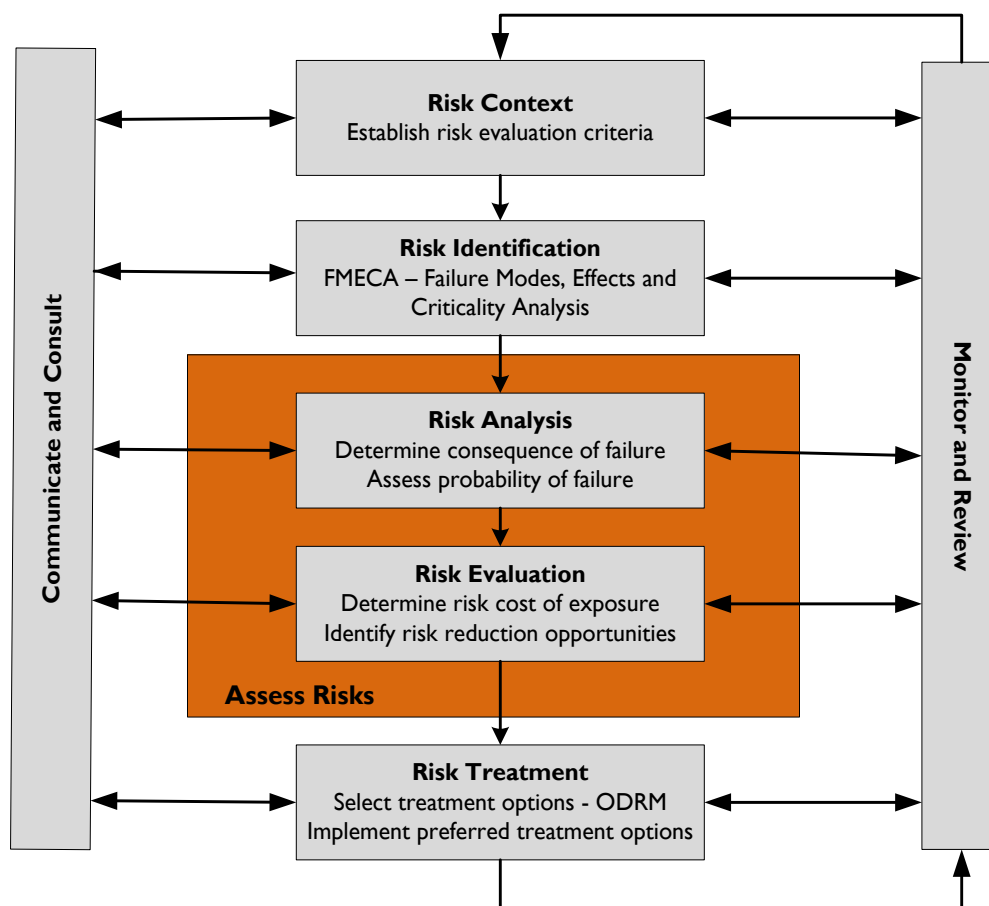


Figure 7.1 – Risk Management Process

The Risk Management Plan is part of the Company's Quality Management system.

The objective of this plan is to detail the processes that are required and the actions undertaken in the identification, assessment, review and management of risks that Horizon Energy is exposed to. The risk management plan seeks to:

- Identify risks to Horizon Energy;
- Assess the risks in accordance with consequence and likelihood;
- Monitor, treat, control and manage all risks; and
- Ensure that recovery plans are developed and implemented.

The Risk Management Plan has been developed by the Management team through group discussion, consideration of past incidents and an analysis of the Company's insurance assessments. The document details actions that can be undertaken to mitigate the impact of adverse events and the time and resource needed to undertake the correction.

7.2.2. Risk Assessment

The Management team have identified health and safety and business risks using the following methodology. Each hazard has been assessed against the likely consequence, frequency and probability scores before the controls have been applied. The hazards are subsequently reassessed after controls being applied to mitigate risk, resulting in most cases a residual risk.

Risk = Consequence x Frequency x Probability			
Risk Score	Risk	Initial Risk – without Controls	Residual Risk – with all Controls
<40	Acceptable	Hazard identification required	Proceed and monitor changes that could increase risk
40 to 200	Medium	Hazard ID required. “Significant Hazards” apply hierarchy of controls	Team Leader/Manager approval required
200 to 800	High	Hazard ID required. “Significant Hazards” apply hierarchy of controls	Manager approval required. Reassess using Root Cause Analysis or other quantitative risk assessment method
800+	Extreme	Hazard ID required. “Significant Hazards” apply hierarchy of controls	Proceed and monitor changes that could increase risk

Table 7.1 – Risk Severity Definitions

Consequence	
0.1	Negligible, superficial damage, nil or very low business interruption or financial exposure
5	First aid, property readily repaired in DIY form, minor business disruption or minor financial exposure
20	Medical treatment, property damage requires minor work, medium business disruption or medium financial exposure
40	Serious injury, hospitalisation, significant property damage, considerable business interruption, corporate image damaged or significant financial exposure
100	Catastrophic, fatality, total property destruction, major business interruption, significant loss in value and corporate image

Table 7.2 – Consequence definitions

Frequency	
1	Rarely
10	Yearly/seldom
12	Monthly/occasional
15	Weekly/frequent
20	Daily/continuous

Probability	
0.04	Improbable
0.2	Conceivable but unlikely to occur with exposure
0.4	Possible but not expected
0.8	Likely to occur with each exposure
1	Almost certain with every exposure

Table 7.3 – Likelihood definitions

7.2.3. Risk Register

The risk register is a database of all identified risks to the Company. The register is developed by the senior Management team and is reviewed regularly and twice by the Board during the year. The Company has identified all exposed risks in the broad areas detailed above.

The risk register is monitored monthly to identify changes in risk profiles.

7.2.4. Risk Treatment

When assessing the risk severity the impact of the controls that have been put in place for each identified risk is assessed using the following criteria:

- | | |
|---|------------------|
| 1 | Acceptable risk. |
| 2 | Medium risk. |
| 3 | High risk. |
| 4 | Extreme risk. |

These controls will either impact on the Consequence, the Likelihood or both. These controls are managed through the Audit Committee detailed in Section 7.3.1.

7.3. Risk Mitigation Measures

7.3.1. Responsibility and Governance

Part of Horizon Energy's risk management process and methodology is the allocation of responsibility for managing risk. Horizon Energy's Senior Management and Board members put a great emphasis on risk management and monitor the operational and financial risks of its activities on a regular basis. Risk management is part of the Board's monthly meeting agenda.

The Audit Committee consists of senior Management and Board members and meets on a bi-annual basis. The Company's risk exposure including legislative compliance is discussed along with internal controls such as delegated authorities and policies. The Risk Management Plan summarised in Sections 7.2 are reported and approved by the Audit Committee at its annual risk management meeting.

7.3.2. Environmental Management

Environmental responsibility is part of Horizon Energy's vision and reflects the importance that the Company places on environmental management. Horizon Energy aims to achieve and maintain a high standard of environmental care as part of the Eastern Bay of Plenty business community. Complying with the Resource Management Act, specific resource consent conditions and the District Plan is a business risk for Horizon Energy.

All works contracted by Horizon Energy shall include consideration for environmental effects such as:

- Disturbance to domestic services such as water supply;
- Final clean up and reinstatement following construction or maintenance works to reinstate the area of works equivalent to the condition which existed prior to commencement of the operation or to such other conditions as may be required by the Environmental Controlling Authority;
- Operating noise. Contractors carrying out works for Horizon Energy shall not be permitted to use equipment which is unnecessarily noisy;

- Equipment or machinery that emits excessive or unnecessary fumes or pollution is not permitted on Horizon's works sites; and
- On any site where there is a risk of oil or fuel contamination, steps shall be taken to minimise the effects of any spill. Oil spill response kits are available at all the zone substations.

7.3.3. *Health and Safety*

Horizon Energy is committed to providing a safe and healthy work environment – all practical steps are taken to see that our operations do not place our staff or the community at risk. Horizon Energy has achieved tertiary level ACC accreditation, is certified as compliant with AS/NZS 4801 Safety Management Standard and NZS 7901 Public Safety Standard.

Staff

- Safety committee comprising management and staff personnel;
- Monthly Health & Safety Committee meetings;
- Representatives from Management, contractors, and staff;
- Health and Safety Co-ordinator and a Group Safety Manager; and
- Staff competencies maintained through training and supervision.

Contractors

- Contractor job site audits undertaken by appropriate Horizon Energy staff;
- Engineering staff have a quota of inspections that must be undertaken each month and the results of these inspections are reported monthly to the Board; and
- Contractors that operate on the Horizon Energy network system undergo regular Health and Safety system audits. These audits are monitored by the Horizon Energy's Health & Safety Coordinator.

Public

- Identified significant electrical hazards in the public arena are controlled through prudent selection of equipment and its positioning to reflect life cycle risks;
- Physical barriers and appropriate signage are used to restrict access to site works;
- Established safety protocols for all of its Zone Substations;
- Emergency hotline for public to call in faults;
- Pillar boxes are now being installed with hotline phone number on the box; and
- Priority for safety or hazard orientated defects.

7.3.4. *Emergency Response and Contingency Plan Summary*

Horizon Energy has a number of emergency plans in place to cover various emergency situations. All these plans are reviewed at least annually and updated as appropriate. The following are some of the plans:

- Maintains alliances with Civil Defence and Regional Council and takes part in civil defence exercises. The tactical response to civil defence risks is based on contingency plans summarised in Section 7.3.5;
- Pandemic – Horizon Energy has in place response preparedness plans should a pandemic occur. This plan is detailed in the Company's Business Continuity Plan.;
- Emergency Preparedness – The identification of emergency situations that may arise in Horizon Energy's area of control and appropriate preparedness plans are part of the Company's Business Continuity Plan;
- Disaster Recovery – Summarised in Section 7.3.6 of this document;
- Injury Accidents – As part of the Health and Safety Manual the management of injuries is set out in Section 5.1: Accident and Incident Management, and Section 5.2: Serious Harm Accident; and

- Emergency Works – QM4-I0 Section 13 sets out Horizon Energy’s emergency work plan.

7.3.5. *Network Contingency Plans*

- A transportable IMVA generator plant has been scoped for purchase in 2013 to support network areas that are unable to be meshed. This supplements two 300KVA generators;
- An increased number of SCADA controlled switches provides for faster restoration of faulted areas in meshed networks than manual switching;
- Operational contingency plans are in place for major outages such as zone substations;
- Critical loads are also identified with contingency plans to ensure the effect of any outage is minimised; and
- A review of critical spares resulting in an identification of and procurement of critical spares.

7.3.6. *Disaster Recovery*

Horizon Energy has a long established Network Disaster Recovery Plan that describes recovery plans to restore supply following a disaster that may cause extensive loss of supply. The plan details the backup available and specifies the repair time. The plan assessed the major risks to the following asset groups:

- Zone substations;
- Major network components;
- SCADA system;
- VHF/UHF radio network;
- Office based systems;
- Warehouse;
- Mill Road archive store;
- Load control systems; and
- Commercial records.

The Network Disaster Recovery Plan operates in conjunction with the Company’s Business Continuity Plan for managing the business following a major disruptive event which results in loss of business, resources or people.

Operational functionality is maintained in the event of the main control room having to be abandoned by the establishment of a remote SCADA access terminal located at Station Road substation.

7.3.7. *Zone Substation Locations*

As part of the disaster recovery or disaster management plan the GPS location of each large energy distribution site is recorded and is available to forward to emergency response services who may not necessarily know the actual location of each site. The sites are recorded in GIS, disaster recovery emergency response kits, and are repeated below:

Substation	Location
East Bank	1936826.11, 5789649.38
Galatea	1924758.64, 5739320.87
Kawerau	1926536.64, 5779170.47
Kaingaroa	1910076.73, 5742610.48
Kopeopeo	1949793.50, 5791094.42
Ohope	1955729.80, 5788860.00
Plains	1936423.27, 5788790.64
Station Road	1947690.89, 5788959.50
Te Kaha	2012948.71, 5812389.53
Waiotahi	1967977.38, 5783082.03
Waiohau	1936379.21, 5766053.53

Other Critical Sites	Location
Edgecumbe GXP	1936385.12, 5788735.98
Aniwhenua Power Station	1931617.64, 5754819.58
Snake Hill switching station	1933420.50, 5754030.65
Te Rahu substation	1947632.41, 5789052.75
Putauaki Radio site	1927467.98, 5775957.02
Pukehoko Radio Site	1953144.40, 5784167.33
Commerce St Control Room	1951115.94, 5791865.51

7.3.8. Engineering Lifelines

Horizon Energy is an active member of the Bay of Plenty Lifelines Advisory Group, (BOPLAG). The Civil Defence Emergency Management (CDEM) Act 2002 stipulates that Lifeline Utilities must:

- Plan for and be able to ensure continuity of service, particularly in support of critical functions;
- Be capable of managing its own response to emergencies;
- Develop plans cooperatively to coordinate across its sector and with other sectors; and
- Establish relationships with CDEM groups consistent across regions.

The BOPLAG currently has a regionally based project underway to understand risk areas common to different utilities with the lifelines group on a geographic basis, and to improve co-ordination between the groups to reduce or minimise risk.

7.3.9. *Specific Development Projects to Mitigate Risk*

- Te Rahu –Gateway interconnection;
- 1 MVA transportable generator;
- Kope T2 replacement;
- Plains T1 replacement;
- Galatea 11kV CB replacements;
- Waiotahi CB replacements;
- Ohope CB replacements;
- CBD substation;
- 33kV sub-transmission dual circuit feeders reconfigure; and
- Various feeder cable overlays.

7.3.10. *Specific Maintenance Programmes to Mitigate Risk*

Maintenance response and routine inspections are a key part of the risk management philosophy. Particular maintenance programmes to manage risk are detailed in Section 6 and include:

- Pole testing regime;
- Vegetation control;
- Routine inspections of zone substations;
- Regular inspections of distribution switchgear;
- 33kV and 11kV lines inspections;
- Thermal imaging and partial discharge testing; and
- Earth bank testing.

8. Financial Summary

8.1. Introduction

The Electricity Distribution (Information Disclosure) Requirements 2012 issued by the Commerce Commission on 1 October 2012 require that financial forecasts developed as part of the asset management process be separated into the following components:

CAPITAL EXPENDITURE ON SYSTEM FIXED ASSETS

Disclosure Requirement	Horizon Job Coding
Customer Connection	Classification ID = 130
System Growth	Classification ID = 140
Reliability, Quality Of Service	Classification ID = 151
Reliability , Legislative and Regulatory	Classification ID = 152
Reliability, Safety and Environment	Classification ID = 153
Asset Replacement and Renewal	Classification ID = 160
Asset Relocations	Classification ID = 170
Non-Network	Classification ID = 200

MAINTENANCE EXPENDITURE

Disclosure Requirement	Horizon Job Coding
Routine and Preventative Maintenance	Classification ID = 100
Refurbishment and Renewal Maintenance	Classification ID = 110
Fault and Emergency Maintenance	Classification ID = 120
Vegetation Management	Classification ID = 105

This AMP follows the requirements for all financial and project planning and reporting.

Where expenditure classification used in this report has been summarised by a number, the classification ID is as above.

This Plan is different to previous versions in that the financial forecasts reflect the elimination of intercompany margins on related party work. The tables and charts also include the Business support and non network CAPEX categories.

8.2. Annual Budgets

Annual budgets are derived from projects included in the 10 year plan and the network operating budget for the planning year.

Some works contain both a capital and a maintenance cost component. An example of this is a line upgrade project where the conductor and poles are capitalised but crossarm replacements may be classed as maintenance. All project budgets contain an estimate of the maintenance component of capital works, and operations budgets also estimate the capital component of maintenance works.

The annual budget is developed and itemised by estimated capital materials, consumable materials, labour, labour type, cash flow, and project timing to assist contractors who will be involved in the undertaking of this work to complete their annual planning and operating budgets.

8.3. Financial Reviews

Most projects and tasks are estimated to a detailed level using estimating tools and unit rate assemblies to give a high level of pricing confidence, and the actual to estimated cost is analysed once the project is completed. Monthly reports are produced for Management and Directors summarising progress and adherence to annual budget targets.

Actual results often vary from forecast, as not all projects are fully scoped or have completed pre-feasibility studies prior to budget publication. Consequently, as projects evolve, their viability and priority is reassessed, and during a planning year some projects may be accelerated and some deferred or altered.

The longer term planning goal is to achieve a greater lead time between design and implementation, to allow better project definition.

8.4. Maintenance

The maintenance, or operational, component of the budgets is made up of several different categories as follows:

Planned fixed and routine maintenance activities comprise:

1. Zone substation maintenance; including routine inspections and periodic testing of protection and transformers.
2. Communication, SCADA and protective devices testing to meet regulatory guidelines.
3. Thermal imaging of critical lines and equipment.
4. Battery bank testing and scheduled battery replacement.
5. Earth bank testing.
6. Tree trimming.
7. Standby fault support.

These activities are planned and budgeted ten years ahead based on recommended service intervals for equipment servicing, routine testing requirements and estimated lifetime replacement (e.g. batteries). Yearly adjustment may be made on the budgets and work plans following assessment of reliability and/or performance statistics.

Variable components of the maintenance budget include:

8. Immediate fault response.
9. Remedial works from faults.
10. Defect work.
11. Safety or environmental works.

When defect remedial and fault work results in the replacement of a 'minimum asset unit' then a portion of this work is capitalised. This introduces a variable component into the capital budget that is difficult to predict on a year by year basis.

Within many projects there can be a component of both capital and maintenance expenditure. Annually, the capital component of maintenance works varies between 35-45%.

The increased use of live line work has resulted in the average cost of 11kV defect and AFS connection work to increase after 2010-11, but this cost increase is offset against a reduced number of planned network outages.

8.5. Capital

Major projects planned for the next ten years together with their drivers and justification are described in appendix C. There are over 475 individual projects identified over the next ten year period with a combined value close to \$80M.

Network areas with a high density of defects or assets nearing the end of their useful life have been grouped into projects. These projects have a component of both maintenance and capital expenditure as described above. This component alters depending on the work type; typically transformer replacement projects are 80% capital, 20% maintenance, line refurbishment projects average 70% capital, 30% maintenance.

Mean regional population increases are predicted to diminish over the next ten years and this is reflected in a constant amount budgeted for new customer connections.

Undergrounding projects are budgeted at the beginning of each financial year in consultation with the affected Local Authority and this program can be changed or deferred by Councils depending on the availability of Council funds.

Major projects greater than \$500,000 included in the ten year plan are summarised in Table 8.1 below:

Year Start	Project Name	Value(000)
2014	Gateway-33kV development & integration to CHH Y1	\$845
2015	1000 KVA Generator #2	\$687
	Gateway-33kV development & integration to CHH Y2	\$1302
	Opotiki Substation Development Y1- Engineering	\$517
	Plains- T2 New	\$1056
2016	2nd 33kV line into Aniwhenua	\$718
	Opotiki Substation Development Y2-Site development	\$3235
2017	Opotiki Substation Development Y3-110kV line, Tx Y1	\$3774
2018	Express 33 kV Cable Gateway to CBD-4.25km	\$1150
	Opotiki Substation Development Y4-110kV line, Tx Y2	\$2049
	Whakatane CBD Substation Y1	\$863
2019	Kope 33kV indoor Conversion	\$1268
	Lines upgrades	\$521
	Whakatane CBD Substation Y2	\$2157
2020	Lines upgrades	\$521
	Underground Harbour feeder Stage 1	\$847
	WBMS 33kV Sub Transmission Capacity Upgrade	\$560
2021	Hawai Zone Substation	\$951
	Lines upgrades	\$521
	Ohope-11kV Indoor Conversion	\$1150

Year Start	Project Name	Value(000)
2022	Opotiki Substation Development T2	\$1203
	Underground Harbour feeder Stage 2	\$1005
	2nd 33kV line to Ohope (8.7km)	\$863
	Lines upgrades	\$521
	Station Road Replace T1	\$1056
2023	Underground Harbour feeder Stage 3	\$773
	Underground Pohutukawa feeder Stage 1	\$717
	Lines upgrades	\$521
	Ohope-33kV Transformer T1 replacement	\$1162
	Station Road Replace T2	\$1056
2024	Underground Pohutukawa feeder Stage 2	\$726
	Lines replacements	\$2020
	Lines upgrades	\$521
	Mobile 33/11kV Substation	\$1585

Table 8.1 – Major Projects List

8.6. Evaluation of Performance

This Section evaluates Horizon Energy's performance against the previous AMP for the 2011/12 year. Commentary on the variance between actual and budget is provided where this information is available.

Progress against the 2012-13 AMP

The final financial performance to budget for the 2012-13 year as reported in the 2013 disclosure documents is shown in Table 8.2.

7(ii): Expenditure on Assets	Forecast (\$000) ²	Actual (\$000)	% variance
Consumer connection	720	788	9%
System growth	711	375	(47%)
Asset replacement and renewal	3,572	3,313	(7%)
Asset relocations	18	10	(47%)
Reliability, safety and environment:			
Quality of supply	3,114	1,799	(42%)
Legislative and regulatory	-	-	-
Other reliability, safety and environment	-	-	-
Total reliability, safety and environment	3,114	1,799	(42%)
Expenditure on network assets	8,135	6,284	(23%)
Non-network capex		594	-
Expenditure on assets	8,135	6,878	(15%)
7(iii): Operational Expenditure			
Service interruptions and emergencies	677	719	6%
Vegetation management	-	371	-
Routine and corrective maintenance and inspection	1,058	641	(39%)
Asset replacement and renewal	860	748	(13%)
Network opex	2,595	2,479	(4%)

Table 8.2 – Expenditure Comparison for the 2012-13 AMP

Significant differences are as follows:

- System growth project Opotiki substation deferred;
- Reliability driven project Gateway 33kV development deferred;

- Asset Relocations are a very minor category making budget variations insignificant when considered over total forecast spend;
- Vegetation Management moved out of routine and corrective maintenance category.

8.7. Financial Forecasts 2014-2024

10 year financial summaries, Figure 8.1a and Table 8.3a, show the projected capital and maintenance budgets until 2024 for the Scenario without the Purchase of the Transpower Assets east of Edgecumbe.

During March 2014 the Commerce Commission requested information relating to the transfer of assets from Transpower to Distribution Lines businesses. Horizon Energy is currently considering the purchase of the Transpower assets east of Edgecumbe.

The Board will consider a recommendation from management relating to the purchase in early in the new financial year which, if approved, will result in the assets being purchased within the 2015-2020 pricing period. In the interest of disclosure and to ensure that Commerce Commission has regard to the Company's plans in its forthcoming price reset process, the following expenditure charts are included to inform interested parties.

For these reasons Figure 8.1b and Table 8.3b, show the projected capital and maintenance budgets for the same period under the second scenario of the Horizon Energy purchasing:

- The 110kV line from Edgecumbe to Waiotahi;
- The Waiotahi GXP substation;
- The 50kV line from Waiotahi to Te Kaha; and
- The Te Kaha GXP substation.

The second scenario reflects purchase of the assets in 2017 and adds over \$3M directly to the OPEX budget and approximately \$6M to the CAPEX (excluding the Purchase price) over the forecast period.

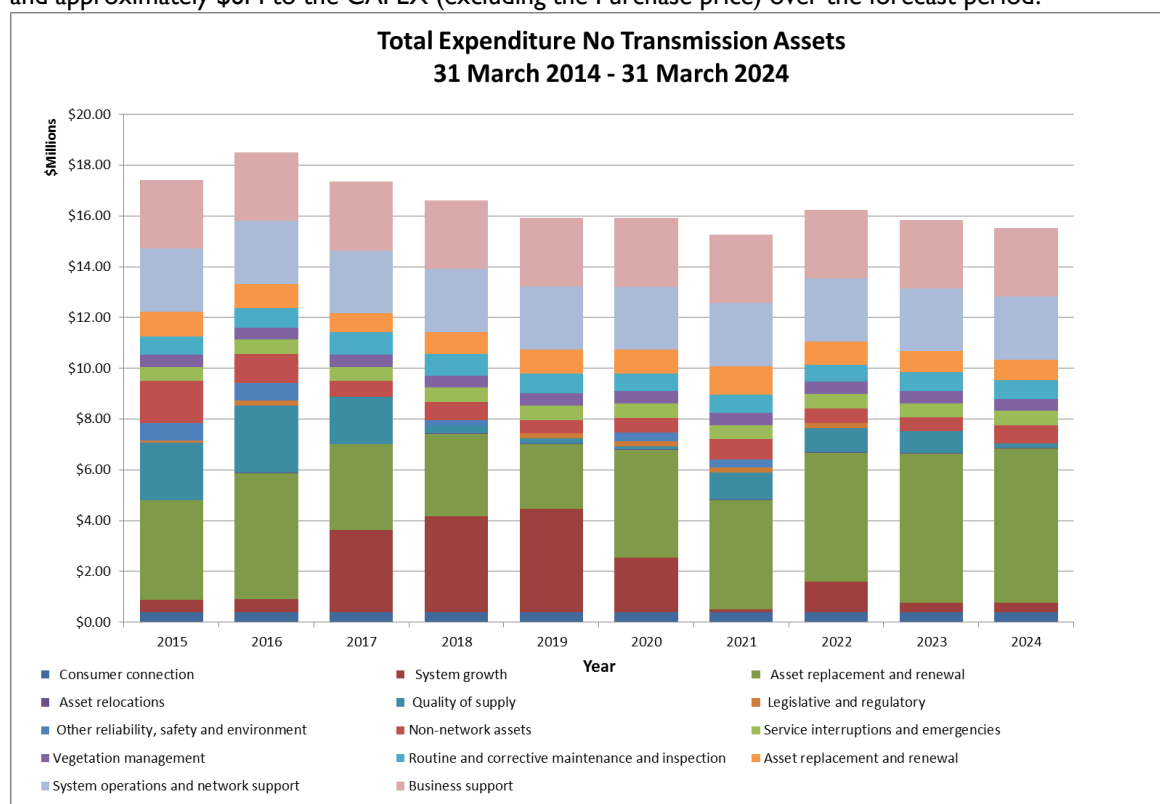


Figure 8.1a – 10 Year Financial Summary

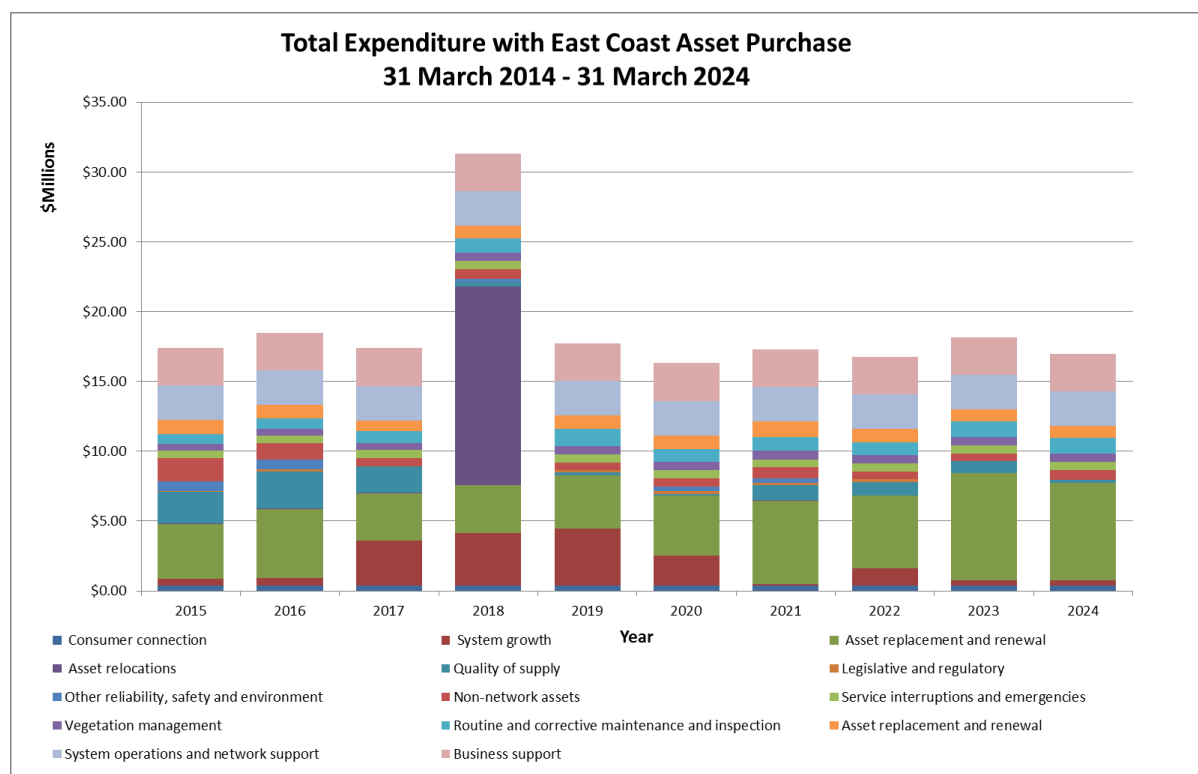


Figure 8.1b – 10 Year Financial Summary with East Coast Asset Purchase

Table 8.3a – 10 Year Financial Forecast (Millions) with No East Coast Asset Purchase

Projected Expenditure	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Consumer connection	\$0.39	\$0.39	\$0.39	\$0.39	\$0.39	\$0.39	\$0.39	\$0.39	\$0.39	\$0.39
System growth	\$0.49	\$0.52	\$3.24	\$3.77	\$4.06	\$2.16	\$0.11	\$1.20	\$0.38	\$0.38
Asset replacement and renewal	\$3.92	\$4.97	\$3.38	\$3.26	\$2.57	\$4.25	\$4.32	\$5.09	\$5.88	\$6.08
Asset relocations	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02
Quality of supply	\$2.26	\$2.64	\$1.84	\$0.30	\$0.20	\$0.11	\$1.07	\$0.95	\$0.86	\$0.18
Legislative and regulatory	\$0.08	\$0.19	\$0.00	\$0.00	\$0.19	\$0.19	\$0.19	\$0.19	\$0.00	\$0.00
Other reliability, safety and environment	\$0.70	\$0.70	\$0.00	\$0.23	\$0.00	\$0.36	\$0.30	\$0.00	\$0.00	\$0.00
Non-network assets	\$1.65	\$1.15	\$0.63	\$0.72	\$0.53	\$0.58	\$0.80	\$0.59	\$0.53	\$0.71
Total CAPEX	\$9.50	\$10.57	\$9.49	\$8.68	\$7.97	\$8.05	\$7.20	\$8.43	\$8.07	\$7.76
Service interruptions and emergencies	\$0.56	\$0.56	\$0.56	\$0.56	\$0.56	\$0.56	\$0.56	\$0.56	\$0.56	\$0.56
Vegetation management	\$0.48	\$0.48	\$0.48	\$0.48	\$0.48	\$0.48	\$0.48	\$0.48	\$0.48	\$0.48
Routine and corrective maintenance and inspection	\$0.71	\$0.77	\$0.89	\$0.84	\$0.77	\$0.69	\$0.73	\$0.67	\$0.75	\$0.72
Asset replacement and renewal	\$0.99	\$0.93	\$0.75	\$0.87	\$0.96	\$0.95	\$1.11	\$0.93	\$0.82	\$0.82
System operations and network support	\$2.48	\$2.48	\$2.48	\$2.48	\$2.48	\$2.48	\$2.48	\$2.48	\$2.48	\$2.48
Business support	\$2.70	\$2.70	\$2.70	\$2.70	\$2.70	\$2.70	\$2.70	\$2.70	\$2.70	\$2.70
Total OPEX	\$7.92	\$7.92	\$7.85	\$7.92	\$7.96	\$7.86	\$8.07	\$7.82	\$7.78	\$7.76
Total Expenditure	\$17.41	\$18.50	\$17.35	\$16.61	\$15.93	\$15.91	\$15.26	\$16.24	\$15.85	\$15.52

Table 8.3b – 10 Year Financial Forecast (Millions) with East Coast Asset Purchase

Projected Expenditure	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Consumer connection	\$0.39	\$0.39	\$0.39	\$0.39	\$0.39	\$0.39	\$0.39	\$0.39	\$0.39	\$0.39
System growth	\$0.49	\$0.52	\$3.24	\$3.77	\$4.06	\$2.16	\$0.11	\$1.20	\$0.38	\$0.38
Asset replacement and renewal	\$3.92	\$4.97	\$3.38	\$3.39	\$3.80	\$4.26	\$5.97	\$5.22	\$7.67	\$6.96
Asset relocations	\$0.02	\$0.02	\$0.06	\$14.25	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02
Quality of supply	\$2.26	\$2.64	\$1.84	\$0.30	\$0.20	\$0.11	\$1.07	\$0.95	\$0.86	\$0.18
Legislative and regulatory	\$0.08	\$0.19	\$0.00	\$0.00	\$0.19	\$0.19	\$0.19	\$0.19	\$0.00	\$0.00
Other reliability, safety and environment	\$0.70	\$0.70	\$0.00	\$0.23	\$0.00	\$0.36	\$0.30	\$0.00	\$0.00	\$0.00
Non-network assets	\$1.65	\$1.15	\$0.63	\$0.72	\$0.53	\$0.58	\$0.80	\$0.59	\$0.53	\$0.71
Total CAPEX	\$9.50	\$10.57	\$9.53	\$23.05	\$9.20	\$8.07	\$8.85	\$8.56	\$9.85	\$8.64
Service interruptions and emergencies	\$0.56	\$0.56	\$0.56	\$0.57	\$0.57	\$0.57	\$0.57	\$0.57	\$0.57	\$0.57
Vegetation management	\$0.48	\$0.48	\$0.48	\$0.61	\$0.61	\$0.61	\$0.61	\$0.61	\$0.61	\$0.61
Routine and corrective maintenance and inspection	\$0.71	\$0.77	\$0.89	\$1.04	\$1.21	\$0.92	\$0.97	\$0.90	\$1.13	\$1.15
Asset replacement and renewal	\$0.99	\$0.93	\$0.75	\$0.87	\$0.96	\$0.95	\$1.11	\$0.93	\$0.82	\$0.82
System operations and network support	\$2.48	\$2.48	\$2.48	\$2.48	\$2.48	\$2.48	\$2.48	\$2.48	\$2.48	\$2.48
Business support	\$2.70	\$2.70	\$2.70	\$2.70	\$2.70	\$2.70	\$2.70	\$2.70	\$2.70	\$2.70
Total OPEX	\$7.92	\$7.92	\$7.85	\$8.28	\$8.54	\$8.24	\$8.45	\$8.20	\$8.32	\$8.34
Total Expenditure	\$17.41	\$18.50	\$17.39	\$31.32	\$17.74	\$16.31	\$17.30	\$16.76	\$18.17	\$16.98

Significant Factors in this Financial Forecast are:

Capital – Asset Relocations. Generally this category of expenditure is driven by customer AFS requirements when transformers get replaced by load driven upgrades and is embedded within the AFS budget. There are no significant relocations of assets planned.

Capital – System Growth. Capital system growth budget increases significantly in 2014-17 due to the historic load growth development of Opotiki substation.

Capital Reliability, Quality of Supply. This category value is at a high level due to the on-going implementation of rural feeder reliability projects, and the inclusion of Gateway 33kV substation, but reduces over the 10 year planning period. Load driven asset replacement projects in the middle of the planning period replace the reliability expenditure to even out the cashflow and labour requirements.

Capital Asset Replacement and Renewal. An average of \$4.7 million is budgeted per annum for renewals over the 10 year planning period, with expenditure slowly increasing annually throughout the period as ageing assets are replaced.

Capital Customer Connection. No significant increase is expected in this category.

The basis for the financial forecasts is explained in the lifecycle management plan (Section 6). The following general assumptions have been made in preparing the 10 year expenditure forecast:

- The completion of the major infrastructure projects at Waiotahi and Gateway zone substations and associated projects will ensure the network has minimal or no load constraint issues unless there is unforeseen population growth;
- An increase in replacement and maintenance expenditure due to asset ageing is expected and this has been included at a low level from 2013 onwards. Asset age charts in Section 6 show that increased expenditure is likely beyond 2021;
- Maintenance and renewal allocations have been based on preserving current levels of services;
- Stated in Real 2014 dollars.

Using a simple age-based replacement model across all assets, based on the ODV handbook average asset life and current replacement costs smoothed across the period 2013 to 2023, gives an average replacement expenditure requirement of approximately \$4.5 million per annum over this period to replace end of life assets. The average planned expenditure on asset replacement and renewals, plus maintenance refurbishment and renewal, is \$4.7 million per annum over the next 10 years.

8.8. Forecast Uncertainty and Assumptions

There are a number of significant assumptions used in the determining of works and demand growth identified in this AMP that may affect the financial outcomes and forecasting. The reasoning behind the assumptions are generally covered in the body of the document but the likely effect of these uncertainties on the financial or work outputs are summarised as follows:

Issue	Basis for the assumption and the likely impact of this uncertainty
Load Growth	Load growth is based on historical growth trends. No step change loads are allowed for in the forecasts, unless these have been clearly identified with actual timing and the expected demand load. Possible step changes at Kaingaroa and Opotiki have not been included.
Customer Growth	<p>It has been assumed the annual quantity of new customer connections will continue to reduce; this prediction correlates well with Statistic NZ data. Any change in this trend is likely to be relatively insignificant on the network due to the small total quantity of connections. If a significant number of connections were to occur there is sufficient capacity within the network to accommodate significant additional domestic loads apart from at Opotiki.</p> <p>Increased commercial loads in Whakatane would have the effect of bringing forward capacity driven expenditure on the Strand North, Strand South, and Rex Morpeth feeders and the proposed CBD or Gateway substations.</p>
Economic Activity	<p>The Eastern Bay of Plenty has minimal growth and is predicted to have negative population and economic growth over the next 20 years (Statistics NZ). This is unlikely to alter the planned asset refurbishment programs as ageing assets affect the overall reliability of the network. The potential shutdown or down-sizing of major industry customers would result in either stranded assets or alternatively release assets that may be used to defer load driven asset replacements, depending on the area affected.</p> <p>It is highly probable that some major industries currently supplied will reduce demand during the planning period.</p>
Economic Activity Opotiki	Opotiki already has load related issues. Any step change in load will seriously affect the ability of the network to deliver this load. A request for significant load will require an acceleration of the planned Opotiki substation or alternative means of providing a supply. This project is held back due to regulatory uncertainties regarding the possible use of Transpower assets and the uncertainty of load growth forecasts. A generator procured in 2013 will be used for peak load lopping if required which will allow short term deferral of the Opotiki substation.
Network Priorities	Network priorities are driven by both planned and unplanned events. Significant unplanned events (weather events, unanticipated customer requests, defect discovery, major faults) that impact the availability of labour or finances will prompt a re-prioritisation of projects. This may alter the financial spread of projects across the reporting categories. Historically, Horizon Energy has tended to defer larger strategic projects as long as practicable, but adherence to a priority matrix will ensure these projects retain their focus.
Shareholder Expectations	Shareholders expect a certain level of return on investment. Significant events (as above) that alter the annual cash flow requirements will force a review of expenditure in any period. This will flow into a re-prioritisation of projects to maintain annual budgets.

Issue	Basis for the assumption and the likely impact of this uncertainty
Customer Expectations	Surveys in 2012 indicated that customers will not tolerate a reduction in service or quality (outages, supply quality), nor will they accept an increase in charges. Economic reliability will continue to be a major driver of projects, and reliability projects dominate the next two to three years of the works plan, to be overtaken by expenditure on asset refurbishment projects. With the completion of reliability projects on the most unreliable feeders, future reliability projects will be used more and more as float projects and will be scheduled around strategic and load driven projects to balance cash and work flow. This approach will tend to slow down the implementation of reliability improvements on what are currently the more reliable feeders.
Strategic Projects	Strategic and load driven projects dominate the planning over the next five years. As the projects enter the detailed planning phase complexities in the planning, design and delivery processes may impact the scheduled delivery and budgets of these projects. This is likely to result in some of the project expenditure being spread over different years to that originally planned.
Asset Refurbishments and Renewals	Increased expenditure on assets due to age and condition is planned over the next few years. Not all asset data is available at the time of publication but there is sufficient data to predict the levels of effort required to maintain and refurbish the assets across the network. Uncertainties in the condition assumptions resulting in either more or less work will result in deferral or acceleration of projects depending on the actual work required to recondition the assets.
Faults and Emergency	Major weather events are the main cause of wide-spread and costly unplanned outages. These are impossible to predict. The result of a major event will be the likely delay of all works as resources are diverted into the fault restoration and remedial works. It is accepted by the network that a major weather event will be treated as an unbudgeted expense for that year.
Initial Budgets	Initially, individual projects are budgeted at a high level only. As projects are further engineered, the budgets become more accurate. The overall annual projects budget treats the total projects budget as a pool, so as budgets are confirmed additional projects are prioritised and are released into, or withdrawn from, the pool of projects for the year.
Cancelled or Deferred Works	During the year projects may be cancelled or deferred for any number of reasons. Funds from these projects will be released into the project budget pool for reallocation to other projects and the original redesigned or rescheduled.
Unbudgeted Works	Occasionally works are identified that the network determines are beneficial to proceed with. A common example is customer initiated works where the customer contributes some or all of the costs. This is treated like an accelerated project and is elevated in priority, and a lower priority project may be delayed if resources are unavailable.
Resources	Resource availability has a direct effect on the ability to complete works. Shortage of engineering or construction staff will invariably result in either delays or increased costs. Experience has shown the use of contractors from outside the district can increase project costs.

Issue	Basis for the assumption and the likely impact of this uncertainty
Inflation	Forward budgets are at the current year's value with no inflation adjustment. As the projects are reviewed for the succeeding year the costs are re-assessed. It is accepted that any sustained high inflationary period will require a reassessment of the project plan as costs increase.

Budget Reporting and Monitoring Improvement Plan

The Microsoft Dynamics NAV financial reporting system is implemented to enable greater detailed control and accuracy of entry data, coupled with direct data input at source from stores and contracting. More regimented cost and budget category reporting is resulting in a better ability to estimate works. Planned system improvements are:

- Improved reporting templates;
- Automation of regulatory reporting;
- Increased contractor accountability;
- Project engineering completed earlier and ability to refresh prices as unit prices alter;
- Increasingly projects are being pre-engineered and to a greater level of accuracy prior to being submitted for budgetary approval;
- Tighter integration between the AMP 10 Year Plan and the Annual Plan;
- Increased number of maintenance renewal and condition works being managed as projects; and
- Benchmarking against other lines companies.

9. Improvement Plan

9.1. Asset Management Planning Framework

The process for developing and using this AMP is illustrated below in Figure 9.1.

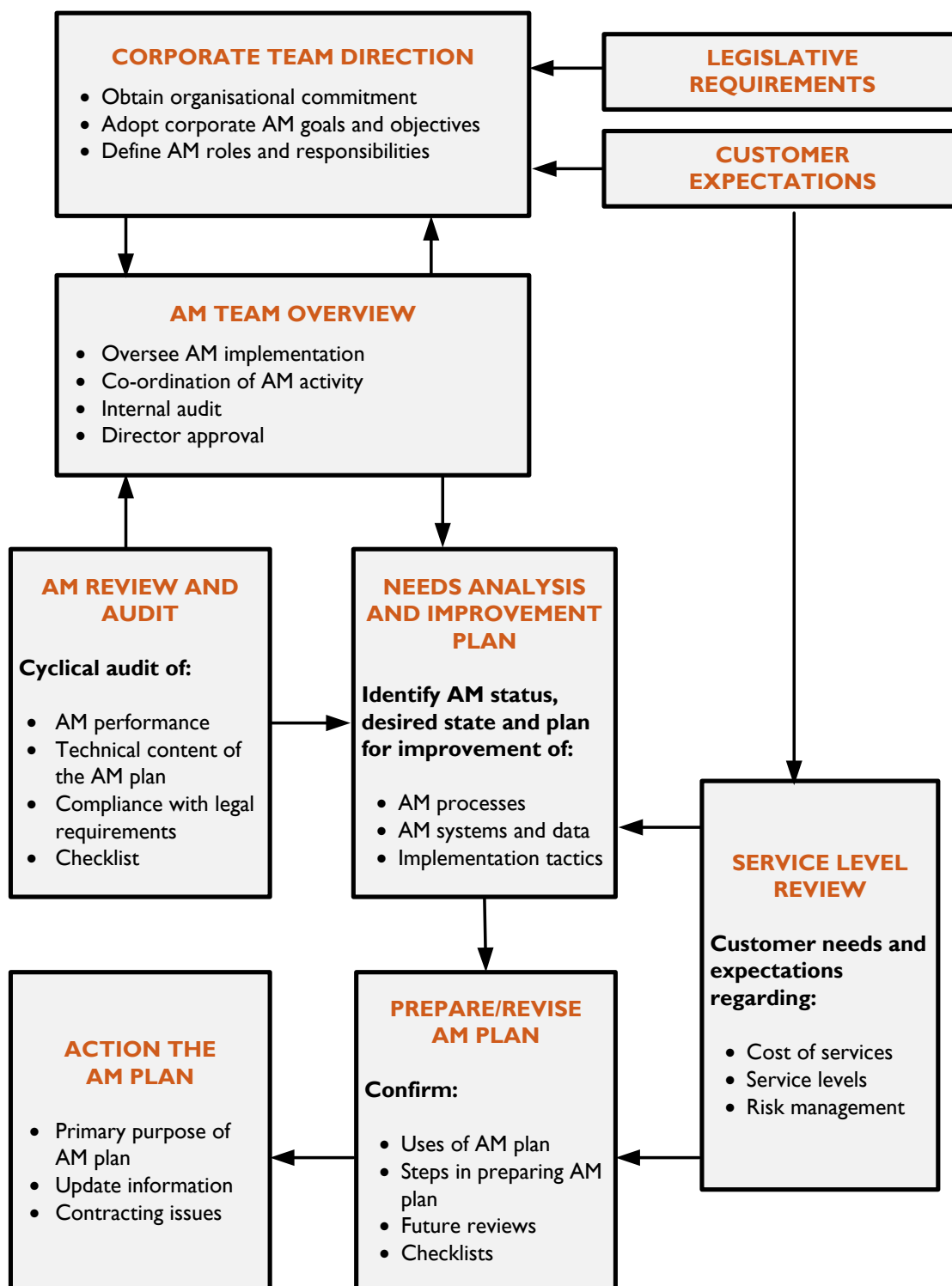


Figure 9.1 – Flow Chart for Developing and using AM Plans

9.2. Responsibilities

Responsibilities are allocated for the management of the various asset management functions. The activities involved and the position responsible is as follows:

Activity	Responsibility
Co-ordinate the preparation of programmes, estimates, project plans and performance measures for the improvement of asset management practices	General Manager Network with assistance from the Senior Planning Engineer
Periodically review the asset management improvement programme and specific improvement projects	General Manager Network, Asset Manager, Service Delivery Manager, Planning Engineer
Provide AMP budgets	Chief Executive
Identify internal/external peer reviews of asset management plan improvements	General Manager Network
Approve the Plan as being reflective of the emphasis that the Company places on its asset management function	Board of Directors
Engage consultants to assist with asset management improvements as required	General Manager Network
Monitor and report on all aspects of network projects	Service Delivery Manager

Table 9.1 – Activities and Responsibilities

9.3. Current Status of Asset Management

The document reflects the Company's structure as a dedicated lines business. The plan also reflects the staffing structure of the Company and the use of contracting staff (both internal and external) for the implementation of works.

The Company has a comprehensive Quality Manual system providing requirements for all activities that need to be undertaken. In particular, Part 4 of QM 4-2 Network Management and Planning formulates activities for Asset Management. The components of the Quality Manual are periodically revised to ensure co-ordination with the existing Company structure. Staff members are able to effectively adapt the quality requirements in an appropriate manner.

9.4. Improvement Plan

Improvement plans and objectives in the planning process are noted throughout the document in each relevant section. In summary, priority improvement projects are:

- Completion of GIS upgrade project;
- Investigations into asset management information systems;
- Continual review and formal acceptance of design standards;
- System improvements to allow for accreditation in PAS55 Asset Management Practices;
- Continual data gathering and data accuracy verification projects;
- Service level agreements and management of contractors and work flows; and
- Increase forward planning for planned works up to a year in advance.

Appendix AI – EDB AMP Information Disclosure Requirements Cross Reference List

No.	Disclosure requirements	Relevant AMP Section
3	The AMP must include the following-	
3.1	A summary that provides a brief overview of the contents and highlights information that the EDB considers significant	1.1 - 1.10 8 pages
3.2	Details of the background and objectives of the EDB's asset management and planning processes	2.1-2.9 19 pages
3.3	A purpose statement which-	
3.3.1	Makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes	2.4
3.3.2	States the corporate mission or vision as it relates to asset management	2.4
3.3.3	Identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB	2.13 fig 2.2
3.3.4	States how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management	2.13
3.3.5	Includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans	2.7, 2.13
3.4	Details of the AMP planning period , which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed	2.8
3.5	The date that it was approved by the directors	2.9
3.6	A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates-	2.10
3.6.1	How the interests of stakeholders are identified	2.10 Table 2.2

3.6.2	What these interests are	2.10 Table 2.2
3.6.3	How these interests are accommodated in asset management practices	2.10 Table 2.2
3.6.4	How conflicting interests are managed	2.10.3
3.7	A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	2.11
3.7.1	Governance—a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors	2.11
3.7.2	Executive—an indication of how the in-house asset management and planning organisation is structured	2.11.2
3.7.3	Field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used	2.11.3
3.8	All significant assumptions	8.8
3.8.1	Quantified where possible	8.8
3.8.2	Clearly identified in a manner that makes their significance understandable to interested persons, including	8.8
3.8.3	A description of changes proposed where the information is not based on the EDB's existing business	na
3.8.4	The sources of uncertainty and the potential effect of the uncertainty on the prospective information	2.12, 8.8
3.8.5	The price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b.	Na
3.9	Description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures	8.8



3.10	An overview of asset management strategy and delivery	2.3-2.4 11 pages
	<i>How the asset management strategy is consistent with the EDB's other strategy and policies;</i>	2.4
	<i>How the asset strategy takes into account the life cycle of the assets;</i>	2.4, 6
	<i>The link between the asset management strategy and the AMP;</i>	2.4
	<i>Processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.</i>	6.5,
3.11	An overview of systems and information management data	2.12
	<i>To support the AMMAT disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe-</i>	
	<i>The processes used to identify asset management data requirements that cover the whole of life cycle of the assets;</i>	2.12., 5.2.4
	<i>The systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets;</i>	2.12
	<i>The systems and controls to ensure the quality and accuracy of asset management information; and</i>	2.12
	<i>The extent to which these systems, processes and controls are integrated.</i>	2.13
3.12	A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data	2.12.1
	<i>Discussion of the limitations of asset management data is intended to enhance the transparency of the AMP and identify gaps in the asset management system.</i>	2.12.1
3.13	A description of the processes used within the EDB for-	

3.13.1	Managing routine asset inspections and network maintenance	Sect 6.1.3
3.13.2	Planning and implementing network development projects	Sect 5.3
3.13.3	Measuring network performance.	5.2.4, 5.2.5
3.14	An overview of asset management documentation, controls and review processes	2.12, 2.13, 2.13
	<i>To support the AMMAT disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should-</i>	
	<i>(i) identify the documentation that describes the key components of the asset management system and the links between the key components;</i>	
	<i>(ii) describe the processes developed around documentation, control and review of key components of the asset management system;</i>	
	<i>(iii) where the EDB outsources components of the asset management system, the processes and controls that the EDB uses to ensure efficient and cost effective delivery of its asset management strategy;</i>	6.5
	<i>(iv) where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house; and</i>	
	<i>(v) audit or review procedures undertaken in respect of the asset management system.</i>	na
3.15	An overview of communication and participation processes	2.5

	<i>To support the AMMAT disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should-</i>	
	<i>(i) communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants;</i>	
	<i>(ii) demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements.</i>	
3.16	The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise;	8
3.17	The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	
	Assets covered	
4	The AMP must provide details of the assets covered, including-	
4.1	A high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	3.1
4.1.1	The region(s) covered	3.1
4.1.2	Identification of large consumers that have a significant impact on network operations or asset management priorities	3.4
4.1.3	Description of the load characteristics for different parts of the network	3.3
4.1.4	Peak demand and total energy delivered in the previous year, broken down by sub-network , if any.	5.4
4.2	A description of the network configuration, including-	5.5
4.2.1	Identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point;	5.5



4.2.2	A description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s) . The AMP must identify the supply security provided at individual zone substations , by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings;	3.2, 5.6
4.2.3	A description of the distribution system, including the extent to which it is underground;	3.8, 5, 6
4.2.4	A brief description of the network's distribution substation arrangements;	6.3.3
4.2.5	A description of the low voltage network including the extent to which it is underground; and	6.3.6
4.2.6	Injection systems, SCADA and telecommunications systems.	6.3.7, 6.3.8
4.3	If sub-networks exist, the network configuration information referred to in subclause 4.2 above must be disclosed for each sub-network .	na
	Network assets by category	
4.4	The AMP must describe the network assets by providing the following information for each asset category-	
4.4.1	Voltage levels;	3,6
4.4.2	Description and quantity of assets;	3.8,6
4.4.3	Age profiles; and	6
4.4.4	A discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	6
4.5	The asset categories discussed in subclause 4.4 above should include at least the following-	6

4.5.1	Sub transmission	5.6
4.5.2	Zone substations	5
4.5.3	Distribution and LV lines	6
4.5.4	Distribution and LV cables	6
4.5.5	Distribution substations and transformers	6
4.5.6	Distribution switchgear	6
4.5.7	Other system fixed assets	6
4.5.8	Other assets;	6
4.5.9	assets owned by the EDB but installed at bulk electricity supply points owned by others;	Na
4.5.10	EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	6.3.12
4.5.11	Other generation plant owned by the EDB .	6.3.12
	Service Levels	
5	The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period . The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period .	4.4

6	Performance indicators for which targets have been defined in clause 5 above must include SAIDI and SAIFI values for the next 5 disclosure years .	4.4.2
7	Performance indicators for which targets have been defined in clause 5 above should also include-	
7.1	Consumer oriented indicators that preferably differentiate between different consumer types;	4.4
7.2	Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	??
8	The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	4.4.1
9	Targets should be compared to historic values where available to provide context and scale to the reader.	
10	Where forecast expenditure is expected to materially affect performance against a target defined in clause 5 above, the target should be consistent with the expected change in the level of performance.	8
	<i>Performance against target must be monitored for disclosure in the Evaluation of Performance section of each subsequent AMP.</i>	
	Network Development Planning	
11	AMPs must provide a detailed description of network development plans, including—	5.2
11.1	A description of the planning criteria and assumptions for network development;	5.2.1
11.2	Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	5, Appendix C
11.3	A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	5.2.2
11.4	The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	

11.4.1	The categories of assets and designs that are standardised;	5.2.3
11.4.2	The approach used to identify standard designs.	5.2.3
11.5	A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network .	5.3.6
11.6	A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network .	5.2
11.7	A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision.	5.3.3
11.8	Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand;	5.4
11.8.1	Explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	5.4.1
11.8.2	Provide separate forecasts to at least the zone substation level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	5.4
11.8.3	Identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period ; and	5.5 on
11.8.4	Discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network , and the projected impact of any demand management initiatives.	
11.9	Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including-	
11.9.1	The reasons for choosing a selected option for projects where decisions have been made;	Appendix C
11.9.2	The alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described;	Appendix C



11.9.3	Consideration of planned innovations that improve efficiencies within the network , such as improved utilisation, extended asset lives, and deferred investment.	Appendix C
11.10	A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-	5.3.5 Appendix C
11.10.1	A detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months;	NA
11.10.2	A summary description of the programmes and projects planned for the following four years (where known); and	NA
11.10.3	An overview of the material projects being considered for the remainder of the AMP planning period .	Appendix F
11.11	A description of the EDB's policies on distributed generation , including the policies for connecting distributed generation . The impact of such generation on network development plans must also be stated.	3.5
11.12	A description of the EDB's policies on non-network solutions, including-	5.3.5
11.12.1	Economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation; and	5.3.5
11.12.2	the potential for non-network solutions to address network problems or constraints.	5.3.5, Appendix C
	Lifecycle Asset Management Planning (Maintenance and Renewal)	Section 6
12	The AMP must provide a detailed description of the lifecycle asset management processes, including—	
12.1	The key drivers for maintenance planning and assumptions;	Section 6
12.2	Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	Section 6
12.2.1	The approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done;	Section 6

12.2.2	Any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	Section 6
12.2.3	Budgets for maintenance activities broken down by asset category for the AMP planning period .	Section 8
12.3	Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	Section 6
12.3.1	The processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets;	6.3 by type
12.3.2	A description of innovations made that have deferred asset replacement;	Section 6
12.3.3	A description of the projects currently underway or planned for the next 12 months;	Appendix D
12.3.4	A summary of the projects planned for the following four years (where known); and	Appendix E
12.3.5	An overview of other work being considered for the remainder of the AMP planning period .	Appendix F
12.4	The asset categories discussed in subclauses 12.2 and 12.3 above should include at least the categories in subclause 4.5 above.	
	Non-Network Development, Maintenance and Renewal	6.3.12
13	AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	6.3.12
13.1	A description of non-network assets;	6.3.12
13.2	Development, maintenance and renewal policies that cover them;	6.3.12
13.3	A description of material capital expenditure projects (where known) planned for the next five years;	6.3.12

13.4	A description of material maintenance and renewal projects (where known) planned for the next five years.	6.3.12
	Risk Management	
14	AMPs must provide details of risk policies, assessment, and mitigation, including—	Section 7
14.1	Methods, details and conclusions of risk analysis;	7
14.2	Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events;	7.3.8
14.3	A description of the policies to mitigate or manage the risks of events identified in subclause 16.2;	7
14.4	Details of emergency response and contingency plans.	7.3.4
	Evaluation of performance	
15	AMPs must provide details of performance measurement, evaluation, and improvement, including—	
15.1	A review of progress against plan, both physical and financial;	8.6
	<i>Referring to the most recent disclosures made under Section 2.6 of this determination, discussing any significant differences and highlighting reasons for substantial variances;</i>	8
	<i>Commenting on the progress of development projects against that planned in the previous AMP and provide reasons for substantial variances along with any significant construction or other problems experienced;</i>	8
	<i>Commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.</i>	6.1.3
15.2	An evaluation and comparison of actual service level performance against targeted performance;	Section 4.4

	<i>In particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the AMP in the previous AMP and explain any significant variances;</i>	
15.3	An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB 's asset management and planning processes.	Appendix A2
15.4	An analysis of gaps identified in subclauses 15.2 and 15.3 above. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	2.11
	Capability to deliver	
16	AMPs must describe the processes used by the EDB to ensure that-	
16.1	The AMP is realistic and the objectives set out in the plan can be achieved;	2.12.2
16.2	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2.10

Appendix A2 – EDB Information Disclosure Requirements Schedules 11-15

Schedule 11a: Report on Forecast Capital Expenditure

												Company Name	Horizon Energy Distribution Limited
												AMP Planning Period	1 April 2014 – 31 March 2024
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													
7		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 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
9	11a(i): Expenditure on Assets Forecast	\$000 (in nominal dollars)											
10	Consumer connection	140	394	405	416	428	440	452	465	478	491	505	
11	System growth	96	492	539	3,466	4,157	4,599	2,510	129	1,479	479	492	
12	Asset replacement and renewal	5,712	3,977	5,178	3,618	3,592	2,911	4,946	5,170	6,257	7,439	7,905	
13	Asset relocations	71	20	20	21	21	22	23	23	24	25	25	
14	Reliability, safety and environment:												
15	Quality of supply	1,685	2,292	2,750	1,974	330	227	126	1,276	1,170	1,091	238	
16	Legislative and regulatory	285	77	202	-	-	219	226	232	238	-	-	
17	Other reliability, safety and environment	13	710	729	-	250	-	421	361	-	-	-	
18	Total reliability, safety and environment	1,983	3,078	3,680	1,974	581	447	773	1,870	1,408	1,091	238	
19	Expenditure on network assets	8,002	7,961	9,823	9,495	8,779	8,419	8,704	7,657	9,645	9,524	9,166	
20	Non-network assets	950	1,669	1,198	674	788	605	669	955	720	675	923	
21	Expenditure on assets	8,952	9,629	11,020	10,169	9,566	9,023	9,373	8,611	10,365	10,200	10,089	
22													
23	plus Cost of financing	104	103	128	123	114	109	113	100	125	124	119	
24	less Value of capital contributions	265	269	276	284	292	300	308	317	326	335	344	
25	plus Value of vested assets												
26													
27	Capital expenditure forecast	8,791	9,464	10,872	10,008	9,388	8,833	9,178	8,394	10,164	9,988	9,863	
28													
29	Value of commissioned assets	8,206	9,701	10,569	10,114	9,563	8,939	9,169	8,630	9,853	10,057	9,975	
30		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10	
		for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
32		\$000 (in constant prices)											
33	Consumer connection	140	388	388	388	388	388	388	388	388	388	388	
34	System growth	96	485	517	3,235	3,774	4,062	2,157	108	1,203	379	379	
35	Asset replacement and renewal	5,712	3,922	4,968	3,377	3,261	2,571	4,249	4,321	5,086	5,883	6,081	
36	Asset relocations	71	19	19	19	19	19	19	19	19	19	19	
37	Reliability, safety and environment:												
38	Quality of supply	1,685	2,261	2,638	1,842	300	201	108	1,067	951	863	183	
39	Legislative and regulatory	285	76	194	-	-	194	194	194	194	-	-	
40	Other reliability, safety and environment	13	700	699	-	227	-	362	302	-	-	-	
41	Total reliability, safety and environment	1,983	3,036	3,531	1,842	527	395	664	1,562	1,145	863	183	
42	Expenditure on network assets	8,002	7,851	9,424	8,861	7,970	7,435	7,477	6,398	7,841	7,532	7,051	
43	Non-network assets	950	1,646	1,149	629	715	534	575	798	585	534	710	
44	Expenditure on assets	8,952	9,497	10,573	9,490	8,685	7,969	8,052	7,196	8,426	8,066	7,761	
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	298	278	322	205	319	161	197	1,107	1,135	1,620	986	
49	Research and development												

Schedule I Ia: Report on Forecast Capital Expenditure

	for year ended	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
		31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
Difference between nominal and constant price forecasts		\$000										
Consumer connection		-	5	16	28	39	51	64	76	89	103	116
System growth		-	7	22	231	383	537	354	21	277	100	114
Asset replacement and renewal		-	55	210	241	331	340	697	850	1,170	1,556	1,824
Asset relocations		-	0	1	1	2	3	3	4	4	5	6
Reliability, safety and environment:												
Quality of supply		-	31	112	132	30	27	18	210	219	228	55
Legislative and regulatory		-	1	8	-	-	26	32	38	45	-	-
Other reliability, safety and environment		-	10	30	-	23	-	59	59	-	-	-
Total reliability, safety and environment		-	42	149	132	53	52	109	307	263	228	55
Expenditure on network assets		-	109	399	633	809	984	1,226	1,258	1,804	1,993	2,115
Non-network assets		-	23	49	45	73	71	94	157	135	141	213
Expenditure on assets		-	132	447	678	881	1,054	1,321	1,415	1,939	2,134	2,328

	for year ended	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
		31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19
11a(ii): Consumer Connection							
<i>Consumer types defined by EDB*</i>		\$000 (in constant prices)					
General		140	388	388	388	388	388
[EDB consumer type]							
[EDB consumer type]							
[EDB consumer type]							
[EDB consumer type]							
<i>*Include additional rows if needed</i>							
Consumer connection expenditure		140	388	388	388	388	388
less Capital contributions funding consumer connection		265	265	265	265	265	265
Consumer connection less capital contributions		(125)	123	123	123	123	123

11a(iii): System Growth							
Subtransmission		96					
Zone substations			485	517	3,235	3,774	2,912
Distribution and LV lines							
Distribution and LV cables							1,150
Distribution substations and transformers							
Distribution switchgear							
Other network assets							
System growth expenditure		96	485	517	3,235	3,774	4,062
less Capital contributions funding system growth							
System growth less capital contributions		96	485	517	3,235	3,774	4,062

Schedule I Ia: Report on Forecast Capital Expenditure

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19
11a(iv): Asset Replacement and Renewal	\$000 (in constant prices)						
Subtransmission	5,712	24	186	425	24	256	
Zone substations		453	2,286	197	698	12	
Distribution and LV lines		781	697	566	548	605	
Distribution and LV cables		690	1,010	1,171	912	912	
Distribution substations and transformers		257	293	408	541	407	
Distribution switchgear		155	78	129	78	78	
Other network assets		1,563	419	481	460	302	
Asset replacement and renewal expenditure	5,712	3,922	4,968	3,377	3,261	2,571	
less Capital contributions funding asset replacement and renewal							
Asset replacement and renewal less capital contributions	5,712	3,922	4,968	3,377	3,261	2,571	
11a(v): Asset Relocations							
<i>Project or programme*</i>							
Transformer relocations driven by customer requests		19	19	19	19	19	
(Description of material project or programme)							
(Description of material project or programme)							
(Description of material project or programme)							
(Description of material project or programme)							
<i>*Include additional rows if needed</i>							
All other asset relocations projects or programmes	71						
Asset relocations expenditure	71	19	19	19	19	19	
less Capital contributions funding asset relocations							
Asset relocations less capital contributions	71	19	19	19	19	19	
11a(vi): Quality of Supply							
<i>Project or programme*</i>							
4th Poletop repeater- Installation				216			
2nd 33kV line into Aniwhenua				718			
Gateway-33kV development & integration to CHH Y1		845					
Manawahe Voltage regulator					207		
SCADA System-smart network enhancements				310			
Underground Plains-East bank high capacity tie feeder				277			
Valley Road Tie Kawerau		291					
Manawahe-McIvor Rd tie line Stage 3				227			
Gateway-33kV development & integration to CHH Y2			1,302				
<i>*Include additional rows if needed</i>							
All other quality of supply projects or programmes	1,685	1,125	1,336	93	93	201	
Quality of supply expenditure	1,685	2,261	2,638	1,842	300	201	
less Capital contributions funding quality of supply							
Quality of supply less capital contributions	1,685	2,261	2,638	1,842	300	201	

Schedule I Ia: Report on Forecast Capital Expenditure

142	11a(vii): Legislative and Regulatory						
143	<i>Project or programme*</i>						
144	(Description of material project or programme)						
145	(Description of material project or programme)						
146	(Description of material project or programme)						
147	(Description of material project or programme)						
148	(Description of material project or programme)						
149	<i>*Include additional rows if needed</i>						
150	All other legislative and regulatory projects or programmes	285	76	194			194
151	Legislative and regulatory expenditure	285	76	194	-	-	194
152	less Capital contributions funding legislative and regulatory						
153	Legislative and regulatory less capital contributions	285	76	194	-	-	194
161							
162		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
163	for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19
163	11a(viii): Other Reliability, Safety and Environment						
164	<i>Project or programme*</i>						
165	Te Rahu South /WBM South Structures reconfigure					227	
166	Galatea 33kV bus upgrade plus line CB's		259				
167	1000 KVA Generator #2			687			
168	(Description of material project or programme)						
169	(Description of material project or programme)						
170	<i>*Include additional rows if needed</i>						
171	All other reliability, safety and environment projects or programmes	13	441	13			
172	Other reliability, safety and environment expenditure	13	700	699	-	227	-
173	less Capital contributions funding other reliability, safety and environment						
174	Other reliability, safety and environment less capital contributions	13	700	699	-	227	-
175							
176							
177							
178	11a(ix): Non-Network Assets						
179	Routine expenditure						
180	<i>Project or programme*</i>						
181	Information and technology systems	487	661	306	501	672	506
182	Asset management systems	17	3				
183	Office buildings, depots, and workshops	31	42	5	25	5	25
184	Office furniture and equipment	166	8	3	3	3	3
185	Motor vehicles	54		35		35	
186	<i>*Include additional rows if needed</i>						
187	All other routine expenditure projects or programmes						
188	Routine expenditure	755	714	349	529	715	534
189	Atypical expenditure						
190	<i>Project or programme*</i>						
191	Information and technology systems			300	100		
192	Asset management systems	195	932	500			
193	(Description of material project or programme)						
194	(Description of material project or programme)						
195	(Description of material project or programme)						
196	<i>*Include additional rows if needed</i>						
197	All other atypical projects or programmes						
198	Atypical expenditure	195	932	800	100	-	-
199							
200	Non-network assets expenditure	950	1,646	1,149	629	715	534

Schedule 11b: Report on Forecast Operational Expenditure

Company Name **Horizon Energy Distribution Limited**
 AMP Planning Period **1 April 2014 – 31 March 2024**

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
7		31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
8	for year ended											
9	Operational Expenditure Forecast	\$000 (in nominal dollars)										
10	Service interruptions and emergencies	701	564	579	596	612	635	653	671	690	709	729
11	Vegetation management	364	482	495	509	523	538	553	569	585	601	618
12	Routine and corrective maintenance and inspection	548	723	807	952	921	875	801	877	824	942	942
13	Asset replacement and renewal	1,088	1,001	974	803	960	1,091	1,107	1,330	1,140	1,033	1,063
14	Network Opex	2,701	2,769	2,855	2,860	3,017	3,139	3,113	3,446	3,238	3,285	3,351
15	System operations and network support	2,187	2,517	2,587	2,660	2,734	2,811	2,890	2,970	3,054	3,139	3,227
16	Business support	2,710	2,741	2,818	2,897	2,978	3,061	3,147	3,235	3,326	3,419	3,514
17	Non-network opex	4,897	5,258	5,405	5,557	5,712	5,872	6,037	6,206	6,379	6,558	6,742
18	Operational expenditure	7,598	8,027	8,260	8,416	8,729	9,011	9,150	9,652	9,617	9,843	10,093
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 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
21		\$000 (in constant prices)										
22	Service interruptions and emergencies	701	556	556	556	556	561	561	561	561	561	561
23	Vegetation management	364	475	475	475	475	475	475	475	475	475	475
24	Routine and corrective maintenance and inspection	548	714	774	889	836	773	688	733	670	745	724
25	Asset replacement and renewal	1,088	987	934	749	871	964	951	1,111	926	817	818
26	Network Opex	2,701	2,731	2,739	2,669	2,739	2,772	2,674	2,880	2,632	2,598	2,578
27	System operations and network support	2,187	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482
28	Business support	2,710	2,704	2,704	2,704	2,704	2,704	2,704	2,704	2,704	2,704	2,704
29	Non-network opex	4,897	5,186	5,186	5,186	5,186	5,186	5,186	5,186	5,186	5,186	5,186
30	Operational expenditure	7,598	7,917	7,925	7,855	7,925	7,958	7,860	8,066	7,818	7,784	7,764
31	Subcomponents of operational expenditure (where known)											
32	Energy efficiency and demand side management, reduction of energy losses											
33	Direct billing*											
34	Research and Development											
35	Insurance											
36												
37	* Direct billing expenditure by suppliers that direct bill the majority of their consumers											
38		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
39		31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
40	for year ended											
41	Difference between nominal and real forecasts	\$000										
42	Service interruptions and emergencies	-	8	24	40	56	74	92	110	129	148	168
43	Vegetation management	-	7	20	34	48	63	78	93	109	126	143
44	Routine and corrective maintenance and inspection	-	10	33	64	85	102	113	144	154	197	217
45	Asset replacement and renewal	-	14	40	54	88	128	156	219	213	216	245
46	Network Opex	-	38	116	191	278	367	439	566	606	687	773
47	System operations and network support	-	35	105	177	252	328	407	488	571	657	745
48	Business support	-	38	114	193	274	358	443	532	622	715	811
49	Non-network opex	-	72	219	371	526	686	851	1,020	1,193	1,372	1,556
50	Operational expenditure	-	110	335	561	804	1,053	1,289	1,586	1,799	2,059	2,329

Schedule 12a: Report on Asset Condition

Company Name **Horizon Energy Distribution Limited**
 AMP Planning Period **1 April 2014 – 31 March 2024**

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)										
	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
7											
8											
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	-	0.86%	99.14%	-	-	3	1.05%
11	All	Overhead Line	Wood poles	No.	-	3.90%	96.10%	-	-	3	4.40%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	3	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	100.00%	-	-	3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	N/A	-	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	100.00%	-	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	N/A	-	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	N/A	-	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	N/A	-	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	N/A	-	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	N/A	-	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	N/A	-	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	N/A	-	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	N/A	-	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	88.89%	11.11%	-	3	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	N/A	-	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	100.00%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	100.00%	-	-	4	50.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	0	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	-	100.00%	-	3	20.00%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	N/A	-	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	N/A	-	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	N/A	-	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	100.00%	-	-	3	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	66.67%	33.33%	-	-	3	60.00%

Schedule 12a: Report on Asset Condition

Asset condition at start of planning period (percentage of units by grade)											
	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
42											
43											
44											
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	100.00%	-	-	4	9.09%
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	-	100.00%	-	-	3	0.33%
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	N/A	-
48	HV	Distribution Line	SWER conductor	km	-	9.38%	90.63%	-	-	3	9.38%
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	100.00%	-	-	2	-
50	HV	Distribution Cable	Distribution UG PILC	km	-	-	100.00%	-	-	2	-
51	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	N/A	-
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	71.83%	28.17%	-	3	-
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	100.00%	-	-	3	-
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	-	100.00%	-	-	2	0.63%
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	N/A	-
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	6.67%	88.00%	5.33%	-	3	13.33%
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	-	100.00%	-	-	2	1.85%
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	100.00%	-	-	3	6.85%
59	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	100.00%	-	4	-
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	100.00%	-	-	3	5.88%
61	LV	LV Line	LV OH Conductor	km	-	-	100.00%	-	-	2	2.09%
62	LV	LV Cable	LV UG Cable	km	-	-	100.00%	-	-	2	0.64%
63	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	100.00%	-	-	2	0.89%
64	LV	Connections	OH/UG consumer service connections	No.	-	1.25%	98.75%	-	-	3	2.08%
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	55.67%	20.62%	23.71%	-	4	60.82%
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	100.00%	-	-	3	100.00%
67	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	100.00%	-	4	-
68	All	Load Control	Centralised plant	Lot	-	25.00%	75.00%	-	-	3	25.00%
69	All	Load Control	Relays	No.	-	-	-	-	-	N/A	-
70	All	Civils	Cable Tunnels	km	-	-	-	-	-	N/A	-

Schedule 12b: Report on Forecast Capacity

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.										
Company Name								Horizon Energy Distribution Limited		
AMP Planning Period								1 April 2014 – 31 March 2024		
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
7	East Bank	8	N		20	-	-	-	No constraint within +5 years	N-1 switched security of supply from adjacent substations
8	Galatea	5	N-1		-	61%	8	62%	No constraint within +5 years	None
9	Kaingaroa	3	N-1		-	48%	5	48%	No constraint within +5 years	None
10	Kopeopeo	14	N-1		12	109%	13	120%	Subtransmission circuit	Incoming cables thermal capacity exceeded
11	Ohope	4	N		4	-	-	-	Transformer	Single phase tx with one installed spare
12	Plains	7	N		17	-	-	-	No constraint within +5 years	N-1 switched security of supply from adjacent substations
13	Station Road	10	N-1		18	101%	10	103%	Transformer	N-1 switched security of supply from adjacent substations
14	[Zone Substation_08]					-			[Select one]	
15	[Zone Substation_09]					-			[Select one]	
16	[Zone Substation_10]					-			[Select one]	
17	[Zone Substation_11]					-			[Select one]	
18	[Zone Substation_12]					-			[Select one]	
19	[Zone Substation_13]					-			[Select one]	
20	[Zone Substation_14]					-			[Select one]	
21	[Zone Substation_15]					-			[Select one]	
22	[Zone Substation_16]					-			[Select one]	
23	[Zone Substation_17]					-			[Select one]	
24	[Zone Substation_18]					-			[Select one]	
25	[Zone Substation_19]					-			[Select one]	
26	[Zone Substation_20]					-			[Select one]	
¹ Extend forecast capacity table as necessary to disclose all capacity by each zone substation										
12b(ii): Transformer Capacity										
		(MVA)								
Distribution transformer capacity (EDB owned)		225								
Distribution transformer capacity (Non-EDB owned)		79								
Total distribution transformer capacity		304								
Zone substation transformer capacity		88								

Schedule 12c: Report on Forecast Network Demand

Company Name **Horizon Energy Distribution Limited**AMP Planning Period **1 April 2014 – 31 March 2024****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

12c(i): Consumer Connections

Number of ICPs connected in year by consumer type

	Number of connections					
	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19

Consumer types defined by EDB*

All Consumer types

[EDB consumer type]

[EDB consumer type]

[EDB consumer type]

[EDB consumer type]

Connections total

*Include additional rows if needed

Distributed generation

Number of connections

Installed connection capacity of distributed generation (MVA)

	55	43	39	36	33	31
	55	43	39	36	33	31
	31	45	60	75	90	105
	4	4	4	4	5	5

12c(ii) System Demand**Maximum coincident system demand (MW)**

GXP demand

plus Distributed generation output at HV and above

Maximum coincident system demand

less Net transfers to (from) other EDBs at HV and above

Demand on system for supply to consumers' connection points

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19

	80	81	82	83	85	86
	4	4	4	4	4	4
	84	85	86	88	89	90
	84	85	86	88	89	90

Electricity volumes carried (GWh)

Electricity supplied from GXPs

less Electricity exports to GXPs

plus Electricity supplied from distributed generation

less Net electricity supplied to (from) other EDBs

Electricity entering system for supply to ICPs

less Total energy delivered to ICPs

Losses

Load factor

Loss ratio

	445	445	445	445	445	445
	112	112	112	112	112	112
	-	-	-	-	-	-
	557	557	557	557	557	557
	534	534	534	534	534	534
	23	23	23	23	23	23
	76%	75%	74%	73%	72%	70%
	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%

Schedule 12d: Report on Forecast Interruptions and Duration

Company Name	Horizon Energy Distribution Limited
AMP Planning Period	1 April 2014 – 31 March 2024
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		for year ended	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
			31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19
8								
9								
10	SAIDI							
11	Class B (planned interruptions on the network)		45.0	20.0	20.0	20.0	20.0	20.0
12	Class C (unplanned interruptions on the network)		100.0	125.0	125.0	125.0	120.0	120.0
13	SAIFI							
14	Class B (planned interruptions on the network)		0.30	0.14	0.14	0.14	0.14	0.14
15	Class C (unplanned interruptions on the network)		1.50	1.60	1.60	1.60	1.60	1.60

Schedule 13: Report on Asset Management Maturity

Company Name

AMP Planning Period

Asset Management Standard Applied

Horizon Energy Distribution Limited

1 April 2014 – 31 March 2024

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	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	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?	2.9	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 policies, 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?	2.9	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?	2.9	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).

Schedule 13: Report on Asset Management Maturity

<div> <div>Company Name</div> <div>AMP Planning Period</div> <div>Asset Management Standard Applied</div> </div> <div> <div>Horizon Energy Distribution Limited</div> <div>1 April 2014 – 31 March 2024</div> </div>							
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.

Schedule 13: Report on Asset Management Maturity

Company Name

AMP Planning Period

Asset Management Standard Applied

Horizon Energy Distribution Limited

1 April 2014 – 31 March 2024

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Why	Who	Record/document 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?	2.9	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?	2.9	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)	2.9	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 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?	2.8	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.

Schedule 13: Report on Asset Management Maturity

Company Name

AMP Planning Period

Asset Management Standard Applied

Horizon Energy Distribution Limited

1 April 2014 – 31 March 2024

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.

Schedule 13: Report on Asset Management Maturity

Company Name

AMP Planning Period

Asset Management Standard Applied

Horizon Energy Distribution Limited

1 April 2014 – 31 March 2024

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Why	Who	Record/document 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	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?	3	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	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 walkabouts 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?	2.3	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.

Schedule 13: Report on Asset Management Maturity

<div> <div>Company Name</div> <div>AMP Planning Period</div> <div>Asset Management Standard Applied</div> </div> <div> <div>Horizon Energy Distribution Limited</div> <div>1 April 2014 – 31 March 2024</div> <div></div> </div>							
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 organisation's 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 organisation's 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.

Schedule 13: Report on Asset Management Maturity

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)						
Question No.	Function	Question	Score	Why	Who	Record/document 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)?	2.6	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?	2.6	Widely used AM standards require that organisations 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?	0	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.

Schedule 13: Report on Asset Management Maturity

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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				Company Name	Horizon Energy Distribution Limited	
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				Asset Management Standard Applied		
SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)						
Question No.	Function	Question	Score	Why	Who	Record/document 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?	3.1	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?	3.1	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?	2.8	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?	2.8	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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				Company Name	Horizon Energy Distribution Limited	
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)						
Question No.	Function	Question	Score	Why	Who	Record/document Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2.8	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?	2.8	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?	2.5	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?	2.8	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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				Company Name AMP Planning Period Asset Management Standard Applied				Horizon Energy Distribution Limited 1 April 2014 – 31 March 2024	
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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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)						
Question No.	Function	Question	Score	Why	Who	Record/document 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?	2.6	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?	2.6	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	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 conformance is clear, unambiguous, understood and communicated?	2.2	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 conformance. 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.

Schedule 13: Report on Asset Management Maturity

				Company Name	Horizon Energy Distribution Limited	
				AMP Planning Period	1 April 2014 – 31 March 2024	
				Asset Management Standard Applied		
SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)						
Question No.	Function	Question	Score	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))?	2.7	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?	3.2	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	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 than 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?	3	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.

Schedule 13: Report on Asset Management Maturity

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.

APPENDIX A2 – Schedule 14a Mandatory Explanatory Notes on Forecast Information

1. This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.
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, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

Difference between nominal and constant price capital expenditure forecasts is due to forecast indexation applied at 2.8% throughout the 10 year period. This is based on an annualised average forecast indexation using consumer price index estimates of 2.3%, plus 50 basis points to reflect the higher annualised average forecast indexation using labour cost index estimates.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the disclosure year, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

Difference between nominal and constant price capital expenditure forecasts is due to forecast indexation applied at 2.8% throughout the 10 year period. This is based on an annualised average forecast indexation using consumer price index estimates of 2.3%, plus 50 basis points to reflect the higher annualised average forecast indexation using labour cost index estimates.

APPENDIX A2 – Schedule 15 Voluntary Explanatory Notes

1. This Schedule enable EDBs to provide, should they wish to-
 - 1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.6.5;
 - 1.2 information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.
2. Information in this Schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.
3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

1. All forecast capital expenditure provided for in schedule 11a is intended to be included in the value of assets commissioned relating to the RAB.

APPENDIX A3 – EDB Information Disclosure Requirements Schedule II with Transmission Assets Included

Schedule I Ia Report on Forecast Capital Expenditure

												Company Name	Horizon Energy Distribution Limited
												AMP Planning Period	1 April 2014 – 31 March 2024
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													
7		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10	
8													
9	11a(i): Expenditure on Assets Forecast	\$000 (in nominal dollars)											
10	Consumer connection	140	394	405	416	428	440	452	465	478	491	505	
11	System growth	96	492	539	3,466	4,157	4,599	2,510	129	1,479	479	492	
12	Asset replacement and renewal	5,712	3,977	5,178	3,618	3,739	4,300	4,961	7,145	6,424	9,697	9,053	
13	Asset relocations	71	20	20	65	15,692	22	23	23	24	25	25	
14	Reliability, safety and environment:												
15	Quality of supply	1,685	2,292	2,750	1,974	330	227	126	1,276	1,170	1,091	238	
16	Legislative and regulatory	285	77	202	-	-	219	226	232	238	-	-	
17	Other reliability, safety and environment	13	710	729	-	250	-	421	361	-	-	-	
18	Total reliability, safety and environment	1,983	3,078	3,680	1,974	581	447	773	1,870	1,408	1,091	238	
19	Expenditure on network assets	8,002	7,961	9,823	9,539	24,596	9,807	8,719	9,632	9,812	11,782	10,314	
20	Non-network assets	950	1,669	1,198	674	788	605	669	955	720	675	923	
21	Expenditure on assets	8,952	9,629	11,020	10,213	25,384	10,412	9,388	10,587	10,532	12,458	11,236	
22													
23	plus Cost of financing	104	103	128	124	320	127	113	125	128	153	134	
24	less Value of capital contributions	265	269	276	284	292	300	308	317	326	335	344	
25	plus Value of vested assets												
26													
27	Capital expenditure forecast	8,791	9,464	10,872	10,053	25,412	10,240	9,193	10,395	10,334	12,276	11,026	
28	WIP												
29	Value of commissioned assets	8,206	9,701	10,569	10,151	25,559	10,134	9,433	10,274	10,349	11,981	11,347	
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													
32		\$000 (in constant prices)											
33	Consumer connection	140	388	388	388	388	388	388	388	388	388	388	
34	System growth	96	485	517	3,235	3,774	4,062	2,157	108	1,203	379	379	
35	Asset replacement and renewal	5,712	3,922	4,968	3,377	3,394	3,798	4,262	5,971	5,222	7,668	6,964	
36	Asset relocations	71	19	19	60	14,246	19	19	19	19	19	19	
37	Reliability, safety and environment:												
38	Quality of supply	1,685	2,261	2,638	1,842	300	201	108	1,067	951	863	183	
39	Legislative and regulatory	285	76	194	-	-	194	194	194	194	-	-	
40	Other reliability, safety and environment	13	700	699	-	227	-	362	302	-	-	-	
41	Total reliability, safety and environment	1,983	3,036	3,531	1,842	527	395	664	1,562	1,145	863	183	
42	Expenditure on network assets	8,002	7,851	9,424	8,903	22,330	8,661	7,490	8,049	7,977	9,317	7,934	
43	Non-network assets	950	1,646	1,149	629	715	534	575	798	585	534	710	
44	Expenditure on assets	8,952	9,497	10,573	9,532	23,045	9,195	8,065	8,847	8,562	9,851	8,644	
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	298	278	322	205	319	161	197	1,107	1,135	1,620	986	
49	Research and development												

Schedule I Ia Report on Forecast Capital Expenditure

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Difference between nominal and constant price forecasts	\$000										
Consumer connection	-	5	16	28	39	51	64	76	89	103	116
System growth	-	7	22	231	383	537	354	21	277	100	114
Asset replacement and renewal	-	55	210	241	344	503	699	1,174	1,202	2,029	2,089
Asset relocations	-	0	1	4	1,446	3	3	4	4	5	6
Reliability, safety and environment:											
Quality of supply	-	31	112	132	30	27	18	210	219	228	55
Legislative and regulatory	-	1	8	-	-	26	32	38	45	-	-
Other reliability, safety and environment	-	10	30	-	23	-	59	59	-	-	-
Total reliability, safety and environment	-	42	149	132	53	52	109	307	263	228	55
Expenditure on network assets	-	109	399	636	2,266	1,146	1,229	1,583	1,836	2,465	2,380
Non-network assets	-	23	49	45	73	71	94	157	135	141	213
Expenditure on assets	-	132	447	681	2,339	1,217	1,323	1,740	1,970	2,606	2,593

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
11a(ii): Consumer Connection	\$000 (in constant prices)					
Consumer types defined by EDB*						
General	140	388	388	388	388	388
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
*Include additional rows if needed						
Consumer connection expenditure	140	388	388	388	388	388
less Capital contributions funding consumer connection	265	265	265	265	265	265
Consumer connection less capital contributions	(125)	123	123	123	123	123

	96	485	517	3,235	3,774	2,912
11a(iii): System Growth						
Subtransmission	96					
Zone substations		485	517	3,235	3,774	2,912
Distribution and LV lines						1,150
Distribution and LV cables						
Distribution substations and transformers						
Distribution switchgear						
Other network assets						
System growth expenditure	96	485	517	3,235	3,774	4,062
less Capital contributions funding system growth						
System growth less capital contributions	96	485	517	3,235	3,774	4,062

Schedule I Ia Report on Forecast Capital Expenditure

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
11a(iv): Asset Replacement and Renewal	\$000 (in constant prices)					
Subtransmission	5,712	24	186	425	24	256
Zone substations		453	2,286	197	698	12
Distribution and LV lines		781	697	566	548	605
Distribution and LV cables		690	1,010	1,171	912	912
Distribution substations and transformers		257	293	408	541	407
Distribution switchgear		155	78	129	78	78
Other network assets		1,563	419	481	594	1,529
Asset replacement and renewal expenditure	5,712	3,922	4,968	3,377	3,394	3,798
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	5,712	3,922	4,968	3,377	3,394	3,798
11a(v): Asset Relocations						
<i>Project or programme*</i>						
Transformer relocations driven by customer requests		19	19	60	14,246	19
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
<i>*Include additional rows if needed</i>						
All other asset relocations projects or programmes	71					
Asset relocations expenditure	71	19	19	60	14,246	19
less Capital contributions funding asset relocations						
Asset relocations less capital contributions	71	19	19	60	14,246	19
11a(vi): Quality of Supply						
<i>Project or programme*</i>						
4th Poletop repeater- Installation				216		
2nd 33kV line into Aniwhenua				718		
Gateway-33kV development & integration to CHH Y1		845				
Manawahe Voltage regulator					207	
SCADA System-smart network enhancements				310		
Underground Plains-East bank high capacity tie feeder				277		
Valley Road Tie Kawerau		291				
Manawahe-McIvor Rd tie line Stage 3				227		
Gateway-33kV development & integration to CHH Y2			1,302			
<i>*Include additional rows if needed</i>						
All other quality of supply projects or programmes	1,685	1,125	1,336	93	93	201
Quality of supply expenditure	1,685	2,261	2,638	1,842	300	201
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	1,685	2,261	2,638	1,842	300	201

Schedule I Ia Report on Forecast Capital Expenditure

142	11a(vii): Legislative and Regulatory						
143	<i>Project or programme*</i>						
144	[Description of material project or programme]						
145	[Description of material project or programme]						
146	[Description of material project or programme]						
147	[Description of material project or programme]						
148	[Description of material project or programme]						
149	<i>*Include additional rows if needed</i>						
150	All other legislative and regulatory projects or programmes	285	76	194			194
151	Legislative and regulatory expenditure	285	76	194	-	-	194
152	<i>less</i> Capital contributions funding legislative and regulatory						
153	Legislative and regulatory less capital contributions	285	76	194	-	-	194
161							
162		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
163	11a(viii): Other Reliability, Safety and Environment						
164	<i>Project or programme*</i>						
165	Te Rahu South /WBM South Structures reconfigure					227	
166	Galatea 33kV bus upgrade plus line CB's		259				
167	1000 KVA Generator #2			687			
168	[Description of material project or programme]						
169	[Description of material project or programme]						
170	<i>*Include additional rows if needed</i>						
171	All other reliability, safety and environment projects or programmes	13	441	13			
172	Other reliability, safety and environment expenditure	13	700	699	-	227	-
173	<i>less</i> Capital contributions funding other reliability, safety and environment						
174	Other reliability, safety and environment less capital contributions	13	700	699	-	227	-
175							
176							
177							
178	11a(ix): Non-Network Assets						
179	Routine expenditure						
180	<i>Project or programme*</i>						
181	Information and technology systems	487	661	306	501	672	506
182	Asset management systems	17	3				
183	Office buildings, depots, and workshops	31	42	5	25	5	25
184	Office furniture and equipment	166	8	3	3	3	3
185	Motor vehicles	54		35		35	
186	<i>*Include additional rows if needed</i>						
187	All other routine expenditure projects or programmes						
188	Routine expenditure	755	714	349	529	715	534
189	Atypical expenditure						
190	<i>Project or programme*</i>						
191	Information and technology systems			300	100		
192	Asset management systems	195	932	500			
193	[Description of material project or programme]						
194	[Description of material project or programme]						
195	[Description of material project or programme]						
196	<i>*Include additional rows if needed</i>						
197	All other atypical projects or programmes						
198	Atypical expenditure	195	932	800	100	-	-
199							
200	Non-network assets expenditure	950	1,646	1,149	629	715	534

Schedule IIb Report on Forecast Operational Expenditure

										Company Name
										Horizon Energy Distribution Limited
										AMP Planning Period
										1 April 2014 – 31 March 2024
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										
7	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9
8										CY+10
9	Operational Expenditure Forecast									
10	\$000 (in nominal dollars)									
11	Service interruptions and emergencies	701	564	579	596	622	645	663	682	701
12	Vegetation management	364	482	495	509	674	693	713	733	753
13	Routine and corrective maintenance and inspection	548	723	807	952	1,149	1,374	1,076	1,164	1,113
14	Asset replacement and renewal	1,088	1,001	974	803	960	1,091	1,107	1,330	1,140
15	Network Opex	2,701	2,769	2,855	2,860	3,405	3,803	3,557	3,908	3,707
16	System operations and network support	2,187	2,517	2,587	2,660	2,734	2,811	2,890	2,970	3,054
17	Business support	2,710	2,741	2,818	2,897	2,978	3,061	3,147	3,235	3,326
18	Non-network opex	4,897	5,258	5,405	5,557	5,712	5,872	6,037	6,206	6,379
19	Operational expenditure	7,598	8,027	8,260	8,416	9,117	9,676	9,593	10,114	10,086
20										
21										
22	\$000 (in constant prices)									
23	Service interruptions and emergencies	701	556	556	556	565	570	570	570	570
24	Vegetation management	364	475	475	475	612	612	612	612	612
25	Routine and corrective maintenance and inspection	548	714	774	889	1,043	1,213	923	972	905
26	Asset replacement and renewal	1,088	987	934	749	871	964	951	1,112	926
27	Network Opex	2,701	2,731	2,739	2,669	3,091	3,359	3,056	3,266	3,013
28	System operations and network support	2,187	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482
29	Business support	2,710	2,704	2,704	2,704	2,704	2,704	2,704	2,704	2,704
30	Non-network opex	4,897	5,186	5,186	5,186	5,186	5,186	5,186	5,186	5,186
31	Operational expenditure	7,598	7,917	7,925	7,855	8,277	8,545	8,241	8,452	8,199
32										
33										
34	Subcomponents of operational expenditure (where known)									
35	Energy efficiency and demand side management, reduction of energy losses									
36	Direct billing*									
37	Research and Development									
38	Insurance									
39	* Direct billing expenditure by suppliers that direct bill the majority of their consumers									
40										
41										
42	Difference between nominal and real forecasts									
43	\$000									
44	Service interruptions and emergencies	-	8	24	40	57	75	93	112	131
45	Vegetation management	-	7	20	34	62	81	100	120	141
46	Routine and corrective maintenance and inspection	-	10	33	64	106	161	151	191	208
47	Asset replacement and renewal	-	14	40	54	88	128	156	219	213
48	Network Opex	-	38	116	191	314	444	501	642	693
49	System operations and network support	-	35	105	177	252	328	407	488	571
50	Business support	-	38	114	193	274	358	443	532	622
51	Non-network opex	-	72	219	371	526	686	851	1,020	1,193
52	Operational expenditure	-	110	335	561	840	1,131	1,352	1,662	1,887

Appendix B – Glossary of Terms

ABS	Air Break Switch
AC	Alternating Current
ACC	Accident Compensation Corporation
ACSR	Aluminium Conductor Steel Reinforced Cable
AL	Aluminium Conductor
AMP	Asset Management Plan
BCP	Business Continuity Planning
BOPLAG	Bay of Plenty Lifelines Advisory Group
CAIDI	Customer Average Interruption Duration Index - SAIDI/SAIFI
CAPEX	Capital Expenditure
CB	Circuit Breaker
CDEM	Civil Defence Emergency Management
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CT	Current Transformer
CU	Copper conductor
DC	Direct Current
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DRC	Depreciated Replacement Cost
EEA	Electricity Engineers Association
EDB	Electricity Distribution Business
ELB	Electricity Lines Business
EO	Engineering Officer
GIS	Geographic Information System
GPS	Global Positioning System
GWh	Giga Watts per hour (10^6 Watts)
GXP	Transpower Grid Exit Point
H&S	Health and Safety
HEIL	Horizon Energy Investments Limited
Horizon	Horizon Investments Contracting
Horizon Energy	Horizon Energy Distribution Limited
HV	High Voltage
Hz	Hertz
ICP	Installation Control Point
ICCP	Inter-Control Centre Protocol, a Transpower communications system
IFRS	International Financial Reporting Standards
kV	Kilo Volts (10^3 Volts)
kW	Kilo Watt
kWh	Kilo Watt per hour
LCP	Legislative Compliance Programme
LV	Low Voltage
MEN	Multiple Earthed Neutral system

MD	Maximum Demand
MIND	Mineral Insulated Non Draining insulated cable
MV	Medium Voltage, 11kV and 33kV
MVA	Mega Volt-Amps
MVAR	Mega Volt-Amps reactive
MW	Megawatt
MWh	Megawatt per hour
N security	Peak load may only be supplied without curtailment or interruption if all zone substation transformers are operating
N-1 security	Peak load may be supplied without curtailment or interruption including if the largest zone substation transformer is not operating
N-2	Peak load may be supplied without curtailment or interruption including if the largest 2 zone substation transformers are not operating
N-1 switched	Peak load may be supplied following a brief interruption during which switching is carried out to re-establish supply following an unexpected outage of the largest zone substation transformer
NPV	Net Present Value
ODRC	Optimised Deprival Replacement Cost
ODV	Optimised Deprival Value
OH or O/H	Overhead
ONAN	Natural oil flow and natural air flow cooling for transformers
ONAF	Natural oil flow and forced air flow cooling for transformers
OFAF	Pumped oil flow and forced air flow cooling for transformers
OPEX	Operational Expenditure
PILC	Paper Insulated, Lead Covered cable
PAS55	British Standard specification for the optimized management of physical assets
PLC	Programmable Logic Controller
POS	Point of Supply
PVC	Polyvinyl Chloride
RMS	11kV Ring Main Switch
rms	Root Mean Square
RMU	Ring Main Unit
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index (minutes) Sum of customer interruption duration / total number of customers
SAIFI	System Average Interruption Frequency Index Number of customer interruptions / total number of customers
SCADA	Supervisory Control and Data Acquisition
SCS	SCADA Controlled Switch
SF6	Sulphur Hexafluoride gas
SLT	Service Level Target
SWER	Single Wire Earth Return
UG or U/G	Underground
UHF	Ultra High Frequency
VA	Volt-Amps

VAR	Volt-Amps Reactive
VHF	Very High Frequency
VLf	Very Low Frequency
VT	Voltage Transformer
XPLE	Cross Linked Polyethylene insulation
ZS	Zone Substation

Appendix C– Major Projects List

The following sections summarise the significant projects planned and includes discussion on the main driver for the projects, options considered, and the preferred outcome.

All projects in the AMP are subject to continual review, managerial and Board approval on an individual basis, and the final outcome of any particular project is dependent on meeting the needs analysis and priority assessment for that project against the requirements of all projects and the needs of the organisation.

Ref Numbers/ Name:	
785 - Te Rahu South 33kV Sub-transmission Capacity Upgrade	
75 - WBM South 33kV Sub-transmission Capacity Upgrade	
Description:	
Increase the capacity of Te Rahu South and WBM South 33kV feeders	
Constraint:	
<p>33kV feeders Te Rahu South and WBM South are a smaller conductor size than the parallel conductors Te Rahu North, Te Rahu Central, and WBM North feeders which supply Te Rahu and the future Gateway substations. This conductor limits the load carrying capacity of the conductors to 17MVA compared to the parallel feeders rating of 24MVA.</p> <p>When required to operate in reinforcement role, in case of the loss of one of the parallel circuits, the overall circuit capacity is limited to that of the small conductor. Under existing load conditions this is not a problem, and will not become a problem until the network load increases beyond 40MVA.</p> <p>In normal operation there is uneven load distribution across the parallel feeders. This is not an issue at present but will become more of an issue as total load increases.</p>	
Network Options:	
Increase the conductor size to match the size of the other parallel feeders	Balances all loads to provide full redundancy. Pole spacing and physical line layout is adequate for this.
Increase the conductor size to be greater than the parallel feeders	Requires a new line design. Moves the constraint onto the opposite parallel circuit. Provides for future capacity. Uses non-standard network conductor. Reduces line losses.
Non-Network Options:	
Thermally re-rate the lines from the designed rating of 55 deg. C to 75 deg. C	Does nothing to correct line resistance, line losses, or volt drop. Existing loss when loaded to 19MVA is 2MVA which provides a delivery capacity of only 17MVA. Losses increase at re-rated full capacity and volt drop becomes the limiting factor. Lines require re-sagging and tensioning. Low cost option.
Implement summer/winter protection settings	Does not address the full load line losses. Low cost option.
Do nothing	With the Te Rahu and proposed Gateway substations operating properly in a parallel configuration the existing full load utilisation factors for the five lines in parallel is around 47%. Loss of one circuit, leaving four circuits, has about 60% utilisation. This will provide adequate system resilience until beyond 2040 unless there is a step change in loads.
Preferred Option:	
<p>Detailed feasibility study yet to be completed.</p> <p>Completion of Gateway 33kV substation will provide good resilience to the network and these projects may be deferred indefinitely.</p>	
Estimated Cost/Accuracy:	
785; \$500k, +- 30% 75; \$500k, +- 30%	
Projected Implementation Year: Deferred pending Gateway substation development	

Ref Numbers/ Name:	
I4 - Gateway 33kV Switching Station	
Description:	
Install a 33kV substation at Mill Road Whakatane and supply from feeders WBM North, WBM South, and Poroporo feeders.	
Constraint:	
Gateway 33kV sub station was always planned to support the Te Rahu 33kV substation. The existing system supplying Whakatane Mill Limited is load restricted when on a single feeder, and Te Rahu substation is restricted when on a single feeder. Gateway operating in a live bus arrangement with Te Rahu provides the required any time n-1 level of support between both substations. This substation will supply 33kV for the proposed CBD substation.	
Network Options:	
Develop an indoor 33kV substation at Mill Road for integrating three 33kV feeders and provide a tie link to Te Rahu Road	More costly option but provides a robust industry standard solution.
Install a series of poletop circuit breakers to perform the same function	Shorter lifecycle than indoor switchgear Lower cost. More exposure to weather or wildlife impact. No benefit to WML. Visual impact.
Site location under review. Cost of getting circuits into and out of proposed Mill Road site is high. Possible integration with Whakatane Mill Ltd	WML site option is closer to the load sources and allows full underground integration with WML transformers and retirement of aged WML equipment.
Install new feeders to remove constraints	Existing assets have sufficient capacity if used as planned. Only one spare bay at Edgecumbe GXP. Cost of new feeders out of Edgecumbe more costly and visually less appealing. Resource consenting issues for new feeders.
Non-Network Options:	
Do nothing	Te Rahu and WML 33kV overload risks are not reduced.
Encourage load saving initiatives	Benefits of these options are discussed in section 5.3.5.
Preferred Option:	
Develop 33kV substation on WML site and integrate to WML and Te Rahu substations.	
Estimated Cost/Accuracy: \$2.1M +/-10%	
Projected Implementation Year: Start 2014, complete 2015	

Ref Numbers/ Name:	
I5 - Gateway 11kV Development	
Description:	
Build a new zone substation located adjacent to the Gateway industrial zone. The scope of this project is for the 11kV infrastructure only.	
Constraint:	
A substation is required to take load off Kope and Station Road substations, to provide 11kV support between the two substations, and support load in the Piripai-Coastlands area. Estimate initial load is up to 6MVA.	
Network Options:	
Build a new zone substation to support load in the Gateway/ Piripai area adjacent to Coastlands	Estimated growth in the Piripai-Coastlands area 500 dwellings by 2050 (WDC, 2011) is an additional demand of 1.5MVA. No land identified. Allows support to CBD by cable under river.
Build a substation at Gateway 33kV substation	Close to existing loads and infrastructure. Allows integration with WML for support. 33kV infrastructure from Gateway 33kV bus.
Build a substation in the Whakatane CBD load area to support Kope and the CBD loads	Provides better overall support to CBD than a substation located at Gateway or Coastlands. Can distribute more load into three existing 11kV feeders
Non-Network Options:	
Utilise spare 11kV capacity from Whakatane Mill Ltd	While being a viable option for support, both parties are uncomfortable with this as a permanent solution due to security of supply concerns.
Do nothing	The long term concept plan to off load Kope substation is to share load between Gateway, Station Road, and a future CBD substation. This substation is a crucial part of this plan. Do nothing is not considered a viable alternative.
Preferred Option:	
Deferred beyond 2023 or until area load growth drives development	
Estimated Cost/Accuracy: \$1.2M, +/-30%	
Projected Implementation Year: 2024	

Ref Numbers/ Name:	
45 - Express 33kV Cable Gateway to CBD-4.25km	
Description:	
Install a 33kV insulated cable from Gateway substation to a central location in the Whakatane CBD. Cable will use an existing duct along the river stop bank.	
Constraint:	
As the CBD grows there is limited capacity available from the Kope substation to support this growth, both from capacity and available cable routes and sizes out of Kope. Gateway substation is required completed to support this project as defined	
Network Options:	
Install cable as described	Duct already installed along a large portion of the length.
Run cable /overhead along Keepa Road and thrust under river	Thrusting risk with rocks embedded in river. No comparative costs obtained so no cost benefit yet established.
Install larger feeder cables and transformers at Kope	Kope substation needs upgraded 33kV supplies, transformers, and 11kV distribution. Currently there is limited means of supporting Kope for a full outage in other than low load periods. Kope 11kV incomer circuit breakers rated at 15.2MVA
Non-Network Options:	
Do nothing	Load growth in the Whakatane CBD will force a load demand strategy to support this load. Other options have been considered including a substation at Mokorua and larger capacity at Kope.
Local generation	This is not regarded as an economic long term solution due to the flat load profile of commercial loads.
Preferred Option:	
A new CBD zone substation is the preferred long term solution. Support at 11kV from a remote substation is an interim measure. Whether this is Gateway substation, a CBD substation, or a substation at Piripai or Mokorua will be determined once final site location decisions are made. There is a valid argument to progress this substation as a single transformer 12/16MVA site ahead of Gateway 11kV. Any development will be driven by a load needs basis.	
Estimated Cost/Accuracy: \$1.2M, -+30%	
Projected Implementation Year: Earliest 2018	

Ref Numbers/ Name:	
59 - Ohope-33kV Transformer T1 replacement	
Description:	
Install new transformer at Ohope zone substation.	
Constraint:	
<p>Ohope Zone substation peak load is approaching the available transformer capacity and was previously predicted to overload by 2014 during peak periods. The existing bank is a bank of three single phase transformers.</p> <p>The implementation of enhanced load control and limited peak load growth has reduced the constraint previously identified. The replacement has been deferred until 2023 pending continual review of the asset condition and loading.</p>	
Network Options:	
Replace transformer with larger transformer 7.5/15 MVA	Same size as East Bank. A larger size may be considered to maintain a standard transformer across the network. Galatea transformers would also be a good fit at Ohope.
Install a dual transformer bank at Ohope	More costly but provides a higher level of security albeit with only a single 33kV feeder line.
Non-Network Options:	
Allow the transformer bank run in overload condition through peaks	Ohope peaks are very short duration so allowing the transformer to overload (130%) for up to two hours is technically acceptable – this could be used to defer the replacement by up to 10 years.
Manage peak loads	Peaks are primarily caused by load control restoration spikes. Load management to correct this will reduce the peaks allowing for a delay in the scheduled transformer replacement.
Load displacement	Dynamically displace peak loads to an adjacent substation. Feasible if automated switching is installed between Pohutukawa feeder and Mokorua feeder. This could provide a solution for up to 10-15 years.
Peak load cropping generation	Good option to manage peak loads as well as providing some back up security of supply. Could be used to defer transformer replacement.
Preferred Option:	
<p>Yet to be determined. The transformer bank was manufactured in 1966 so age based assessment for replacement is due for consideration in 2021. The optimal solution is to implement the non-network load management options above and defer the transformer replacement until condition and age force replacement. The lack of redundancy issue is a separate consideration that is discussed next.</p>	
Estimated Cost/Accuracy: \$1.1M, +-20%	
Projected Implementation Year: 2023	

Ref Numbers/ Name:	
741, 781 – Ohope T2, Ohope 2nd 33kV line	
Description:	
Ohope Reinforcement	
Constraint:	
Ohope Zone substation lack of 33kV reinforcement. Ohope is a single bank transformer supplied from a single 33kV line. Reinforcement is via 11kV from Station Road. As Ohope load increases the ability to provide reinforcement at 11kV becomes more constrained.	
Network Options:	
Continue to supply reinforcement at 11kV from Station Road Mokorua feeder	This feeder was upgraded to provide more capacity in 2009. It can physically supply Ohope but there are voltage quality issues at the end of Harbour feeder with this reinforcement route.
Install a substation at Mokorua to support Ohope from Pohutukawa feeder	Would not be considered viable unless load demand in the Mokorua region warrants additional capacity.
Insert a second transformer at Ohope	Provides a high level of 11kV security. Does nothing to remedy the single 33kV feeder line issue.
Convert the existing 33kV circuit to dual circuit	This does not provide the level of security a separate circuit would provide. Should be easier to consent than a new line. Less cost than a separate line. Issues maintaining supply during construction.
Install 2 nd 33kV circuit	Very costly option. Resource consenting difficult. Line route difficult.
Install 110kV line off the Waiotahi 110kV supply	This option has not been investigated in detail but is feasible in the longer term. Phase shift would need to be considered. Load at Ohope is insufficient at this stage to make this option a realistic alternative.
Connect supply from Waiotahi by thrusting a cable under the harbour	Phase shift between Waiotahi and Ohope. Expensive. May not be compatible with Opotiki development plans.
Non-Network Options:	
Install voltage support regulator/s	A voltage regulator at the tie point to Pohutukawa feeder would regulate the voltage into the Ohope region under reinforcement. This would be unused except during load reinforcement. Any regulator would need to be >5MVA to supply the full load of Ohope.
Install capacitor bank	Initial modelling results indicate that capacitive support would be beneficial for voltage support during reinforcement. This would need to be centralised to enable automated switching to remove the capacitors when on normal supply from Ohope. Assets would be stranded under normal configuration.
Demand load management	Options discussed in section 5.3.5 could be applied as interim measures to manage peak demand load.
Support from Waiotahi at 11kV	There is a phase shift between Waiotahi and Ohope that

	requires break before make switching. Also the distribution feeders from Waiotahi are generally smaller conductors so voltage support becomes an issue. Capacitor banks and /or regulators would assist this.
Embedded generation	Peak load >4MVA would require 6MVA generation. 1MVA in conjunction with 11kV support from Station Road substation would be a short term viable option during peak load periods.
Preferred Option:	
The preferred option at this stage is to not install a second feeder and to continue to support Ohope at 11kV until the load at this voltage becomes unsustainable, then support with generation during peak periods.	
Estimated Cost/Accuracy:	
There are a number of projects that apply to this constraint. Detailed engineering is yet to be complete to determine the best solution in the long term.	
Projected Implementation Year:	
>2026	

Ref Numbers/ Name:	
379 - 33kV-2nd 33kV line into Aniwhenua	
Description:	
Install a second 33kV circuit into Aniwhenua power station and connect to Kopuriki feeder.	
Constraint:	
Galatea and Kaingaroa combined loads are approaching the limits of the capacity of the Snake Hill 33kV feeder from Edgecumbe due to line voltage drop causing the transformer regulators at Galatea and Kaingaroa to saturate.	
Network Options:	
Upgrade the Snake Hill conductor size	Snake Hill feeder is connected to CB52 at Edgecumbe. This feeder is 37km long and runs through rugged terrain. Estimated cost to re conductor this feeder exceeds the cost of installing a new line into Aniwhenua and does nothing to enhance the reliability for Galatea.
Install a new line into Aniwhenua	This would provide full redundancy for Galatea, and additional security is provided by the Aniwhenua connection to the 110kV. Two potential line routes are available.
Install new transformers with larger tap ranges	The existing transformers have extended range tap changers. All four transformers are not yet due for replacement and there is no load constraint to force replacement.
Voltage regulator and/or capacitive support for the Snake Hill feeder	These devices will correct for the line losses to enable the Galatea and Kaingaroa transformer voltage regulators to work within their ranges. Estimated costs are similar to a new line build without the benefits of reduced line losses and reliability.
Non-Network Options:	
Demand Management	This is a short term alternative. Peak load is in summer due to irrigation, which is run at night so load demand management will have minimal effectiveness.
Generation support	Good alternative. Capital and running costs are high. Portable generation could be located in Galatea for the four months of the peak load period. There would be a high annual cost for standby generation.
Preferred Option:	
A full study is yet to be completed but at present the new 33kV line option is preferred.	
Estimated Cost/Accuracy: \$720,000 +/-30%	
Projected Implementation Year: 2016 unless step load change forces acceleration	

Ref Numbers/ Name:	
384,385 - Kopeopeo 33kV Feeder Cables thermal upgrade	
Description:	
Upgrade thermal rating for Kope 33kV cables.	
Constraint:	
33kV cables are de-rated to below transformer full load capacity due to high soil thermal resistivity.	
Network Options:	
Replace cables	Expensive. Cables currently at ½ nominal life. Project to coincide with Kope 33kV indoor conversion
Non-Network Options:	
Do nothing	Conductor thermal loading can be managed with load management. Not a problem as long as cables are run in parallel
Develop support substation 33kV ring feeders	Completion of planned satellite substations Gateway and/or CBD along with ring feed 33kV sub-transmission would provide alternative 33kV parallel supplies that would reduce the load on the Kope feeders. Would require sophisticated protection systems to prevent undesirable fault response trips
Improve thermal conductivity of ducting by installing thermal mix into ducts	Viable option that would extend thermal rating of cables Low cost May not work Will make future cable replacements within the existing ducts difficult
Install thermal fill around cable ducts	Very costly option Easy to do now due to good access to route. Potential future area development is likely to restrict access.
Install thermal sensors onto cables	Use to manage heat loading.
Preferred Option:	
Not yet defined.	
Estimated Cost/Accuracy: \$400K +- 30%	
Projected Implementation Year: 2015-2017	

Ref Numbers/ Name:	
380 - Whakatane CBD zone substation	
Description:	
Build a 33/11kV zone substation to support the Whakatane CBD loads.	
Constraint:	
<p>Supplies into the Whakatane CBD from Kope zone substation are restricted by the 33kV supply into Kope, the Kope transformer size, and the 11kV distribution out of Kope. Kope is 1.8km away from the CBD load centre and is located in the middle of a commercial and residential area.</p> <p>A CBD located single transformer zone substation will support Kope as well as supplying the CBD loads, and will be supported by Kope using the existing feeders.</p>	
Network Options:	
Build a 33/11kV substation adjacent to the CBD	Substation is close to load. Losses reduce and distribution into loads is easier from a more centralised substation.
Upgrade Kope substation and distribution cables	<p>This option is more costly and provides fewer benefits when compared to a separate substation.</p> <p>Would require extensive feeder 11kV cable overlays.</p>
Non-Network Options:	
Demand load management	Options discussed in section 5.3.5 could be applied as interim measures to manage peak demand load but not regarded as a permanent solution.
Alter the mix of domestic to commercial loads on the Kope substation	Limited opportunities to achieve this. As the domestic/commercial dual zoned areas close to the CBD are gradually converted to commercial use the load is taking on a more commercial profile, with a daytime peak.
Preferred Option:	
<p>33/11kV substation; Initial studies show that a 16MVA transformer would support Kope during a full outage if used in conjunction with Station Road and Gateway for the next 30 years.</p> <p>A full CDR study is yet to be completed to verify this preference.</p> <p>Any substation constructed in the CBD area would need to be constructed as a fully indoor solution to reduce visual impact. Indoor solutions are commonly used in other network companies in urban environments.</p>	
Estimated Cost/Accuracy: \$3.2M, +-20%	
Projected Implementation Year: 2019	

Ref Numbers/ Name:	
Various - Kope Zone Substation off-loading projects	
Description:	
Install high capacity distribution feeders between Kope, Station Road, Gateway, and the CBD zone substations.	
Constraint:	
The load management plan for the heavily loaded Kope substation is to re-distribute the loads between the adjacent substations, by providing high capacity tie feeders between the substations to provide inter-substation support. This allows single transformer substations to be constructed that are supported by adjoining substations at 11kV.	
Network Options:	
Upgrade various 11kV feeders	Feeders are existing. Certain sections require upgrading to enable additional load to be carried for cross supporting substations.
Construct all new substations as dual transformer substations	This creates a number of physically large substation sites, with redundant assets solely for back up purposes.
Install express feeders between substations	This is an ideal solution to maximise load transfer between substations and will be used when new feeders are able to be run. For existing feeders it is more economical to use the existing cables and accept the distribution of load along the feeder.
Non-Network Options:	
Install feeder automaton to enable dynamic load switching	A good option that allows loads to be dynamically switched as required balancing substation peak loads, especially providing an ability to mix commercial and domestic loads. This is described in more detail in section 5.12.7.
Share loading between adjacent substations	This is the preferred option and is actively being implemented.
Preferred Option:	
Continue the option of installing high capacity feeders between substations to dynamically share loads with adjacent substations.	
Estimated Cost/Accuracy:	
Various	
Projected Implementation Year:	
On-going	

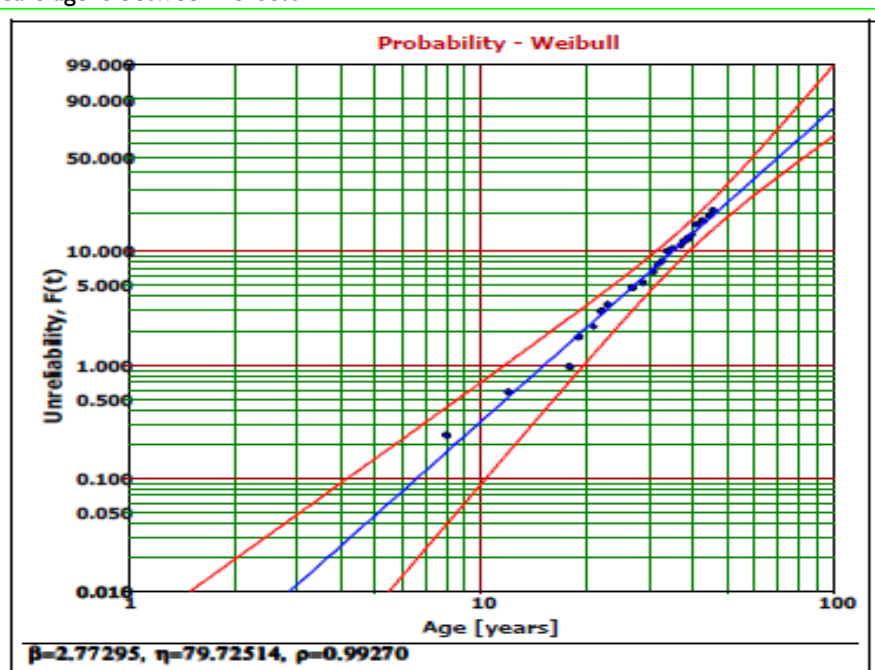
Ref Numbers/ Name:	
928 - Kope 33kV indoor conversion	
Description:	
Extend the existing 11kV switchroom and install indoor 33kV switchboard	
Constraint:	
<ul style="list-style-type: none"> - Replacement of aged outdoor 33kV gear in an urban environment. - Includes additional circuit breakers for a 33kV ring system to supply future CBD and/or Gateway substations, - Converts Kope to an total indoor substation except for the transformers - Eliminates existing minimum approach distance safety hazard with the overhead 33kV bus 	
Network Options:	
Do nothing or delay	CB's are 46 years old minimum oil devices. Scheduled time based replacement needed within 5 years. Safety issues have been identified with the existing overhead bus
Rebuild outdoor system	Although a cheaper option, this is not a preferred option in an urban environment for both visual and safety reasons
Install indoor option	Extend existing 11kV building. Re-route 33kV cables to new location. Allows the substation site to be reduced and allows room for a green belt to help disguise the substation
Non-Network Options:	
None	
Preferred Option:	
Indoor installation	
Estimated Cost/Accuracy:	
\$1.2M +/-20%	
Projected Implementation Year:	
2019-2021	

Ref Numbers/ Name:**768 - Plains TI Replacement****Description:**

Replace Plains TI three single phase transformers

Constraint:

- Proximity of transformers to each other and control building creates an un-manageable fire risk
- There is no bund for oil spill containment
- Transformers are 47 years old as at 2013. Tap changer oil tests indicating some deterioration is occurring within the transformer.
- Existing transformer bank is marginally sized to support both Fonterra and East Bank under certain load conditions
- A Transformer probability of failure chart is below which shows the probability of failure of this bank at 50 years age is between 15-35%

**Network Options:**

Do nothing or delay	Increased risk of failure with time
Relocate existing TI transformers to reduce fire risk	Only addresses one issue of many
Install new three phase TI on site to north of control room with provision in future for a second bank	Preferred option allows for parallel installation with the existing bank

Non-Network Options:

None

Preferred Option:

New transformer in yard to the north of the switchroom.

Estimated Cost/Accuracy:

\$1.1M +/-20%

Projected Implementation Year:

2015-2016

Ref Numbers/ Name:	
63 - Ohope 11kV indoor conversion	
Description:	
Install indoor 11kV circuit breakers for Ohope. Increase substation to four feeders	
Constraint:	
<p>Ohope currently has two feeders. Both feeders have a significant number of ICP's and consequently accrue a significant level of SAIDI impact during faults. Some work is being completed to add more backup reinforcement to Harbour feeder. Once the Harbour loop cabling is complete this will be split into a third feeder, with a fourth feeder being the Cheddar Valley rural feeder.</p> <p>Due to reliability issues with the existing circuit breakers these are being replaced in 2013 with Nova pole top circuit breakers. Whilst a good solution for the existing system configuration, replacing the transformer will introduce a requirement for more sophisticated transformer differential protection and reverse flow protection schemes, and the additional benefits of more feeders justifies an 11kV expansion. The preferred option for this is the prefabricated solution installed as installed in Galatea</p>	
Network Options:	
Install an indoor 11kV switchroom using the Galatea pattern	Repeat design.
Install outdoor CB's	Area is coastal and equipment suffers corrosion issues. Outdoor CB's require an extensive bus structure system
Non-Network Options:	
Do nothing	Doesn't address the large number of customers per feeder.
Preferred Option:	
Prefabricated indoor substation solution to coincide with T1 replacement	
Estimated Cost/Accuracy:	
\$1.1M +/-20%	
Projected Implementation Year:	
2022	

Ref Numbers/ Name:	
768 – Plains T2, Kope T1 replacement	
Description:	
Install new transformer at Kope, relocate Kope T1 to Plains	
Constraint:	
Kope T1 and Kope T2 have dis-similar transformer impedances and full load power, meaning that the transformers are not load balanced. 10/13MVA T1 was manufactured in 1986 so is suitable for re-deployment at another substation site.	
Network Options:	
Replace T1 with transformer identical to T2	Allows balanced load sharing. T1 available for re-location to alternative service and would be considered for Ohope, Plains, or CBD substations development
Non-Network Options:	
Do Nothing	Mismatched transformers create high internal circulating currents that reduce the overall capacity of the transformer pair, as well as causing un-necessary heating of the transformers. This can be managed to some degree by the tap change controllers. Total substation output is determined by the rating of the lowest rated transformer.
Other Considerations	
Kope T1 has no oil containment system. Also the transformer is within 10 meters of the control room and fails to comply with the fire risk provisions of AS2067, Substations and High Voltage Installations Exceeding 1kV AC	
Preferred Option:	
Replace with a transformer matched to T2. Relocate Kopeoepo T1 to Plains substation	
Estimated Cost/Accuracy:	
\$1.1M +/-20%	
Projected Implementation Year:	
2015	

Ref Numbers/ Name:	
766 - Galatea Load Control Plant replacement	
Description:	
Retire obsolete load control plant and implement non-ripple control methods to control street lighting	
Constraint:	
Ripple plant is rotating plant 750hz 40 years old. There is no economic justification for replacing the plant to control the small number of consumers in the Galatea region.	
Network Options:	
Replace load control plant with 317 Hz plant	Requires replacement of all control relays.
Load control spill from Edgecumbe at 33kV	Load is not always connected to Edgecumbe CB52
Non-Network Options:	
Install smart meters	Requires replacement of all relays. Technically complex. Requires extensive communications infrastructure. Additional benefits include point of use metering and remote disconnect-reconnect
Do Nothing	Allow the plant to run to failure and not replace. Requires a method of controlling street lighting to be implemented.
Preferred Option:	
Feasibility study 2013 considers the amount of switchable load does not justify the capital required to replace the ripple plant and load control relays, so the preferred option is to run the ripple plant to failure. A consequential project is to install local daylight sensors on the street lighting to remove the streetlight control from the ripple control plant then allow the ripple plant to run to failure.	
Estimated Cost/Accuracy: \$100,000 +/-20%	
Projected Implementation Year: 2014-2015	

Ref Numbers/ Name:	
921,924 - Galatea – 11kV Capacitor banks	
Description:	
Install local, non-switched, capacitor banks on each of the four feeders	
Constraint:	
High level of losses in the Galatea region	
Network Options:	
Install 300kVA capacitor banks towards the end of each feeder	Provides localised compensation for inductive line losses and local inductive loads.
Non-Network Options:	
Compel local users to install power factor correction at 400V	This is currently a requirement for larger motor installations
Preferred Option:	
Feasibility study options underway 2014. Scope reduced to two feeders, Galatea and Jolly Road	
Estimated Cost/Accuracy: \$47,000 +/-30% per project	
Projected Implementation Year: 2014, 2015	

Ref Numbers/ Name:	
8 – Galatea 33kV bus upgrade	
Description:	
Upgrade 33kV CB's and install a bus section. Provide n-1 capability from Snake Hill and improved reliability to Kaingaroa. Install line circuit breakers	
Constraint:	
Aged oil circuit breakers (1972) Kaingaroa is supplied off only one 33kV incoming providing a break before make supply arrangement	
Network Options:	
Replace existing CB's with new substation mounted pole top circuit breakers or outdoor ground CB	Most economical solution compared to 33kV indoor
Install indoor 33kV bus arrangement	Has longer life cycle but considerably more expensive than a poletop installation. Existing control building could be re-modelled and used but only marginally more cost effective than a new purpose build building
Retain existing CB's and upgrade bus using redundant transformer circuit breakers	Requires re-using 11kV bus incomer CB's and reconfiguring into the 33kV bus. Cost not much lower than new poletop CB solution
Retain existing transformer incomer 33kV CB's, reconfigure Kaingaroa take-off as a bus section, and install new line CB's	Existing CB's are aged but have done very little work. Being oil filled they are subject to a higher level of maintenance than vacuum CB's Improves reliability of supply to Kaingaroa, allows parallel operation of the two 33kV feeders into Galatea from Snake Hill
Non-Network Options:	
Do Nothing	Existing CB's are likely to exceed design life due to low utilisation factors and low fault levels. Does nothing to remedy the Kaingaroa security of supply issue
Preferred Option:	
Feasibility study options underway 2014	
Estimated Cost/Accuracy: \$260,000 +/-30%	
Projected Implementation Year: 2014, 2015	

Ref Numbers/ Name:	
466 - Waiotahi Substation Feeders	
Description:	
Replace aged feeder KFE circuit breakers	
Constraint:	
CB's are at end of life and are not rated to the full close in fault current	
Network Options:	
Replace with new pole top circuit breakers	Difficult to do and maintain supplies. Requires larger footprint. Lower cost than preferred option. Shorter life than indoor switchgear.
Install pole-top CB's outside the substation and bypass the CB's inside the substation yard	Allows staged installation. Low cost alternative and easy implementation Communications via pole-top VHF radio is simple and proven. Low cost option that reduces the investment loss if Waiotahi substation is eventually stranded by the development of a substation at Opotiki CB's can be re-deployed if made redundant
Install ground mount switchgear in transportable building	Same design as Galatea. \$1.1M cost Allows assets to be re-deployed if made redundant
Non-Network Options:	
Extend Transpower Bus	Viable alternative. Costs passed on as interconnection charges, or charges may be reduced with capital contribution. More costly than network option but technically integrating into the existing bus and building is a technically more elegant solution with lower overall lifecycle costs. Would leave stranded assets if Waiotahi substation is made redundant by an Opotiki development
Do Nothing	Viable alternative only if Opotiki substation is built at 110kV at Opotiki, and Waiotahi substation abandoned or down scaled. Would still require a circuit breaker to supply Waimana feeder
Preferred Option:	
Still being assessed. Technical preference is to extend Transpower bus. Project to be considered along with Opotiki development plan and possible long term dis-establishment or down-scaling of Waiotahi substation.	
Estimated Cost/Accuracy:	
\$1.2M +/- 15%	
Projected Implementation Year:	
2014-16	

Ref Numbers/ Name:	
785 - Waiotahi and Opotiki Development	
Description:	
Build a new zone substation at Opotiki.	
Constraint:	
Opotiki area load growth is constrained by the capacity of the existing feeders supplying Opotiki from Waiotahi. Losses and volt drop are excessive and the three 11kV feeders exceed 50% capacity at peak loads, which reduces their ability to provide N-1 security during these times. Voltage support levels are out of tolerance under certain load conditions especially during reinforcement without interventions. There is limited ability to provide for step change load requests at Opotiki.	
Network Options:	
Increase the conductor size from Waiotahi to Opotiki	Costly option and would only provide a short term solution due to the transmission distance. Voltage regulators and reactive capacitors could compensate for some of the losses but this option has high losses, high capital cost, and a relatively short utilisation time.
Extend the Waiotahi 110kV line from Waiotahi to Opotiki and develop a 110/11kV substation at Opotiki	Upgrade the existing Transpower 50kV Te Kaha line route to 110kV and build a 110/11kV substation at Opotiki. This would leave Transpower with stranded assets at Waiotahi. Only one substation site would need to be developed, at Opotiki. Requires high capital investment to get the required level of security. Site could be developed by Transpower. Eliminates the 33kV to 11kV transformation step which saves on the cost of 33kV transformers and infrastructure. Would require step up transformers to supply Te Kaha out of Opotiki.
Convert 50kV line to 33kV, Convert Opotiki feeder to 33kV, Convert Waiotahi GXP to 110/33kV Build 33kV/11kV substation at Opotiki	Most costly option. Provides a fully redundant solution that can be developed in stages. Would require a third 33kV line within 15-30 years. Some duplication of assets between Waiotahi and Opotiki. Allows the possibility of a 33kV feed to support Ohope out of Waiotahi. Allows for future sub-transmission at 33kV around Opotiki and to supply Te Kaha. N security only from Edgecumbe to Opotiki.
Non-Network Options:	
Implement load management options	Short term solution only.
Supplement with generation	Not viable as a long term solution.
Implement summer/winter protection settings for the distribution feeders and thermally re-rate lines	Does not address the full load 11kV line I ² R losses and volt drop issues. Low cost option provides temporary relief. Would need voltage regulators to compensate for increased line losses.
Load balance 11kV feeders	Currently at peak loads the Waiotahi to Opotiki distribution system is approaching the ability of the system to provide N-1 security. This option is currently being done seasonally now. Very limited life cycle.

**Preferred Option:**

Several studies have been completed on this project. A firm decision on the 33kV option vs the 110kV option has not yet been made and is also dependant on negotiations with Transpower.

Estimated Cost/Accuracy:

\$9M +/- 30%

Projected Implementation Year:

2016 to 2019

Ref Numbers/ Name:	
933 - 4th Poletop repeater	
Description:	
Install 4 th pole top repeater to provide additional coverage in Plains area	
Constraint:	
The number of installed pole top devices is predicted to reach the bandwidth limits of the existing repeater covering the Plains region by 2016.	
Network Options:	
Install repeater at existing sites either Mt Putauaki or Plains substation	Economic to do as infrastructure exists for connection to existing IP network Part of an existing ring communications circuit.
Install repeater at Manawahe to provide improved coverage to the network beyond Manawahe ranges as well as plains area	Expensive as a two radio links are required- one to connect to the ring loop, another for the poletop repeater. Would need to lease a site at Manawahe. Not on ring loop unless three radio links are installed Limited number of devices in the Manawahe region.
Option of VHF vs high frequency VHF or UHF repeater	Changing the repeater frequency will require different radios then currently employed in Poletop applications Digital radios at higher frequencies provides capability of IP connectivity to poletop devices UHF requires line of sight to repeaters so will likely have more black areas.
Non-Network Options:	
Reduce the poletop devices data polling interval	Introduces more time lag delays into the information gathering required for smart network implementation
Preferred Option:	
Still being assessed but digital VHF preferred.	
Estimated Cost/Accuracy:	
\$90,000 -\$250,000	
Projected Implementation Year:	
2016-17	

Ref Numbers/ Name:	
740 - Manawahe-Mclvor Rd tie line	
Description:	
Construct a tie line to connect Manawahe Feeder to Te Teko Feeder. Project spread across three stages	
Constraint:	
The extreme ends of Manawahe and Te-Teko feeders are both spur feeders with no support. This project provides support to both line sections	
Network Options:	
Line build	Project also upgrades two areas of galvanised conductor and two wire circuit. 200 customers on Manawahe, 30 customers Te Teko
Non-Network Options:	
Generation	Generation would provide adequate support for the loads on each feeder but due to the travel distance establishment time is minimum two hours
Preferred Option:	
Line build	
Estimated Cost/Accuracy:	
\$597k across 3 projects	
Projected Implementation Year:	
2014, 2015, 2016	

Ref Numbers/ Name:	
485 - Ground fault Neutraliser Galatea	
Description:	
Install ground fault neutraliser at Galatea Substation	
Constraint:	
GFN eliminates a single earth fault by applying a neutral displacement to the transformer neutral point, effectively removing the effect of the fault while leaving the network live	
Network Options:	
	GFN have been considered for several substations. Galatea is regarded as a suitable substation as it is mostly rural, has long feeders, remote from support, and Horizon owns the transformers. The switchgear installed 2013 has been specified to suit the GFN metering requirements
Non-Network Options:	
	None considered
Preferred Option:	
Full assessment of project benefits and risks yet to be completed	
Estimated Cost/Accuracy:	
\$350k +/-30%	
Projected Implementation Year:	
2019	

Ref Numbers/ Name:	
920 - Valley Road Tie Kawerau	
Description:	
Underground cable to connect to tail end of Valley road Kawerau spur line	
Constraint:	
Valley road contains 438 customers with no back feed capability.	
Network Options:	
Cable from 22S066 to 22S075	More costly cable option. Provides secure supply to all but 48 ICP
Line from Hardy Ave to 22S075	Unable to secure line access from land owner
Non-Network Options:	
Generation	Number of connections would require a IMVA generator with an establishment time of 4 hour.
Preferred Option:	
Install cable from 22S066	
Estimated Cost/Accuracy:	
\$300k +/-15%	
Projected Implementation Year:	
2014	

Ref Numbers/ Name:	
904 - Transpower Inter-Control Centre Protocol (ICCP) connection project	
Description:	
Connect to Transpower Control Centre to provide dynamic data transfer between Transpower and HEDL control rooms.	
Constraint:	
This is a new initiative developed by Transpower during 2012 to eliminate interconnections between substation RTU's at substation level and to facilitate connections at control room level with direct SCADA to SCADA connections over internet connections. Transpower are committed to removing all direct connects to their field RTU's.	
Network Options:	
None	
Benefits	
Displaces planned RTU and radio upgrade projects at Kawerau, Waiotahi, and Te Kaha. Provides more data including distance to fault and more faults event data. Enables obsolete RTU's to be retired. Will enable load control plants at Kawerau and Waiotahi to be converted to low cost VHF communications on existing pole top frequencies.	
Preferred Option:	
Implement ICCP conversion.	
Estimated Cost/Accuracy: \$130k, +- 30%	
Full scope of load control plant conversions not yet fully estimated.	
Projected Implementation Year: 2014	

Ref Numbers/ Name:	
502 - Manawahe, Herepuru Road and Pikowai Road Tie	
Description:	
Install tie line Manawahe, Herepuru Road and Pikowai Road Tie	
Constraint:	
Manawahe feeder is a long spur line without any reinforcement connections	
Network Options:	
Install new tie line 5.2km	Enables meshing of 10km of rural feeder. Somewhat rugged terrain. Some existing plantation forestry but due to be cleared soon.
Non-Network Options:	
Install Generation	Good alternative for planned maintenance but unless installed permanently not viable for quick restoration during faults.
Do Nothing	
Preferred Option:	
Yet to be engineered	
Estimated Cost/Accuracy:	
\$220,000 +- 30%	
Projected Implementation Year:	
2015-16	

Appendix D – Current Year Projects 2014-15

Project Number	Project Name	Project Cost (000)
I056	Opotiki Substation Development -Consenting & line design	\$216
I097	Gateway-33kV development & integration to CHH Y1	\$845
I116	Station Rd -Pirapai Feeder ABS 152 SCS	\$52
I268	Sub 23B051 Murupara Replace low test paper lead cable	\$38
I271	Cable replacement-Rex-Kope ZS RMC 12 to RMC108	\$149
I276	East Bank fire risk mitigation	\$27
I277	Kope-fire risk mitigation	\$27
I278	Kaingaroa Fire Risk Mitigation design	\$81
I289	Manawahe-Mclvor Rd tie line Stage 1	\$189
I291	Ohope- branch radio upgrade	\$104
I362	Sub 23B053 Murupara Replace low test paper lead cable	\$38
I363	Taneatua Fdr; Proposed Tie Line between 28S009 & 28S011	\$87
I364	Taneatua Fdr; Proposed Tie Line between 28T034 & 28T015	\$86
I365	Galatea Load Control Plant Subsitute Project	\$96
I382	Fonterra Protection Systems Upgrade	\$377
I417	SS DDO replacement program Y2	\$55
I419	ABS replacements	\$102
I439	Waiotahi- Waioeka SWER poles replacement -5 year program Y3	\$145
I440	Waiotahi -Hospital Feeder ABS850 (CB 1355)	\$57
I441	Waiotahi Factory feeder lines maintainence upgrade 2014	\$45
I442	Waiotahi-Toatoa Poles replacement- stage 1	\$99
I444	East Bank-Westbank-Thornton tie SCS 1504	\$52
I445	Plains tie -Westbank/Awaiti Feeder ABS 410 SCS	\$52
I446	East Bank -Westbank Feeder ABS 409 Sect	\$52
I447	Plains tie -Thornton/Awaiti Feeder ABS 408 SCS	\$52
I452	East Bank -Thornton Feeder ABS 242 Sect	\$52
I453	East Bank -Thornton Feeder ABS 302 Sect	\$52
I454	Plains tie -Thornton/Thornton Feeder ABS 709 SCS	\$52
I456	East Bank -Thornton Feeder 25L002 Fuse	\$3
I457	East Bank -Thornton Feeder 25L038 Fuse	\$3
I458	East Bank -Thornton Feeder ABS 1461 Fuse	\$3
I459	East Bank -Westbank Feeder ABS 759 Fuse	\$8
I463	Replace Tx 29M002 with a total pad CFC 200kVA unit	\$69
I464	Replace Tx 29M003 with a total pad CFCC 200kVA	\$106
I465	Complete tie cable between Harbour Rd and Ocean Rd	\$53
I469	Install fuse savers linked to SCADA	\$27
I470	Install fuse savers linked to SCADA	\$27
I476	East Bank -Thornton Feeder 26L005 Fuse	\$3
I478	East Bank -Thornton Feeder 26L020 Fuse	\$3
I479	East Bank -Thornton Feeder ABS 788 Fuse	\$3

I492	4th Poletop repeater	\$54
I493	Plateau feeder -Spencer Ave reconfigure- CCCC unit	\$92
I494	Waiotahi Factory feeder lines maintenance upgrade 2014	\$91
I495	Manawahe Feeder Upgrade stage 3	\$137
I496	Concrete pillar box replacements- 200 per year 2014 Stage 5	\$226
I497	Kawerau Undergrounding 2014	\$86
I498	Main St Edgecumbe -Pole damage risk mitigation	\$154
I499	Ohope -Harbour Feeder 776 CB	\$57
I500	City South Upgrade river crossing	\$35
I501	Hinemoa St South undergrounding	\$212
I502	Te Kaha Lines 2014	\$91
I503	Galatea Sub RTU retirement	\$79
I504	Galatea 33kV bus upgrade plus line CB's	\$259
I505	Plains- T2 - engineering and procurement	\$162
I506	Whakatane CBD Substation Land Purchase	\$270
I507	RMC10 Andelect + 28M101 500kVA replacement	\$88
I508	28M030-Arawara Rd replace with ground mount 300KVA	\$83
I509	State Highway Low Road Crossing remediation Y3	\$93
I510	23P050-NS Ponds-Transformer- transformer refurbish and bunding	\$24
I511	Waimana-Bryans Beach Cable Replacement	\$16
I512	Cable upgrade Kope CB K14 to RMC10- 157m	\$36
I513	Victoria St -Hub tie-ABS, 209, 27M108 replace with automated CFCC	\$102
I514	Outage Management System	\$86
I515	Valley Road Tie Kawerau	\$291
I516	Capacitor Banks Jolly Road Feeder	\$49
I517	Capacitor Banks Galatea Feeder	\$49

Appendix E –Planned Projects 2015-2018

Year Start	Project Name	Project Cost (000)
2015	1000 KVA Generator #2	\$687
	23B024 Murupara- replace 2 pole structure Ngatimanawa Rd	\$19
	23B058 Murupara- replace 2 pole structure Rewa Cr	\$19
	23H003-Minginui replace with ground mount 100KVA	\$31
	23P049-NS Ponds-Transformer- transformer refurbish and bunding	\$24
	24P010-Te Teko replace with ground mount 100KVA	\$31
	ABS replacements	\$95
	Concrete pillar box replacements- 200 per year 2015 Stage 6	\$226
	Edgecumbe 33 Bus Replacement	\$97
	Factory Feeder- Waioeka towers upgrade	\$155
	Gateway-33kV development & integration to CHH Y2	\$1302
	Hinemoa St North undergrounding	\$212
	Kaingaroa RTU upgrade	\$31
	Kaingaroa sub branch radios	\$47
	Kaingaroa- Upgrade 11kV bus	\$256
	Kaingaroa upgrade protection	\$93
	Kawerau Undergrounding 2015	\$86
	Kawerau ZS- Kawerau feeder cable fault level compliance 145m	\$35
	Kawerau ZS- Onepu feeder cable fault level compliance 140m	\$63
	LT end of run earthing project Y1	\$239
	MAG 1KIT 23S046 Replacement	\$79
	MAG 2KIT 22S068 Replacement	\$79
	Manawahe-McIvor Rd tie line Stage 2	\$144
	Ohope -Harbour Feeder ABS 1010 Sect	\$52
	Ohope -Harbour Feeder ABS 1418 DDO Sect	\$16
	Ohope -Harbour Feeder ABS 300017 Sect	\$52
	Ohope -Harbour Feeder ABS 360 Fuse	\$3
	Ohope -Harbour Feeder ABS 363 Sect	\$52
	Ohope -Harbour Feeder ABS 599 Fuse	\$3
	Ohope -Harbour Feeder ABS 669 DDO Sect	\$16
	Ohope -Harbour Feeder ABS 908 DDO Sect	\$16
	Ohope -Harbour Feeder ABS 911 CB	\$57
	Ohope -Harbour Feeder ABS 912 DDO Sect	\$16
	Ohope -Harbour Feeder ABS 913 DDO Sect	\$16
	Ohope -Harbour Feeder ABS 924 DDO Sect	\$16
	Ohope -Pohutukawa Feeder ABS 1022 Sect	\$52
	Ohope -Pohutukawa Feeder ABS 489 CB	\$57
	Ohope -Pohutukawa Feeder ABS 762 Fuse	\$3
	Opotiki 833 Tie CCC automated switch	\$87

	Opotiki Substation Development Y1 - Engineering	\$517
	Opotiki undergrounding 2015	\$44
	Plains -Awakeri Feeder ABS 1500a SCS	\$52
	Plains -Awakeri Feeder ABS 1500b SCS	\$52
	Plains -Awakeri Feeder ABS 250008 DDO Sect	\$16
	Plains -Awakeri Feeder ABS 376 CB	\$57
	Plains -Awakeri Feeder ABS 446 sect	\$52
	Plains -Awakeri Feeder ABS 447 DDO Sect	\$16
	Plains- reconfigure 33kV structure (per Mitton report)	\$106
	Reconductor to Dog 8km Gatalea feeder Te Teko Road Y1	\$98
	RMC2 Andelect Replacement	\$88
	Split West bank feeder off Rangeteiki feeder	\$183
	SS DDO replacement program Y3	\$55
	Station road- Upgrade tap change controllers	\$36
	Taneatua Fdr; Proposed Tie Line between 28T003 & 28T004	\$167
	Te Kaha Lines 2015	\$91
	Waiotahi -Factory Feeder ABS 881 Sect	\$52
	Waiotahi -Factory Feeder ABS 882 Sect	\$52
	Waiotahi Factory feeder lines maintenance upgrade 2015	\$91
	Waiotahi- Load control Plant upgrade	\$259
	Waiotahi- Replace Substation circuit breakers Y1	\$102
	Waiotahi- Replace Substation circuit breakers Y2	\$211
	Procure additional Historian tags	\$6
	Plains- T2 New	\$1056
2016	22S052 replace Transformer + RMU	\$78
	22S065 replace Transformer	\$57
	25M053-Edgecumbe replace with ground mount 200KVA	\$36
	2nd 33kV line into Aniwhenua	\$718
	33kV cable-St Joesphs Thermal upgrade to Kope (462m)	\$185
	33kV Tuhoe cable-Thermal upgrade to Kope (462m)	\$216
	33O009-Otara Rd replace with ground mount 100KVA	\$31
	4th Poletop repeater- Installation	\$216
	ABS replacements	\$95
	ABS375- SCADA switch- replace SCS	\$52
	Cable Replacement-RMC108-RMC4 -373m	\$79
	Cable Replacement-RMC4-28M083 : Rex	\$116
	Cable Upgrade Kope RMC10 to 27M112-. Replace RTE 27M112 -307m	\$148
	Generator connection sites Y1	\$115
	Kawerau Undergrounding 2016	\$86
	Kawerau ZS- Plateau feeder cable fault level compliance 262m	\$63
	MAG 3KIT 22S067 Replacement	\$79
	Manawahe-Mclvor Rd tie line Stage 3	\$227
	Opotiki Substation Development Y2-Site development	\$3235
	Opotiki undergrounding 2016	\$44

	Porcelain Fuse Holder Upgrades Y1	\$62
	RTE 28M073 Replacement	\$78
	RTE 28M084 Replacement	\$78
	SCADA computer hardware replacement- Servers	\$32
	SCADA System-smart network enhancements	\$310
	SCADA-Commerce St UPS Upgrade	\$54
	SS DDO replacement program Y4	\$55
	Te Kaha Lines 2016	\$91
	Tunui Place Undergrounding	\$76
	Underground Plains-East bank high capacity tie feeder	\$277
	Waiotahi Factory feeder lines maintenance upgrade 2016	\$91
	Waiotahi- Waioeka SWER poles replacement -5 year program Y5	\$97
	Waiotahi-Toatoa Poles replacement- stage 2	\$99
2017	22S018 Replace poletopm tx	\$56
	ABS replacements	\$95
	Generator connection sites Y2	\$115
	James St East King to Hinemoa (LT)	\$189
	Kawerau Undergrounding 2017	\$86
	Kawerau-Load Control Plant Upgrade	\$259
	MAG 3KIT 22S062 Replacement	\$79
	Manawahe Voltage regulator	\$207
	Opotiki Substation Development Y3-110kV line, Tx Y1	\$3774
	Opotiki undergrounding 2017	\$44
	Plains Load Control Plant Upgrade	\$264
	Porcelain Fuse Holder Upgrades Y2	\$62
	Reconductor to Dog 8km Gatalea feeder Te Teko Road Y2	\$98
	Replace transformer 33kV oil circuit breakers	\$164
	RMC3 SD3 + SDF + 500KVA Tx Replacement	\$78
	RMS Andelect FUSE SWITCH RMC9 Replacement	\$31
	RTE 28M069 Replacement	\$78
	RTE 28M074 Replacement	\$78
	RTE 28M081 Replacement	\$78
	RTE 28M085 Replacement	\$78
	RTE 28M087 Replacement	\$78
	SS DDO replacement program Y5	\$55
	Te Kaha Lines 2017	\$91
	Te Rahu South /WBM South Structures reconfigure	\$280
	Waiotahi Factory feeder lines maintenance upgrade 2017	\$91
2018	ABS replacements	\$95
	Express 33 kV Cable Gateway to CBD-4.25km	\$1150
	GEC RMU DDFD RMC67 /27M076 Replacement	\$82
	Generator connection sites Y3	\$115
	Kawerau Undergrounding 2018	\$86
	Lines upgrades	\$190

LT end of run earthing project Y2	\$239
MAG IKIT 22S069 Replacement	\$79
Opotiki Substation Development Y4-110kV line, Tx Y2	\$2049
Opotiki undergrounding 2018	\$44
Porcelain Fuse Holder Upgrades Y3	\$62
RTE 28M102 Replacement	\$78
RTE 28M108 Replacement	\$78
RTE 28M110 Replacement	\$78
RTE 28M112 Replacement	\$78
SS DDO replacement program Y6	\$55
Te Kaha Lines 2018	\$91
Te Rahu Central and Te Rahu North Structure Re-configuration & Maintenance	\$324
Waiotahi Factory feeder lines maintenance upgrade 2018	\$91
Whakatane Undergrounding 2018	\$31
Whakatane CBD Substation Y1	\$863
Poletop digital rollout Y1	\$108

Appendix F – Proposed Major Projects 2019-2024

Year Start	Project Name	Project Cost (000)
2019	Distribution Transformer Replacements	\$411
	Ground Fault Neutraliser-Galatea	\$362
	Kope 33kV indoor Conversion	\$1268
	Lines upgrades	\$521
	Whakatane CBD Substation Y2	\$2157
2020	Distribution Transformer Replacements	\$411
	Hillcrest 16mm Cable Upgrade 492m	\$255
	Kope/SR/Gateway 11kV distribution tie points automation (6 units)	\$335
	Large Distribution Transformers load and condition monitoring	\$372
	Lines upgrades	\$521
	Underground Harbour feeder Stage 1	\$847
	Upgrade Popoporo feeder Dog sections-3.4km	\$278
	WBMS 33kV Sub Transmission Capacity Upgrade	\$560
2021	Distribution Transformer Replacements	\$411
	Hawai Zone Substation	\$951
	Lines upgrades	\$521
	LV cable replacements	\$373
	Ohope-11kV Indoor Conversion	\$1150
	Opotiki Substation Development T2	\$1203
	Underground Harbour feeder Stage 2	\$1005
2022	2nd 33kV line to Ohope (8.7km)	\$863
	Distribution Transformer Replacements	\$411
	Lines upgrades	\$521
	LV cable replacements	\$373
	Manawahe Feeder upgrade to 33kV Y1	\$379
	Station Road Replace T1	\$1056
	Underground Harbour feeder Stage 3	\$773
	Underground Pohutukawa feeder Stage 1	\$717
2023	Distribution Transformer Replacements	\$411
	Lines upgrades	\$521
	LV cable replacements	\$373
	Manawahe Feeder upgrade to 33kV Y2	\$379
	Ohope-33kV Transformer T1 replacement	\$1162
	Station Road Replace T2	\$1056
	Underground Pohutukawa feeder Stage 2	\$726
2024	Distribution Transformer Replacements	\$411
	Lines replacements	\$2020
	Lines upgrades	\$521
	LV cable replacements	\$373
	Mobile 33/11kV Substation	\$1585

Appendix G – Certificate for Asset Management Plan

Certification for Year-beginning Disclosure – Asset Management Plan

Clause 2.9.1 of section 2.9

We, ROBERT TAIT and CHRISTOPHER BOYLE, being directors of HORIZON ENERGY DISTRIBUTION LIMITED certify that, having made all reasonable enquiry, to the best of our knowledge -

- a) the following attached information of HORIZON ENERGY DISTRIBUTION LIMITED prepared for the purposes of clause 2.6.1 and subclause 2.6.5(3) 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.

Dated: 25 day of March 2014



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ROBERT TAIT



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CHRISTOPHER BOYLE